Cost and Performance Baseline for Fossil Energy Plants

DOE/NETL-2007/1281

Volume 1: Bituminous Coal and Natural Gas to Electricity

Final Report (Original Issue Date, May 2007)

Revision 1, August 2007

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NETL Viewpoint

Background

The goal of Fossil Energy Research, Development and Demonstration (RD&D) is to ensure the availability of ultra-clean ("zero" emissions), abundant, low-cost, domestic electricity and energy (including hydrogen) to fuel economic prosperity and strengthen energy security. A broad portfolio of technologies is being developed within the Clean Coal Program to accomplish this objective. Ever increasing technological enhancements are in various stages of the research "pipeline," and multiple paths are being pursued to create a portfolio of promising technologies for development, demonstration, and eventual deployment. The technological progress of recent years has created a remarkable new opportunity for coal. Advances in technology are making it possible to generate power from fossil fuels with great improvements in the efficiency of energy use while at the same time significantly reducing the impact on the environment, including the long-term impact of fossil energy use on the Earth's climate. The objective of the Clean Coal RD&D Program is to build on these advances and bring these building blocks together into a new, revolutionary concept for future coal-based power and energy production.

Objective

To establish baseline performance and cost estimates for today's fossil energy plants, it is necessary to look at the current state of technology. Such a baseline can be used to benchmark the progress of the Fossil Energy RD&D portfolio. This study provides an accurate, independent assessment of the cost and performance for Pulverized Coal Combustion (PC), Integrated Gasification Combined Cycles (IGCC), and Natural Gas Combined Cycles (NGCC), all with and without carbon dioxide capture and storage assuming that the plants use technology available today.

Approach

The power plant configurations analyzed in this study were modeled using the ASPEN Plus modeling program. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, cost and performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of existing vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. O&M costs and the cost for transporting, storing and monitoring CO_2 in the cases with carbon capture were also estimated based on reference data and scaled estimates. Levelized cost of electricity (LCOE) was determined for all plants assuming investor owned utility financing. The initial results of this analysis were subjected to a significant peer review by industry experts, academia and government research and regulatory agencies. Based on the feedback from these experts, the report was updated both in terms of technical content and revised costs.

Results

This independent assessment of fossil energy plant cost and performance is considered to be the most comprehensive set of publicly available data to date. While input was sought from various technology vendors, the final assessment of performance and cost was determined independently, and may not represent the view of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors. Selection of system components and plant configurations from the range of potential options and the current rapid escalation in labor and material costs made it a challenge to develop state-of-the-art configurations and cost estimates. The rigorous expert technical review and systematic use of existing vendor quotes and project design/build data to develop the cost estimates in this report are believed to provide the most up-to-date performance and costs available in the public literature. Highlights of the study are the following:

- Coal-based plants using today's technology are capable of producing electricity at relatively high efficiencies of about 39%, HHV (without capture) on bituminous coal and at the same time meet or exceed current environmental requirements for criteria pollutants.

- Capital cost (total plant cost) for the non-capture plants are as follows: NGCC, $554/kW; PC, $1,562/kW (average); IGCC, $1,841/kW (average). With capture, capital costs are: NGCC, $1,172/kW; PC, $2,883/kW (average); IGCC, $2,496/kW (average).

- At fuel costs of $1.80/ton of coal and $6.75/MMBtu of natural gas, the 20-year levelized cost of electricity for the non-capture plants are: 64 mills/kWh (average) for PC, 68 mills/kWh for NGCC, and 78 mills/kWh (average) for IGCC.

- When today's technology for carbon capture and sequestration is integrated into these new power plants, the resultant 20-year levelized COE including the cost of CO_2 transport, storage and monitoring is: 97 mills/kWh for NGCC; 106 mills/kWh (average) for IGCC; and 117 mills/kWh (average) for PC. The cost of transporting CO_2 50 miles for storage in a geologic formation with over 30 years of monitoring is estimated to add about 4 mills/kWh. This represents only about 10% of the total carbon capture and sequestration costs.

- A sensitivity study on natural gas price reveals that the COE for IGCC is equal to that of NGCC at $7.73/MMBtu, and for PC, the COE is equivalent to NGCC at a gas price of $8.87/MMBtu. In terms of capacity factor, when the NGCC drops below 60 percent, such as in a peaking application, the resulting COE is higher than that of an IGCC operating at baseload (80 percent capacity factor).

Fossil Energy RD&D is aimed at improving the performance and cost of clean coal power systems including the development of new approaches to capture and sequester greenhouse gases. Improved efficiencies and reduced costs are required to improve the competitiveness of these systems in today's market and regulatory environment as well as in a carbon constrained scenario. The results of this analysis provide a starting point from which to measure the progress of RD&D achievements.

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ACKNOWLEDGEMENTS

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LIST OF ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
AC	Alternating current
AEO	Annual Energy Outlook
AGR	Acid gas removal
ANSI	American National Standards Institute
ASU	Air separation unit
BACT	Best available control technology
BEC	Bare erected cost
BFD	Block flow diagram
Btu	British thermal unit
Btu/h	British thermal unit per hour
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
Btu/scf	British thermal unit per standard cubic foot
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCF	Capital Charge Factor
CDR	Carbon Dioxide Recovery
CF	Capacity factor
CFM	Cubic feet per minute
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
cm	Centimeter
CO_2	Carbon dioxide
COE	Cost of electricity
CoP	ConocoPhillips
COR	Contracting Officer's Representative
COS	Carbonyl sulfide
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CTG	Combustion Turbine-Generator
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DI	De-ionized
Dia.	Diameter
DLN	Dry low NOx
DOE	Department of Energy
EAF	Equivalent availability factor

E-Gas^{TM}	ConocoPhillips gasifier technology
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPRI	Electric Power Research Institute
EPCM	Engineering/Procurement/Construction Management
EU	European Union
ESP	Electrostatic precipitator
FD	Forced draft
FERC	Federal Energy Regulatory Commission
FG	Flue gas
FGD	Flue gas desulfurization
FOAK	First of a kind
FRP	Fiberglass-reinforced plastic
ft	Foot, Feet
ft, w.g.	Feet of water gauge
GADS	Generating Availability Data System
gal	Gallon
gal/MWh	Gallon per megawatt hour
GDP	Gross domestic product
GEE	GE Energy
gpm	Gallons per minute
gr/100 scf	grains per one hundred standard cubic feet
GT	Gas turbine
h	Hour
H_2	Hydrogen
H_2SO_4	Sulfuric acid
HAP	Hazardous air pollutant
HCl	Hydrochloric acid
Hg	Mercury
HDPE	High density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HSS	Heat stable salts
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
ICR	Information Collection Request
ID	Induced draft
IGVs	Inlet guide vanes
In. H_2O	Inches water

In. Hga	Inches mercury (absolute pressure)
In. W.C.	Inches water column
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated gasification combined cycle
IGV	Inlet guide vanes
IOU	Investor-owned utility
IP	Intermediate pressure
IPM	Integrated Planning Model
IPP	Independent power producer
ISO	International Standards Organization
KBR	Kellogg, Brown and Root, a subsidiary of Halliburton
kg/GJ	Kilogram per gigajoule
kg/h	Kilogram per hour
kJ	Kilojoules
kJ/h	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
KO	Knockout
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/h	Pounds per hour
lb/ft^2	Pounds per square foot
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
lb/TBtu	Pounds per trillion British thermal units
LCOE	Levelized cost of electricity
LF_{Fn}	Levelization factor for category n fixed operating cost
LF_{Vn}	Levelization factor for category n variable operating cost
LGTI	Louisiana Gasification Technology, Inc.
LHV	Lower heating value
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
m	Meters
m/min	Meters per minute
m^3/min	Cubic meter per minute
MAF	Moisture and Ash Free
MCR	Maximum continuous rate
MDEA	Methyldiethanolamine

MEA	Monoethanolamine
MHz	Megahertz
MJ/Nm^3	Megajoule per normal cubic meter
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/h	Million British thermal units (also shown as 10^6 Btu) per hour
MMkJ	Million kilojoules (also shown as 10^6 kJ)
MMkJ/h	Million kilojoules (also shown as 10^6 kJ) per hour
MNQC	Multi Nozzle Quiet Combustor
MPa	Megapascals
MVA	Mega volt-amps
MWe	Megawatts electric
MWh	Megawatt-hour
MWt	Megawatts thermal
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NFPA	National Fire Protection Association
NGCC	Natural gas combined cycle
Nm^3	Normal cubic meter
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation and maintenance
OC_{Fn}	Category n fixed operating cost for the initial year of operation
OC_{Vnq}	Category n variable operating cost for the initial year of operation
OD	Outside diameter
OFA	Overfire air
OP/VWO	Over pressure/valve wide open
OSHA	Occupational Safety and Health Administration
OTR	Ozone transport region
PA	Primary air
PAC	Powdered activated carbon
PC	Pulverized coal
PF	Power Factor
PM	Particulate matter
PM_{10}	Particulate matter measuring 10 µm or less
POTW	Publicly Owned Treatment Works
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
PPS	Polyphenylensulfide

PRB	Powder River Basin coal region
PSA	Pressure Swing Adsorption
PSD	Prevention of Significant Deterioration
psia	Pounds per square inch absolute
psid	Pounds per square inch differential
psig	Pounds per square inch gage
PTFE	Teflon (Polytetrafluoroethylene)
Qty	Quantity
RDS	Research and Development Solutions, LLC
RH	Reheater
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
Sch.	Schedule
scmh	Standard cubic meter per hour
SCOT	Shell Claus Off-gas Treating
SCR	Selective catalytic reduction
SG	Specific gravity
SGC	Synthesis gas cooler
SGS	Sour gas shift
SIP	State implementation plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
SRU	Sulfur recovery unit
SS	Stainless steel
SS Amine	SS Specialty Amine
STG	Steam turbine generator
TCR	Total capital requirement
TEWAC	Totally Enclosed Water-to-Air Cooled
TGTU	Tail gas treating unit
Tonne	Metric Ton (1000 kg)
TPC	Total plant cost
TPD	Tons per day
TPH	Tons per hour
TPI	Total plant investment
TS&M	Transport, storage and monitoring
V-L	Vapor Liquid portion of stream (excluding solids)
vol%	Volume percent
WB	Wet bulb
wg	Water gauge
wt%	Weight percent
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule

EXECUTIVE SUMMARY

The objective of this report is to present an accurate, independent assessment of the cost and performance of fossil energy power systems, specifically integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants, using a consistent technical and economic approach that accurately reflects current market conditions for plants starting operation in 2010. This is Volume 1 of a three volume report. The three volume series consists of the following:

- Volume 1: Electricity production using bituminous coal for coal-based technologies
- Volume 2: Synthetic natural gas production and repowering using a variety of coal types
- Volume 3: Electricity production from low rank coal (PC and IGCC)

The cost and performance of the various fossil fuel-based technologies will most likely determine which combination of technologies will be utilized to meet the demands of the power market. Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Fuel prices
- Cost of electricity (COE)
- Availability, reliability and environmental performance
- Current and potential regulation of air, water, and solid waste discharges from fossil-fueled power plants
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE's) Clean Coal Programs

Twelve power plant configurations were analyzed as listed in Exhibit ES-1. The list includes six IGCC cases utilizing General Electric Energy (GEE), ConocoPhillips (CoP), and Shell gasifiers each with and without CO_2 capture; four PC cases, two subcritical and two supercritical, each with and without CO_2 capture; and two NGCC plants with and without CO_2 capture. Two additional cases were originally included in this study and involve production of synthetic natural gas (SNG) and the repowering of an existing NGCC facility using SNG. The two SNG cases were subsequently moved to Volume 2 of this report resulting in the discontinuity of case numbers (1-6 and 9-14). The two SNG cases are now cases 2 and 2a in Volume 2.

While input was sought from various technology vendors, the final assessment of performance and cost was determined independently, and may not represent the views of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors.

The methodology included performing steady-state simulations of the various technologies using the Aspen Plus (Aspen) modeling program. The resulting mass and energy balance data from the Aspen model were used to size major pieces of equipment. These equipment sizes formed the basis for cost estimating. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgement. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Baseline fuel costs for this analysis were determined using data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007. The first year (2010) costs used are $1.71/MMkJ ($1.80/MMBtu) for coal (Illinois No. 6) and $6.40/MMkJ ($6.75/MMBtu) for natural gas, both on a higher heating value (HHV) basis and in 2007 U.S. dollars.

Exhibit ES-1 Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H_2S Separation/ Removal	Sulfur Removal/ Recovery	CO_2 Separa-tion
1	IGCC	1800/1050/1050	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	
2	IGCC	1800/1000/1000	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
3	IGCC	1800/1050/1050	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	
4	IGCC	1800/1000/1000	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
5	IGCC	1800/1050/1050	2 x Advanced F Class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	
6	IGCC	1800/1000/1000	2 x Advanced F Class	Shell	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
--	--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--	--
9	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	
10	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Amine Absorber
11	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	
12	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Amine Absorber
13	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air			
14	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air			Amine Absorber

All plant configurations are evaluated based on installation at a greenfield site. Since these are state-of-the-art plants, they will have higher efficiencies than the average power plant population. Consequently, these plants would be expected to be near the top of the dispatch list and the study capacity factor is chosen to reflect the maximum availability demonstrated for the specific plant type, i.e. 80 percent for IGCC and 85 percent for PC and NGCC configurations. Since variations in fuel costs and other factors can influence dispatch order and capacity factor, sensitivity of levelized COE to capacity factor is evaluated and presented later in this Executive Summary (Exhibit ES-10) and in the body of the report.

The nominal net plant output for this study is set at 550 MW. The actual net output varies between technologies because the combustion turbines in the IGCC and NGCC cases are manufactured in discrete sizes, but the boilers and steam turbines in the PC cases are readily available in a wide range of capacities. The result is that all of the PC cases have a net output of 550 MW, but the IGCC cases have net outputs ranging from 517 to 640 MW. The range in IGCC net output is caused by the much higher auxiliary load imposed in the CO_2 capture cases, primarily due to CO_2 compression, and the need for extraction steam in the water-gas shift reactions, which reduces steam turbine output. Higher auxiliary load and extraction steam requirements can be accommodated in the PC cases (larger boiler and steam turbine) but not in the IGCC cases where it is impossible to maintain a constant net output from the steam cycle given the fixed input (combustion turbine). Likewise, the two NGCC cases have a net output of 560 and 482 MW because of the combustion turbine constraint.

Exhibit ES-2 shows the cost, performance and environmental profile summary for all cases. The results are discussed below in the following order:

- Performance (efficiency and raw water usage)
- Cost (total plant cost and levelized cost of electricity)
- Environmental profile

PERFORMANCE

ENERGY EFFICIENCY

The net plant efficiency (HHV basis) for all 12 cases is shown in Exhibit ES-3. The primary conclusions that can be drawn are:

- The NGCC with no CO_2 capture has the highest net efficiency of the technologies modeled in this study with an efficiency of 50.8 percent.
- The NGCC case with CO_2 capture results in the highest efficiency (43.7 percent) among all of the capture technologies.
- The NGCC with CO_2 capture results in an efficiency penalty of 7.1 absolute percent, relative to the non-capture case. The NGCC penalty is less than for the PC cases because natural gas is less carbon intensive than coal, and there is less CO_2 to capture and to compress for equal net power outputs.
- The energy efficiency of the IGCC non-capture cases is as follows: the dry-fed Shell gasifier (41.1 percent), the slurry-fed, two-stage CoP gasifier (39.3 percent) and the slurry-fed, single-stage GEE gasifier (38.2 percent).
- When CO_2 capture is added to the IGCC cases, the energy efficiency of all three cases is almost equal, ranging from 31.7 percent for CoP to 32.5 percent for GEE, with Shell intermediate at 32.0 percent.

Exhibit ES-2 Cost and Performance Summary and Environmental Profile for All Cases

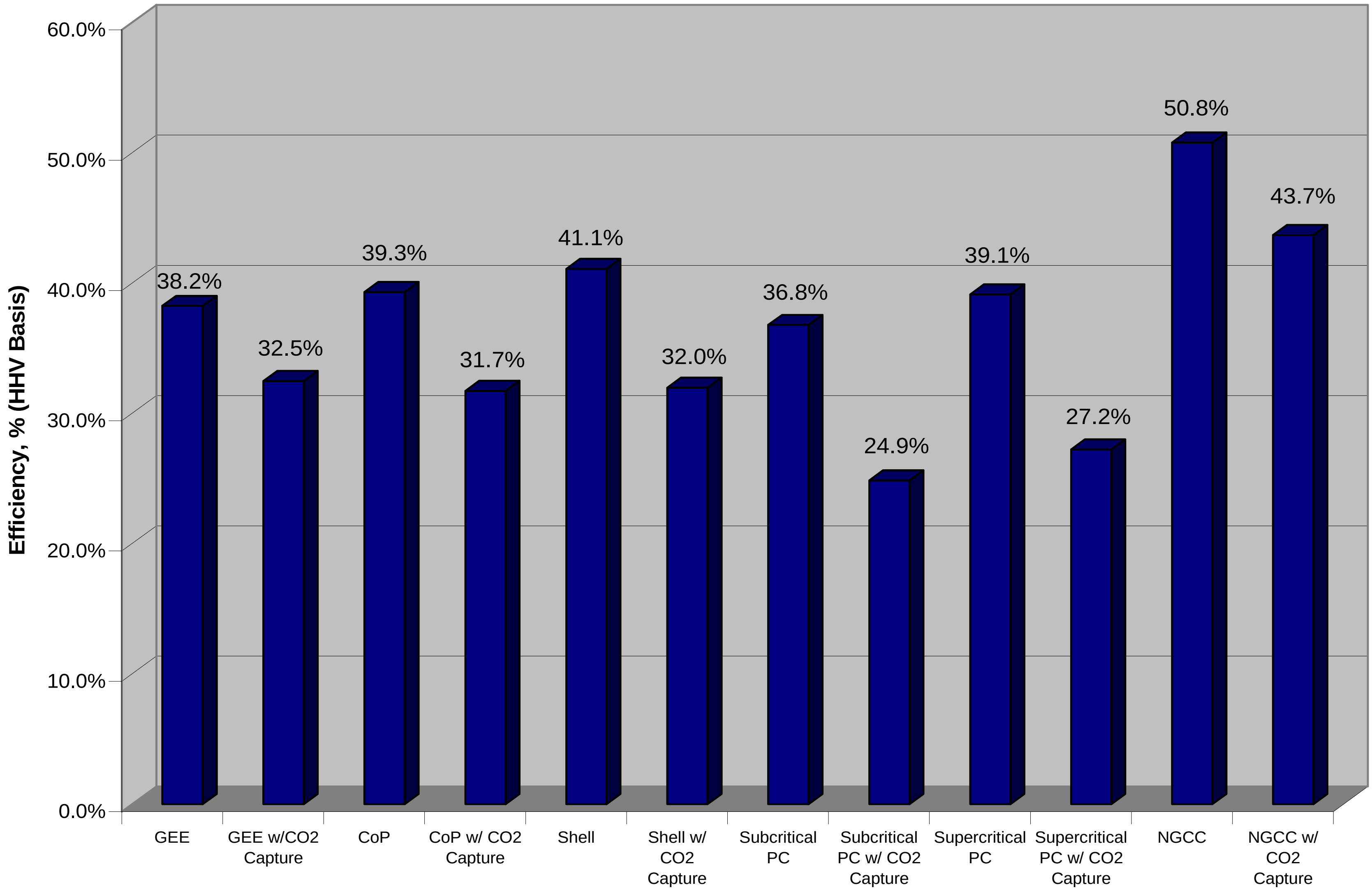
	Integrated Gasification Combined Cycle						Pulverized Coal Boiler				NGCC	
	GEE		CoP		Shell		PC Subcritical		PC Supercritical		Advanced F Class	
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14
CO_2 Capture	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes
Gross Power Output (kW_e)	770,350	744,960	742,510	693,840	748,020	693,555	583,315	679,923	580,260	663,445	570,200	520,090
Auxiliary Power Requirement (kW_e)	130,100	189,285	119,140	175,600	112,170	176,420	32,870	130,310	30,110	117,450	9,840	38,200
Net Power Output (kW_e)	640,250	555,675	623,370	518,240	635,850	517,135	550,445	549,613	550,150	545,995	560,360	481,890
Coal Flowrate (lb/hr)	489,634	500,379	463,889	477,855	452,620	473,176	437,699	646,589	411,282	586,627	N/A	N/A
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	165,182	165,182
HHV Thermal Input (kW_{th})	1,674,044	1,710,780	1,586,023	1,633,771	1,547,493	1,617,772	1,496,479	2,210,668	1,406,161	2,005,660	1,103,363	1,103,363
Net Plant HHV Efficiency (%)	38.2%	32.5%	39.3%	31.7%	41.1%	32.0%	36.8%	24.9%	39.1%	27.2%	50.8%	43.7%
Net Plant HHV Heat Rate (Btu/kW-hr)	8,922	10,505	8,681	10,757	8,304	10,674	9,276	13,724	8,721	12,534	6,719	7,813
Raw Water Usage, gpm	4,003	4,579	3,757	4,135	3,792	4,563	6,212	12,187	5,441	10,444	2,511	3,901
Total Plant Cost ($ x 1,000)	1,160,919	1,328,209	1,080,166	1,259,883	1,256,810	1,379,524	852,612	1,591,277	866,391	1,567,073	310,710	564,628
Total Plant Cost ($/kW)	1,813	2,390	1,733	2,431	1,977	2,668	1,549	2,895	1,575	2,870	554	1,172
LCOE (mills/kWh)[1]	78.0	102.9	75.3	105.7	80.5	110.4	64.0	118.8	63.3	114.8	68.4	97.4
CO_2 Emissions (lb/hr)	1,123,781	114,476	1,078,144	131,328	1,054,221	103,041	1,038,110	152,975	975,370	138,681	446,339	44,634
CO_2 Emissions (tons/year) @ CF[1]	3,937,728	401,124	3,777,815	460,175	3,693,990	361,056	3,864,884	569,524	3,631,301	516,310	1,661,720	166,172
CO_2 Emissions (tonnes/year) @ CF[1]	3,572,267	363,896	3,427,196	417,466	3,351,151	327,546	3,506,185	516,667	3,294,280	468,392	1,507,496	150,750
CO_2 Emissions (lb/MMBtu)	197	19.6	199	23.6	200	18.7	203	20.3	203	20.3	119	11.9
CO_2 Emissions (lb/MWh)[2]	1,459	154	1,452	189	1,409	149	1,780	225	1,681	209	783	85.8
CO_2 Emissions (lb/MWh)[3]	1,755	206	1,730	253	1,658	199	1,886	278	1,773	254	797	93
SO_2 Emissions (lb/hr)	73	56	68	48	55	58	433	Negligible	407	Negligible	Negligible	Negligible
SO_2 Emissions (tons/year) @ CF[1]	254	196	237	167	194	204	1,613	Negligible	1,514	Negligible	Negligible	Negligible
SO_2 Emissions (tonnes/year) @ CF[1]	231	178	215	151	176	185	1,463	Negligible	1,373	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MMBtu)	0.0127	0.0096	0.0125	0.0085	0.0105	0.0105	0.0848	Negligible	0.0847	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MWh)[2]	0.0942	0.0751	0.0909	0.0686	0.0739	0.0837	0.7426	Negligible	0.7007	Negligible	Negligible	Negligible
NOx Emissions (lb/hr)	313	273	321	277	309	269	357	528	336	479	34	34
NOx Emissions (tons/year) @ CF[1]	1,096	955	1,126	972	1,082	944	1,331	1,966	1,250	1,784	127	127
NOx Emissions (tonnes/year) @ CF[1]	994	867	1,021	882	982	856	1,207	1,783	1,134	1,618	115	115
NOx Emissions (lb/MMBtu)	0.055	0.047	0.059	0.050	0.058	0.049	0.070	0.070	0.070	0.070	0.009	0.009
NOx Emissions (lb/MWh)[2]	0.406	0.366	0.433	0.400	0.413	0.388	0.613	0.777	0.579	0.722	0.060	0.066
PM Emissions (lb/hr)	41	41	38	40	37	39	66	98	62	89	Negligible	Negligible
PM Emissions (tons/year) @ CF[1]	142	145	135	139	131	137	247	365	232	331	Negligible	Negligible
PM Emissions (tonnes/year) @ CF[1]	129	132	122	126	119	125	224	331	211	300	Negligible	Negligible
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0130	0.0130	0.0130	0.0130	Negligible	Negligible
PM Emissions (lb/MWh)[2]	0.053	0.056	0.052	0.057	0.050	0.057	0.114	0.144	0.107	0.134	Negligible	Negligible
Hg Emissions (lb/hr)	0.0033	0.0033	0.0031	0.0032	0.0030	0.0032	0.0058	0.0086	0.0055	0.0078	Negligible	Negligible
Hg Emissions (tons/year) @ CF[1]	0.011	0.012	0.011	0.011	0.011	0.011	0.022	0.032	0.020	0.029	Negligible	Negligible
Hg Emissions (tonnes/year) @ CF[1]	0.010	0.011	0.010	0.010	0.010	0.010	0.020	0.029	0.019	0.026	Negligible	Negligible
Hg Emissions (lb/TBtu)	0.571	0.571	0.571	0.571	0.571	0.571	1.14	1.14	1.14	1.14	Negligible	Negligible
Hg Emissions (lb/MWh)[2]	4.24E-06	4.48E-06	4.16E-06	4.59E-06	4.03E-06	4.55E-06	1.00E-05	1.27E-05	9.45E-06	1.18E-05	Negligible	Negligible

[1] Capacity factor is 80% for IGCC cases and 85% for PC and NGCC cases

[2] Value is based on gross output

[3] Value is based on net output

Exhibit ES-3 Net Plant Efficiency (HHV Basis)



- Supercritical PC without CO_2 capture has an efficiency of 39.1 percent, which is nearly equal to the average of the three non-capture IGCC technologies. Subcritical PC has an efficiency of 36.8 percent, which is the lowest of all the non-capture cases in the study.
- The addition of CO_2 capture to the PC cases (Fluor's Econamine FG Plus process) has a much greater impact on efficiency than CO_2 capture in the IGCC cases. This is primarily because the low partial pressure of CO_2 in the flue gas from a PC plant requires a chemical absorption process rather than physical absorption. For chemical absorption processes, the regeneration requirements are much more energy intensive. Thus the energy penalty for both subcritical and supercritical PC is 11.9 absolute percent resulting in post-capture efficiencies of 24.9 percent and 27.2 percent, respectively.

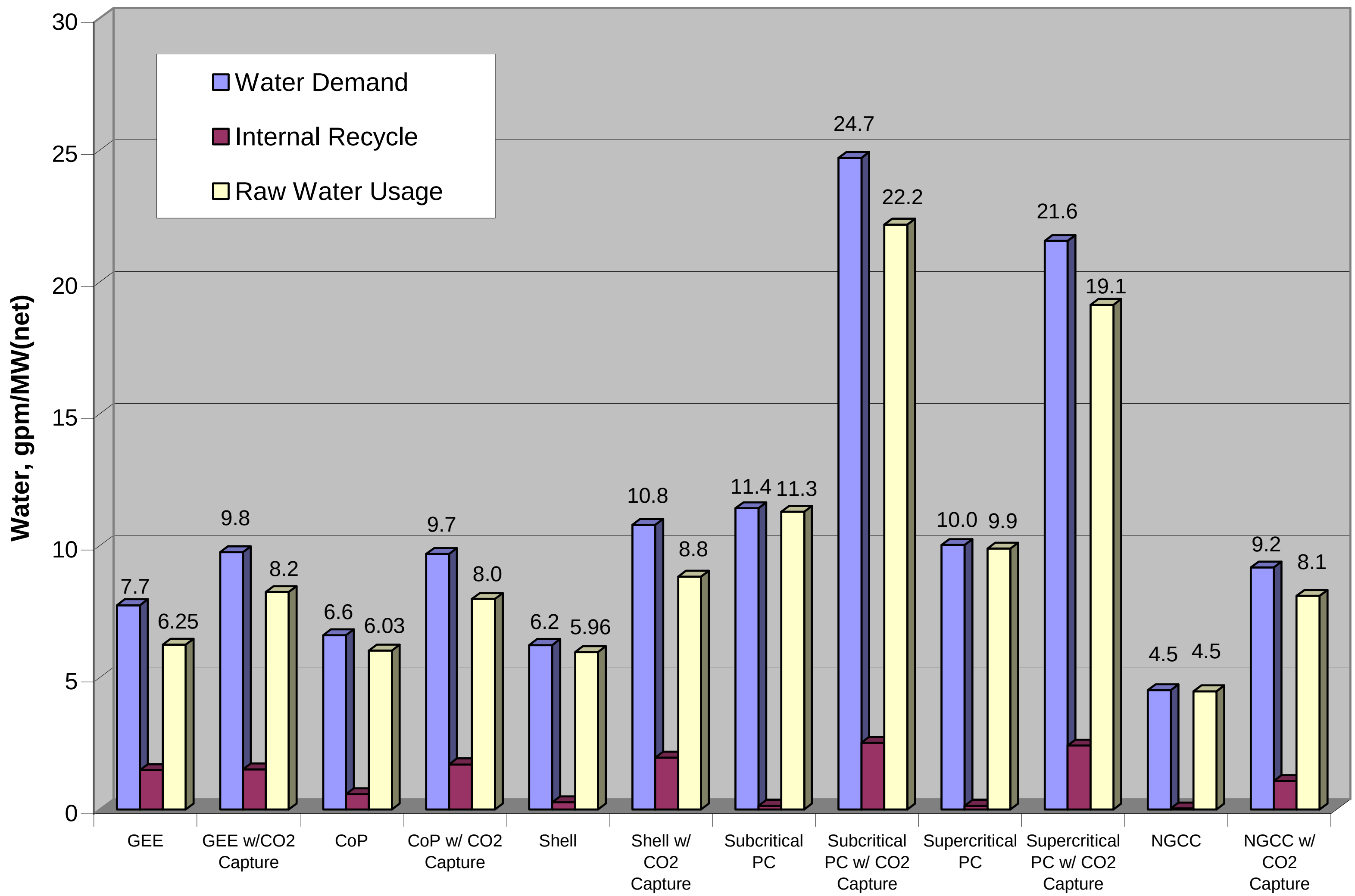
WATER USE

Three water values are presented for each technology in Exhibit ES-4: water demand, internal recycle and raw water usage. Each value is normalized by net output. Demand is the amount of water required to satisfy a particular process (slurry, quench, FGD makeup, etc.) and internal recycle is water available within the process (boiler feedwater blowdown, condensate, etc.). Raw water usage is the difference between demand and recycle, and it represents the overall impact of the process on the water source, which in this study is considered to be 50 percent from groundwater (wells) and 50 percent from a municipal source. All plants are equipped with evaporative cooling towers, and all process blowdown streams are assumed to be treated and recycled to the cooling tower. The primary conclusions that can be drawn are:

- In all cases the primary water consumer is cooling tower makeup, which ranges from 71 to 99 percent of the total raw water usage.
- Among non-capture cases, NGCC requires the least amount of raw water makeup, followed by IGCC and PC. If an average raw water usage for the three IGCC cases and two PC cases is used, the relative normalized raw water usage for the technologies is 2.4:1.4:1.0 (PC:IGCC:NGCC). The relative results are as expected given the much higher steam turbine output in the PC cases which results in higher condenser duties, higher cooling water requirements and ultimately higher cooling water makeup. The IGCC cases and the NGCC case have comparable steam turbine outputs, but IGCC requires additional water for coal slurry (GEE and CoP), syngas quench (GEE), humidification (CoP and Shell), gasifier steam (Shell), and slag handling (all cases), which increases the IGCC water demand over NGCC.
- Among capture cases, the raw water requirement increases (relative to non-capture cases) much more dramatically for the PC and NGCC cases than for IGCC cases because of the large cooling water demand of the Econamine process which results in much greater cooling water makeup requirements. If average water usage values are used for IGCC and PC cases, the relative normalized raw water usage for the technologies in CO_2 capture cases is 2.6:1.03:1.0 (PC:IGCC:NGCC). The NGCC CO_2 capture case still has the lowest water requirement, but the difference between it and the average of the three IGCC cases is minimal.

- CO_2 capture increases the average raw water usage for all three technologies evaluated, but the increase is lowest for the IGCC cases. The average normalized raw water usage for the three IGCC cases increases by about 37 percent due primarily to the need for additional water in the syngas to accomplish the water gas shift reaction and the increased auxiliary load. With the addition of CO_2 capture, PC normalized raw water usage increases by 95 percent and NGCC by 81 percent. The large cooling water demand of the Econamine process drives this substantial increase for PC and NGCC.

Exhibit ES-4 Water Demand and Usage



COST RESULTS

TOTAL PLANT COST

The total plant cost (TPC) for each technology was determined through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Owner's costs are not included.

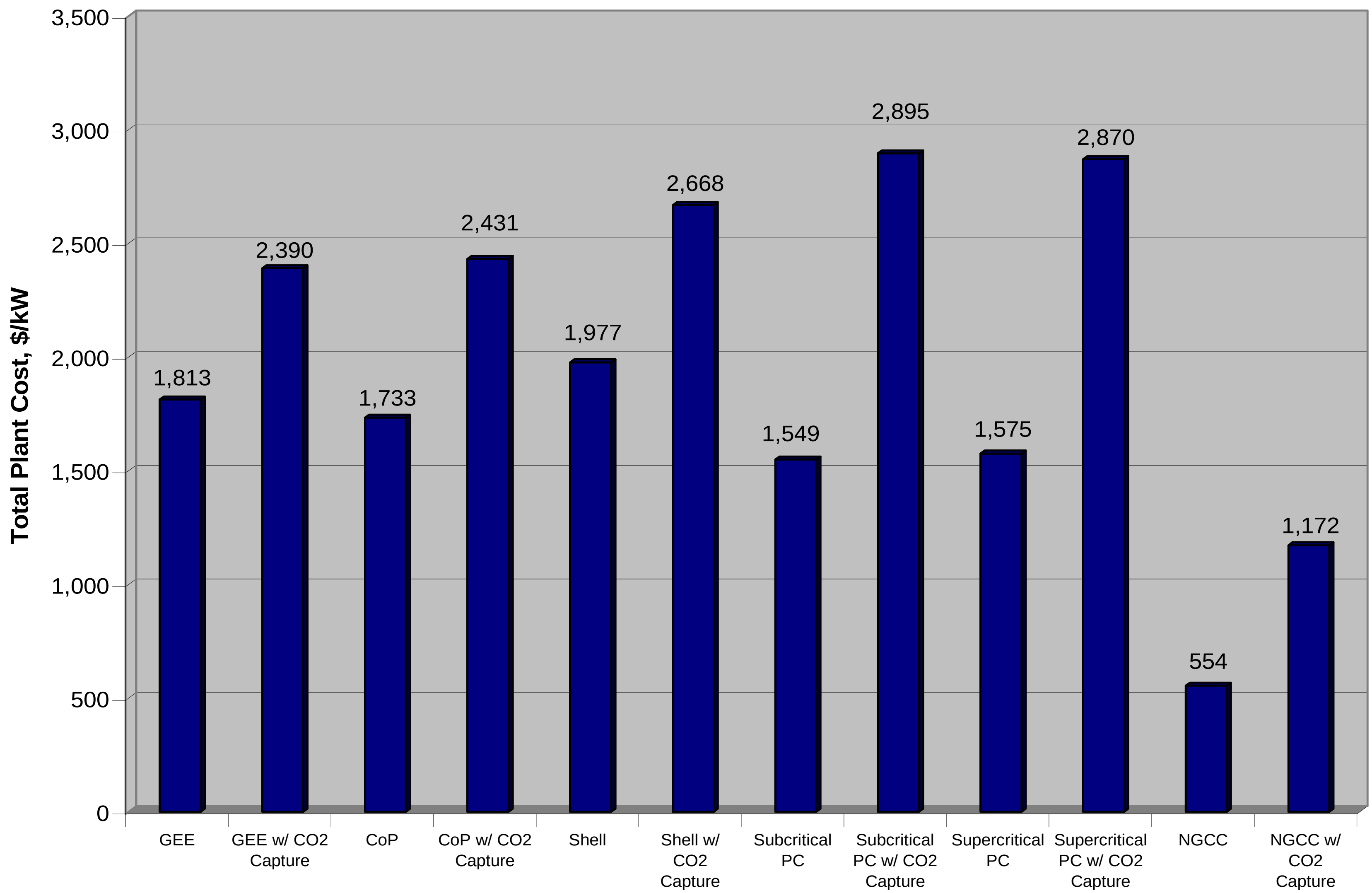
The cost estimates carry an accuracy of ±30 percent, consistent with the screening study level of design engineering applied to the various cases in this study. The value of the study lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

Project contingencies were added to the Engineering/Procurement/Construction Management (EPCM) capital accounts to cover project uncertainty and the cost of any additional equipment that would result from a detailed design. The contingencies represent costs that are expected to occur. Each bare erected cost (BEC) account was evaluated against the level of estimate detail and field experience to determine project contingency. Process contingency was added to cost account items that were deemed to be first-of-a-kind or posed significant risk due to lack of operating experience. The cost accounts that received a process contingency include:

- Slurry Prep and Feed – 5 percent on GE IGCC cases - systems are operating at approximately 800 psia as compared to 600 psia for the other IGCC cases.
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases – next-generation commercial offering and integration with the power island.
- Two Stage Selexol – 20 percent on all IGCC capture cases – lack of operating experience at commercial scale in IGCC service.
- Mercury Removal – 5 percent on all IGCC cases – minimal commercial scale experience in IGCC applications.
- CO_2 Removal System – 20 percent on all PC/NGCC capture cases - post-combustion process unproven at commercial scale for power plant applications.
- Combustion Turbine Generator – 5 percent on all IGCC non-capture cases – syngas firing and ASU integration; 10 percent on all IGCC capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all IGCC accounts and 5 percent on the PC and NGCC capture cases – integration issues.

The normalized total plant cost (TPC) for each technology is shown in Exhibit ES-5. The following conclusions can be drawn:

Exhibit ES-5 Total Plant Cost



- Among the non-capture cases, NGCC has the lowest capital cost at $554/kW followed by PC with an average cost of $1,562/kW and IGCC with an average cost of $1,841/kW. The average IGCC cost is 18 percent greater than the average PC cost. The process contingency for the IGCC cases ranges from $44-51/kW while there is zero process contingency for the PC and NGCC non-capture cases. The differential between IGCC and PC is reduced to 15 percent when process contingency is eliminated.
- The three IGCC non-capture cases have a capital cost ranging from $1,733/kW (CoP) to $1,977/kW (Shell) with GEE intermediate at $1,813/kW.
- Among the capture cases, NGCC has the lowest capital cost, despite the fact that the capital cost of the NGCC capture case is more than double the cost of the non-capture case at $1,172/kW.
- Among the capture cases, the PC cases have the highest capital cost at an average of $2,883/kW. The average capital cost for IGCC CO_2 capture cases is $2,496/kW, which is 13 percent less than the average of the PC cases. The process contingency for the IGCC capture cases ranges from $101-105/kW, for the PC cases from $99-104/kW and $59/kW for the NGCC case. If process contingency is removed from the PC and IGCC cases, the cost of IGCC is 16 percent less than PC.

LEVELIZED COST OF ELECTRICITY (LCOE)

The 20-year LCOE was calculated for each case using the economic parameters shown in Exhibit ES-6. The cases were divided into two categories, representing high risk and low risk projects undertaken at investor owned utilities. High risk projects are those in which commercial scale operating experience is limited. The IGCC cases (with and without CO_2 capture) and the PC and NGCC cases with CO_2 capture were considered to be high risk. The non-capture PC and NGCC cases were considered to be low risk.

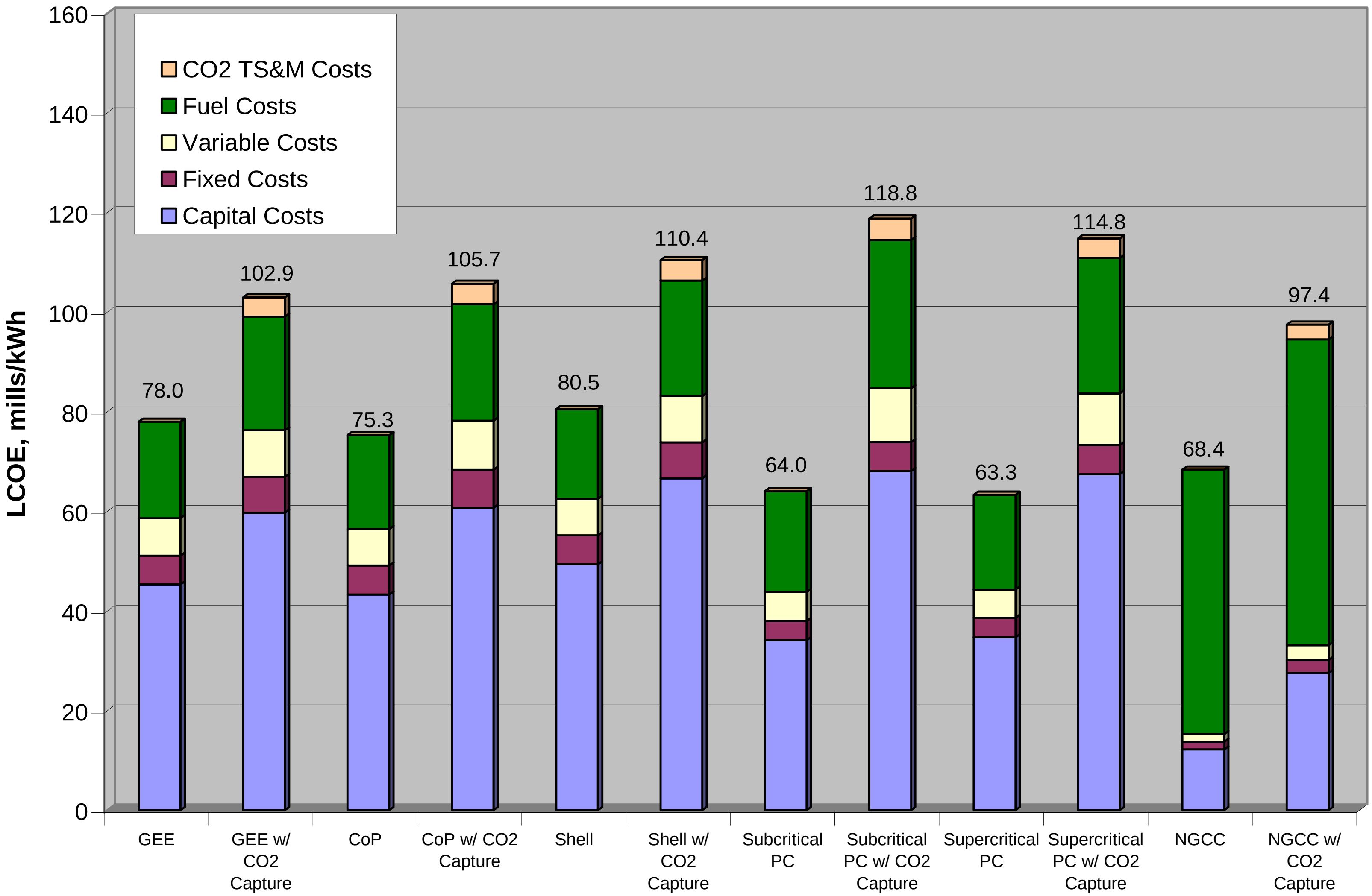
Exhibit ES-6 Economic Parameters Used to Calculate LCOE

	High Risk	Low Risk
Capital Charge Factor	0.175	0.164
Coal Levelization Factor	1.2022	1.2089
Natural Gas Levelization Factor	1.1651	1.1705
Levelization for all other O&M	1.1568	1.1618

The LCOE results are shown in Exhibit ES-7 with the capital cost, fixed operating cost, variable operating cost and fuel cost shown separately. In the capture cases the CO_2 transport, storage and monitoring (TS&M) costs are also shown as a separate bar segment. The following conclusions can be drawn:

- In non-capture cases, PC plants have the lowest LCOE (average 63.7 mills/kWh), followed by NGCC (68.4 mills/kWh) and IGCC (average 77.9 mills/kWh).

Exhibit ES-7 LCOE By Cost Component



- In capture cases, NGCC plants have the lowest LCOE (97.4 mills/kWh), followed by IGCC (average 106.3 mills/kWh) and PC (average 116.8 mills/kWh).
- The LCOE for the three IGCC non-capture cases ranges from 75.3 mills/kWh (CoP) to 80.5 mills/kWh (Shell) with GEE in between at 78.0 mills/kWh. The study level of accuracy is insufficient to distinguish between the LCOE of the three IGCC technologies.
- Non-capture supercritical PC has an LCOE of 63.3 mills/kWh and subcritical PC is 64.0 mills/kWh, an insignificant difference given the level of accuracy of the study estimate.
- PC is the most expensive technology with CO_2 capture, 10 percent higher than IGCC and nearly 20 percent higher than NGCC.
- The capital cost component of LCOE is between 53 and 62 percent in all IGCC and PC cases. It represents only 18 percent of LCOE in the NGCC non-capture case and 28 percent in the CO_2 capture case.
- The fuel component of LCOE ranges from 21-25 percent for the IGCC cases and the PC CO_2 capture cases. For the PC non-capture cases the fuel component varies from 30-32 percent. The fuel component is 78 percent of the total in the NGCC non-capture case and 63 percent in the CO_2 capture case.
- CO_2 transport, storage and monitoring is estimated to add 4 mills/kWh to the LCOE, which is less than 4 perecent of the total LCOE for all capture cases.

Exhibit ES-8 shows the LCOE sensitivity to fuel costs for the non-capture cases. The solid line is the LCOE of NGCC as a function of natural gas cost. The points on the line represent the natural gas cost that would be required to make the LCOE of NGCC equal to PC or IGCC at a given coal cost. The coal prices shown ($1.35, $1.80 and $2.25/MMBtu) represent the baseline cost and a range of ±25 percent around the baseline. As an example, at a coal cost of $1.80/MMBtu, the LCOE of PC equals NGCC at a natural gas price of $6.15/MMBtu.

Another observation from Exhibit ES-8 is that the LCOE of IGCC at a coal price of $1.35/MMBtu is greater than PC at a coal price of $2.25/MMBtu, due to the higher capital cost of IGCC and its relative insensitivity to fuel price. For example, a decrease in coal cost of 40 percent (from $2.25 to $1.35/MMBtu) results in an IGCC LCOE decrease of only 13 percent (82.5 to 73.2 mills/kWh).

Fuel cost sensitivity is presented for the CO_2 capture cases in Exhibit ES-9. Even at the lowest coal cost shown, the LCOE of NGCC is less than IGCC and PC at the baseline natural gas price of $6.75/MMBtu. For the coal-based technologies at the baseline coal cost of $1.80/MMBtu to be equal to NGCC, the cost of natural gas would have to be $7.73/MMBtu (IGCC) or $8.87/MMBtu (PC). Alternatively, for the LCOE of coal-based technologies to be equal to NGCC at the high end coal cost of $2.25/MMBtu, natural gas prices would have to be $8.35/MMBtu for IGCC and $9.65/MMBtu for PC.

Exhibit ES-8 LCOE Sensitivity to Fuel Costs in Non-Capture Cases

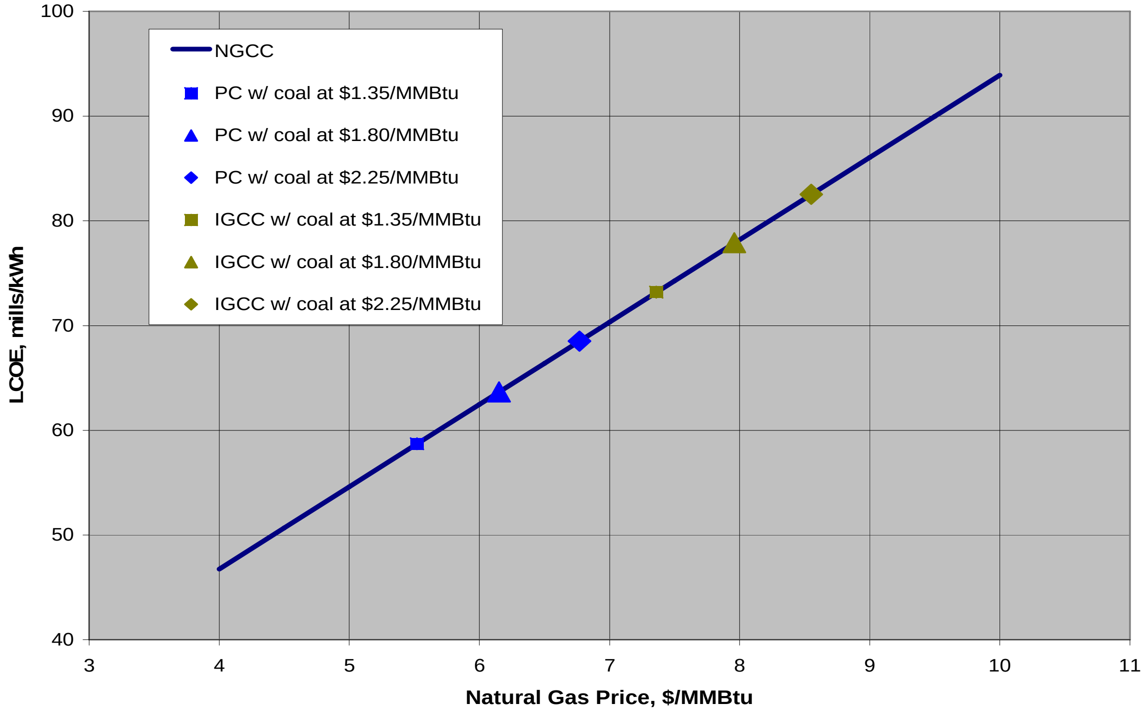
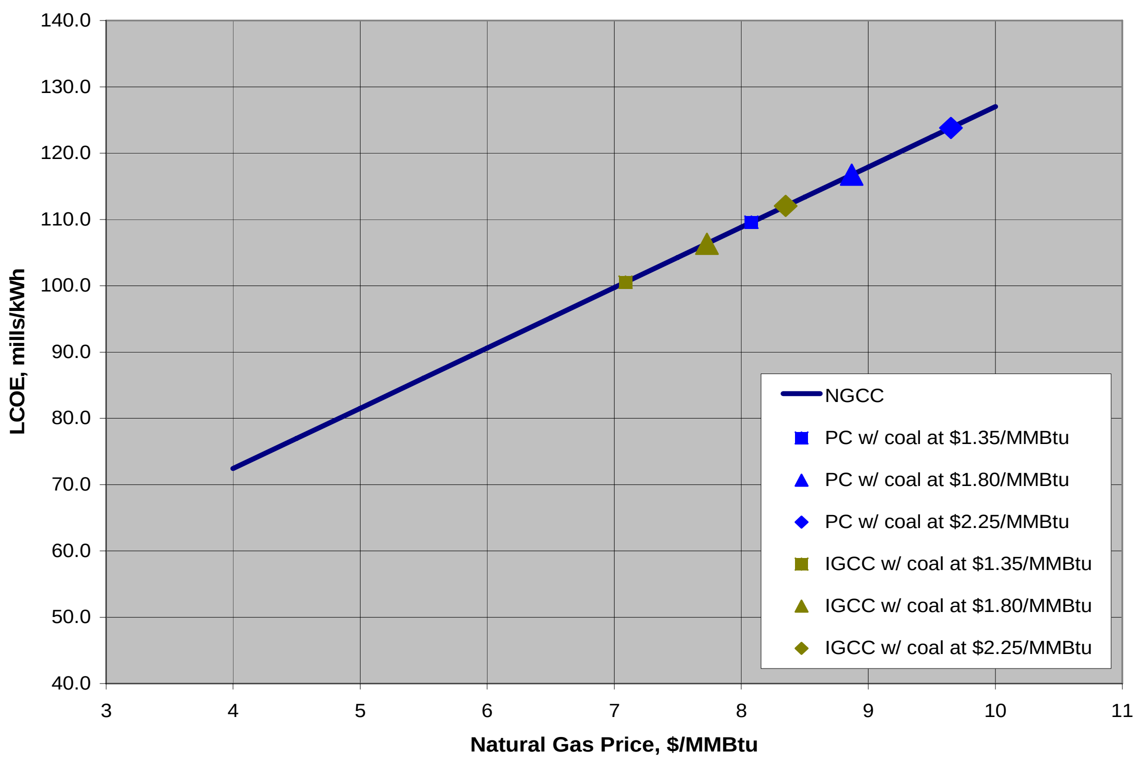
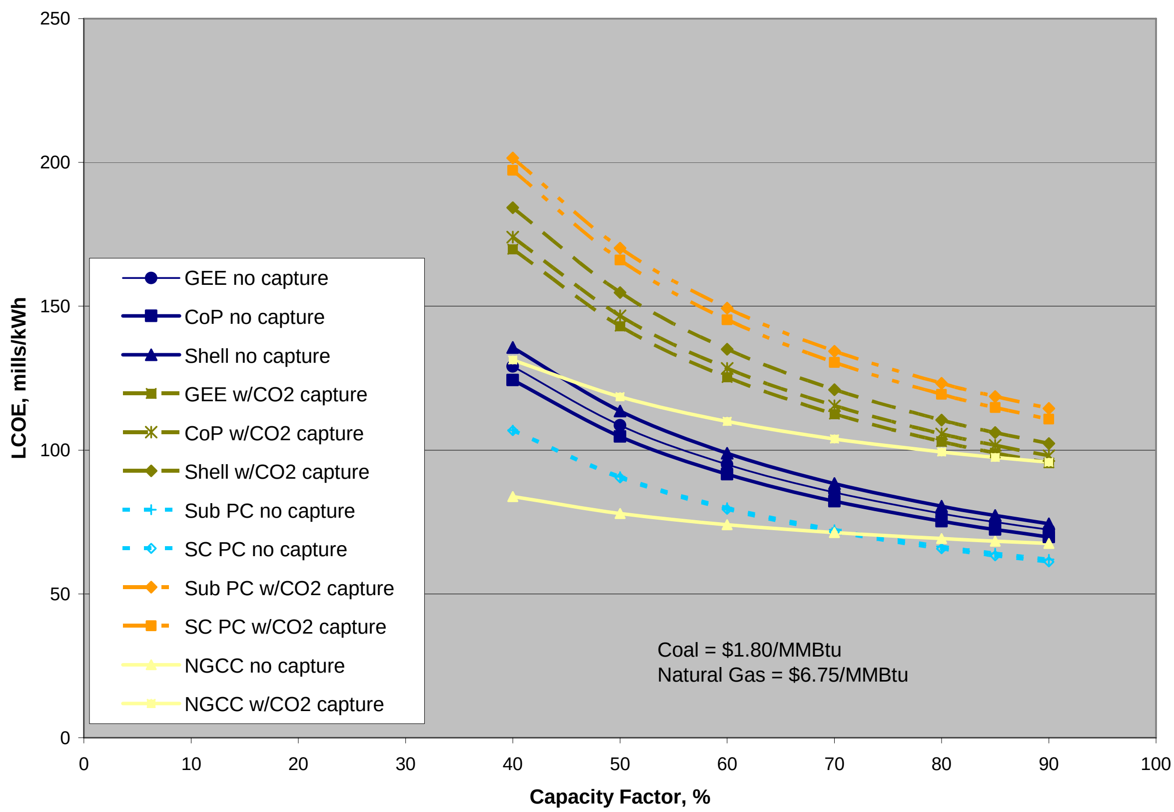


Exhibit ES-9 LCOE Sensitivity to Fuel Costs in CO_2 Capture Cases



The sensitivity of LCOE to capacity factor is shown for all technologies in Exhibit ES-10. The subcritical and supercritical PC cases with no CO_2 capture are nearly identical so that the two curves appear as a single curve on the graph. The capacity factor is plotted from 40 to 90 percent. The baseline capacity factor is 80 percent for IGCC cases with no spare gasifier and is 85 percent for PC and NGCC cases. The curves plotted in Exhibit ES-10 for the IGCC cases assume that the capacity factor could be extended to 90 percent with no spare gasifier. Similarly, the PC and NGCC curves assume that the capacity factor could reach 90 percent with no additional capital equipment.

Exhibit ES-10 LCOE Sensitivity to Capacity Factor



Technologies with high capital cost (PC and IGCC with CO_2 capture) show a greater increase in LCOE with decreased capacity factor. Conversely, NGCC with no CO_2 capture is relatively flat because the LCOE is dominated by fuel charges which decrease as the capacity factor decreases. Conclusions that can be drawn from Exhibit ES-10 include:

- At a capacity factor below 72 percent NGCC has the lowest LCOE in the non-capture cases.
- The LCOE of NGCC with CO_2 capture is the lowest of the capture technologies in the baseline study, and the advantage increases as capacity factor decreases. The relatively low capital cost component of NGCC accounts for the increased cost differential with decreased capacity factor.

- In non-capture cases NGCC at 40 percent capacity factor has the same LCOE as the average of the three IGCC cases at 72 percent capacity factor further illustrating the relatively small impact of capacity factor on NGCC LCOE.

COST OF CO_2 REMOVED/AVOIDED

The cost of CO_2 capture was calculated in two ways, the cost of CO_2 removed and the cost of CO_2 avoided, as illustrated in Equations ES-1 and ES-2, respectively.

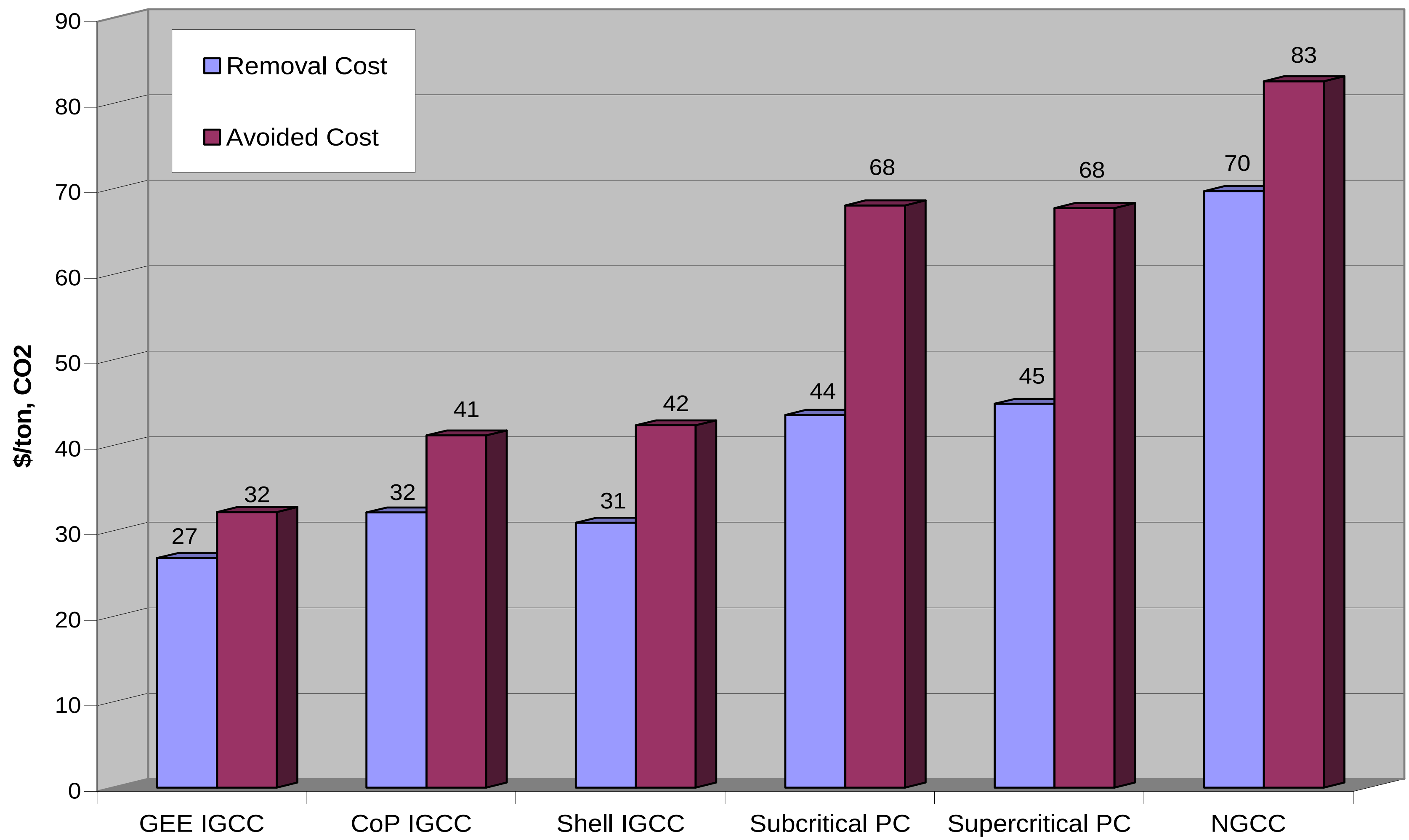
$$Removal\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{CO_2\ \ removed\}\ tons/MWh} \qquad \text{(ES-1)}$$

$$Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh} \qquad \text{(ES-2)}$$

The LCOE with CO_2 removal includes the costs of capture and compression as well as TS&M costs. The resulting removal and avoided costs are shown in Exhibit ES-11 for each of the six technologies modeled. The following conclusions can be drawn:

- The total cost of CO_2 avoided is \$39/ton (average IGCC), \$68/ton (average PC), and \$83/ton (NGCC).
- CO_2 removal and avoided costs for IGCC plants are substantially less than for PC and NGCC because the IGCC CO_2 removal is accomplished prior to combustion and at elevated pressure using physical absorption.
- CO_2 removal and avoided costs for IGCC plants are less than NGCC plants because the baseline CO_2 emissions for NGCC plants are 46 percent less than for IGCC plants. Consequently, the normalized removal cost for NGCC plants is divided by a smaller amount of CO_2.
- CO_2 removal and avoided costs for the GEE IGCC plant are less than for the CoP and Shell IGCC plants. This is consistent with the efficiency changes observed when going from a non-capture to capture configuration for the GEE IGCC plant. The GEE plant started with the lowest efficiency of the IGCC plants but realized the smallest reduction in efficiency between the non-capture and capture configurations.

Exhibit ES-11 CO_2 Capture Costs



ENVIRONMENTAL PERFORMANCE

The environmental targets for each technology are summarized in Exhibit ES-12. Emission rates of SO_2, NOx and PM are shown graphically in Exhibit ES-13, and emission rates of Hg are shown separately in Exhibit ES-14 because of the orders of magnitude difference in emission rate values. Targets were chosen on the basis of the environmental regulations that would most likely apply to plants built in 2010.

Exhibit ES-12 Study Environmental Targets

Technology / Pollutant	IGCC	PC	NGCC
SO_2	0.0128 lb/MMBtu	0.085 lb/MMBtu	Negligible
NOx	15 ppmv (dry) @ 15% O_2	0.070 lb/MMBtu	2.5 ppmv (dry) @ 15% O_2
PM (Filterable)	0.0071 lb/MMBtu	0.013 lb/MMBtu	Negligible
Hg	>90% capture	1.14 lb/TBtu	N/A

Environmental targets were established for each of the technologies as follows:

- IGCC cases use the EPRI targets established in their CoalFleet for Tomorrow work as documented in the *CoalFleet User Design Basis Specification for Coal-Based Integrated Gasification Combined Cycle (IGCC) Power Plants: Version 4*.
- PC and NGCC cases are based on best available control technology.

The primary conclusions that can be drawn are:

- The NGCC baseline plant generates the lowest emissions, followed by IGCC and then PC.
- In NGCC cases, study assumptions result in zero emissions of SO_2, PM and Hg. If the pipeline natural gas contained the maximum amount of sulfur allowed by EPA definition (0.6 gr/100 scf), SO_2 emissions would be 0.000839 kg/GJ (0.00195 lb/MMBtu).
- Based on vendor data it was assumed that dry low NOx burners could achieve 25 ppmv (dry) at 15 percent O_2 and, coupled with a selective catalytic reduction (SCR) unit that achieves 90 percent NOx reduction efficiency, would result in the environmental target of 2.5 ppmv (dry) at 15 percent O_2 for both NGCC cases.
- Based on vendor data it was assumed that Selexol, Sulfinol-M and refrigerated MDEA could all meet the sulfur environmental target, hence emissions of approximately 0.0128 lb/MMBtu in each of the IGCC non-capture cases. In the CO_2 capture cases, to achieve 95 percent CO_2 capture from the syngas, the sulfur removal is greater than in the non-capture cases resulting in emissions of approximately 0.0041 kg/GJ (0.0095 lb/MMBtu).

Exhibit ES-13 SO_2, NOx and Particulate Emission Rates

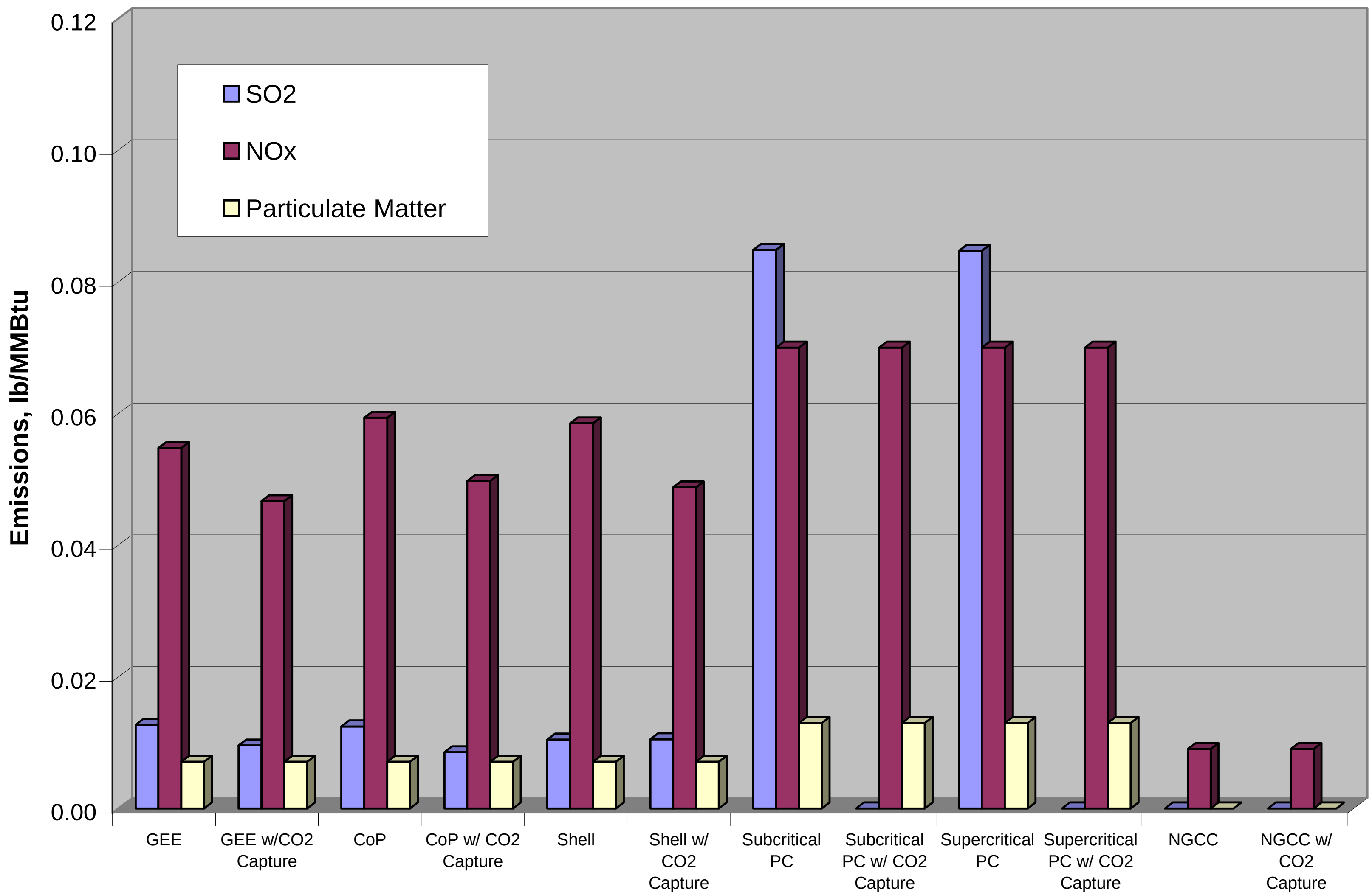
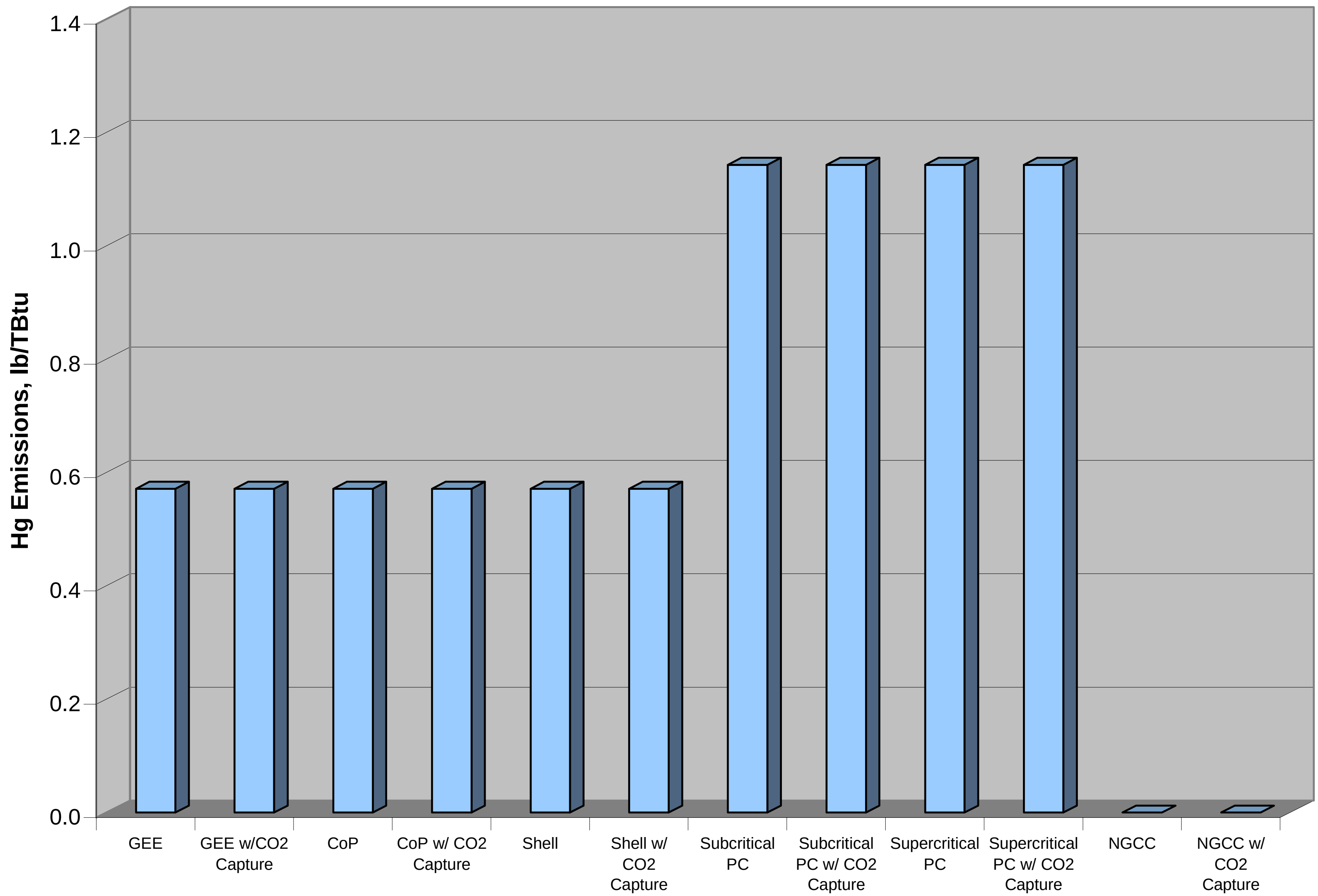


Exhibit ES-14 Mercury Emission Rates



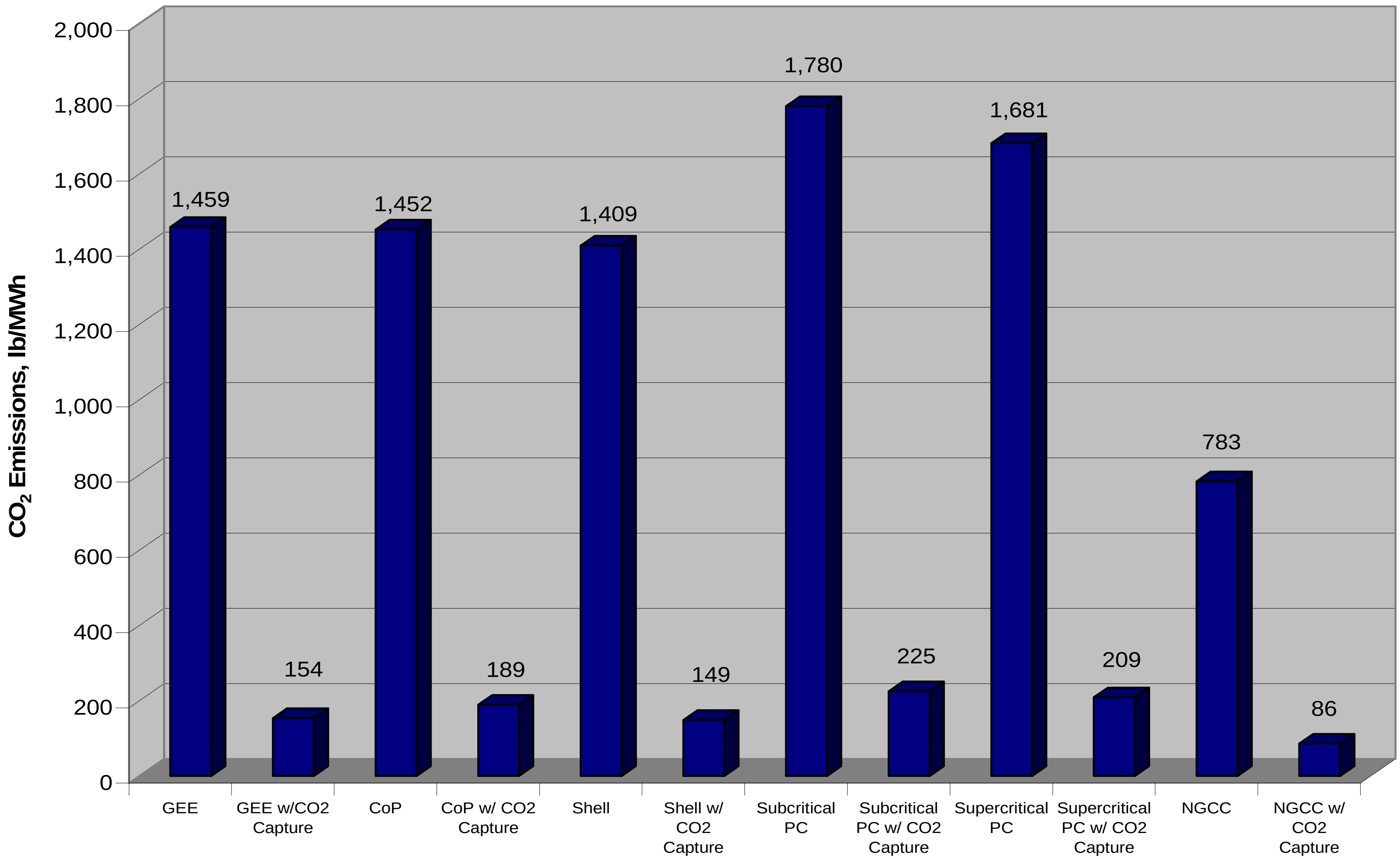
- It was a study assumption that each IGCC technology could meet the filterable particulate emission limit with the combination of technologies employed. In the case of Shell and CoP, this consists of cyclones, candle filters and the syngas scrubber. In the case of GEE particulate control consists of a water quench and syngas scrubber.
- Based on vendor data it was assumed that a combination of low NOx burners and nitrogen dilution could limit IGCC NOx emissions to the environmental target of 15 ppmv (dry) at 15 percent O_2. The small variations in NOx emissions are due to small variations in combustion turbine gas volumes.
- Based on vendor data it was assumed that 95 percent Hg removal could be achieved using carbon beds thus meeting the environmental target. The Hg emissions are reported in Exhibit ES-14 as lb/10 per trillion Btu to make the values the same order of magnitude as the other reported values.
- It was a study assumption that the PC flue gas desulfurization (FGD) unit would remove 98 percent of the inlet SO_2, resulting in the environmental target of 0.037 kg/GJ (0.085 lb/MMBtu). In the CO_2 capture cases, the Econamine system employs a polishing scrubber to reduce emissions to 10 ppmv entering the CO_2 absorber. Nearly all of the remaining SO_2 is absorbed by the Econamine solvent resulting in negligible emissions of SO_2 in those cases.
- In PC cases, it was a study assumption that a fabric filter would remove 99.9 percent of the entering particulate and that there is an 80/20 split between fly ash and bottom ash. The result is the environmental target of 0.006 kg/GJ (0.013 lb/MMBtu) of filterable particulate.
- In PC cases, it was a study assumption that NOx emissions exiting the boiler equipped with low NOx burners and overfire air would be 0.22 kg/GJ (0.50 lb/MMBtu) and that an SCR unit would further reduce the NOx by 86 percent, resulting in the environmental target of 0.030 kg/GJ (0.070 lb/MMBtu).
- In PC cases, it was a study assumption that the environmental target of 90 percent of the incoming Hg would be removed by the combination of SCR, fabric filter and wet FGD thus eliminating the need for activated carbon injection. The resulting Hg emissions for each of the PC cases are 4.92×10^{-7} kg/GJ (1.14 lb/TBtu).

Carbon dioxide emissions are not currently regulated. However, since there is increasing momentum for establishing carbon limits, it was an objective of this study to examine the relative amounts of carbon capture achievable among the six technologies. CO_2 emissions are presented in Exhibit ES-15 for each case, normalized by gross output. In the body of the report CO_2 emissions are presented on both a net and gross MWh basis. New Source Performance Standards (NSPS) contain emission limits for SO_2 and NOx on a lb/(gross) MWh basis. However, since CO_2 emissions are not currently regulated, the potential future emission limit basis is not known and hence the two reported values of CO_2. The following conclusions can be drawn:

- In cases with no carbon capture, NGCC emits 55 percent less CO_2 than PC and 46 percent less CO_2 than IGCC per unit of gross output. The lower NGCC CO_2 emissions reflect the lower carbon intensity of natural gas relative to coal. Based on the fuel compositions used in this study, natural gas contains 32 pounds of carbon per million Btu of heat input and coal contains 55 pounds per million Btu.

- The CO_2 reduction goal in this study was a nominal 90 percent in all cases. The result is that the controlled CO_2 emissions follow the same trend as the uncontrolled, i.e., the NGCC case emits less CO_2 than the IGCC cases which emit less than the PC cases.
- In the IGCC cases the nominal 90 percent CO_2 reduction was accomplished by adding sour gas shift (SGS) reactors to convert CO to CO_2 and using a two-stage Selexol process with a second stage CO_2 removal efficiency of up to 95 percent, a number that was supported by vendor quotes. In the GEE CO_2 capture case, two stages of SGS and a Selexol CO_2 removal efficiency of 92 percent were required, which resulted in 90.2 percent reduction of CO_2 in the syngas. The CoP capture case required three stages of SGS and 95 percent CO_2 capture in the Selexol process, which resulted in 88.4 percent reduction of CO_2 in the syngas. In the CoP case, the capture target of 90 percent could not be achieved because of the high syngas methane content (3.5 vol% compared to 0.10 vol% in the GEE gasifier and 0.04 vol% in the Shell gasifier). The Shell capture case required two stages of SGS and 95 percent capture in the Selexol process, which resulted in 90.8 percent reduction of CO_2 in the syngas.
- The CO_2 emissions in the three non-capture IGCC cases are nearly identical. The slight difference reflects the relative efficiency between the three technologies. The emissions in the CO_2 capture cases are nearly identical for the Shell and GEE cases, but about 19 percent higher in the CoP case because of the high syngas CH_4 content discussed above.
- The PC and NGCC cases both assume that all of the carbon in the fuel is converted to CO_2 in the flue gas and that 90 percent is subsequently removed in the Econamine FG Plus process, which was also supported by a vendor quote.

Exhibit ES-15 CO_2 Emissions Normalized By Gross Output



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1 INTRODUCTION

The objective of this report is to present an accurate, independent assessment of the cost and performance of fossil energy power systems, specifically integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants, in a consistent technical and economic manner that accurately reflects current market conditions for plants starting operation in 2010. This is Volume 1 of a three volume report. The three volume series consists of the following:

- Volume 1: Electricity production only using bituminous coal for coal-based technologies
- Volume 2: Synthetic natural gas production and repowering using a variety of coal types
- Volume 3: Electricity production only from low rank coal (PC and IGCC)

The cost and performance of the various fossil fuel-based technologies will largely determine which technologies will be utilized to meet the demands of the power market. Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Fuel prices
- Cost of electricity (COE)
- Availability, reliability and environmental performance
- Current and potential regulation of air, water, and solid waste discharges from fossil-fueled power plants
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE) Clean Coal Programs

Twelve different power plant design configurations were analyzed. The configurations are listed in Exhibit 1-1. The list includes six IGCC cases utilizing the General Electric Energy (GEE), ConocoPhillips (CoP), and Shell gasifiers each with and without CO_2 capture, and six cases representing conventional technologies: PC-subcritical, PC-supercritical, and NGCC plants both with and without CO_2 capture. While input was sought from various technology vendors, the final assessment of performance and cost was determined independently, and may not represent the views of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors.

Cases 7 and 8 were originally included in this study and involve production of synthetic natural gas (SNG) and the repowering of an existing NGCC facility using SNG. The two SNG cases were subsequently moved to Volume 2 of this report resulting in the discontinuity of case numbers (1-6 and 9-14). The two SNG cases are now cases 2 and 2a in Volume 2.

GENERATING UNIT CONFIGURATIONS

A summary of plant configurations considered in this study is presented in Exhibit 1-1. Components for each plant configuration are described in more detail in the corresponding report sections for each case.

The IGCC cases have different gross and net power outputs because of the gas turbine size constraint. The advanced F-class turbine used to model the IGCC cases comes in a standard size of 232 MW when operated on syngas. Each case uses two combustion turbines for a combined gross output of 464 MW. In the combined cycle a heat recovery steam generator extracts heat from the combustion turbine exhaust to power a steam turbine. However, the carbon capture cases consume more extraction steam than the non-capture cases, thus reducing the steam turbine output. In addition, the capture cases have a higher auxiliary load requirement than non-capture cases, which serves to further reduce net plant output. While the two combustion turbines provide 464 MW gross output in all six cases, the overall combined cycle gross output ranges from 694 to 770 MW, which results in a range of net output from 517 to 640 MW. The coal feed rate required to achieve the gross power output is also different between the six cases, ranging from 204,117 to 226,796 kg/h (450,000 to 500,000 lb/h).

Similar to the IGCC cases, the NGCC cases do not have a common net power output. The NGCC system is again constrained by the available combustion turbine size, which is 185 MW for both cases (based on the same advanced F class turbine used in the IGCC cases). Since the carbon capture case requires both a higher auxiliary power load and a significant amount of extraction steam, which significantly reduces the steam turbine output, the net output in the NGCC case is also reduced.

All four PC cases have a net output of 550 MW. The boiler and steam turbine industry's ability to match unit size to a custom specification has been commercially demonstrated enabling a common net output comparison of the PC cases in this study. The coal feed rate was increased in the carbon capture cases to increase the gross steam turbine output and account for the higher auxiliary load, resulting in a constant net output.

The balance of this report is organized as follows:

- Chapter 2 provides the basis for technical, environmental and cost evaluations.
- Chapter 3 describes the IGCC technologies modeled and presents the results for the six IGCC cases.
- Chapter 4 describes the PC technologies modeled and presents the results for the four PC cases.
- Chapter 5 desribes the NGCC technologies modeled and presents the results for the two NGCC cases.
- Chapter 6 contains the reference list.

Exhibit 1-1 Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H_2S Separation/ Removal	Sulfur Removal/ Recovery	PM Control	NOx Control	CO_2 Separa-tion	CO_2 Capture	CO_2 Sequestra-tion
1	IGCC	1800/1050/1050	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Quench, scrubber and AGR adsorber	N_2 dilution			
2	IGCC	1800/1000/1000	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Quench, scrubber and AGR adsorber	N_2 dilution	Selexol 2nd stage	90% (1)	Off-Site
3	IGCC	1800/1050/1050	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution			
4	IGCC	1800/1000/1000	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution	Selexol 2nd stage	88% (1)	Off-Site
5	IGCC	1800/1050/1050	2 x Advanced F Class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution			
6	IGCC	1800/1000/1000	2 x Advanced F Class	Shell	95 mol% O_2	Selexol	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution	Selexol 2nd stage	90% (1)	Off-Site
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--	--	--	--	--	--	--	--	--	--	--	--	--
9	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR			
10	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Amine Absorber	90%	Off-Site
11	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR			
12	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Amine Absorber	90%	Off-Site
13	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air				LNB and SCR			
14	NGCC	2400/1050/950	2 x Advanced F Class	HRSG	Air				LNB and SCR	Amine Absorber	90%	Off-Site

Note (1) Defined as the percentage of carbon in the syngas that is captured; differences are explained in Chapter 3.

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2 GENERAL EVALUATION BASIS

For each of the plant configurations in this study an AspenPlus model was developed and used to generate material and energy balances, which in turn were used to provide a design basis for items in the major equipment list. The equipment list and material balances were used as the basis for generating the capital and operating cost estimates. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgement. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/buil projects, or a combination of the two. Ultimately a 20-year levelized cost of electricity (LCOE) was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

The balance of this chapter documents the design basis common to all technologies, as well as environmental targets and cost assumptions used in the study. Technology specific design criteria are covered in subsequent chapters.

2.1 SITE CHARACTERISTICS

All plants in this study are assumed to be located at a generic plant site in Midwestern USA, with ambient conditions and site characteristics as presented in Exhibit 2-1 and Exhibit 2-2. The ambient conditions are the same as ISO conditions.

Exhibit 2-1 Site Ambient Conditions

Elevation, m (ft)	0
Barometric Pressure, MPa (psia)	0.10 (14.696)
Design Ambient Temperature, Dry Bulb, °C (°F)	15 (59)
Design Ambient Temperature, Wet Bulb, °C (°F)	11 (51.5)
Design Ambient Relative Humidity, %	60

Exhibit 2-2 Site Characteristics

Location	Greenfield, Midwestern USA
Topography	Level
Size, acres	300 (PC/IGCC) 100 (NGCC)
Transportation	Rail
Ash/Slag Disposal	Off Site
Water	Municipal (50%) / Groundwater (50%)
Access	Land locked, having access by train and highway
CO_2 Storage	Compressed to 15.3 MPa (2,215 psia), transported 80 kilometers (50 miles) and sequestered in a saline formation at a depth of 1,239 meters (4,055 feet)

The land area for PC and IGCC cases assumes 30 acres are required for the plant proper and the balance provides a buffer of approximately 0.25 miles to the fence line. The extra land could also provide for a rail loop if required. In the NGCC cases it was assumed the plant proper occupies about 10 acres leaving a buffer of 0.15 miles to the plant fence line.

In all cases it was assumed that the steam turbine is enclosed in a turbine building and in the PC cases the boiler is also enclosed. The gasifier in the IGCC cases and the combustion turbines in the IGCC and NGCC cases are not enclosed.

The following design parameters are considered site-specific, and are not quantified for this study. Allowances for normal conditions and construction are included in the cost estimates.

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Fire protection
- Local code height requirements
- Noise regulations – Impact on site and surrounding area

2.2 COAL CHARACTERISTICS

The design coal is Illinois No. 6 with characteristics presented in Exhibit 2-3. The coal properties are from NETL's Coal Quality Guidelines. [1]

The first year cost of coal used in this study is $1.71/MMkJ ($1.80/MMBtu) (2010 cost of coal in 2007 dollars). The cost was determined using the following information from the Energy Information Administration's (EIA) 2007 Annual Energy Outlook (AEO):

- The 2010 minemouth cost of coal in 2005 dollars, $35.23/tonne ($31.96/ton), was obtained from Supplemental Table 113 of the EIA's 2007 AEO for eastern interior high-sulfur bituminous coal.
- The delivery costs were assumed to be 25 percent of the minemouth cost for eastern interior coal delivered to Illinois and surrounding states. [2]
- The 2010 delivered cost ($44.04/tonne [$39.95/ton]) was escalated to 2007 dollars using the gross domestic product (GDP) chain-type price index from AEO 2007, resulting in a delivered 2010 price in 2007 dollars of $45.32/tonne ($41.11/ton) or $1.71/MMkJ ($1.80/MMBtu). [3] (Note: The conversion of $41.11/ton to dollars per million Btu results in $1.8049/MMBtu which was used in calculations, but only two decimal places are shown in the report.)

Exhibit 2-3 Design Coal

Rank	**Bituminous**	
Seam	**Illinois No. 6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate Analysis (weight %) (Note A)		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg	27,113	30,506
HHV, Btu/lb	11,666	13,126
LHV, kJ/kg	26,151	29,544
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen (Note B)	6.88	7.75
Total	100.00	100.00

Notes: A. The proximate analysis assumes sulfur as volatile matter
B. By difference

2.3 NATURAL GAS CHARACTERISTICS

Natural gas is utilized as the main fuel in Cases 13 and 14 (NGCC with and without CO_2 capture), and its composition is presented in Exhibit 2-4. [4]

Exhibit 2-4 Natural Gas Composition

Component		Volume Percentage	
Methane	CH_4	93.9	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1.0	
Nitrogen	N_2	0.8	
	Total	100.0	
		LHV	**HHV**
kJ/kg		47,764	52,970
MJ/scm		35	39
Btu/lb		20,552	22,792
Btu/scf		939	1,040

Note: Fuel composition is normalized and heating values are calculated

The first year cost of natural gas used in this study is \$6.40/MMkJ (\$6.75/MMBtu) (2010 cost of natural gas in 2007 dollars). The cost was determined using the following information from the EIA's 2007 AEO:

- The 2010 national average delivered cost of natural gas to electric utilities in 2005 dollars, \$6.07/MMkJ (\$6.40/MMBtu), was obtained from the AEO 2007 reference case Table 13.
- The 2010 cost was escalated to 2007 dollars using the GDP chain-type price index from AEO 2007, resulting in a delivered 2010 price in 2007 dollars of \$6.40/MMkJ (\$6.75/MMBtu). [3]

2.4 ENVIRONMENTAL TARGETS

The environmental targets for the study were considered on a technology- and fuel-specific basis. In setting the environmental targets a number of factors were considered, including current emission regulations, regulation trends, results from recent permitting activities and the status of current best available control technology (BACT).

The current federal regulation governing new fossil-fuel fired electric utility steam generating units is the New Source Performance Standards (NSPS) as amended in February 2006 and shown in Exhibit 2-5, which represents the minimum level of control that would be required for a new fossil energy plant. [5] Stationary combustion turbine emission limits are further defined in 40 CFR Part 60, Subpart KKKK.

Exhibit 2-5 Standards of Performance for Electric Utility Steam Generating Units Built, Reconstructed, or Modified After February 28, 2005

	New Units		Reconstructed Units		Modified Units	
	Emission Limit	% Reduction	Emission Limit (lb/MMBtu)	% Reduction	Emission Limit (lb/MMBtu)	% Reduction
PM	0.015 lb/MMBtu	99.9	0.015	99.9	0.015	99.8
SO_2	1.4 lb/MWh	95	0.15	95	0.15	90
NOx	1.0 lb/MWh	N/A	0.11	N/A	0.15	N/A

The new NSPS standards apply to units with the capacity to generate greater than 73 MW of power by burning fossil fuels, as well as cogeneration units that sell more than 25 MW of power and more than one-third of their potential output capacity to any utility power distribution system. The rule also applies to combined cycle, including IGCC plants, and combined heat and power combustion turbines that burn 75 percent or more synthetic-coal gas. In cases where both an emission limit and a percent reduction are presented, the unit has the option of meeting one or the other. All limits with the unit lb/MWh are based on gross power output.

Other regulations that could affect emissions limits from a new plant include the New Source Review (NSR) permitting process and Prevention of Significant Deterioration (PSD). The NSR process requires installation of emission control technology meeting either BACT determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the Environmental Protection Agency (EPA) Green Book Non-attainment Area Map relatively few areas in the Midwestern U.S. are classified as “non-attainment” so the plant site for this study was assumed to be in an attainment area. [6]

In addition to federal regulations, state and local jurisdictions can impose even more stringent regulations on a new facility. However, since each new plant has unique environmental requirements, it was necessary to apply some judgment in setting the environmental targets for this study.

The Clean Air Mercury Rule (CAMR) established NSPS limits for Hg emissions from new pulverized coal-fired boilers based on coal type as well as for IGCC units independent of coal type. The NSPS limits, based on gross output, are shown in Exhibit 2-6. [7] The applicable limit in this study is 20 x 10^{-6} lb/MWh for both bituminous coal-fired PC boilers and for IGCC units.

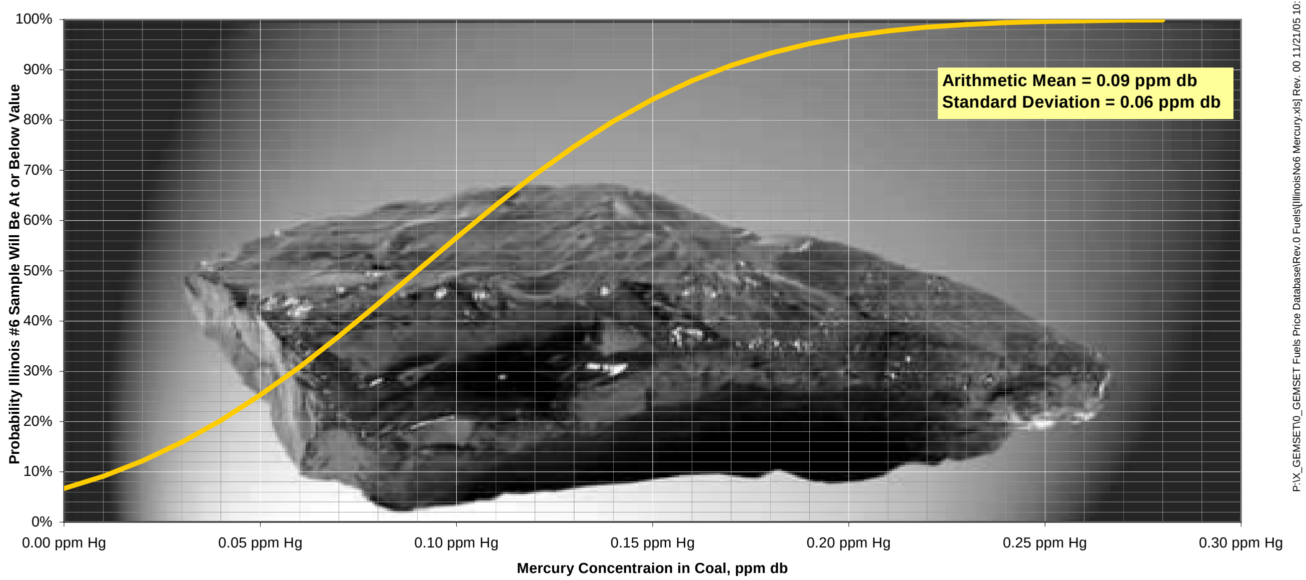
Exhibit 2-6 NSPS Mercury Emission Limits

Coal Type / Technology	Hg Emission Limit
Bituminous	**20×10^{-6} lb/MWh**
Subbituminous (wet units)	66×10^{-6} lb/MWh
Subbituminous (dry units)	97×10^{-6} lb/MWh
Lignite	175×10^{-6} lb/MWh
Coal refuse	16×10^{-6} lb/MWh
IGCC	**20×10^{-6} lb/MWh**

The mercury content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppm (dry basis) with standard deviation of 0.06 based on coal samples shipped by Illinois mines. [8] Hence, as illustrated in Exhibit 2-7, there is a 50 percent probability that the mercury content in the Illinois No. 6 coal would not exceed 0.09 ppm (dry basis). The coal mercury content for this study was assumed to be 0.15 ppm (dry) for all IGCC and PC cases, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all of the coal Hg enters the gas phase and none leaves with the bottom ash or slag.

The current NSPS emission limits are provided below for each technology along with the environmental targets for this study and the control technologies employed to meet the targets. In some cases, application of the control technology results in emissions that are less than the target, but in no case are the emissions greater than the target.

Exhibit 2-7 Probability Distribution of Mercury Concentration in the Illinois No. 6 Coal



2.4.1 IGCC

The IGCC environmental targets were chosen to match the Electric Power Research Institute's (EPRI) design basis for their CoalFleet for Tomorrow Initiative and are shown in Exhibit 2-8. [9] EPRI notes that these are design targets and are not to be used for permitting values.

Exhibit 2-8 Environmental Targets for IGCC Cases

Pollutant	Environmental Target	NSPS Limit[1]	Control Technology
NOx	15 ppmv (dry) @ 15% O_2	1.0 lb/MWh (0.116 lb/MMBtu)	Low NOx burners and syngas nitrogen dilution
SO_2	0.0128 lb/MMBtu	1.4 lb/MWh (0.162 lb/MMBtu)	Selexol, MDEA or Sulfinol (depending on gasifier technology)
Particulate Matter (Filterable)	0.0071 lb/MMBtu	0.015 lb/MMBtu	Quench, water scrubber, and/or cyclones and candle filters (depending on gasifier technology)
Mercury	> 90% capture	20×10^{-6} lb/MWh (2.3 lb/TBtu)	Carbon bed

[1] The value in parentheses is calculated based on an average heat rate of 8,640 Btu/kWh from the three non-CO_2 capture gasifier cases.

Based on published vendor literature, it was assumed that low NOx burners (LNB) and nitrogen dilution can achieve 15 ppmv (dry) at 15 percent O_2, and that value was used for all IGCC cases. [10, 11]

To achieve an environmental target of 0.0128 lb/MMBtu of SO_2 requires approximately 28 ppmv sulfur in the sweet syngas. The acid gas removal (AGR) process must have a sulfur capture efficiency of about 99.7 percent to reach the environmental target. Vendor data on each of the three AGR processes used in the non-capture cases indicate that this level of sulfur removal is possible. In the CO_2 capture cases, the two-stage Selexol process was designed for 95 percent CO_2 removal which results in a sulfur capture of greater than 99.7 percent, hence the lower sulfur emissions in the CO_2 capture cases.

Most of the coal ash is removed from the gasifier as slag. The ash that remains entrained in the syngas is captured in the downstream equipment, including the syngas scrubber and a cyclone and either ceramic or metallic candle filters (CoP and Shell). The environmental target of 0.0071 lb/MMBtu filterable particulates can be achieved with each combination of particulate control devices so that in each IGCC case it was assumed the environmental target was met exactly.

The environmental target for mercury capture is greater than 90 percent. Based on experience at the Eastman Chemical plant, where syngas from a GEE gasifier is treated, the actual mercury removal efficiency used is 95 percent. Sulfur-impregnated activated carbon is used by Eastman as the adsorbent in the packed beds operated at 30°C (86°F) and 6.2 MPa (900 psig). Mercury removal between 90 and 95 percent has been reported with a bed life of 18 to 24 months. Removal efficiencies may be even higher, but at 95 percent the measurement precision limit was reached. Eastman has yet to experience any mercury contamination in its product. [12] Mercury removals of greater than 99 percent can be achieved by the use of dual beds, i.e., two beds in series. However, this study assumes that the use of sulfur-impregnated carbon in a single carbon bed achieves 95 percent reduction of mercury emissions which meets the environmental target and NSPS limits in all cases.

2.4.2 PC

BACT was applied to each of the PC cases and the resulting emissions compared to NSPS limits and recent permit averages. Since the BACT results met or exceeded the NSPS requirements and the average of recent permits, they were used as the environmental targets as shown in Exhibit 2-9. The average of recent permits is comprised of 8 units at 5 locations. The 5 plants include Elm Road Generating Station, Longview Power, Prairie State, Thoroughbred and Cross.

It was assumed that LNBs and staged overfire air (OFA) would limit NOx emissions to 0.5 lb/MMBtu and that selective catalytic reduction (SCR) technology would be 86 percent efficient, resulting in emissions of 0.07 lb/MMBtu for all cases.

The wet limestone scrubber was assumed to be 98 percent efficient which results in SO_2 emissions of 0.085 lb/MMBtu. Current technology allows flue gas desulfurization (FGD) removal efficiencies in excess of 99 percent, but based on NSPS requirements and recent permit averages, such high removal efficiency is not necessary.

The fabric filter used for particulate control was assumed to be 99.8 percent efficient. The result is particulate emissions of 0.013 lb/MMBtu in all cases, which also exceeds NSPS and recent permit average requirements.

Exhibit 2-9 Environmental Targets for PC Cases

Pollutant	Environmental Target	NSPS Limit	Average of Recent Permits	Control Technology
NOx	0.07 lb/MMBtu	1.0 lb/MWh (0.111 lb/MMBtu)	0.08 lb/MMBtu	Low NOx burners, overfire air and SCR
SO_2	0.085 lb/MMBtu	1.4 lb/MWh (0.156 lb/MMBtu)	0.16 lb/MMBtu	Wet limestone scrubber
Particulate Matter (Filterable)	0.013 lb/MMBtu	0.015 lb/MMBtu	0.017 lb/MMBtu	Fabric filter
Mercury	1.14 lb/TBtu	20×10^{-6} lb/MWh (2.2 lb/TBtu)	2.49 lb/TBtu	Co-benefit capture

Mercury control for PC cases was assumed to occur through 90 percent co-benefit capture in the fabric filter and the wet FGD scrubber. EPA used a statistical method to calculate the Hg co-benefit capture from units using a “best demonstrated technology” approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8 to 98.8 percent. [13] EPA’s documentation for their Integrated Planning Model (IPM) provides mercury emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency. For PC boilers (as opposed to cyclones, stokers, fluidized beds and ‘others’) with a fabric filter, SCR and wet FGD, the EMF is 0.1 which corresponds to a removal efficiency of 90 percent. [14] The average reduction in total Hg emissions developed from EPA’s Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters and wet FGD is 98 percent. [15] The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter and a wet FGD system between 83.8 and 98 percent. Ninety percent was chosen as near the mid-point of this range and it also matches the value used by EPA in their IPM.

Since co-benefit capture alone exceeds the requirements of NSPS and recent permit averages, no activated carbon injection is included in this study.

2.4.3 <u>NGCC</u>

BACT was applied to the NGCC cases and the resulting emissions compared to NSPS limits. The NGCC environmental targets were chosen based on reasonably obtainable limits given the control technologies employed and are presented in Exhibit 2-10.

Exhibit 2-10 Environmental Targets for NGCC Cases

Pollutant	Environmental Target	40 CFR Part 60, Subpart KKKK Limits	Control Technology
NOx	2.5 ppmv @ 15% O_2	15 ppmv @ 15% O_2	Low NOx burners and SCR
SO_2	Negligible	0.9 lb/MWh (0.135 lb/MMBtu)[1]	Low sulfur content fuel
Particulate Matter (Filterable)	N/A	N/A	N/A
Mercury	N/A	N/A	N/A

[1] Assumes a heat rate of 6,690 Btu/kWh.

Published vendor literature indicates that 25 ppmv NOx at 15 percent O_2 is achievable using natural gas and dry low NOx (DLN) technology. [16, 17] The application of SCR with 90 percent efficiency further reduces NOx emissions to 2.5 ppmv, which was selected as the environmental target.

For the purpose of this study, natural gas was assumed to contain a negligible amount of sulfur compounds, and therefore generate negligible sulfur emissions. The EPA defines pipeline natural gas as containing >70 percent methane by volume or having a gross calorific value of between 35.4 and 40.9 MJ/Nm^3 (950 and 1,100 Btu/scf) and having a total sulfur content of less than 13.7 mg/Nm^3 (0.6 gr/100 scf). [18] Assuming a sulfur content equal to the EPA limit for pipeline natural gas, resulting SO_2 emissions for the two NGCC cases in this study would be 21 tonnes/yr (23.2 tons/yr) at 85 percent capacity factor or 0.00084 kg/GJ (0.00195 lb/MMBtu). Thus for the purpose of this study, SO_2 emissions were considered negligible.

The pipeline natural gas was assumed to contain no particulate matter and no mercury resulting in no emissions of either.

2.4.4 CARBON DIOXIDE

Carbon dioxide (CO_2) is not currently regulated. However, the possibility exists that carbon limits will be imposed in the future and this study examines cases that include a reduction in CO_2 emissions. Because the form of emission limits, should they be imposed, is not known, CO_2 emissions are reported on both a lb/(gross) MWh and lb/(net) MWh basis in each capture case emissions table.

For the IGCC cases that have CO_2 capture, the basis is a nominal 90 percent removal based on carbon input from the coal and excluding carbon that exits the gasifier with the slag. The minimum number of water gas shift reactors was used with a maximum Selexol CO_2 removal efficiency of 95 percent (based on a vendor quote) to achieve an overall CO_2 removal efficiency of 90 percent. Once the number of shift reactors was determined, the Selexol removal efficiency was decreased from 95 percent if possible while still meeting the 90 percent overall target. In the case of the E-Gas™ gasifier, CO_2 capture is limited to 88.4 percent because of the relatively high methane content in the syngas that is not converted to CO_2 in the shift reactors.

For PC and NGCC cases that have CO_2 capture, it is assumed that all of the fuel carbon is converted to CO_2 in the flue gas. CO_2 is also generated from limestone in the FGD system, and 90 percent of the CO_2 exiting the FGD absorber is subsequently captured using the Econamine FG Plus technology.

The cost of CO_2 capture was calculated in two ways, the cost of CO_2 removed and the cost of CO_2 avoided, as illustrated in Equations 1 and 2, respectively. The cost of electricity in the CO_2 capture cases includes transport, storage and monitoring (TS&M) as well as capture and compression.

$$(1) \qquad Removal\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{CO_2\ removed\}\ tons/MWh}$$

$$(2) \qquad Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh}$$

2.5 CAPACITY FACTOR

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore capacity factor and availability are equal. The availability for PC and NGCC cases was determined using the Generating Availability Data System (GADS) from the North American Electric Reliability Council (NERC). [19] Since there are only two operating IGCC plants in North America, the same database was not useful for determining IGCC availability. Rather, input from EPRI and their work on the CoalFleet for Tomorrow Initiative was used.

NERC defines an equivalent availability factor (EAF), which is essentially a measure of the plant capacity factor assuming there is always a demand for the output. The EAF accounts for planned and scheduled derated hours as well as seasonal derated hours. As such, the EAF matches this study's definition of capacity factor.

The average EAF for coal-fired plants in the 400-599 MW size range was 84.9 percent in 2004 and averaged 83.9 percent from 2000-2004. Given that many of the plants in this size range are older, the EAF was rounded up to 85 percent and that value was used as the PC plant capacity factor.

The average EAF for NGCC plants in the 400-599 MW size range was 84.7 percent in 2004 and averaged 82.7 percent from 2000-2004. Using the same rationale as for PC plants, the EAF was rounded up to 85 percent and that value was also used as the NGCC plant capacity factor.

EPRI examined the historical forced and scheduled outage times for IGCCs and concluded that the reliability factor (which looks at forced or unscheduled outage time only) for a single train IGCC (no spares) would be about 90 percent. [20] To get the availability factor, one has to deduct the scheduled outage time. In reality the scheduled outage time differs from gasifier technology-to-gasifier technology, but the differences are relatively small and would have minimal impact on the capacity factor, so for this study it was assumed to be constant at a 30-day planned outage per year (or two 15-day outages). The planned outage would amount to 8.2 percent of the year, so the availability factor would be (90 percent - 8.2 percent), or 81.2 percent.

There are four operating IGCC's worldwide that use a solid feedstock and are primarily power producers (Polk, Wabash, Buggenum and Puertollano). A 2006 report by Higman et al. examined the reliability of these IGCC power generation units and concluded that typical annual on-stream times are around 80 percent. [21] The capacity factor would be somewhat less than the on-stream time since most plants operate at less than full load for some portion of the operating year. Given the results of the EPRI study and the Higman paper, a capacity factor of 80 percent was chosen for IGCC with no spare gasifier required.

The addition of CO_2 capture to each technology was assumed not to impact the capacity factor. This assumption was made to enable a comparison based on the impact of capital and variable operating costs only. Any reduction in assumed capacity factor would further increase the LCOE for the CO_2 capture cases.

2.6 RAW WATER USAGE

A water balance was performed for each case on the major water consumers in the process. The total water demand for each subsystem was determined and internal recycle water available from various sources like boiler feedwater blowdown and condensate from syngas or flue gas (in CO_2 capture cases) was applied to offset the water demand. The difference between demand and recycle is raw water usage.

Raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from groundwater. 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, boiler feedwater makeup, slurry preparation makeup, ash handling makeup, syngas humidification, quench system makeup, and FGD system makeup. Usage represents the overall impact of the process on the water source.

The largest consumer of raw water in all cases is cooling tower makeup. It was assumed that all cases utilized a mechanical draft, evaporative cooling tower, and all process blowdown streams were assumed to be treated and recycled to the cooling tower. The design ambient wet bulb temperature of 11°C (51.5°F) (Exhibit 2-1) was used to achieve a cooling water temperature of 16°C (60°F) using an approach of 5°C (8.5°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following [22]:

- 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 were calculated as follows:
    - Blowdown Losses = Evaporative Losses / (Cycles of Concentration - 1)

      Where cycles of concentration is a measure of water quality, and a mid-range value of 4 was chosen for this study.

The water balances presented in subsequent sections include the water demand of the major water consumers within the process, the amount provided by internal recycle, and by difference, the amount of raw water required.

2.7 COST ESTIMATING METHODOLOGY

The Total Plant Cost (TPC) and Operation and Maintenance (O&M) costs for each of the cases in the study were estimated by WorleyParsons Group Inc. (WorleyParsons). The estimates carry an accuracy of ±30 percent, consistent with the screening study level of information available for the various study power technologies.

WorleyParsons used an in-house database and conceptual estimating models for the capital cost and O&M cost estimates. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design and design/build projects.

The capital costs for each cost account were reviewed by comparing individual accounts across all of the other cases and technologies to ensure an accurate representation of the relative cost differences between the cases and accounts.

All capital and O&M costs are presented as “overnight costs” expressed in December 2006 dollars. In this study the first year of plant construction is assumed to be 2007, and the resulting LCOE is expressed in year 2007 dollars. The capital and operating costs in December 2006 dollars were treated as a January 2007 year cost throughout the report without escalation. In this report December 2006 dollars and January 2007 dollars are considered to be equal.

Capital costs are presented at the TPC level. TPC includes:

- Equipment (complete with initial chemical and catalyst loadings),
- Materials,
- Labor (direct and indirect),
- Engineering and construction management, and
- Contingencies (process and project).

Owner’s costs are excluded.

System Code-of-Accounts

The costs are grouped according to a process/system oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process so they are included in the specific system account. (This would not be the case had a facility, area, or commodity account structure been chosen instead).

Non-CO_2 Capture Plant Maturity

The case estimates provided include technologies at different commercial maturity levels. The estimates for the non-CO_2-capture PC and NGCC cases represent well-developed commercial technology or “n^{th} plants.” The non-capture IGCC cases are also based on commercial offerings, however, there have been very limited sales of these units so far. These non-CO_2-capture IGCC plant costs are less mature in the learning curve, and the costs listed reflect the “next commercial offering” level of cost rather than mature n^{th}-of-a-kind cost. Thus, each of these cases reflects the expected cost for the next commercial sale of each of these respective technologies.

CO_2 Removal Maturity

The post-combustion CO_2 removal technology for the PC and NGCC capture cases is immature technology. This technology remains unproven at commercial scale in power generation applications.

The pre-combustion CO_2 removal technology for the IGCC capture cases has a stronger commercial experience base. Pre-combustion CO_2 removal from syngas streams has been proven in chemical processes with similar conditions to that in IGCC plants, but has not been demonstrated in IGCC applications. While no commercial IGCC plant yet uses CO_2 removal technology in commercial service, there are currently IGCC plants with CO_2 capture well along in the planning stages.

Contracting Strategy

The estimates are based on an Engineering/Procurement/Construction Management (EPCM) approach utilizing multiple subcontracts. This approach provides the Owner with greater control of the project, while minimizing, if not eliminating most of the risk premiums typically included in an Engineer/Procure/Construct (EPC) contract price.

In a traditional lump sum EPC contract, the Contractor assumes all risk for performance, schedule, and cost. However, as a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. Rather, the current trend appears to be a modified EPC approach where much of the risk remains with the Owner. Where Contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, Contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the Owner. While the Owner retains the risks, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Estimate Scope

The estimates represent a complete power plant facility on a generic site. Site-specific considerations such as unusual soil conditions, special seismic zone requirements, or unique local conditions such as accessibility, local regulatory requirements, etc. are not considered in the estimates.

The estimate boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system, but terminating at the high voltage side of the main power transformers. The single exception to the fence line limit is in the CO_2 capture cases where costs are included for TS&M of the CO_2.

Labor costs are based on Merit Shop (non-union), in a competitive bidding environment.

Capital Costs

WorleyParsons developed the capital cost estimates for each plant using the company's in-house database and conceptual estimating models for each of the specific technologies. This database and the respective models are maintained by WorleyParsons as part of a commercial power plant design base of experience for similar equipment in the company's range of power and process projects. A reference bottoms-up estimate for each major component provides the basis for the estimating models. This provides a basis for subsequent comparisons and easy modification when comparing between specific case-by-case variations.

Key equipment costs for each of the cases were calibrated to reflect recent quotations and/or purchase orders for other ongoing in-house power or process projects. These include, but are not limited to the following equipment:

- Pulverized Coal Boilers
- Combustion Turbine Generators
- Steam Turbine Generators
- Circulating Water Pumps and Drivers
- Cooling Towers
- Condensers
- Air Separation Units (partial)
- Main Transformers
- Econamine FG Plus CO_2 Capture Process (quote provided specifically for this project)

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. Costs would need to be re-evaluated for projects at different locations or for projects employing union labor.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-diems or bonuses have been included to attract craft labor.
- While not included at this time, labor incentives may ultimately be required to attract and retain skilled labor depending on the amount of competing work in the region, and the availability of skilled craft in the area at the time the projects proceed to construction. Current indications are that regional craft shortages are likely over the next several years. The types and amounts of incentives will vary based on project location and timing relative to other work. The cost impact resulting from an inadequate local work force can be significant.
- The estimates are based on a greenfield site.
- The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Costs are limited to within the "fence line," terminating at the high voltage side of the main power transformers with the exception of costs included for TS&M of CO_2 in all capture cases.

- Engineering and Construction Management were estimated as a percent of bare erected cost; 10 percent for IGCC and PC technologies, and 9 percent for NGCC technologies. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety and field inspection.
- All capital costs are presented as "Overnight Costs" in December 2006 dollars. As previously mentioned, December 2006 and January 2007 dollars are considered equivalent in this report. Escalation to period-of-performance is specifically excluded.

Price Escalation

A significant change in power plant cost occurred in recent years due to the significant increases in the pricing of equipment and bulk materials. This estimate includes these increases. All vendor quotes used to develop these estimates were received within the last two years. The price escalation of vendor quotes incorporated a vendor survey of actual and projected pricing increases from 2004 through the third quarter of 2006 that WorleyParsons conducted for a recent project. The results of that survey were used to validate/recalibrate the corresponding escalation factors used in the conceptual estimating models.

Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs. As noted above, the capital costs were reviewed and compared across all of the cases, accounts, and technologies to ensure that a consistent representation of the relative cost differences is reflected in the estimates.

In performing such a comparison, it is important to reference the technical parameters for each specific item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies. There are a number of cases where differences in design philosophy occur. Some key examples are:

- The combustion turbine account in the GEE IGCC cases includes a syngas expander which is not required for the CoP or Shell cases.
- The combustion turbines for the IGCC capture cases include an additional cost for firing a high hydrogen content fuel.
- The Shell gasifier syngas cooling configuration is different between the CO_2-capture and non-CO_2-capture cases, resulting in a significant differential in thermal duty between the syngas coolers for the two cases.

Exclusions

The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (Engineering and Construction Management), and contingency. The following items are <u>excluded</u> from the capital costs:

- Escalation to period-of-performance

- Owner's costs – including, but not limited to land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, allowance for funds-used-during construction, legal fees, Owner's engineering, pre-production costs, furnishings, Owner's contingency, etc.
- All taxes, with the exception of payroll taxes
- Site specific considerations – including but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.
- Labor incentives in excess of a 5-day/10-hour work week
- Additional premiums associated with an EPC contracting approach

Contingency

Both the project contingency and process contingency costs represent costs that are expected to be spent in the development and execution of the project that are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any additional equipment that would be required as a result of continued technology development.

Project Contingency

Project contingencies were added to each of the capital accounts to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Each bare erected cost account was evaluated against the level of estimate detail, field experience, and the basis for the equipment pricing to define project contingency.

The capital cost estimates associated with the plant designs in this study were derived from various sources which include prior conceptual designs and actual design and construction of both process and power plants.

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. On the surface, the level of project definition of the cases evaluated in this study would appear to fall under an AACE International Class 5 Estimate, associated with less than 2 percent project definition, and based on preliminary design methodology. However, the study cases are actually more in line with the AACE International Class 4 Estimate, which is associated with equipment factoring, parametric modeling, historical relationship factors, and broad unit cost data.

Based on the AACE International contingency guidelines as presented in NETL's "Quality Guidelines for Energy System Studies" it would appear that the overall project contingencies for the subject cases should be in the range of 30 to 40 percent. [4] However, such contingencies are believed to be too high when the basis for the cost numbers is considered. The costs have been extrapolated from an extensive data base of project costs (estimated, quoted, and actual), based on both conceptual and detailed designs for the various technologies. This information has been used to calibrate the costs in the current studies, thus improving the quality of the overall estimates. As such, the overall project contingencies should be more in the range of 15 to 20 percent based on the specific technology; with the PC and NGCC cases being at the lower end of the range, and the IGCC cases at the higher end, and the capture cases being higher than the non-capture cases.

Process Contingency

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases - systems are operating at approximately 800 psia as compared to 600 psia for the other IGCC cases
- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases – next-generation commercial offering and integration with the power island
- Two Stage Selexol – 20 percent on all IGCC capture cases - unproven technology at commercial scale in IGCC service
- Mercury Removal – 5 percent on all IGCC cases – minimal commercial scale experience in IGCC applications
- CO_2 Removal System – 20 percent on all PC/NGCC capture cases - post-combustion process unproven at commercial scale for power plant applications
- Combustion Turbine Generator – 5 percent on all IGCC non-capture cases – syngas firing and ASU integration; 10 percent on all IGCC capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all IGCC accounts and 5 percent on the PC and NGCC capture cases – integration issues

AACE International provides standards for process contingency relative to technology status; from commercial technology at 0 to 5 percent to new technology with little or no test data at 40 percent. The process contingencies as applied in this study are consistent with the AACE International standards.

All contingencies included in the TPC, both project and process, represent costs that are expected to be spent in the development and execution of the project.

Operations and Maintenance (O&M)

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (that is, a negative cost for any by-products sold)

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation.

Operating Labor

Operating labor cost was determined based on of the number of operators required for each specific case. The average base labor rate used to determine annual cost is $33/hr. The associated labor burden is estimated at 30 percent of the base labor rate.

Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section. The exception to this is the maintenance cost for the combustion turbines, which is calculated as a function of operating hours.

It should be noted that a detailed analysis considering each of the individual gasifier components and gasifier refractory life is beyond the scope of this study. However, to address this at a high level, the maintenance factors applied to the gasifiers vary between the individual gasifier technology suppliers. The gasifier maintenance factors used for this study are as follows:

- GE – 10 percent on all gasifier components
- CoP and Shell – 7.5 percent on the gasifier and related components, and 4.5 percent on the syngas cooling.

Administrative and Support Labor

Labor administration and overhead charges are assessed at rate of 25 percent of the burdened operation and maintenance labor.

Consumables

The cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Quantities for major consumables such as fuel and sorbent were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or capacity factor.

Initial fills of the consumables, fuels and chemicals, are different from the initial chemical loadings, which are included with the equipment pricing in the capital cost.

Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. In this study both slag from the IGCC cases and fly ash and bottom ash from the PC cases are considered a waste with a disposal cost of $17.03/tonne ($15.45/ton). The carbon used for mercury control in the IGCC cases is considered a hazardous waste with disposal cost of $882/tonne ($800/ton).

Co-Products and By-Products

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically gypsum and sulfur, no credit was taken for their potential salable value. Nor were any of the technologies penalized for their potential disposal cost. That is, for this evaluation, it is assumed that the by-product or co-product value simply offset disposal costs, for a net zero in operating costs.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether or not added capital should be included in the plant costs to produce a particular co-product. Ash and slag are both potential by-products in certain markets, and in the absence of activated carbon injection in the PC cases, the fly ash would remain uncontaminated and have potential marketability. However, as stated above, the ash and slag are considered wastes in this study with a concomitant disposal cost.

CO_2 Transport, Storage and Monitoring

For those cases that feature CO_2 capture, the capital and operating costs for CO_2 transport, storage and monitoring (TS&M) were independently estimated by the National Energy Technology Laboratory (NETL). Those costs were converted to a levelized cost of electricity (LCOE) and combined with the plant capital and operating costs to produce an overall LCOE. The TS&M costs were levelized over a twenty-year period using the methodology described in the next subsection of this report.

CO_2 TS&M costs were estimated based on the following assumptions:

- CO_2 is supplied to the pipeline at the plant fence line at a pressure of 15.3 MPa (2,215 psia). The CO_2 product gas composition varies in the cases presented, but is expected to meet the specification described in Exhibit 2-11. [23]

Exhibit 2-11 CO_2 Pipeline Specification

Parameter	Units	Parameter Value
Inlet Pressure	MPa (psia)	15.3 (2,215)
Outlet Pressure	MPa (psia)	10.4 (1,515)
Inlet Temperature	°C (°F)	26 (79)
N_2 Concentration	ppmv	< 300
O_2 Concentration	ppmv	< 40
Ar Concentration	ppmv	< 10

- The CO_2 is transported 80 kilometers (50 miles) via pipeline to a geologic sequestration field for injection into a saline formation.
- The CO_2 is transported and injected as a supercritical fluid in order to avoid two-phase flow and achieve maximum efficiency. [24] The pipeline is assumed to have an outlet

pressure (above the supercritical pressure) of 10.4 MPa (1,515 psia) with no recompression along the way. Accordingly, CO_2 flow in the pipeline was modeled to determine the pipe diameter that results in a pressure drop of 4.8 MPa (700 psi) over an 80 kilometer (50 mile) pipeline length. [25] (Although not explored in this study, the use of boost compressors and a smaller pipeline diameter could possibly reduce capital costs for sufficiently long pipelines.) The diameter of the injection pipe will be of sufficient size that frictional losses during injection are minimal and no booster compression is required at the well-head in order to achieve an appropriate down-hole pressure.

- The saline formation is at a depth of 1,239 meters (4,055 ft) and has a permeability of 22 millidarcy (a measure of permeability defined as roughly 10^{-12} Darcy) and formation pressure of 8.4 MPa (1,220 psig). [23] This is considered an average storage site and requires roughly one injection well for each 9,360 tonnes (10,320 short tons) of CO_2 injected per day. [23] The assumed aquifer characteristics are tabulated in Exhibit 2-12.

Exhibit 2-12 Deep, Saline Aquifer Specification

Parameter	Units	Base Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	md	22
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (ton) CO_2/day	9,360 (10,320)

For CO_2 transport and storage, capital and O&M costs were assessed using metrics from a 2001 Battelle report. [24] These costs were scaled from the 1999-year dollars described in the report to Dec-2006-year dollars using U.S. Bureau of Labor Statistics (BLS) Producer Price Indices for the oil and gas industry and the *Chemical Engineering* Plant Cost Index. Project and process contingencies of thirty and twenty percent, respectively, were applied to the Battelle costs to cover additional costs that are expected to arise from: i) developing a more detailed project definition, and ii) using technologies that have not been well-demonstrated to date in a similar commercial application.

For CO_2 monitoring, costs were assessed using metrics for a saline formation “enhanced monitoring package” as reported in a 2004 International Energy Agency (IEA) report. [26] The IEA report presented costs for two types of saline formations: those with low and high residual gas saturations. The reported monitoring costs were higher for saline formations with low residual gas saturation, and those costs were used as the basis for this report. The IEA report calculated the present value of life-cycle monitoring costs using a ten percent discount rate. The present value cost included the initial capital cost for monitoring as well as O&M costs for monitoring over a period of eighty years (a thirty-year injection period followed by fifty years of post-injection monitoring).

For this study, the present value reported in the IEA report was adjusted from Nov-2004-year dollars to Dec-2006-year dollars using U.S. BLS Producer Price Indices for the oil and gas industry. Project and process contingencies of thirty and thirty-five percent, respectively, were applied to the IEA value to cover additional costs that are expected to arise as described above. The resulting metric used for this report is a present value of \$0.176 per metric ton of CO_2 stored over a thirty-year injection period.

In accordance with the IEA's present-value, life-cycle methodology, this report levelized monitoring costs over a twenty-year period by simply applying a capital charge factor to the present value of life-cycle monitoring costs (10 percent discount rate). This approach is representative of a scenario in which the power plant owner establishes a "CO_2 Monitoring Fund" prior to plant startup that is equal to the present value of life-cycle monitoring costs. Establishing such a fund at the outset could allay concerns about the availability of funds to pay for monitoring during the post-injection period, when the plant is no longer operating. While it is recognized that other, more nuanced, approaches could be taken to levelizing eighty years of monitoring costs over a twenty-year period, the approach applied in this report was chosen because it is simple to describe and should result in a conservative (i.e., higher) estimate of the funds required.

Levelized Cost of Electricity

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit in this report is cost of electricity (COE) levelized over a 20 year period and expressed in mills/kWh (numerically equivalent to \$/MWh). The 20-year LCOE was calculated using a simplified model derived from the NETL Power Systems Financial Model. [27]

The equation used to calculate LCOE is as follows:

$$LCOE_P = \frac{(CCF_P)(TPC) + [(LF_{F1})(OC_{F1}) + (LF_{F2})(OC_{F2}) + \ldots] + (CF)[(LF_{V1})(OC_{V1}) + (LF_{V2})(OC_{V2}) + \ldots]}{(CF)(MWh)}$$

where

$LCOE_P$ =	levelized cost of electricity over P years, \$/MWh
P =	levelization period (e.g., 10, 20 or 30 years)
CCF =	capital charge factor for a levelization period of P years
TPC =	total plant cost, \$
LF_{Fn} =	levelization factor for category n fixed operating cost
OC_{Fn} =	category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)
CF =	plant capacity factor

LF_{Vn} = levelization factor for category n variable operating cost

OC_{Vn} = category n variable operating cost at 100 percent capacity factor for the initial year of operation (but expressed in “first-year-of-construction” year dollars)

MWh = annual net megawatt-hours of power generated at 100 percent capacity factor

All costs are expressed in “first-year-of-construction” year dollars, and the resulting LCOE is also expressed in “first-year-of-construction” year dollars. In this study the first year of plant construction is assumed to be 2007, and the resulting LCOE is expressed in year 2007 dollars. The capital cost in December 2006 dollars was treated as a 2007 year cost.

In CO_2 capture cases, the LCOE for TS&M costs was added to the LCOE calculated using the above equation to generate a total cost including CO_2 capture, sequestration and subsequent monitoring.

Although their useful life is usually well in excess of thirty years, a twenty-year levelization period is typically used for large energy conversion plants and is the levelization period used in this study.

The technologies modeled in this study were divided into one of two categories for calculating LCOE: investor owned utility (IOU) high risk and IOU low risk. All IGCC cases as well as PC and NGCC cases with CO_2 capture are considered high risk. The non-capture PC and NGCC cases are considered low risk. The resulting capital charge factor and levelization factors are shown in Exhibit 2-13.

Exhibit 2-13 Economic Paramenters for LCOE Calculation

	High Risk	Low Risk	Nominal Escalation, %[1]
Capital Charge Factor	0.175	0.164	N/A
Coal Levelization Factor	1.2022	1.2089	2.35
Natural Gas Levelization Factor	1.1651	1.1705	1.96
General O&M Levelization Factor	1.1568	1.1618	1.87

[1] Nominal escalation is the real escalation plus the general annual average inflation rate of 1.87 percent.

The economic assumptions used to derive the capital charge factors are shown in Exhibit 2-14. The difference between the high risk and low risk categories is manifested in the debt-to-equity ratio and the weighted cost of capital. The values used to generate the capital charge factors and levelization factors in this study are shown in Exhibit 2-15.

Exhibit 2-14 Parameter Assumptions for Capital Charge Factors

Parameter	Value
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Depreciation	20 years, 150% declining balance
Working Capital	zero for all parameters
Plant Economic Life	30 years
Investment Tax Credit	0%
Tax Holiday	0 years
Start-Up Costs (% of EPC)[1]	2%
All other additional capital costs ($)	0
EPC escalation	0%
Duration of Construction	3 years

[1] EPC costs equal total plant costs less contingencies

Exhibit 2-15 Financial Structure for Investor Owned Utility High and Low Risk Projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
Low Risk				
Debt	50	9%	4.5%	2.79%
Equity	50	12%	6%	6%
Total			11%	8.79%
High Risk				
Debt	45	11%	4.95%	3.07%
Equity	55	12%	6.6%	6.6%
Total			11.55%	9.67%

2.8 IGCC STUDY COST ESTIMATES COMPARED TO INDUSTRY ESTIMATES

The estimated TPC for IGCC cases in this study ranges from $1,733kW to $1,977/kW for non-$CO_2$ capture cases and $2,390/kW to $2,668/kW for capture cases. Plant size ranges from 623 - 636 MW (net) for non-capture cases and 517 - 556 MW (net) for capture cases.

Within the power industry there are several power producers interested in pursuing construction of an IGCC plant. While these projects are still in the relatively early stages of development, some cost estimates have been published. Published estimates tend to be limited in detail, leaving it to the reader to speculate as to what is contained within the estimate. Published estimates for gasification plants consisting of two gasifier trains range from $2,206/kW to $3,175/kW. [28, 29] Corresponding plant sizes range from 600 - 680 MW. Since none of the published estimates state that CO_2 capture is included, it is assumed that they do not include CO_2 capture or compression equipment.

In comparing costs published in this study to those published by industry, it is important to recognize that the estimates contained in this study are based on a very specific set of criteria for the purpose of comparing the various technologies. Site specific costs and owner’s costs are not included in this report. Excluding these costs is appropriate for a government-sponsored analysis as owner's costs often include varying levels of profits depending on the current market. For example, there is presently a shortage of qualified EPC companies for constructing new power plants, so these companies can demand a very high price for their services. Endorsing these historically high rates as being reasonable, or even attempting to predict them, especially since it may represent a very short-lived market imbalance, is not an appropriate role for the government. These costs, however, are generally included in industry-published estimates.

Differences in Cost Estimates

Project Scope

For this report, the scope of work is generally limited to work inside the project “fence line”. For outgoing power, the scope stops at the high side terminals of the Generator Step-up Transformers (GSU’s).

Some typical examples of items outside the fenceline include:

- New access roads and railroad tracks
- Upgrades to existing roads to accommodate increased traffic
- Makeup water pipe outside the fenceline
- Landfill for on-site waste (slag) disposal
- Natural gas line for backup fuel provisions
- Plant switchyard
- Electrical transmission lines & substation

Estimates in this report are based on a generic mid-western greenfield site having “normal” characteristics. Accordingly, the estimates do not address items such as:

- Piles or caissons
- Rock removal
- Excessive dewatering
- Expansive soil considerations
- Excessive seismic considerations
- Extreme temperature considerations
- Hazardous or contaminated soils
- Demolition or relocation of existing structures
- Leasing of offsite land for parking or laydown

- Busing of craft to site
- Costs of offsite storage

This report is based on a reasonably "standard" plant. No unusual or extraordinary process equipment is included such as:

- Excessive water treatment equipment
- Air-cooled condenser
- Automated coal reclaim
- Zero Liquid Discharge equipment
- Selective catalytic reduction catalyst

For non-capture cases, which are likely the most appropriate comparison against industry published estimates, this report is based on plant equipment sized for non-capture only. None of the equipment is sized to accommodate a future conversion to CO_2 capture.

Labor

This report is based on Merit Shop (non-union) labor. If a project is to use Union labor, there is a strong likelihood that overall labor costs will be greater than those estimated in this report.

This report is based on a 50 hour work week, with an adequate local supply of skilled craft labor. No additional incentives such as per-diems or bonuses have been included to attract and retain skilled craft labor. The construction industry is currently experiencing severe shortages in craft labor. Accordingly, published costs likely include any anticipated labor premiums.

Contracting Methodology

The estimates in this report are based on a competitively bid, multiple subcontract approach, often referred to as EPCM. Accordingly, the estimates do not include premiums associated with an EPC approach. It is believed that, given current market conditions, the premium charged by an EPC contractor could be as much as 30 percent or more over an EPCM approach.

Escalation

All of the estimates included in this report are based on December, 2006 "overnight" costs. No escalation has been added to reflect period of performance dollars. Overall project duration for plants of this type could be as much as five years or more.

Owner's Costs

Owner's costs are excluded from the estimates in this report. Owner's costs as a percentage of TPC can vary dramatically. Conceivably, owner's costs can range from 15 to 25 percent of TPC. Typical Owner's costs include, but are not limited to, the following:

- Permits and licensing (other than construction permits)
- Land acquisition / Rights of way costs
- Economic development
- Project development costs
- Legal fees
- Owner's Engineering / Project and Construction Management Staff

- Plant operators during startup
- Electricity consumed during startup
- Fuel and reagents consumed during startup
- Transmission interconnections and upgrades
- Taxes (other than EPCM payroll taxes)
- Operating spare parts
- Furnishings for new office, warehouse and laboratory
- Financing costs

Most if not all of these cost elements are likely included in published estimates. The addition of these elements to this report would explain most, if not all, of the disparities between estimates in the report and published costs.

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3 IGCC POWER PLANTS

Six IGCC power plant configurations were evaluated and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available to support startup in 2010.

The six cases are based on the GEE gasifier, the CoP E-Gas™ gasifier and the Shell gasifier, each with and without CO_2 capture. As discussed in Section 1, the net output for the six cases varies because of the constraint imposed by the fixed gas turbine output and the high auxiliary loads imparted by the CO_2 capture process.

The combustion turbine is based on an advanced F-class design. The HRSG/steam turbine cycle is 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) for all of the non-CO_2 capture cases and 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) for all of the CO_2 capture cases. The capture cases have a lower main and reheat steam temperature primarily because the turbine firing temperature is reduced to allow for a parts life equivalent to NGCC operation with a high-hydrogen content fuel, which results in a lower turbine exhaust temperature.

The evaluation scope included developing heat and mass balances and estimating plant performance. Equipment lists were developed for each design to support plant capital and operating cost estimates. The evaluation basis details, including site ambient conditions, fuel composition and environmental targets, were provided in Section 2. Section 3.1 covers general information that is common to all IGCC cases, and case specific information is subsequently presented in Sections 3.2, 3.3 and 3.4.

3.1 IGCC COMMON PROCESS AREAS

The IGCC cases have process areas which are common to each plant configuration such as coal receiving and storage, oxygen supply, gas cleanup, power generation, etc. As detailed descriptions of these process areas for each case would be burdensome and repetitious, they are presented in this section for general background information. Where there is case-specific performance information, the performance features are presented in the relevant case sections.

3.1.1 COAL RECEIVING AND STORAGE

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. Coal receiving and storage is identical for all six IGCC cases; however, coal preparation and feed are gasifier-specific.

Operation Description – The coal is delivered to the site by 100-car unit trains comprised of 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

The reclaimer loads the coal into two vibratory feeders located in the reclaim hopper under the pile. The feeders transfer the coal onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3 cm x 0 (1¼" x 0) by the crusher. A conveyor then transfers the coal to a transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of three silos. Two sampling systems are supplied: the as-received sampling system and the as-fired sampling system. Data from the analyses are used to support the reliable and efficient operation of the plant.

3.1.2 AIR SEPARATION UNIT (ASU) CHOICE AND INTEGRATION

In order to economically and efficiently support IGCC projects, air separation equipment has been modified and improved in response to production requirements and the consistent need to increase single train output. "Elevated pressure" air separation designs have been implemented that result in distillation column operating pressures that are about twice as high as traditional plants. In this study, the main air compressor discharge pressure was set at 1.3 MPa (190 psia) compared to a traditional ASU plant operating pressure of about 0.7 MPa (105 psia). [30] For IGCC designs the elevated pressure ASU process minimizes power consumption and decreases the size of some of the equipment items. When the air supply to the ASU is integrated with the gas turbine, the ASU operates at or near the supply pressure from the gas turbine's air compressor.

Residual Nitrogen Injection

The residual nitrogen that is available after gasifier oxygen and nitrogen requirements have been met is often compressed and sent to the gas turbine. Since all product streams are being compressed, the ASU air feed pressure is optimized to reduce the total power consumption and to provide a good match with available compressor frame sizes.

Increasing the diluent flow to the gas turbine by injecting residual nitrogen from the ASU can have a number of benefits, depending on the design of the gas turbine:

- Increased diluent increases mass flow through the turbine, thus increasing the power output of the gas turbine while maintaining optimum firing temperatures for syngas operation. This is particularly beneficial for locations where the ambient temperature and/or elevation are high and the gas turbine would normally operate at reduced output.
- By mixing with the syngas or by being injected directly into the combustor, the diluent nitrogen lowers the firing temperature (relative to natural gas) and reduces the formation of NOx.

In this study, the ASU nitrogen product was used as the primary diluent with a design target of reducing the syngas lower heating value (LHV) to 4.5-4.8 MJ/Nm^3 (120-128 Btu/scf). If the amount of available nitrogen was not sufficient to meet this target, additional dilution was provided through syngas humidification, and if still more dilution was required, the third option was steam injection.

Air Integration

Integration between the ASU and the combustion turbine can be practiced by extracting some, or all, of the ASU's air requirement from the gas turbine. Medium Btu syngas streams result in a higher mass flow than natural gas to provide the same heat content to the gas turbine. Some gas turbine designs may need to extract air to maintain stable compressor or turbine operation in response to increased fuel flow rates. Other gas turbines may balance air extraction against injection of all of the available nitrogen from the ASU. The amount of air extracted can also be varied as the ambient temperature changes at a given site to optimize year-round performance.

An important aspect of air-integrated designs is the need to efficiently recover the heat of compression contained in the air extracted from the gas turbine. Extraction air temperature is normally in the range 399 - 454°C (750 - 850°F), and must be cooled to the last stage main air compressor discharge temperature prior to admission to the ASU. High-level recovery from the extracted air occurs by transferring heat to the nitrogen stream to be injected into the gas turbine with a gas-to-gas heat exchanger.

Elevated Pressure ASU Experience in Gasification

The Buggenum, Netherlands unit built for Demkolec was the first elevated-pressure, fully integrated ASU to be constructed. It was designed to produce up to 1,796 tonnes/day (1,980 TPD) of 95 percent purity oxygen for a Shell coal-based gasification unit that fuels a Siemens V94.2 gas turbine. In normal operation at the Buggenum plant the ASU receives all of its air supply from and sends all residual nitrogen to the gas turbine.

The Polk County, Florida ASU for the Tampa Electric IGCC is also an elevated-pressure, 95 percent purity oxygen design that provides 1,832 tonnes/day (2,020 TPD) of oxygen to a GEE coal-based gasification unit, which fuels a General Electric 7FA gas turbine. All of the nitrogen produced in the ASU is used in the gas turbine. The original design did not allow for air extraction from the combustion turbine. After a combustion turbine air compressor failure in January, 2005, a modification was made to allow air extraction which in turn eliminated a bottleneck in ASU capacity and increased overall power output. [31]

ASU Basis

For this study, air integration is used for the non-carbon capture cases only. In the carbon capture cases, once the syngas is diluted to the target heating value, all of the available combustion air is required to maintain mass flow through the turbine and hence maintain power output.

The amount of air extracted from the gas turbine in the non-capture cases is determined through a process that includes the following constraints:

- The combustion turbine output must be maintained at 232 MW.
- The diluted syngas must meet heating value requirements specified by a combustion turbine vendor, which ranged from 4.5-4.8 MJ/Nm^3 (120-128 Btu/scf) (LHV).

Meeting the above constraints resulted in different levels of air extraction in the three non-carbon capture cases as shown in Exhibit 3-1. It was not a goal of this project to optimize the integration of the combustion turbine and the ASU, although several recent papers have shown that providing 25-30 percent of the ASU air from the turbine compressor provides the best balance between maximizing plant output and efficiency without compromising plant availability or reliability. [32, 33]

Exhibit 3-1 Air Extracted from the Combustion Turbine and Supplied to the ASU in Non-Carbon Capture Cases

Case No.	1	3	5
Gasifier	GEE	CoP	Shell
Air Extracted from Gas Turbine, %	4.1	4.9	6.7
Air Provided to ASU, % of ASU Total	15.7	22.3	31.0

Air Separation Plant Process Description [34]

The air separation plant is designed to produce 95 mole percent O_2 for use in the gasifier. The plant is designed with two production trains, one for each gasifier. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as dilution in the gas turbine combustor. A process schematic of a typical ASU is shown in Exhibit 3-2.

The air feed to the ASU is supplied from two sources. A portion of the air is extracted from the compressor of the gas turbine (non-CO_2 capture cases only). The remaining air is supplied from a stand-alone compressor. Air to the stand-alone compressor is first filtered in a suction filter upstream of the compressor. This air filter removes particulate, which may tend to cause compressor wheel erosion and foul intercoolers. The filtered air is then compressed in the centrifugal compressor, with intercooling between each stage.

Air from the stand-alone compressor is combined with the extraction air, and the combined stream is cooled and fed to an adsorbent-based pre-purifier system. The adsorbent removes water, carbon dioxide, and C_4+ saturated hydrocarbons in the air. After passing through the adsorption beds, the air is filtered with a dust filter to remove any adsorbent fines that may be present. Downstream of the dust filter a small stream of air is withdrawn to supply the instrument air requirements of the ASU.

Regeneration of the adsorbent in the pre-purifiers is accomplished by passing a hot nitrogen stream through the off-stream bed(s) in a direction countercurrent to the normal airflow. The nitrogen is heated against extraction steam (1.7 MPa [250 psia]) in a shell and tube heat exchanger. The regeneration nitrogen drives off the adsorbed contaminants. Following regeneration, the heated bed is cooled to near normal operating temperature by passing a cool nitrogen stream through the adsorbent beds. The bed is re-pressurized with air and placed on stream so that the current on-stream bed(s) can be regenerated.

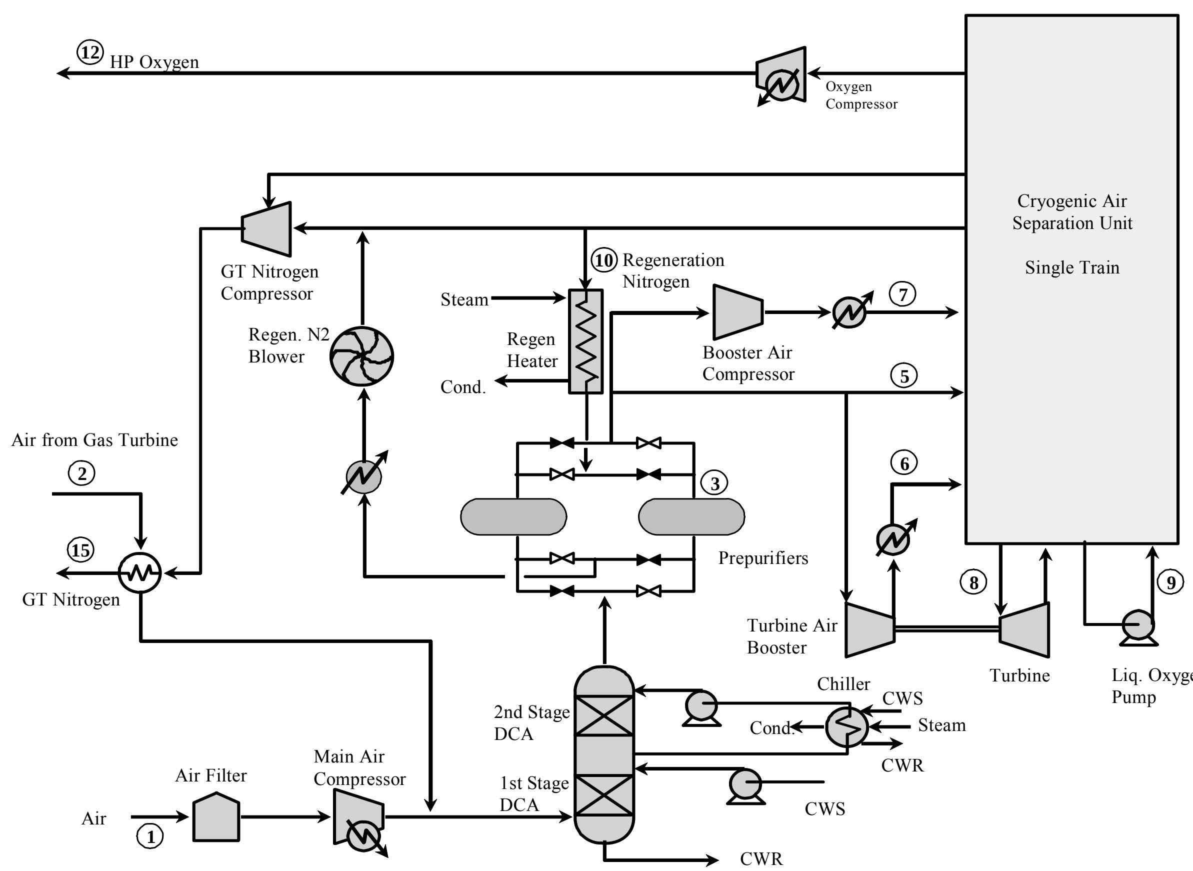
The air from the pre-purifier is then split into three streams. About 70 percent of the air is fed directly to the cold box. About 25 percent of the air is compressed in an air booster compressor. This boosted air is then cooled in an aftercooler against cooling water in the first stage and against chilled water in the second stage before it is fed to the cold box. The chiller utilizes low pressure process steam at 0.3 MPa (50 psia). The remaining 5 percent of the air is fed to a turbine-driven, single-stage, centrifugal booster compressor. This stream is cooled in a shell and tube aftercooler against cooling water before it is fed to the cold box.

All three air feeds are cooled in the cold box to cryogenic temperatures against returning product oxygen and nitrogen streams in plate-and-fin heat exchangers. The large air stream is fed directly to the first distillation column to begin the separation process. The second largest air stream is liquefied against boiling liquid oxygen before it is fed to the distillation columns. The third, smallest air stream is fed to the cryogenic expander to produce refrigeration to sustain the cryogenic separation process.

Inside the cold box the air is separated into oxygen and nitrogen products. The oxygen product is withdrawn from the distillation columns as a liquid and is pressurized by a cryogenic pump. The pressurized liquid oxygen is then vaporized against the high-pressure air feed before being warmed to ambient temperature. The gaseous oxygen exits the cold box and is fed to the centrifugal compressor with intercooling between each stage of compression. The compressed oxygen is then fed to the gasification unit.

Nitrogen is produced from the cold box at two pressure levels. Low-pressure nitrogen is split into two streams. The majority of the low-pressure nitrogen is compressed and fed to the gas turbine as diluent nitrogen. A small portion of the nitrogen is used as the regeneration gas for the pre-purifiers and recombined with the diluent nitrogen. A high-pressure nitrogen stream is also produced from the cold box and is further compressed before it is also supplied to the gas turbine.

Exhibit 3-2 Typical ASU Process Schematic



3.1.3 WATER GAS SHIFT REACTORS

Selection of Technology - In the cases with CO_2 separation and capture, the gasifier product must be converted to hydrogen-rich syngas. The first step is to convert most of the syngas carbon monoxide (CO) to hydrogen and CO_2 by reacting the CO with water over a bed of catalyst. The H_2O:CO molar ratio in the shift reaction, shown below, is adjusted to approximately 2: 1 by the addition of steam to the syngas stream thus promoting a high conversion of CO. In the cases without CO_2 separation and capture, CO shift convertors are not required.

Water Gas Shift: $CO + H_2O \leftrightarrow CO_2 + H_2$

The CO shift converter can be located either upstream of the acid gas removal step (sour gas shift) or immediately downstream (sweet gas shift). If the CO converter is located downstream of the acid gas removal, then the metallurgy of the unit is less stringent but additional equipment must be added to the process. Products from the gasifier are humidified with steam or water and contain a portion of the water vapor necessary to meet the water-to-gas criteria at the reactor inlet. If the CO converter is located downstream of the acid gas removal, then the gasifier product would first have to be cooled and the free water separated and treated. Then additional steam would have to be generated and re-injected into the CO converter feed to meet the required water-to-gas ratio. If the CO converter is located upstream of the acid gas removal step, no additional equipment is required. This is because the CO converter promotes carbonyl sulfide (COS) hydrolysis without a separate catalyst bed. Therefore, for this study the CO converter was located upstream of the acid gas removal unit and is referred to as sour gas shift (SGS).

Process Description - The SGS consists of two paths of parallel fixed-bed reactors arranged in series. Two reactors in series are used in each parallel path to achieve sufficient conversion to meet the 90 percent CO_2 capture target in the Shell and GEE gasifier cases. In the CoP case, a third shift reactor is added to each path to increase the CO conversion. Even with the third reactor added, CO_2 capture is only 88.4 percent in the CoP case because of the relatively high amount of CH_4 present in the syngas.

Cooling is provided between the series of reactors to control the exothermic temperature rise. The parallel set of reactors is required due to the high gas mass flow rate. In all three CO_2 capture cases the heat exchanger after the first SGS reactor is used to vaporize water that is then used to adjust the syngas H_2O:CO ratio to 2:1 on a molar basis. The heat exchanger after the second SGS reactor is used to raise IP steam which then passes through the reheater section of the HRSG in the GEE and CoP cases, and is used to preheat the syngas prior to the first SGS reactor in the Shell case. Approximately 96 percent conversion of the CO is achieved in the GEE and Shell cases, and about 98 percent conversion is achieved in the CoP case.

3.1.4 MERCURY REMOVAL

An IGCC power plant has the potential of removing mercury in a more simple and cost-effective manner than conventional PC plants. This is because mercury can be removed from the syngas at elevated pressure and prior to combustion so that syngas volumes are much smaller than flue gas volumes in comparable PC cases. A conceptual design for a carbon bed adsorption system was developed for mercury control in the IGCC plants being studied. Data on the performance of carbon bed systems were obtained from the Eastman Chemical Company, which uses carbon beds at its syngas facility in Kingsport, Tennessee.[12] The coal mercury content (0.15 ppm dry) and carbon bed removal efficiency (95 percent) were discussed previously in Section 2.4. IGCC-specific design considerations are discussed below.

Carbon Bed Location – The packed carbon bed vessels are located upstream of the sulfur recovery unit and syngas enters at a temperature near 38°C (100°F). Consideration was given to locating the beds further upstream before the COS hydrolysis unit (in non-CO_2 capture cases) at a temperature near 204°C (400°F). However, while the mercury removal efficiency of carbon has been found to be relatively insensitive to pressure variations, temperature adversely affects the removal efficiency. [35] Eastman Chemical also operates their beds ahead of their sulfur recovery unit at a temperature of 30°C (86°F). [12]

Consideration was also given to locating the beds downstream of the sulfur recovery unit (SRU). However, it was felt that removing the mercury and other contaminants before the sulfur recovery unit would enhance the performance of the SRU and increase the life of the various solvents.

Process Parameters – An empty vessel basis gas residence time of approximately 20 seconds was used based on Eastman Chemical's experience. [12] Allowable gas velocities are limited by considerations of particle entrainment, bed agitation, and pressure drop. One-foot-per-second superficial velocity is in the middle of the range normally encountered [35] and was selected for this application.

The bed density of 30 lb/ft^3 was based on the Calgon Carbon Corporation HGR-P sulfur-impregnated pelletized activated carbon. [36] These parameters determined the size of the vessels and the amount of carbon required. Each gasifier train has one mercury removal bed and there are two gasifier trains in each IGCC case, resulting in two carbon beds per case.

Carbon Replacement Time – Eastman Chemicals replaces its bed every 18 to 24 months. [12] However, bed replacement is not because of mercury loading, but for other reasons including:

- A buildup in pressure drop
- A buildup of water in the bed
- A buildup of other contaminants

For this study a 24 month carbon replacement cycle was assumed. Under these assumptions, the mercury loading in the bed would build up to 0.6 - 1.1 weight percent (wt%). Mercury capacity of sulfur-impregnated carbon can be as high as 20 wt%. [37] The mercury laden carbon is considered to be a hazardous waste, and the disposal cost estimate reflects this categorization.

3.1.5 ACID GAS REMOVAL (AGR) PROCESS SELECTION

Gasification of coal to generate power produces a syngas that must be treated prior to further utilization. A portion of the treatment consists of acid gas removal (AGR) and sulfur recovery. The environmental target for these IGCC cases is 0.0128 lb SO_2/MMBtu, which requires that the total sulfur content of the syngas be reduced to less than 30 ppmv. This includes all sulfur species, but in particular the total of COS and H_2S, thereby resulting in stack gas emissions of less than 4 ppmv SO_2.

COS Hydrolysis

The use of COS hydrolysis pretreatment in the feed to the acid gas removal process provides a means to reduce the COS concentration. This method was first commercially proven at the Buggenum plant, and was also used at both the Tampa Electric and Wabash River IGCC projects. Several catalyst manufacturers including Haldor Topsoe and Porocel offer a catalyst that promotes the COS hydrolysis reaction. The non-carbon capture COS hydrolysis reactor designs are based on information from Porocel. In cases with carbon capture, the SGS reactors reduce COS to H_2S as discussed in Section 3.1.3.

The COS hydrolysis reaction is equimolar with a slightly exothermic heat of reaction. The reaction is represented as follows.

$$COS + H_2O \leftrightarrow CO_2 + H_2S$$

Since the reaction is exothermic, higher conversion is achieved at lower temperatures. However, at lower temperatures the reaction kinetics are slower. Based on the feed gas for this evaluation, Porocel recommended a temperature of 177 to 204°C (350 to 400°F). Since the exit gas COS concentration is critical to the amount of H_2S that must be removed with the AGR process, a retention time of 50-75 seconds was used to achieve 99.5 percent conversion of the COS. The Porocel activated alumina-based catalyst, designated as Hydrocel 640 catalyst, promotes the COS hydrolysis reaction without promoting reaction of H_2S and CO to form COS and H_2.

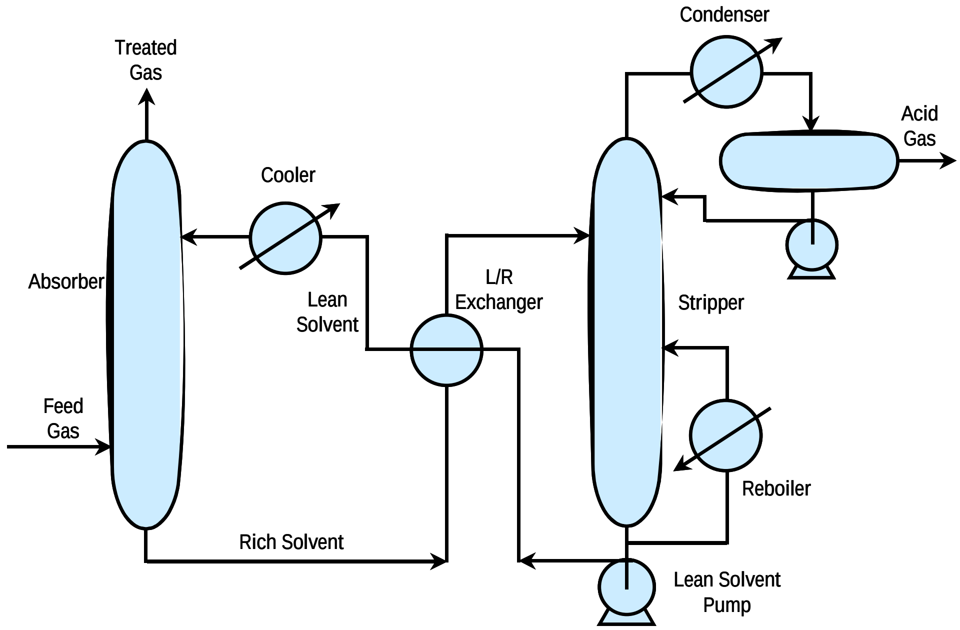
Although the reaction is exothermic, the heat of reaction is dissipated among the large amount of non-reacting components. Therefore, the reaction is essentially isothermal. The product gas, now containing less than 4 ppmv of COS, is cooled prior to entering the mercury removal process and the AGR.

Sulfur Removal

Hydrogen sulfide removal generally consists of absorption by a regenerable solvent. The most commonly used technique is based on countercurrent contact with the solvent. Acid-gas-rich solution from the absorber is stripped of its acid gas in a regenerator, usually by application of heat. The regenerated lean solution is then cooled and recirculated to the top of the absorber, completing the cycle. Exhibit 3-3 is a simplified diagram of the AGR process. [38]

There are well over 30 AGR processes in common commercial use throughout the oil, chemical, and natural gas industries. However, in a 2002 report by SFA Pacific a list of 42 operating and planned gasifiers shows that only six AGR processes are represented: Rectisol, Sulfinol, methyldiethanolamine (MDEA), Selexol, aqueous di-isoproponal (ADIP) amine and FLEXSORB. [40] These processes can be separated into three general types: chemical reagents, physical solvents, and hybrid solvents.

Exhibit 3-3 Flow Diagram for a Conventional AGR Unit



Chemical Solvents

Frequently used for acid gas removal, chemical solvents are more suitable than physical or hybrid solvents for applications at lower operating pressures. The chemical nature of acid gas absorption makes solution loading and circulation less dependent on the acid gas partial pressure. Because the solution is aqueous, co-absorption of hydrocarbons is minimal. In a conventional amine unit, the chemical solvent reacts exothermically with the acid gas constituents. They form a weak chemical bond that can be broken, releasing the acid gas and regenerating the solvent for reuse.

In recent years MDEA, a tertiary amine, has acquired a much larger share of the gas-treating market. Compared with primary and secondary amines, MDEA has superior capabilities for selectively removing H_2S in the presence of CO_2, is resistant to degradation by organic sulfur compounds, has a low tendency for corrosion, has a relatively low circulation rate, and consumes less energy. Commercially available are several MDEA-based solvents that are formulated for high H_2S selectivity.

Chemical reagents are used to remove the acid gases by a reversible chemical reaction of the acid gases with an aqueous solution of various alkanolamines or alkaline salts in water. Exhibit 3-4 lists commonly used chemical reagents along with principal licensors that use them in their processes. The process consists of an absorber and regenerator, which are connected by a circulation of the chemical reagent aqueous solution. The absorber contacts the lean solution with the main gas stream (at pressure) to remove the acid gases by absorption/ reaction with the chemical solution. The acid-gas-rich solution is reduced to low pressure and heated in the stripper to reverse the reactions and strip the acid gas. The acid-gas-lean solution leaves the bottom of the regenerator stripper and is cooled, pumped to the required pressure and recirculated back to the absorber. For some amines, a filter and a separate reclaiming section (not shown) are needed to remove undesirable reaction byproducts.

Exhibit 3-4 Common Chemical Reagents Used in AGR Processes

Chemical Reagent	Acronym	Process Licensors Using the Reagent
Monoethanolamine	MEA	Dow, Exxon, Lurgi, Union Carbide
Diethanolamine	DEA	Elf, Lurgi
Diglycolamine	DGA	Texaco, Fluor
Triethanolamine	TEA	AMOCO
Diisopropanolamine	DIPA	Shell
Methyldiethanolamine	MDEA	BASF, Dow, Elf, Snamprogetti, Shell, Union Carbide, Coastal Chemical
Hindered amine		Exxon
Potassium carbonate	“hot pot”	Eickmeyer, Exxon, Lurgi, Union Carbide

Typically, the absorber temperature is 27 to 49°C (80 to 120°F) for amine processes, and the regeneration temperature is the boiling point of the solutions, generally 104 to 127°C (220 to 260°F). The liquid circulation rates can vary widely, depending on the amount of acid gas being captured. However, the most suitable processes are those that will dissolve 2 to 10 scf acid gas per gallon of solution circulated. Steam consumption can vary widely also: 0.7 to 1.5 pounds per gallon of liquid is typical, with 0.8 to 0.9 being a typical “good” value. Case 3, which utilizes the chemical solvent MDEA, uses 0.88 pounds of steam per gallon of liquid. The steam conditions are 0.45 MPa (65 psia) and 151°C (304°F).

The major advantage of these systems is the ability to remove acid gas to low levels at low to moderate H_2S partial pressures.

Physical Solvents

Physical solvents involve absorption of acid gases into certain organic solvents that have a high solubility for acid gases. As the name implies, physical solvents involve only the physical solution of acid gas – the acid gas loading in the solvent is proportional to the acid gas partial pressure (Henry’s Law). Physical solvent absorbers are usually operated at lower temperatures than is the case for chemical solvents. The solution step occurs at high pressure and at or below ambient temperature while the regeneration step (dissolution) occurs by pressure letdown and indirect stripping with low-pressure 0.45 MPa (65 psia) steam. It is generally accepted that physical solvents become increasingly economical, and eventually superior to amine capture, as the partial pressure of acid gas in the syngas increases.

The physical solvents are regenerated by multistage flashing to low pressures. Because the solubility of acid gases increases as the temperature decreases, absorption is generally carried out at lower temperatures, and refrigeration is often required.

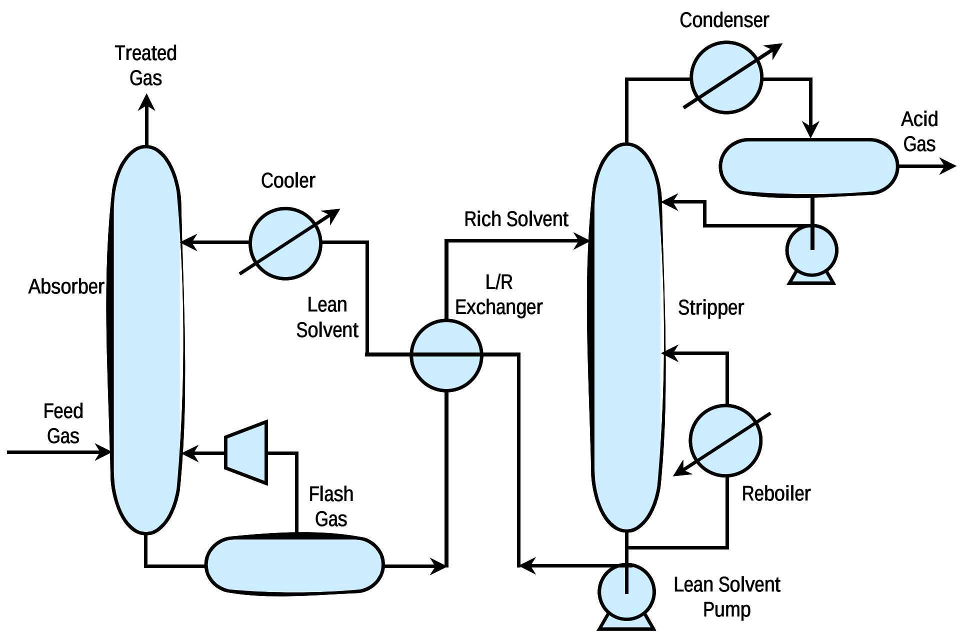
Most physical solvents are capable of removing organic sulfur compounds. Exhibiting higher solubility of H_2S than CO_2, they can be designed for selective H_2S or total acid gas removal. In applications where CO_2 capture is desired the CO_2 is flashed off at various pressures, which reduces the compression work and parasitic power load associated with sequestration.

Physical solvents co-absorb heavy hydrocarbons from the feed stream. Since heavy hydrocarbons cannot be recovered by flash regeneration, they are stripped along with the acid gas during heated regeneration. These hydrocarbon losses result in a loss of valuable product and may lead to CO_2 contamination.

Several physical solvents that use anhydrous organic solvents have been commercialized. They include the Selexol process, which uses dimethyl ether of polyethylene glycol as a solvent; Rectisol, with methanol as the solvent; Purisol, which uses N-methyl-2-pyrrolidone (NMP) as a solvent; and the propylene-carbonate process.

Exhibit 3-5 is a simplified flow diagram for a physical reagent type acid gas removal process. [38] Common physical solvent processes, along with their licensors, are listed in Exhibit 3-6.

Exhibit 3-5 Physical Solvent AGR Process Simplified Flow Diagram



Hybrid Solvents

Hybrid solvents combine the high treated-gas purity offered by chemical solvents with the flash regeneration and lower energy requirements of physical solvents. Some examples of hybrid solvents are Sulfinol, Flexsorb PS, and Ucarsol LE.

Sulfinol is a mixture of sulfolane (a physical solvent), diisopropanolamine (DIPA) or MDEA (chemical solvent), and water. DIPA is used when total acid gas removal is specified, while MDEA provides for selective removal of H_2S.

Exhibit 3-6 Common Physical Solvents Used in AGR Processes

Solvent	Solvent/Process Trade Name	Process Licensors
Dimethyl ether of poly-ethylene glycol	Selexol	UOP
Methanol	Rectisol	Linde AG and Lurgi
Methanol and toluene	Rectisol II	Linde AG
N—methyl pyrrolidone	Purisol	Lurgi
Polyethylene glycol and dialkyl ethers	Sepasolv MPE	BASF
Propylene carbonate	Fluor Solvent	Fluor
Tetrahydrothiophenedioxide	Sulfolane	Shell
Tributyl phosphate	Estasolvan	Uhde and IFP

Flexsorb PS is a mixture of a hindered amine and an organic solvent. Physically similar to Sulfinol, Flexsorb PS is very stable and resistant to chemical degradation. High treated-gas purity, with less than 50 ppmv of CO_2 and 4 ppmv of H_2S, can be achieved. Both Ucarsol LE-701, for selective removal, and LE-702, for total acid gas removal, are formulated to remove mercaptans from feed gas.

Mixed chemical and physical solvents combine the features of both systems. The mixed solvent allows the solution to absorb an appreciable amount of gas at high pressure. The amine portion is effective as a reagent to remove the acid gas to low levels when high purity is desired.

Mixed solvent processes generally operate at absorber temperatures similar to those of the amine-type chemical solvents and do not require refrigeration. They also retain some advantages of the lower steam requirements typical of the physical solvents. Common mixed chemical and physical solvent processes, along with their licensors, are listed in Exhibit 3-7. The key advantage of mixed solvent processes is their apparent ability to remove H_2S and, in some cases, COS to meet very stringent purified gas specifications.

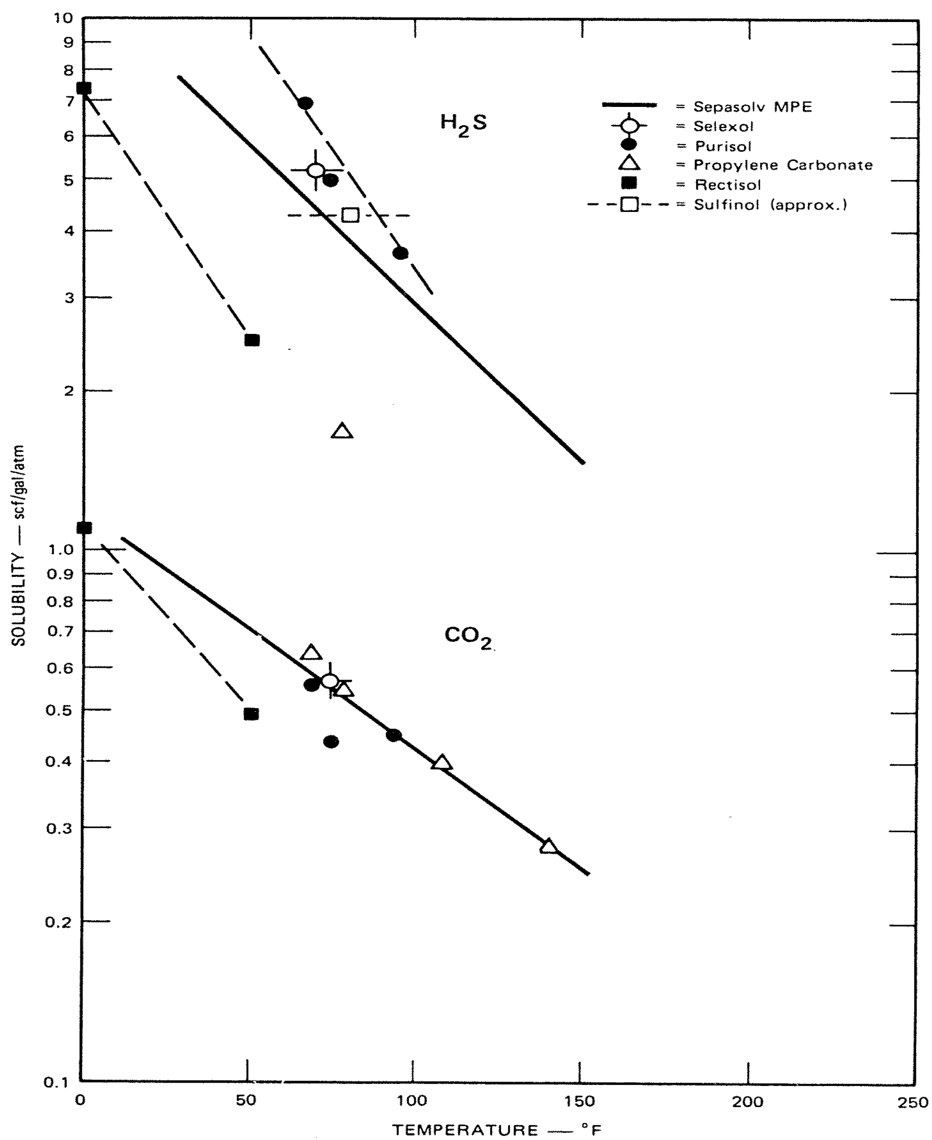
Exhibit 3-8 shows reported equilibrium solubility data for H_2S and CO_2 in various representative solvents [38]. The solubility is expressed as standard cubic feet of gas per gallon liquid per atmosphere gas partial pressure.

The figure illustrates the relative solubilities of CO_2 and H_2S in different solvents and the effects of temperature. More importantly, it shows an order of magnitude higher solubility of H_2S over CO_2 at a given temperature, which gives rise to the selective absorption of H_2S in physical solvents. It also illustrates that the acid gas solubility in physical solvents increases with lower solvent temperatures.

Exhibit 3-7 Common Mixed Solvents Used in AGR Processes

Solvent/Chemical Reagent	Solvent/Process Trade Name	Process Licensors
Methanol/MDEA or diethylamine	Amisol	Lurgi
Sulfolane/MDEA or DIPA	Sulfinol	Shell
Methanol and toluene	Selefining	Snamprogetti
(Unspecified) /MDEA	FLEXSORB PS	Exxon

Exhibit 3-8 Equilibrium Solubility Data on H_2S and CO_2 in Various Solvents



The ability of a process to selectively absorb H_2S may be further enhanced by the relative absorption rates of H_2S and CO_2. Thus, some processes, besides using equilibrium solubility differences, will use absorption rate differences between the two acid gases to achieve selectivity. This is particularly true of the amine processes where the CO_2 and H_2S absorption rates are very different.

CO_2 Capture

A two-stage Selexol process is used for all IGCC capture cases in this study. A brief process description follows.

Untreated syngas enters the first of two absorbers where H_2S is preferentially removed using loaded solvent from the CO_2 absorber. The gas exiting the H_2S absorber passes through the second absorber where CO_2 is removed using first flash regenerated, chilled solvent followed by thermally regenerated solvent added near the top of the column. The treated gas exits the absorber and is sent either directly to the combustion turbine or is partially humidified prior to entering the combustion turbine. A portion of the gas can also be used for coal drying, when required.

The amount of hydrogen recovered from the syngas stream is dependent on the Selexol process design conditions. In this study, hydrogen recovery is 99.4 percent. The minimal hydrogen slip to the CO_2 sequestration stream maximizes the overall plant efficiency. The Selexol plant cost estimates are based on a plant designed to recover this high percentage of hydrogen. For model simplification, a nominal recovery of 100 percent was used with the assumption that the additional 0.6 percent hydrogen sent to the combustion turbine would have a negligible impact on overall system performance.

The CO_2 loaded solvent exits the CO_2 absorber and a portion is sent to the H_2S absorber, a portion is sent to a reabsorber and the remainder is sent to a series of flash drums for regeneration. The CO_2 product stream is obtained from the three flash drums, and after flash regeneration the solvent is chilled and returned to the CO_2 absorber.

The rich solvent exiting the H_2S absorber is combined with the rich solvent from the reabsorber and the combined stream is heated using the lean solvent from the stripper. The hot, rich solvent enters the H_2S concentrator and partially flashes. The remaining liquid contacts nitrogen from the ASU and a portion of the CO_2 along with lesser amounts of H_2S and COS are stripped from the rich solvent. The stripped gases from the H_2S concentrator are sent to the reabsorber where the H_2S and COS that were co-stripped in the concentrator are transferred to a stream of loaded solvent from the CO_2 absorber. The clean gas from the reabsorber is combined with the clean gas from the H_2S absorber and sent to the combustion turbine.

The solvent exiting the H_2S concentrator is sent to the stripper where the absorbed gases are liberated by hot gases flowing up the column from the steam heated reboiler. Water in the overhead vapor from the stripper is condensed and returned as reflux to the stripper or exported as necessary to maintain the proper water content of the lean solvent. The acid gas from the stripper is sent to the Claus plant for further processing. The lean solvent exiting the stripper is first cooled by providing heat to the rich solvent, then further cooled by exchange with the product gas and finally chilled in the lean chiller before returning to the top of the CO_2 absorber.

AGR/Gasifier Pairings

There are numerous commercial AGR processes that could meet the sulfur environmental target of this study. The most frequently used AGR systems (Selexol, Sulfinol, MDEA, and Rectisol) have all been used with the Shell and GE gasifiers in various applications. Both existing E-Gas gasifiers use MDEA, but could in theory use any of the existing AGR technologies. [38] The following selections were made for the AGR process in non-CO_2 capture cases:

- GEE gasifier: Selexol was chosen based on the GE gasifier operating at the highest pressure (815 psia versus 615 psia for CoP and Shell) which favors the physical solvent used in the Selexol process.
- CoP gasifier: Refrigerated MDEA was chosen because the two operating E-Gas gasifiers use MDEA and because CoP lists MDEA as the selected AGR process on their website. [39] Refrigerated MDEA was chosen over conventional MDEA because the sulfur emissions environmental target chosen is just outside of the range of conventional (higher temperature) MDEA.
- Shell gasifier: The Sulfinol process was chosen for this case because it is a Shell owned technology. While the Shell gasifier can and has been used with other AGR processes, it was concluded the most likely pairing would be with the Sulfinol process.

The two-stage Selexol process is used in all three cases that require carbon capture. According to the previously referenced SFA Pacific report, "For future IGCC with CO_2 removal for sequestration, a two-stage Selexol process presently appears to be the preferred AGR process – as indicated by ongoing engineering studies at EPRI and various engineering firms with IGCC interests." [40]

3.1.6 SULFUR RECOVERY/TAIL GAS CLEANUP PROCESS SELECTION

Currently, most of the world's sulfur is produced from the acid gases coming from gas treating. The Claus process remains the mainstay for sulfur recovery. Conventional three-stage Claus plants, with indirect reheat and feeds with a high H_2S content, can approach 98 percent sulfur recovery efficiency. However, since environmental regulations have become more stringent, sulfur recovery plants are required to recover sulfur with over 99.8 percent efficiency. To meet these stricter regulations, the Claus process underwent various modifications and add-ons.

The add-on modification to the Claus plant selected for this study can be considered a separate option from the Claus process. In this context, it is often called a tail gas treating unit (TGTU) process.

The Claus Process

The Claus process converts H_2S to elemental sulfur via the following reactions:

$$H_2S + 3/2\ O_2 \leftrightarrow H_2O + SO_2$$

$$2H_2S + SO_2 \leftrightarrow 2H_2O + 3S$$

The second reaction, the Claus reaction, is equilibrium limited. The overall reaction is:

$$3H_2S + 3/2\ O_2 \leftrightarrow 3H_2O + 3S$$

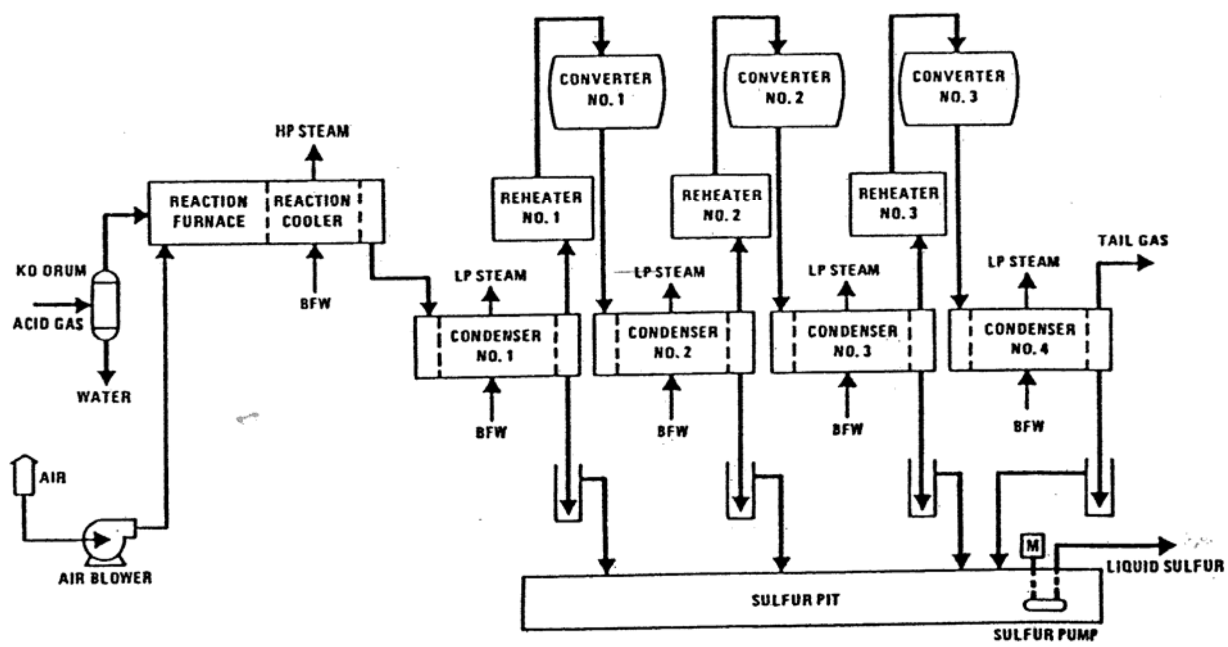
The sulfur in the vapor phase exists as S_2, S_6, and S_8 molecular species, with the S_2 predominant at higher temperatures, and S_8 predominant at lower temperatures.

A simplified process flow diagram of a typical three-stage Claus plant is shown in Exhibit 3-9. [40] One-third of the H_2S is burned in the furnace with oxygen from the air to give sufficient SO_2 to react with the remaining H_2S. Since these reactions are highly exothermic, a waste heat boiler that recovers this heat to generate high-pressure steam usually follows the furnace. Sulfur is condensed in a condenser that follows the high-pressure steam recovery section. Low-pressure steam is raised in the condenser. The tail gas from the first condenser then goes to several catalytic conversion stages, usually 2 to 3, where the remaining sulfur is recovered via the Claus reaction. Each catalytic stage consists of gas preheat, a catalytic reactor, and a sulfur condenser. The liquid sulfur goes to the sulfur pit, while the tail gas proceeds to the incinerator or for further processing in a TGTU.

Claus Plant Sulfur Recovery Efficiency

The Claus reaction is equilibrium limited, and sulfur conversion is sensitive to the reaction temperature. The highest sulfur conversion in the thermal zone is limited to about 75 percent. Typical furnace temperatures are in the range from 1093 to 1427°C (2000 to 2600°F), and as the temperature decreases, conversion increases dramatically.

Exhibit 3-9 Typical Three-Stage Claus Sulfur Plant



Claus plant sulfur recovery efficiency depends on many factors:

- H_2S concentration of the feed gas
- Number of catalytic stages
- Gas reheat method

In order to keep Claus plant recovery efficiencies approaching 94 to 96 percent for feed gases that contain about 20 to 50 percent H_2S, a split-flow design is often used. In this version of the Claus plant, part of the feed gas is bypassed around the furnace to the first catalytic stage, while the rest of the gas is oxidized in the furnace to mostly SO_2. This results in a more stable temperature in the furnace.

Oxygen-Blown Claus

Large diluent streams in the feed to the Claus plant, such as N_2 from combustion air, or a high CO_2 content in the feed gas, lead to higher cost Claus processes and any add-on or tail gas units. One way to reduce diluent flows through the Claus plant and to obtain stable temperatures in the furnace for dilute H_2S streams is the oxygen-blown Claus process.

The oxygen-blown Claus process was originally developed to increase capacity at existing conventional Claus plants and to increase flame temperatures of low H_2S content gases. The process has also been used to provide the capacity and operating flexibility for sulfur plants where the feed gas is variable in flow and composition such as often found in refineries. The application of the process has now been extended to grass roots installations, even for rich H_2S feed streams, to provide operating flexibility at lower costs than would be the case for conventional Claus units. At least four of the recently built gasification plants in Europe use oxygen enriched Claus units.

Oxygen enrichment results in higher temperatures in the front-end furnace, potentially reaching temperatures as high as 1593 to 1649°C (2900 to 3000°F) as the enrichment moves beyond 40 to 70 vol percent O_2 in the oxidant feed stream. Although oxygen enrichment has many benefits, its primary benefit for lean H_2S feeds is a stable furnace temperature. Sulfur recovery is not significantly enhanced by oxygen enrichment. Because the IGCC process already requires an ASU, the oxygen-blown Claus plant was chosen for all cases.

Tail Gas Treating

In many refinery and other conventional Claus applications, tail gas treating involves the removal of the remaining sulfur compounds from gases exiting the sulfur recovery unit. Tail gas from a typical Claus process, whether a conventional Claus or one of the extended versions of the process, usually contains small but varying quantities of COS, CS_2, H_2S, SO_2, and elemental sulfur vapors. In addition, there may be H_2, CO, and CO_2 in the tail gas. In order to remove the rest of the sulfur compounds from the tail gas, all of the sulfur-bearing species must first be converted to H_2S. Then, the resulting H_2S is absorbed into a solvent and the clean gas vented or recycled for further processing. The clean gas resulting from the hydrolysis step can undergo further cleanup in a dedicated absorption unit or be integrated with an upstream AGR unit. The latter option is particularly suitable with physical absorption solvents. The approach of treating the tail gas in a dedicated amine absorption unit and recycling the resulting acid gas to the Claus plant is the one used by the Shell Claus Off-gas Treating (SCOT) process. With tail gas treatment, Claus plants can achieve overall removal efficiencies in excess of 99.9 percent.

In the case of IGCC applications, the tail gas from the Claus plant can be catalytically hydrogenated and then recycled back into the system with the choice of location being technology dependent, or it can be treated with a SCOT-type process. In the two GEE gasifier cases the Claus plant tail gas is hydrogenated, water is separated, the tail gas is compressed and returned to the Selexol process for further treatment. GEE experience at the Polk Power Station is not relevant to this study since the acid gas is converted to sulfuric acid rather than sulfur and the tail gas, containing 150-250 ppm SO_2, is discharged through a dedicated stack. [41] In the two CoP cases the tail gas is treated in the same manner as in the GEE cases except that the recycle endpoint is the gasifier rather than the AGR process. This method is the same as practiced at the CoP Wabash River plant. [42] The two recycle points were chosen based on conversations with the gasifier technology vendors.

In the two Shell cases the Claus tail gas is catalytically hydrogenated and then treated in an amine-based tail gas cleanup process. The bulk of the H_2S in the tail gas is captured and recycled back to the Claus plant inlet gas stream. The sweet gas from the TGTU is combined with a slipstream of clean syngas and the combined stream is combusted in an incinerator. The hot, inert gases from the incinerator are used to dry the feed coal and then vented to atmosphere. Since the Shell Puertollano plant uses a combination of natural gas combustion and IP steam to dry their coal, their tail gas treatment procedure is different than employed in this study. The Claus plant tail gas is hydrogenated and recycled, but the recycle endpoint is not specified. [43]

Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is typically provided to combust and dispose of unreacted gas during startup, shutdown, and upset conditions. However, in all six IGCC cases a flare stack was provided for syngas dumping during startup, shutdown, etc. This flare stack eliminates the need for a separate Claus plant flare.

3.1.7 SLAG HANDLING

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the gasifier pressure boundary through either a proprietary pressure letdown device (CoP) or through the use of lockhoppers (GEE and Shell) to a series of dewatering bins.

The general aspects of slag handling are the same for all three technologies. The slag is dewatered, the water is clarified and recycled and the dried slag is transferred to a storage area for disposal. The specifics of slag handling vary among the gasification technologies regarding how the water is separated and the end uses of the water recycle streams.

In this study the slag bins were sized for a nominal holdup capacity of 72 hours of full-load operation. At periodic intervals, a convoy of slag-hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. Approximately ten truckloads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power. While the slag is suitable for use as a component of road paving mixtures, it was assumed in this study that the slag would be landfilled at a specified cost just as the ash from the PC boiler cases is assumed to be landfilled at the same per ton cost.

3.1.8 POWER ISLAND

Combustion Turbine

The gas turbine generator selected for this application is representative of the advanced F Class turbines. This machine is an axial flow, single spool, and constant speed unit, with variable inlet guide vanes. The turbine includes advanced bucket cooling techniques, compressor aerodynamic design and advanced alloys, enabling a higher firing temperature than the previous generation machines. The standard production version of this machine is fired with natural gas and is also commercially offered for use with IGCC derived syngas, although only earlier versions of the turbine are currently operating on syngas. For the purposes of this study, it was assumed that the advanced F Class turbine will be commercially available to support a 2010 startup date on both conventional and high hydrogen content syngas representative of the cases with CO_2 capture. High H_2 fuel combustion issues like flame stability, flashback and NOx formation were assumed to be solved in the time frame needed to support deployment. However, because these are first-of-a-kind applications, process contingencies were included in the cost estimates as described in Section 2.7. Performance typical of an advanced F class turbine on natural gas at ISO conditions is presented in Exhibit 3-10.

Exhibit 3-10 Advanced F Class Combustion Turbine Performance Characteristics Using Natural Gas

	Advanced F Class
Firing Temperature Class, °C (°F)	1371+ (2500+)
Airflow, kg/s (lb/s)	431 (950)
Pressure Ratio	18.5
NOx Emissions, ppmv	25
Simple Cycle Output, MW	185
Combined cycle performance	
Net Output, MW	280
Net Efficiency (LHV), %	57.5
Net Heat Rate (LHV), kJ/kWh (Btu/kWh)	6,256 (5,934)

In this service, with syngas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the low-Btu gas and expand the combustion products in the turbine section of the machine.

The modifications to the machine include some redesign of the original can-annular combustors. A second modification involves increasing the nozzle areas of the turbine to accommodate the mass and volume flow of low-Btu fuel gas combustion products, which are increased relative to those produced when firing natural gas. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant general arrangement. The generator is a standard hydrogen-cooled machine with static exciter.

Combustion Turbine Package Scope of Supply

The combustion turbine (CT) is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical and control systems as required for CT operation. Site CT installation involves module inter-connection, and linking CT modules to the plant systems. The CT package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. The typical scope of supply is presented in Exhibit 3-11.

Exhibit 3-11 Combustion Turbine Typical Scope of Supply

	System	System Scope
1.0	**ENGINE ASSEMBLY**	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
1.1	Engine Assembly with Bedplate	Variable Inlet Guide, Vane System Compressor, Bleed System, Purge Air System, Bearing Seal Sir System, Combustors, Dual Fuel Nozzles Turbine Rotor Air Cooler
1.2	Walk-in acoustical enclosure	HVAC, Lighting, and Low Pressure CO_2 Fire Protection System
2.0	**MECHANICAL PACKAGE**	HVAC and Lighting, Air Compressor for Pneumatic System, Low Pressure CO_2 Fire Protection System
2.1 2.2	Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister Oil Heaters Oil Interconnect Piping (SS and CS) Oil System Instrumentation Oil for Flushing and First Filling
3.0	**ELECTRICAL PACKAGE**	HVAC and Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant DCS Supervisory System, Bentley Nevada Vibration Monitoring System, Low Pressure CO_2 Fire Protection System, Cable Tray and Conduit Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards
4.0	**INLET AND EXHAUST SYSTEMS**	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self Cleaning Filters, Hoist System For Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Exhaust Silencers Inlet and Exhaust Flow, Pressure and Temperature Ports and Instrumentation
5.0	**FUEL SYSTEMS**	

	System	System Scope
5.1	Fuel Syngas System	Gas Valves Including Vent, Throttle and Trip Valves Gas Filter/Separator Gas Supply Instruments and Instrument Panel
5.2	Backup Fuel System	Specific to backup fuel type
6.0	**STARTING SYSTEM**	Enclosure, Starting Motor or Static Start System, Turning Gear and Clutch Assembly, Starting Clutch Torque Converter
7.0	**GENERATOR**	Static or Rotating Exciter (Excitation transformer to be included for a static system), Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer, and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Generator Breaker, Iso-Phase bus connecting generator and breaker, Grounding System Connectors
7.1	Generator Cooling	TEWAC System (including circulation system, interconnecting piping and controls), or Hydrogen Cooling System (including H_2 to Glycol and Glycol to Air heat exchangers, liquid level detector circulation system, interconnecting piping and controls)
8.0	**Miscellaneous**	Interconnecting Pipe, Wire, Tubing and Cable, Instrument Air System Including Air Dryer, On Line and Off Line Water Wash System, LP CO_2 Storage Tank, Drain System, Drain Tanks, Coupling, Coupling Cover and Associated Hardware

CT Firing Temperature Control Issue for Low Calorific Value Fuel

A gas turbine when fired on low calorific value syngas has the potential to increase power output due to the increase in flow rate through the turbine. The higher turbine flow and moisture content of the combustion products can contribute to overheating of turbine components, affect rating criteria for the parts lives, and require a reduction in syngas firing temperatures (compared to the natural gas firing) to maintain design metal temperature. [44] Uncontrolled syngas firing temperature could result in more than 50 percent life cycle reduction of stage 1 buckets. Control systems for syngas applications include provisions to compensate for these effects by maintaining virtually constant generation output for the range of the specified ambient conditions. Inlet guide vanes (IGV) and firing temperature are used to maintain the turbine output at the maximum torque rating, producing a flat rating up to the IGV full open position. Beyond the IGV full open position, flat output may be extended to higher ambient air temperatures by steam/nitrogen injection.

In this study the firing temperature (defined as inlet rotor temperature) using natural gas in NGCC applications is 1399°C (2550°F) while the firing temperature in the non-capture IGCC cases is 1343-1354°C (2450-2470°F) and in the CO_2 capture cases is 1318-1327°C (2405-

2420°F). The further reduction in firing temperature in the CO_2 capture cases is done to maintain parts life as the H_2O content of the combustion products increases from 8-10 volume percent (vol%) in the non-capture cases to 14-16 vol% in the capture cases. The decrease in temperature also results in the lower temperature steam cycle in the CO_2 capture cases (538°C/538°C [1000°F/1000°F] versus 566°C/566°C [1050°F/1050°F] for non-capture cases).

Combustion Turbine Syngas Fuel Requirements.

Typical fuel specifications and contaminant levels for successful combustion turbine operation are provided in reference [45] and presented for F Class machines in Exhibit 3-12 and Exhibit 3-13. The vast majority of published CT performance information is specific to natural gas operation. Turbine performance using syngas requires vendor input as was obtained for this study.

Exhibit 3-12 Typical Fuel Specification for F-Class Machines

	Max	Min
LHV, kJ/m^3 (Btu/scf)	None	3.0 (100)
Gas Fuel Pressure, MPa (psia)	3.1 (450)	
Gas Fuel Temperature, °C (°F)	(1)	Varies with gas pressure (2)
Flammability Limit Ratio, Rich-to-Lean, Volume Basis	(3)	2:2.1
Sulfur	(4)	

Notes:

1. The maximum fuel temperature is defined in reference [46]
2. To ensure that the fuel gas supply to the gas turbine is 100 percent free of liquids the minimum fuel gas temperature must meet the required superheat over the respective dew point. This requirement is independent of the hydrocarbon and moisture concentration. Superheat calculation shall be performed as described in GEI-4140G [45].
3. Maximum flammability ratio limit is not defined. Fuel with flammability ratio significantly larger than those of natural gas may require start-up fuel
4. The quantity of sulfur in syngas is not limited by specification. Experience has shown that fuel sulfur levels up to 1 percent by volume do not significantly affect oxidation/corrosion rates.

Normal Operation

Inlet air is compressed in a single spool compressor to a pressure ratio of approximately 16:1. This pressure ratio was vendor specified and less than the 18.5:1 ratio used in natural gas applications. The majority of compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the syngas. Compressed air is also used in burner, transition, and film cooling services. About 4-7 percent of the compressor air is extracted and integrated with the air supply of the ASU in non-carbon capture cases. It may be technically possible to integrate the CT and ASU in CO_2 capture cases as well; however, in this study integration was considered only for non-carbon capture cases.

Exhibit 3-13 Allowable Gas Fuel Contaminant Level for F-Class Machines

	Turbine Inlet Limit, ppbw	Fuel Limit, ppmw		
		Turbine Inlet Flow/Fuel Flow		
		50	*12*	*4*
Lead	20	1.0	0.240	.080
Vanadium	10	0.5	0.120	0.040
Calcium	40	2.0	0.480	0.160
Magnesium	40	2.0	0.480	0.160
Sodium + Potassium				
Na/K = 28 (1)	20	1.0	0.240	0.080
Na/K = 3	10	0.5	0.120	0.40
Na/K ≤ 1	6	0.3	0.072	0.024
Particulates Total (2)	600	30	7.2	2.4
Above 10 microns	6	0.3	0.072	0.024

Notes:
1. Na/K=28 is nominal sea salt ratio
2. The fuel gas delivery system shall be designed to prevent generation or admittance of solid particulate to the gas turbine gas fuel system

Pressurized syngas is combusted in several (14) parallel diffusion combustors and syngas dilution is used to limit NOx formation. As described in Section 3.1.2 nitrogen from the ASU is used as the primary diluent followed by syngas humidification and finally by steam dilution, if necessary, to achieve an LHV of 4.5-4.8 MJ/Nm^3 (120-128 Btu/scf). The advantages of using nitrogen as the primary diluent include:

- Nitrogen from the ASU is already partially compressed and using it for dilution eliminates wasting the compression energy.
- Limiting the water content reduces the need to de-rate firing temperature, particularly in the high-hydrogen (CO_2 capture) cases.

There are some disadvantages to using nitrogen as the primary diluent, and these include:

- There is a significant auxiliary power requirement to further compress the large nitrogen flow from the ASU pressures of 0.4 and 1.3 MPa (56 and 182 psia) to the CT pressure of 3.2 MPa (465 psia).

- The low quality heat used in the syngas humidification process does not provide significant benefit to the process in other applications.
- Nitrogen is not as efficient as water in limiting NOx emissions

It is not clear that one dilution method provides a significant advantage over the other. However, in this study nitrogen was chosen as the primary diluent based on suggestions by turbine industry experts during peer review of the report.

Hot combustion products are expanded in the three-stage turbine-expander. Given the assumed ambient conditions, back-end loss, and HRSG pressure drop, the CT exhaust temperature is nominally 599°C (1110°F) for non-CO2 capture cases and 566°C (1050°F) for capture cases.

Gross turbine power, as measured prior to the generator terminals, is 232 MW. The CT generator is a standard hydrogen-cooled machine with static exciter.

3.1.9 STEAM GENERATION ISLAND

Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) is a horizontal gas flow, drum-type, multi-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing medium-Btu gas. High-temperature flue gas exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. Flue gas travels through the HRSG gas path and exits at 132°C (270°F) for all six IGCC cases.

The high pressure (HP) drum produces steam at main steam pressure, while the intermediate pressure (IP) drum produces process steam and turbine dilution steam, if required. The HRSG drum pressures are nominally 12.4/2.9 MPa (1800/420 psia) for the HP/IP turbine sections, respectively. In addition to generating and superheating steam, the HRSG performs reheat duty for the cold/hot reheat steam for the steam turbine, provides condensate and feedwater heating, and also provides deaeration of the condensate.

Natural circulation of steam is accomplished in the HRSG by utilizing differences in densities due to temperature differences of the steam. The natural circulation HRSG provides the most cost-effective and reliable design.

The HRSG drums include moisture separators, internal baffles, and piping for feedwater/steam. All tubes, including economizers, superheaters, and headers and drums, are equipped with drains.

Safety relief valves are furnished in order to comply with appropriate codes and ensure a safe work place.

Superheater, boiler, and economizer sections are supported by shop-assembled structural steel. Inlet and outlet duct is provided to route the gases from the gas turbine outlet to the HRSG inlet and the HRSG outlet to the stack. A diverter valve is included in the inlet duct to bypass the gas when appropriate. Suitable expansion joints are also included.

Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, an IP section, and one double-flow low pressure (LP) section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last stage bucket length of 76 cm (30 in).

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at either 12.4 MPa/566°C (1800 psig/1050°F) for the non-carbon capture cases, or 12.4 MPa/538°C (1800 psig/1000°F) for the carbon capture cases. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 2.6 to 2.9 MPa/566°C (375 to 420 psig/1050°F) for the non-carbon capture cases or 2.6 to 2.9 MPa/538°C (375 to 420 psig/1000°F) for the carbon capture cases. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip an emergency oil pump mounted on the reservoir pumps the oil. When the turbine reaches 95 percent of synchronous speed, the main pump mounted on the turbine shaft pumps oil. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 24 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant DCS, and incorporates on-line repair capability.

Condensate System

The condensate system transfers condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The system consists of one main condenser; two 50 percent capacity, motor-driven, vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater System

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps are provided for each of three pressure levels, HP, IP, and LP. Each pump is provided with inlet and outlet isolation valves, and outlet check valve. Minimum flow recirculation to prevent overheating and cavitation of the pumps during startup and low loads is provided by an automatic recirculation valve and associated piping that discharges back to the deaerator storage tank. Pneumatic flow control valves control the recirculation flow.

The feedwater pumps are supplied with instrumentation to monitor and alarm on low oil pressure, or high bearing temperature. Feedwater pump suction pressure and temperature are also monitored. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

Main and Reheat Steam Systems

The function of the main steam system is to convey main steam generated in the synthesis gas cooler (SGC) and HRSG from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 12.4 MPa/566°C (1800 psig/1050°F) (non-carbon capture cases) or 12.4 MPa/538°C (1800 psig/1000°F) (carbon capture cases) exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 3.1 to 3.4 MPa/341°C (450 to 500 psia/645°F) exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 2.9 to 3.2 MPa/566°C (420 to 467 psia/1050°F) for non-carbon capture cases and 2.9 MPa/538°C (420 psia/1000°F) for carbon capture cases exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Steam piping is sloped from the HRSG to the drip pots located near the steam turbine for removal of condensate from the steam lines. Condensate collected in the drip pots and in low-point drains is discharged to the condenser through the drain system.

Steam flow is measured by means of flow nozzles in the steam piping. The flow nozzles are located upstream of any branch connections on the main headers.

Safety valves are installed to comply with appropriate codes and to ensure the safety of personnel and equipment.

Circulating Water System

The circulating water system is a closed-cycle cooling water system that supplies cooling water to the condenser to condense the main turbine exhaust steam. The system also supplies cooling water to the AGR plant as required, and to the auxiliary cooling system. The auxiliary cooling system is a closed-loop process that utilizes a higher quality water to remove heat from compressor intercoolers, oil coolers and other ancillary equipment and transfers that heat to the main circulating cooling water system in plate and frame heat exchangers. The heat transferred to the circulating water in the condenser and other applications is removed by a mechanical draft cooling tower.

The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel cement-lined interconnecting piping. The pumps are single-stage vertical pumps. The piping system is equipped with butterfly isolation valves and all required expansion joints. The cooling tower is a multi-cell wood frame counterflow mechanical draft cooling tower.

The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or for plugging tubes. This can be done during normal operation at reduced load.

The condenser is equipped with an air extraction system to evacuate the condenser steam space for removal of non-condensable gases during steam turbine operation and to rapidly reduce the condenser pressure from atmospheric pressure before unit startup and admission of steam to the condenser.

Raw Water, Fire Protection, and Cycle Makeup Water Systems

The raw water system supplies cooling tower makeup, cycle makeup, service water and potable water requirements. The water source is 50 percent from a POTW and 50 percent from groundwater. Booster pumps within the plant boundary provide the necessary pressure.

The fire protection system provides water under pressure to the fire hydrants, hose stations, and fixed water suppression system within the buildings and structures. The system consists of pumps, underground and aboveground supply piping, distribution piping, hydrants, hose stations, spray systems, and deluge spray systems. One motor-operated booster pump is supplied on the intake structure of the cooling tower with a diesel engine backup pump installed on the water inlet line.

The cycle makeup water system provides high quality demineralized water for makeup to the HRSG cycle, for steam injection ahead of the water gas shift reactors in CO_2 capture cases, and for injection steam to the auxiliary boiler for control of NOx emissions, if required.

The cycle makeup system consists of two 100 percent trains, each with a full-capacity activated carbon filter, primary cation exchanger, primary anion exchanger, mixed bed exchanger, recycle pump, and regeneration equipment. The equipment is skid-mounted and includes a control panel and associated piping, valves, and instrumentation.

3.1.10 Accessory Electric Plant

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, all required foundations, and standby equipment.

3.1.11 Instrumentation and Control

An integrated plant-wide distributed control system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed control system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to be operational and accessible 99.5 percent of the time it is required (99.5 percent availability). The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are manually implemented, with operator selection of modular automation routines available. The exception to this, and an important facet of the control system for gasification, is the critical controller system, which is a part of the license package from the gasifier supplier and is a dedicated and distinct hardware segment of the DCS.

This critical controller system is used to control the gasification process. The partial oxidation of the fuel feed and oxygen feed streams to form a syngas product is a stoichiometric, temperature- and pressure-dependent reaction. The critical controller utilizes a redundant microprocessor executing calculations and dynamic controls at 100- to 200-millisecond intervals. The enhanced execution speeds as well as evolved predictive controls allow the critical controller to mitigate process upsets and maintain the reactor operation within a stable set of operating parameters.

3.2 GENERAL ELECTRIC ENERGY IGCC CASES

This section contains an evaluation of plant designs for Cases 1 and 2, which are based on the GEE gasifier in the "radiant only" configuration. GEE offers three design configurations [47]:

- Quench: In this configuration, the hot syngas exiting the gasifier passes through a pool of water to quench the temperature to less than 260°C (500°F) before entering the syngas scrubber. It is the simplest and lowest capital cost design, but also the least efficient.
- Radiant Only: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1316°C (2400°F) to 816°C (1500°F), then through a water quench where the syngas is further cooled to about 204°C (400°F) prior to entering the syngas scrubber. Relative to the quench configuration, the radiant only design offers increased output, higher efficiency, improved reliability/availability, and results in the lowest cost of electricity. This configuration was chosen by GEE and Bechtel for the design of their reference plant.
- Radiant-Convective: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1316°C (2400°F) to 760°C (1400°F), then passes over a pool of water where particulate is removed but the syngas is not quenched, then through a convective syngas cooler where the syngas is further cooled to about 371°C (700°F) prior to entering additional heat exchangers or the scrubber. This configuration has the highest overall efficiency, but at the expense of highest capital cost and the lowest availability. This is the configuration used at Tampa Electric's Polk Power Station.

Note that the radiant only configuration includes a water quench and, based on functionality, would be more appropriately named radiant-quench. The term radiant only is used to distinguish it from the radiant-convective configuration. Since radiant only is the terminology used by GEE, it will be used throughout this report.

The balance of Section 3.2 is organized as follows:

- Gasifier Background provides information on the development and status of the GEE gasification technology.
- Process and System Description provides an overview of the technology operation as applied to Case 1. The systems that are common to all gasifiers were covered in Section 3.1 and only features that are unique to Case 1 are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 1 and 2.
- Sparing Philosophy is provided for both Cases 1 and 2.
- Performance Results provides the main modeling results from Case 1, including the performance summary, environmental performance, carbon balance, sulfur balance, water balance, mass and energy balance diagrams and mass and energy balance tables.
- Equipment List provides an itemized list of major equipment for Case 1 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case 1.

- Process and System Description, Performance Results, Equipment List and Cost Estimates are repeated for Case 2.

3.2.1 GASIFIER BACKGROUND

Development and Current Status [48] – Initial development of the GEE gasification technology (formerly licensed by Texaco and then ChevronTexaco) was conducted in the 1940s at Texaco's Montebello, California laboratories. From 1946 to 1954 the Montebello pilot plant produced synthesis gas (hydrogen and carbon monoxide) by partial oxidation of a variety of feedstocks, including natural gas, oil, asphalt, coal tar, and coal. From 1956 to 1958, coal was gasified in a 91 tonne/day (100 TPD) Texaco coal gasifier at the Olin Mathieson Chemical Plant in Morgantown, West Virginia, for the production of ammonia.

The oil price increases and supply disruptions of the 1970s renewed interest in the Texaco partial-oxidation process for gasification of coal or other solid opportunity fuels. Three 14 tonne/day (15 TPD) pilot plants at the Montebello laboratories have been used to test numerous coals. Two larger pilot plants were also built. The first gasified 150 tonne/day (165 TPD) of coal and was built to test synthesis gas generation by Rührchemie and Rührkohle at Oberhausen, Germany, and included a synthesis gas cooler. The second gasified 172 tonne/day (190 TPD) of coal using a quench-only gasifier cooler and was built to make hydrogen at an existing TVA ammonia plant at Muscle Shoals, Alabama. These two large-scale pilot plants successfully operated for several years during the 1980s and tested a number of process variables and numerous coals.

The first commercial Texaco coal gasification plant was built for Tennessee Eastman at Kingsport, Tennessee, and started up in 1983. To date, 24 gasifiers have been built in 12 plants for coal and petroleum coke. Several of the plants require a hydrogen-rich gas and therefore directly water quench the raw gas to add the water for shifting the CO to H_2, and have no synthesis gas coolers.

The Cool Water plant was the first commercial-scale Texaco coal gasification project for the electric utility industry. This facility gasified 907 tonne/day (1,000 TPD) (dry basis) of bituminous coal and generated 120 MW of electricity by IGCC operation. In addition, the plant was the first commercial-sized Texaco gasifier used with a synthesis gas cooler. The Cool Water plant operated from 1984 to 1989 and was a success in terms of operability, availability, and environmental performance.

The Tampa Electric IGCC Clean Coal Technology Demonstration Project built on the Cool Water experience to demonstrate the use of the Texaco coal gasification process in an IGCC plant. The plant utilizes approximately 2,268 tonne/day (2,500 TPD) of coal in a single Texaco gasifier to generate a net of approximately 250 MW_e. The syngas is cooled in a high-temperature radiant heat exchanger, generating high-pressure steam, and further cooled in convective heat exchangers (the radiant-convective configuration). The particles in the cooled gas are removed in a water-based scrubber. The cleaned gas then enters a hydrolysis reactor where COS is converted to H_2S. After additional cooling, the syngas is sent to a conventional AGR unit, where H_2S is absorbed by reaction with an amine solvent. H_2S is removed from the amine by steam stripping and sent to a sulfuric acid plant. The cleaned gas is sent to a General Electric MS 7001FA combustion turbine.

The Delaware Clean Energy Project is a coke gasification and combustion turbine repowering of an existing 130 MW coke-fired boiler cogeneration power plant at the Motiva oil refinery in Delaware City, Delaware. The Texaco coal gasification process was modified to gasify 1,814 tonne/day (2,000 TPD) of this low-quality petroleum coke. The plant is designed to use all the fluid petroleum coke generated at Motiva's Delaware City Plant and produce a nominal 238,136 kg/h (525,000 lb/h) of 8.6 MPa (1250 psig) steam, and 120,656 kg/h (266,000 lb/h) of 1.2 MPa (175 psig) steam for export to the refinery and the use/sale of 120 MW of electrical power. Environmentally, these new facilities help satisfy tighter NO_x and SO_2 emission limitations at the Delaware City Plant.

Gasifier Capacity – The largest GEE gasifier is the unit at Tampa Electric, which consists of the radiant-convective configuration. The daily coal-handling capacity of this unit is 2,268 tonnes (2,500 tons) of bituminous coal. The dry gas production rate is 0.19 million Nm^3/h (6.7 million scfh) with an energy content of about 1,897 million kJ/h (HHV) (1,800 million Btu/h). This size matches the F Class combustion turbines that are used at Tampa.

Distinguishing Characteristics – A key advantage of the GEE coal gasification technology is the extensive operating experience at full commercial scale. Furthermore, Tampa Electric is an IGCC power generation facility, operated by conventional electric utility staff, and is environmentally one of the cleanest coal-fired power plants in the world. The GEE gasifier also operates at the highest pressure of the three gasifiers in this study, 5.6 MPa (815 psia) compared to 4.2 MPa (615 psia) for CoP and Shell.

Entrained-flow gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag. The relatively high H_2/CO ratio and CO_2 content of GEE gasification fuel gas helps achieve low nitrogen oxide (NO_x) and CO emissions in even the higher-temperature advanced combustion turbines.

The key disadvantages of the GEE coal gasification technology are the limited refractory life, the relatively high oxygen requirements and high waste heat recovery duty (synthesis gas cooler design). As with the other entrained-flow slagging gasifiers, the GEE process has this disadvantage due to its high operating temperature. The disadvantage is magnified in the single-stage, slurry feed design. The quench design significantly reduces the capital cost of syngas cooling, while innovative heat integration maintains good overall thermal efficiency although lower than the synthesis gas cooler design. Another disadvantage of the GEE process is the limited ability to economically handle low-rank coals relative to moving-bed and fluidized-bed gasifiers or to entrained-flow gasifiers with dry feed. For slurry fed entrained gasifiers using low-rank coals, developers of two-stage slurry fed gasifiers claim advantages over single-stage slurry fed.

Important Coal Characteristics – The slurry feeding system and the recycle of process condensate water as the principal slurrying liquid make low levels of ash and soluble salts desirable coal characteristics for use in the GEE coal gasification process. High ash levels increase the ratio of water-to-carbon in the feed slurry, thereby increasing the oxygen requirements. The slurry feeding also favors the use of high-rank coals, such as bituminous coal, since their low inherent moisture content increases the moisture-free solids content of the slurry and thereby reduces oxygen requirements.

3.2.2 PROCESS DESCRIPTION

In this section the overall GEE gasification process is described. The system description follows the block flow diagram (BFD) in Exhibit 3-14 and stream numbers reference the same Exhibit. The tables in Exhibit 3-15 provide stream compositions, temperature, pressure, enthalpy and flow rates for the numbered streams in the BFD.

Coal Grinding and Slurry Preparation

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. Coal is then fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which in turn feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62-68 percent using bituminous coal and CoP presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent. [41, 49]

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

Gasification

This plant utilizes two gasification trains to process a total of 5,331 tonnes/day (5,876 TPD) of Illinois No. 6 coal. Each of the 2 x 50 percent gasifiers operates at maximum capacity. The largest operating GEE gasifier is the 2,268 tonne/day (2,500 TPD) unit at Polk Power Station. However, that unit operates at about 2.8 MPa (400 psia). The gasifier in this study, which operates at 5.6 MPa (815 psia), will be able to process more coal and maintain the same gas residence time.

The slurry feed pump takes suction from the slurry run tank, and the discharge is sent to the feed injector of the GEE gasifier (stream 6). Oxygen from the ASU is vented during preparation for startup and is sent to the feed injector during normal operation. The air separation plant supplies 4,560 tonnes/day (5,025 TPD) of 95 mole percent oxygen to the gasifiers (stream 5) and the Claus plant (stream 3). Carbon conversion in the gasifier is assumed to be 98 percent including a fines recycle stream.

The gasifier vessel is a refractory-lined, high-pressure combustion chamber. The coal slurry feedstock and oxygen are fed through a fuel injector at the top of the gasifier vessel. The coal slurry and the oxygen react in the gasifier at 5.6 MPa (815 psia) and 1,316°C (2,400°F) to produce syngas.

The syngas consists primarily of hydrogen and carbon monoxide, with lesser amounts of water vapor and carbon dioxide, and small amounts of hydrogen sulfide, carbonyl sulfide, methane, argon, and nitrogen. The heat in the gasifier liquefies coal ash. Hot syngas and molten solids from the reactor flow downward into a radiant heat exchanger where the syngas is cooled.

Raw Gas Cooling/Particulate Removal

Syngas is cooled from 1,316°C (2,400°F) to 593°C (1,100°F) in the radiant synthesis gas cooler (SGC) (stream 8) and the molten slag solidifies in the process. The solids collect in the water sump at the bottom of the gasifier and are removed periodically using a lock hopper system (stream 7). The waste heat from this cooling is used to generate high-pressure steam. Boiler feedwater in the tubes is saturated, and then steam and water are separated in a steam drum. Approximately 528,118 kg/h (1,164,300 lb/h) of saturated steam at 13.8 MPa (2,000 psia) is produced. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

The syngas exiting the radiant cooler is directed downwards by a dip tube into a water sump. Most of the entrained solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. The syngas exits the quench chamber saturated at a temperature of 210°C (410°F).

The slag handling system removes solids from the gasification process equipment. These solids consist of a small amount of unconverted carbon and essentially all of the ash contained in the feed coal. These solids are in the form of glass, which fully encapsulates any metals. Solids collected in the water sump below the radiant synthesis gas cooler are removed by gravity and forced circulation of water from the lock hopper circulating pump. The fine solids not removed from the bottom of the quench water sump remain entrained in the water circulating through the quench chamber. In order to limit the amount of solids recycled to the quench chamber, a continuous blowdown stream is removed from the bottom of the syngas quench. The blowdown is sent to the vacuum flash drum in the black water flash section. The circulating quench water is pumped by circulating pumps to the quench gasifier.

Syngas Scrubber/Sour Water Stripper

Syngas exiting the water quench passes to a syngas scrubber where a water wash is used to remove remaining chlorides and particulate. The syngas exits the scrubber still saturated at 199°C (390°F) (stream 9).

The sour water stripper removes NH_3, SO_2, and other impurities from the scrubber and other waste streams. The stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from synthesis gas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

Exhibit 3-14 Case 1 Process Flow Diagram, GEE IGCC without CO_2 Capture

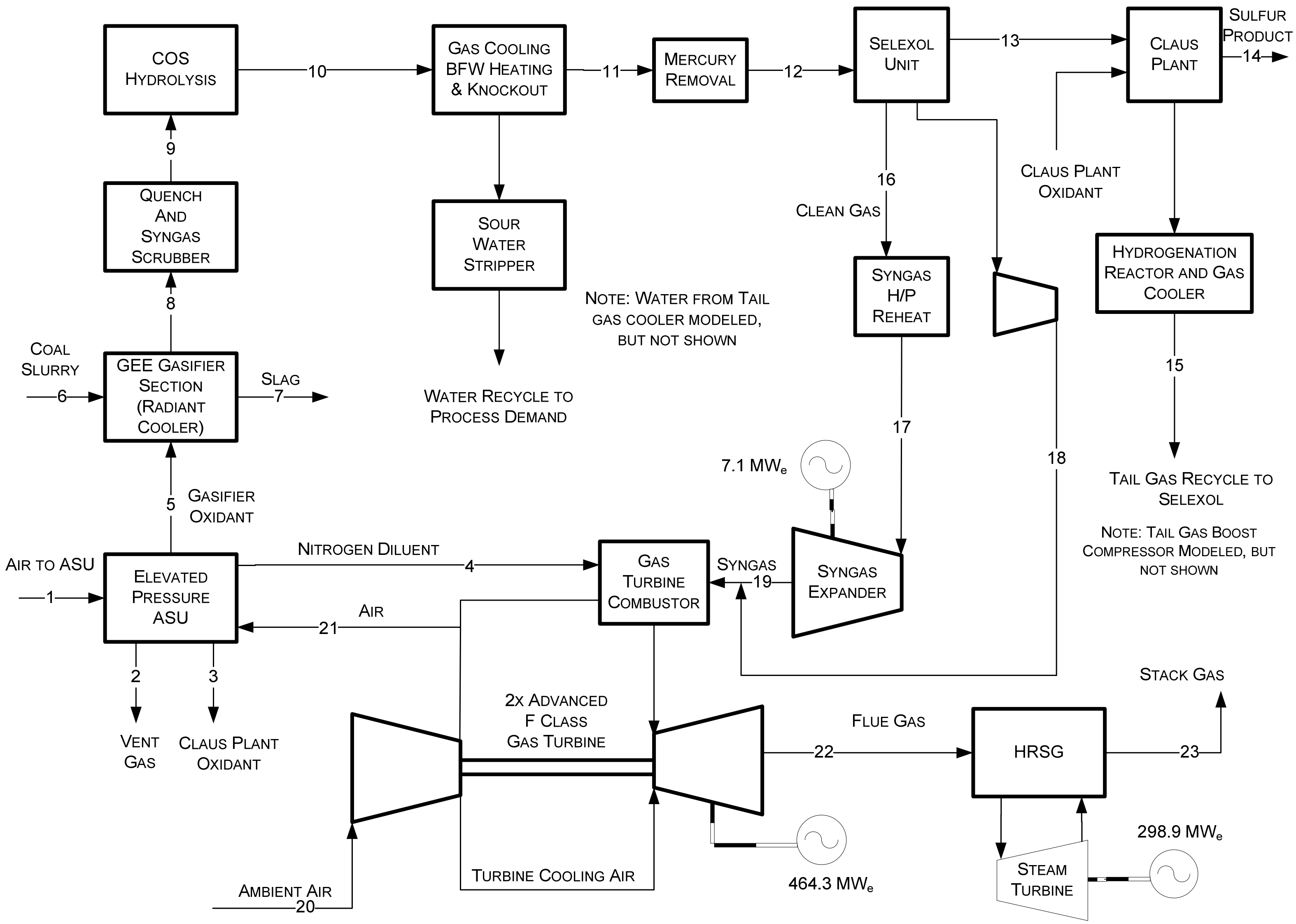


Exhibit 3-15 Case 1 Stream Table, GEE IGCC without CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0094	0.0065	0.0360	0.0023	0.0320	0.0000	0.0000	0.0079	0.0067	0.0067	0.0092	0.0092
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0010	0.0008	0.0008	0.0011	0.0011
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3442	0.2922	0.2922	0.3992	0.3992
CO_2	0.0003	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000	0.1511	0.1276	0.1278	0.1780	0.1780
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3349	0.2849	0.2849	0.3935	0.3935
H_2O	0.0104	0.0496	0.0000	0.0000	0.0000	1.0000	0.0000	0.1429	0.2726	0.2724	0.0012	0.0012
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0061	0.0062	0.0069	0.0069
N_2	0.7722	0.8978	0.0140	0.9924	0.0180	0.0000	0.0000	0.0089	0.0076	0.0076	0.0103	0.0103
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0014	0.0014	0.0006	0.0006
O_2	0.2077	0.0445	0.9500	0.0053	0.9500	0.0000	0.0000	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	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	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	53,342	13,347	277	36,897	12,736	14,199	0	51,296	60,278	60,278	43,585	43,585
V-L Flowrate (lb/hr)	1,539,150	371,000	8,942	1,035,410	409,853	255,589	0	1,046,880	1,206,760	1,206,760	904,411	904,411
Solids Flowrate (lb/hr)	0	0	0	0	0	435,187	53,746	0	0	0	0	0
Temperature (°F)	233	58	90	385	206	141	410	1100	390	390	107	107
Pressure (psia)	190.1	16.4	125.0	460.0	980.0	1050.0	797.7	799.7	792.7	782.7	742.7	732.7
Enthalpy (BTU/lb)[B]	55.6	16.6	12.5	87.8	37.7	---	1,710	535.5	400.3	400.3	27.4	27.4
Density (lb/ft^3)	0.738	0.085	0.683	1.424	4.416	---	---	0.975	1.740	1.718	2.534	2.500
Molecular Weight	28.85	27.80	32.23	28.06	32.18	---	---	20.41	20.02	20.02	20.75	20.75

A - Solids flowrate includes dry coal; V-L flowrate includes slurry water and water from coal
B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-15 Case 1 Stream Table (continued)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0188	0.0097	0.0097	0.0059	0.0097	0.0094	0.0094	0.0091	0.0091
CH_4	0.0000	0.0000	0.0764	0.0012	0.0012	0.0169	0.0012	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0003	0.4195	0.4195	0.0814	0.4195	0.0000	0.0000	0.0000	0.0000
CO_2	0.3803	0.0000	0.6066	0.1414	0.1414	0.5518	0.1414	0.0003	0.0003	0.0859	0.0859
COS	0.0002	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	0.0126	0.4164	0.4164	0.0532	0.4164	0.0000	0.0000	0.0000	0.0000
H_2O	0.0200	0.0000	0.0020	0.0009	0.0009	0.0000	0.0009	0.0104	0.0104	0.0668	0.0668
H_2S	0.3576	0.0000	0.0103	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.2106	0.0000	0.2728	0.0110	0.0110	0.2908	0.0110	0.7722	0.7722	0.7337	0.7337
NH_3	0.0313	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.2077	0.2077	0.1045	0.1045
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	0	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	863	0	860	40,704	40,704	3,978	40,704	242,899	9,914	297,284	297,284
V-L Flowrate (lb/hr)	30,839	0	31,584	795,458	795,458	140,512	795,458	7,008,680	286,060	8,694,000	8,694,000
Solids Flowrate (lb/hr)	0	12,235	0	0	0	0	0	0	0	0	0
Temperature (°F)	120	358	100	112	460	151	380	59	811	1115	270
Pressure (psia)	30.0	24.9	368.0	719.0	714.0	460.0	460.0	14.7	234.9	15.2	15.2
Enthalpy (BTU/lb)[B]	31.1	-99.5	16.1	30.3	162.2	27.1	131.2	13.5	200.0	327.2	103.2
Density (lb/ft^3)	0.172	329.192	2.252	2.289	1.414	2.481	0.998	0.076	0.497	0.026	0.057
Molecular Weight	35.73	256.53	36.74	19.54	19.54	35.33	19.54	28.85	28.85	29.24	29.24

B - Reference conditions are 32.02 F & 0.089 PSIA

COS Hydryolysis, Mercury Removal and Acid Gas Removal

Syngas exiting the scrubber (stream 9) passes through a COS hydrolysis reactor where about 99.5 percent of the COS is converted to CO_2 and H_2S (Section 3.1.5). The gas exiting the COS reactor (stream 10) passes through a series of heat exchangers and knockout drums to lower the syngas temperature to 39°C (103°F) and to separate entrained water. The cooled syngas (stream 11) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

Cool, particulate-free synthesis gas (stream 12) enters the Selexol absorber unit at approximately 5.1 MPa (733 psia) and 39°C (103°F). In this absorber, H_2S is preferentially removed from the fuel gas stream along with smaller amounts of CO_2, COS and other gases such as hydrogen. The rich solution leaving the bottom of the absorber is heated against the lean solvent returning from the regenerator before entering the H_2S concentrator. A portion of the non-sulfur bearing absorbed gases is driven from the solvent in the H_2S concentrator using N_2 from the ASU as the stripping medium. The temperature of the H_2S concentrator overhead stream is reduced prior to entering the reabsorber where a second stage of H_2S absorption occurs. The rich solvent from the reabsorber is combined with the rich solvent from the absorber and sent to the stripper where it is regenerated through the indirect application of thermal energy via condensation of low-pressure steam in a reboiler. The stripper acid gas stream (stream 13), consisting of 36 percent H_2S and 38 percent CO_2 (with the balance mostly N_2), is then sent to the Claus unit. The secondary sweet fuel gas stream from the reabsorber is compressed to 3.2 MPa (460 psia) (stream 18) and combined with the primary sweet syngas after the expansion turbine (stream 19).

Claus Unit

Acid gas from the first-stage stripper of the Selexol unit is routed to the Claus plant. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. About 5,550 kg/h (12,235 lb/h) of elemental sulfur (stream 14) are recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.6 percent.

Acid gas from the Selexol unit is preheated to 232°C (450°F). A portion of the acid gas along with all of the sour gas from the stripper and oxygen from the ASU are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2 at a furnace temperature greater than 1,343°C (2,450°F), which must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Following the thermal stage and condensation of sulfur, two reheaters and two sulfur converters are used to obtain a per-pass H_2S conversion of approximately 99.7 percent. The Claus Plant tail gas is hydrogenated and recycled back to the Selexol process (stream 15). In the furnace waste heat boiler, 8,772 kg/h (19,340 lb/h) of 3.6 MPa (525 psia) steam are generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to produce some steam for the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

Power Block

Clean syngas exiting the Selexol absorber is re-heated (stream 17) using HP boiler feedwater and then expanded to 3.2 MPa (460 psia) using an expansion turbine (stream 19). A second clean gas stream from the Selexol reabsorber is compressed and combined with stream 19. The combined syngas stream is further diluted with nitrogen from the ASU (stream 4) and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and also 16 percent of the air requirements in the ASU (stream 21). The exhaust gas exits the CT at 602°C (1,115°F) (stream 22) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) (stream 23) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit (ASU)

The elevated pressure ASU was described in Section 3.1.2. In Case 1 the air separation unit (ASU) is designed to produce a nominal output of 4,560 tonnes/day (5,025 TPD) of 95 mole percent O_2 for use in the gasifier (stream 5) and Claus plant (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 11,270 tonnes/day (12,425 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor (stream 4). About 4.1 percent of the gas turbine air is used to supply approximately 16 percent of the ASU air requirements (stream 21).

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.2.3 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 1 and 2, GEE IGCC with and without CO_2 capture, are presented in Exhibit 3-16.

Exhibit 3-16 GEE IGCC Plant Study Configuration Matrix

Case	1	2
Gasifier Pressure, MPa (psia)	5.6 (815)	5.6 (815)
O_2:Coal Ratio, kg O_2/kg dry coal	0.95	0.95
Carbon Conversion, %	98	98
Syngas HHV at SGC Outlet, kJ/Nm^3 (Btu/scf)	8,210 (226)	8,210 (226)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1800/1050/1050)	12.4/538/538 (1800/1000/1000)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
Combustion Turbine	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	GEE Radiant Only	GEE Radiant Only
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Slurry Solids Conent, %	63	63
COS Hydrolysis	Yes	Occurs in SGS
Sour Gas Shift	No	Yes
H_2S Separation	Selexol	Selexol 1st Stage
Sulfur Removal, %	99.6	99.6
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Selexol/ Elemental Sulfur	Claus Plant with Tail Gas Recycle to Selexol/ Elemental Sulfur
Particulate Control	Water Quench, Scrubber, and AGR Absorber	Water Quench, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB) and N_2 Dilution	MNQC (LNB) and N_2 Dilution
CO_2 Separation	N/A	Selexol 2nd Stage
CO_2 Capture	N/A	90.2% from Syngas
CO_2 Sequestration	N/A	Off-site Saline Formation

Balance of Plant – Cases 1 and 2

The balance of plant assumptions are common to all cases and are presented in Exhibit 3-17.

Exhibit 3-17 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Slag	30 days
Sulfur	30 days
Sorbent	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local Publicly Owned Treatment Works and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources
Process Wastewater	Water associated with gasification activity and storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant was sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

3.2.4 SPARING PHILOSOPHY

The sparing philosophy for Cases 1 and 2 is provided below. Single trains are utilized throughout with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment.

The plant design consists of the following major subsystems:

- Two air separation units (2 x 50%)
- Two trains of slurry preparation and slurry pumps (2 x 50%)
- Two trains of gasification, including gasifier, synthesis gas cooler, quench and scrubber (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Selexol acid gas removal, single-stage in Case 1 and two-stage in Case 2, (2 x 50%) and one Claus-based sulfur recovery unit (1 x 100%).
- Two combustion turbine/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.2.5 CASE 1 PERFORMANCE RESULTS

The plant produces a net output of 640 MWe at a net plant efficiency of 38.2 percent (HHV basis). GEE has reported a net plant effiency of 38.5 percent for their reference plant, and they also presented a range of efficiencies of 38.5-40 percent depending on fuel type. [50, 51] Typically the higher efficiencies result from fuel blends that include petroleum coke.

Overall performance for the plant is summarized in Exhibit 3-18 which includes auxiliary power requirements. The ASU accounts for over 79 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The cooling water system, including the circulating water pumps and the cooling tower fan, accounts for over 4 percent of the auxiliary load, and the BFW pumps account for an additional 3.5 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-18 Case 1 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,300
Sweet Gas Expander Power	7,130
Steam Turbine Power	298,920
TOTAL POWER, kWe	**770,350**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	450
Coal Milling	2,280
Coal Slurry Pumps	740
Slag Handling and Dewatering	1,170
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	60,070
Oxygen Compressor	11,270
Nitrogen Compressor	30,560
Claus Plant Tail Gas Recycle Compressor	1,230
Boiler Feedwater Pumps	4,590
Condensate Pump	250
Flash Bottoms Pump	200
Circulating Water Pumps	3,710
Cooling Tower Fans	1,910
Scrubber Pumps	300
Selexol Unit Auxiliaries	3,420
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,650
TOTAL AUXILIARIES, kWe	**130,100**
NET POWER, kWe	**640,250**
Net Plant Efficiency, % (HHV)	38.2
Net Plant Heat Rate (Btu/kWh)	8,922
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,705 (1,617)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	222,095 (489,634)
Thermal Input, kWt	1,674,044
Raw Water Usage, m^3/min (gpm)	15.2 (4,003)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 1 is presented in Exhibit 3-19.

Exhibit 3-19 Case 1 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) @ 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.005 (0.0127)	231 (254)	0.043 (0.094)
NO_X	0.024 (0.055)	994 (1,096)	0.184 (0.406)
Particulates	0.003 (0.0071)	129 (142)	0.024 (0.053)
Hg	0.25×10^{-6} ($.57 \times 10^{-6}$)	0.010 (0.011)	1.9×10^{-6} (4.2×10^{-6})
CO_2	85 (197)	3,572,000 (3,938,000)	662 (1,459)
CO_2[1]			796 (1,755)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 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 less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S and then recycled back to the Selexol process, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by nitrogen dilution of the syngas to 15 ppmvd (as NO_2 @15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and ultimately destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-20. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the AspenPlus model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and as CO_2 in the stack gas and ASU vent gas. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance.

Exhibit 3-20 Case 1 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	141,585 (312,142)	**Slag**	2,843 (6,267)
Air (CO_2)	529 (1,165)	**Stack Gas**	139,020 (306,486)
		ASU Vent	111 (245)
		Wastewater	141 (310)
Total	142,114 (313,307)	**Total**	142,114 (313,307)

Exhibit 3-21 shows the sulfur balances for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(12,235/12,290) or
99.6 percent

Exhibit 3-21 Case 1 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,575 (12,290)	**Elemental Sulfur**	5,550 (12,235)
		Stack Gas	16 (36)
		Wastewater	8 (19)
Total	5,575 (12,290)	**Total**	5,575 (12,290)

Exhibit 3-22 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-22 Case 1 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.5 (402)	1.5 (402)	0
Slag Handling	0.5 (140)	0	0.5 (140)
Quench/Scrubber	2.1 (561)	1.6 (427)	0.5 (134)
BFW Makeup	0.2 (49)	0	0.2 (49)
Cooling Tower Makeup	14.4 (3,805)	0.5 (125)	13.9 (3,680)
Total	**18.7 (4,957)**	**3.6 (954)**	**15.2 (4,003)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-23 through Exhibit 3-27:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-28. The power out is the combined combustion turbine, steam turbine and expander power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-18) is calculated by multiplying the power out by a combined generator efficiency of 98.2 percent.

The heat and material balances shown in these figures are shown in U.S. standard units. The following factors can be used for conversion to SI units. The same conversions apply to all cases but are shown only once for Case 1.

P, absolute pressure, psia, multiply by 6.895 $x10^{-3}$ = MPa (megapascals)
°F, temperature, (°F minus 32) divided by 1.8 = °C (Centigrade)
H, enthalpy, Btu/lb, multiply H by 2.3260 = kJ/kg (kilojoules/kilogram)
W, total plant flow, lb/h, multiply W by 0.4536 = kg/h (kilogram/hour)
Heat rate, Btu/kWh, multiply Btu/kWh by 1.0551 = kJ/kWh (kilojoules/kilowatt-hour)

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Exhibit 3-23 Case 1 Coal Gasification and Air Separation Units Heat and Mass Balance Schematic

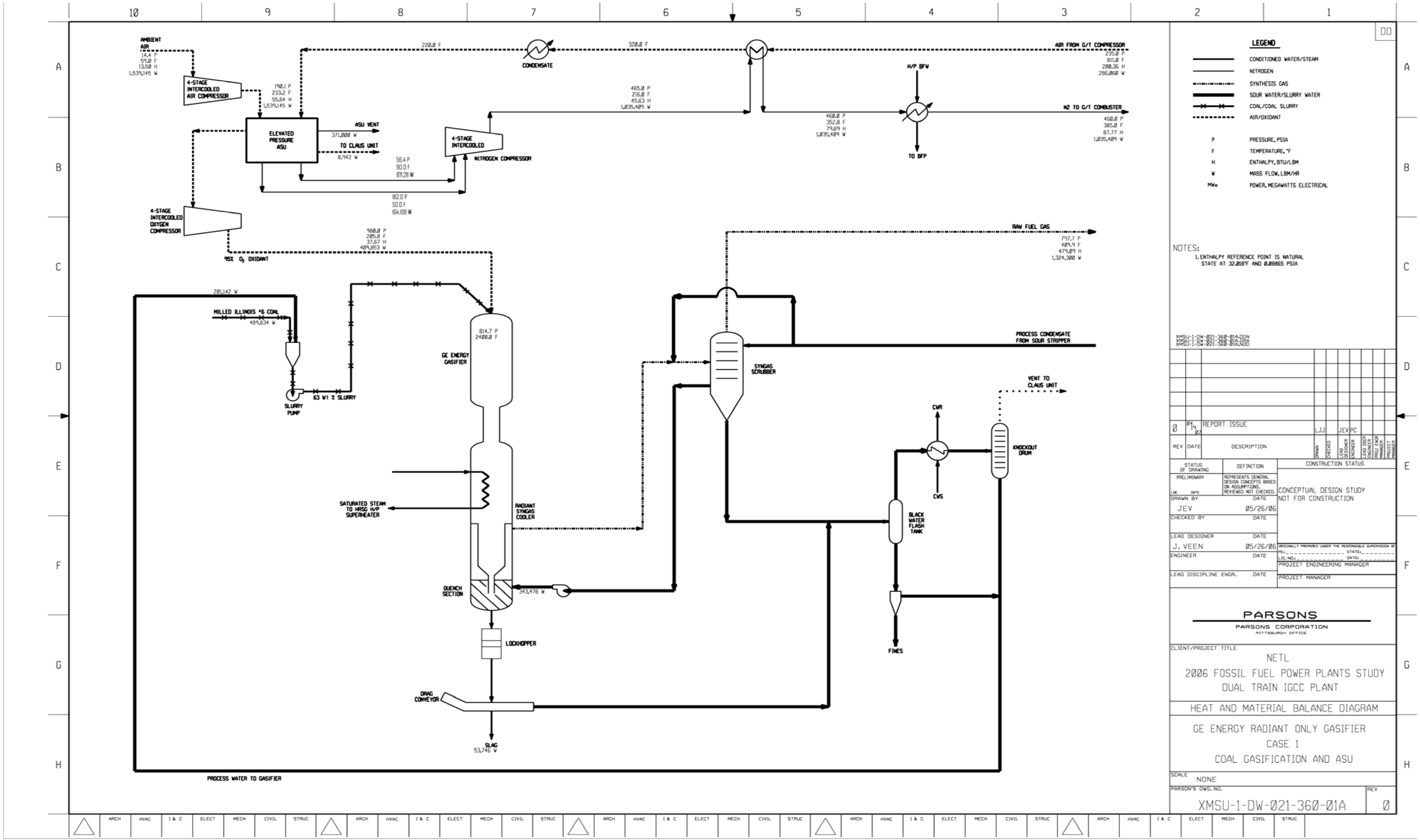

Exhibit 3-24 Case 1 Syngas Cleanup Heat and Mass Balance Schematic

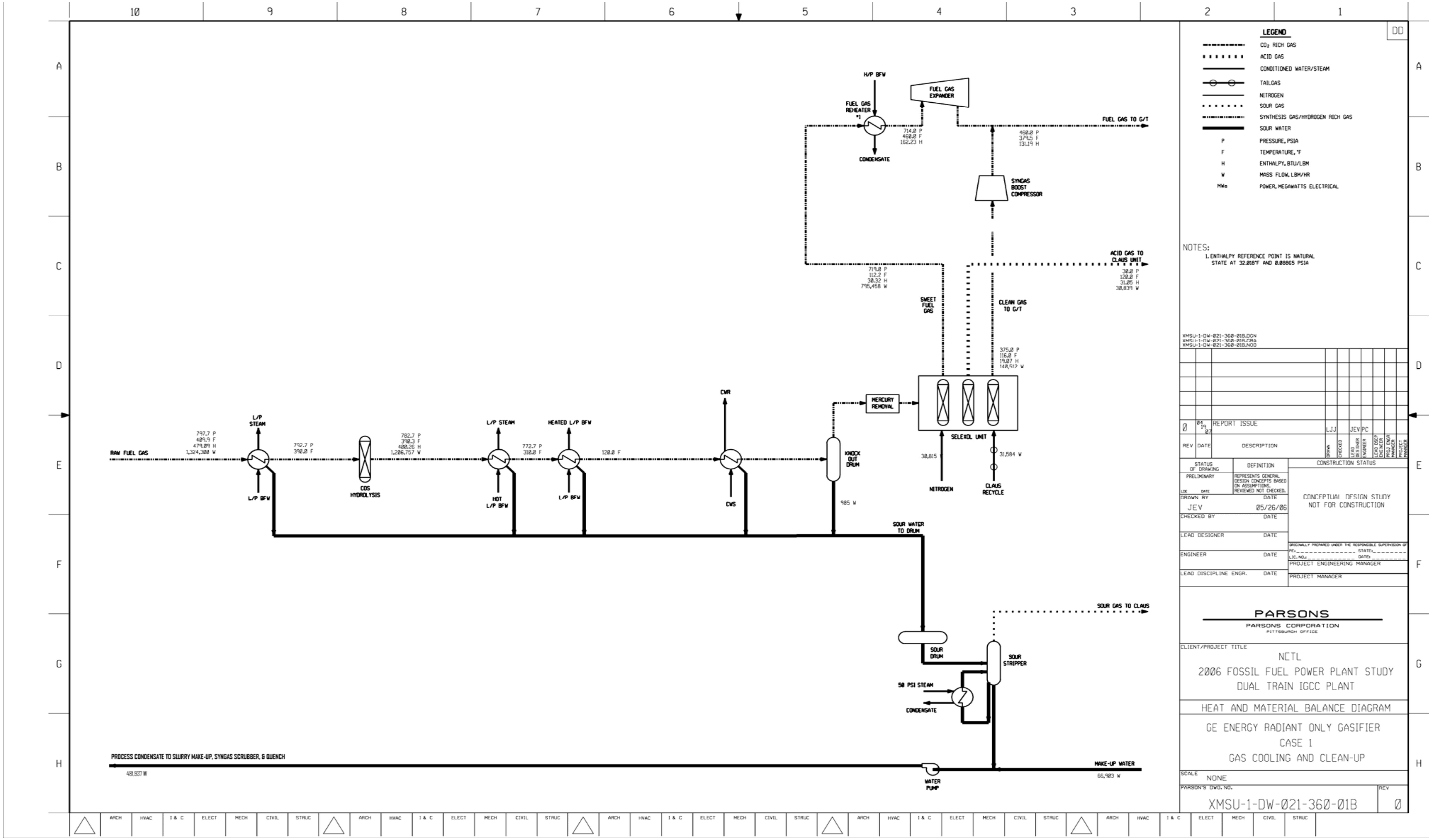

Exhibit 3-25 Case 1 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

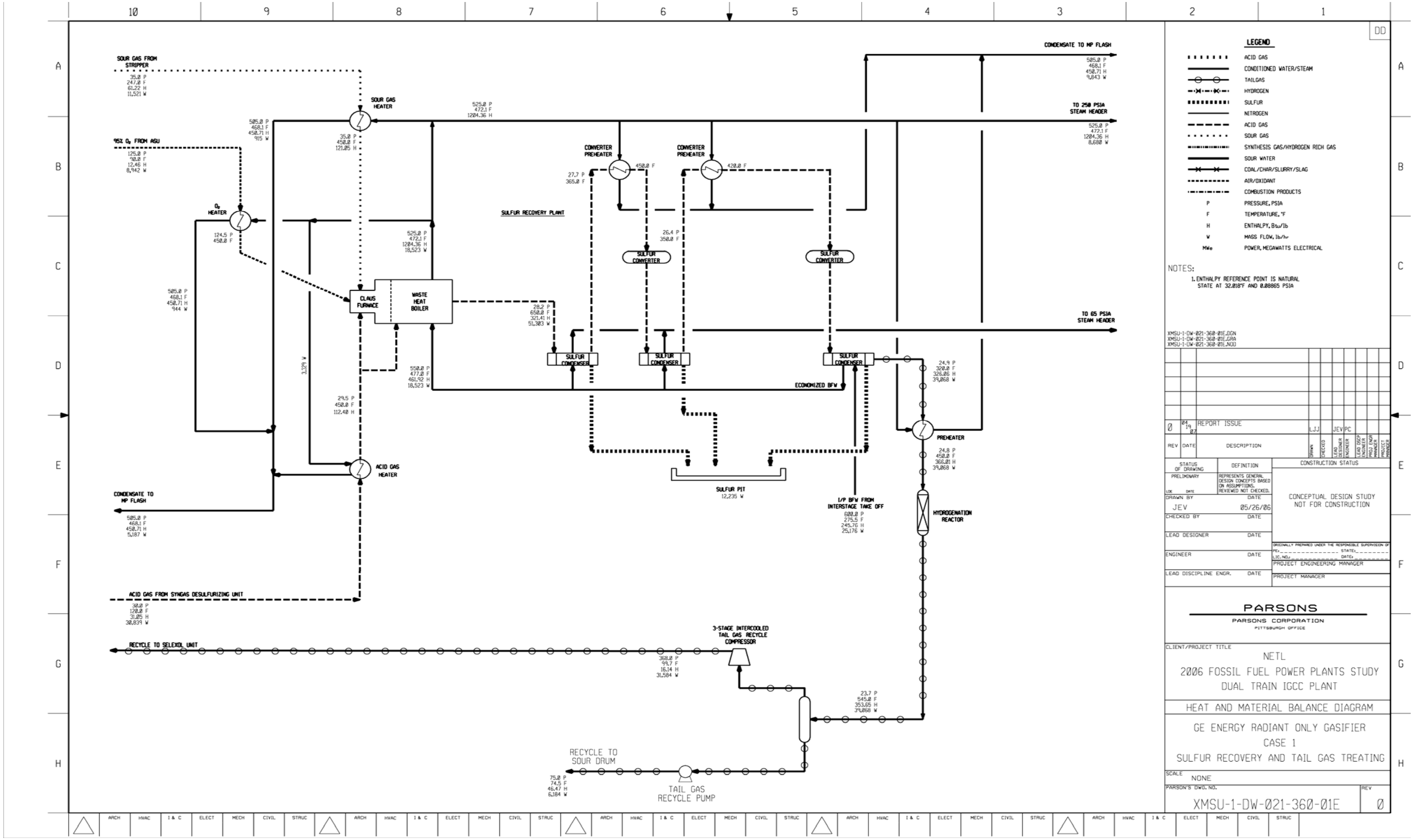

Exhibit 3-26 Case 1 Combined-Cycle Power Generation Heat and Mass Balance Schematic

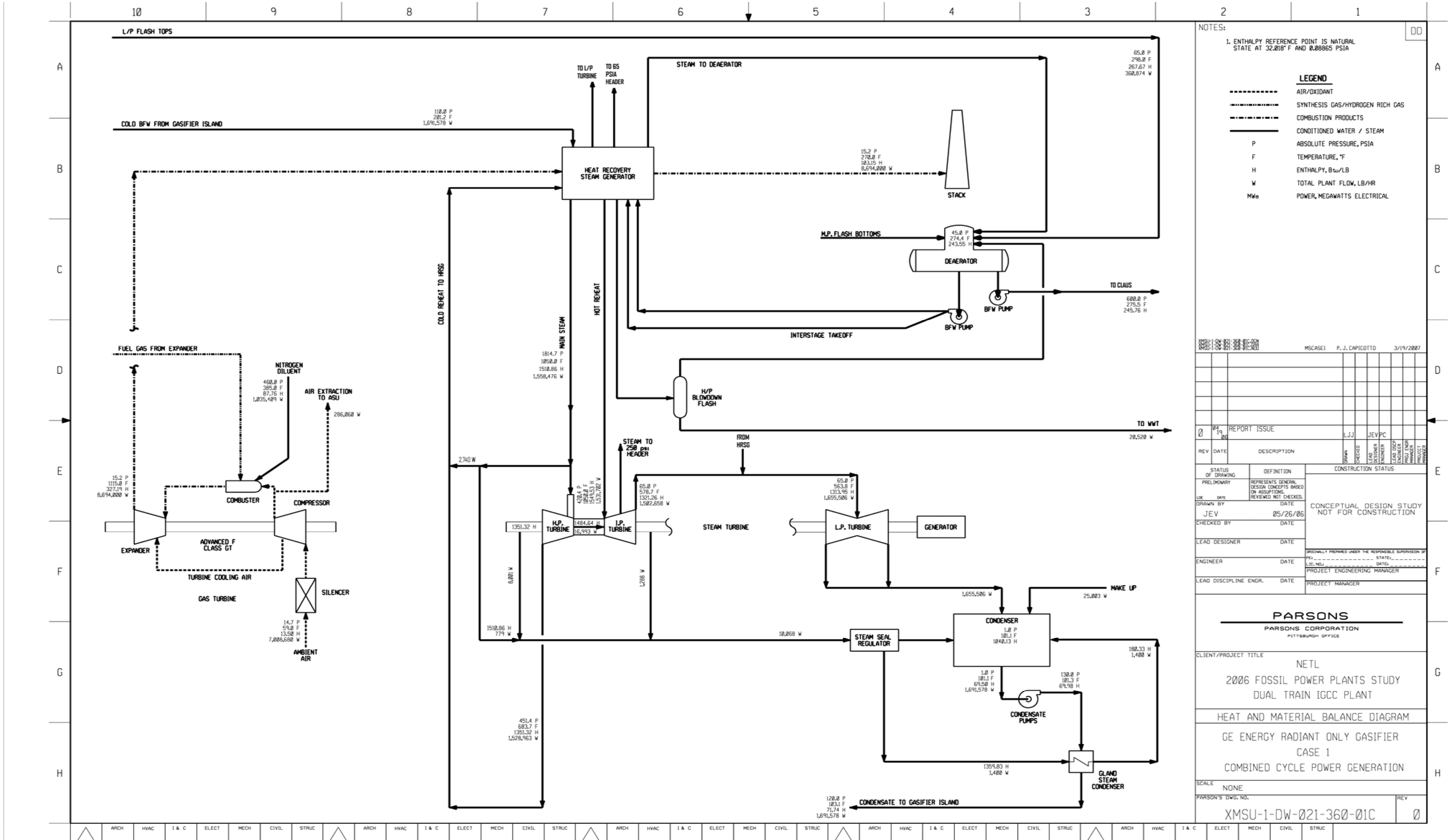

Exhibit 3-27 Case 1 Steam and Feedwater Heat and Mass Balance Schematic

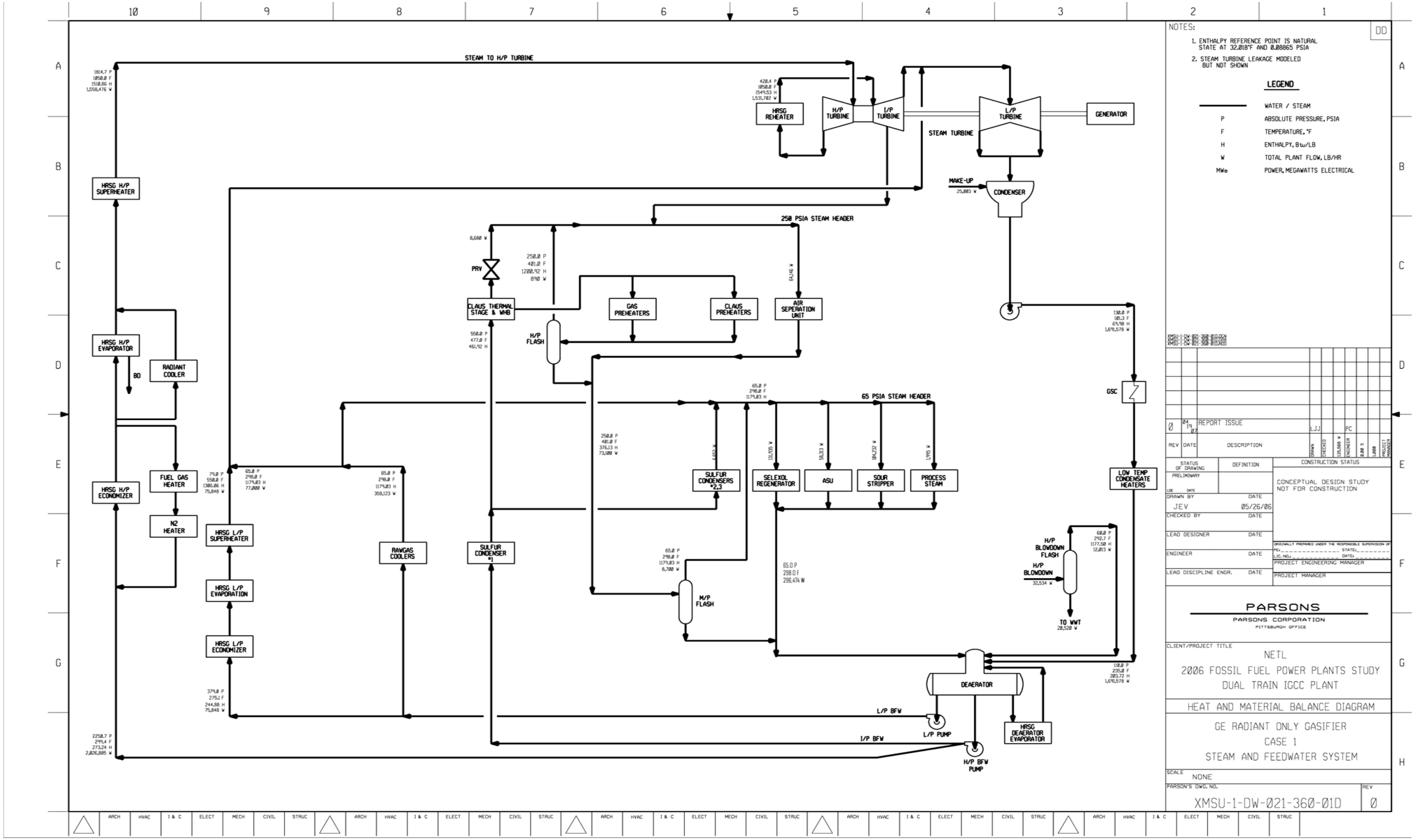

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Exhibit 3-28 Case 1 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,712.1	4.8		5,716.8
ASU Air		20.8		20.8
CT Air		94.6		94.6
Water		2.9		2.9
Auxiliary Power			444.0	444.0
Totals	**5,712.1**	**123.1**	**444.0**	**6,279.2**
Heat Out (MMBtu/hr)				
ASU Intercoolers		228.0		228.0
ASU Vent		6.1		6.1
Slag	88.3	3.6		91.9
Sulfur	48.7	(1.2)		47.5
Tail Gas Compressor Intercoolers		4.4		4.4
HRSG Flue Gas		896.8		896.8
Condenser		1,617.0		1,617.0
Process Losses (1)		710.8		710.8
Power			2,676.7	2,676.7
Totals	**137.0**	**3,465.5**	**2,676.7**	**6,279.2**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.2.6 CASE 1 - MAJOR EQUIPMENT LIST

Major equipment items for the GEE gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.7. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/h (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	363 tonne/h (400 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	363 tonne/h (400 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	363 tonne/h (400 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Gravimetric	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	245 tonne/h (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	490 tonne (540 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	302,835 liters (80,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	2	2
10	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	320,248 liters (84,600 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,650 lpm (700 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	946,361 liters (250,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,337 lpm (1,410 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,650 lpm (700 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	745,732 liters (197,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,079 lpm @ 110 m H2O (1,870 gpm @ 360 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	514,828 kg/h (1,135,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,931 lpm @ 283 m H2O (510 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,890 lpm @ 1,890 m H2O (1,820 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,893 lpm @ 223 m H2O (500 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	8,593 lpm @ 18 m H2O (2,270 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	2,498 lpm @ 49 m H2O (660 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,211,341 liter (320,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	189 lpm (50 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,903 tonne/day, 5.6 MPa (3,200 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	274,424 kg/h (605,000 lb/h)	2	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	330,216 kg/h (728,000 lb/h)	2	0
4	Raw Gas Coolers	Shell and tube with condensate drain	301,186 kg/h (664,000 lb/h)	6	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	218,178 kg/h, 39°C, 5.2 MPa (481,000 lb/h, 103°F, 753 psia)	2	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	330,216 kg/h (728,000 lb/h) syngas	2	0
7	ASU Main Air Compressor	Centrifugal, multi-stage	5,267 m3/min @ 1.3 MPa (186,000 scfm @ 190 psia)	2	0
8	Cold Box	Vendor design	2,540 tonne/day (2,800 tpd) of 95% purity oxygen	2	0
9	Oxygen Compressor	Centrifugal, multi-stage	1,246 m3/min @ 7.1 MPa (44,000 scfm @ 1,030 psia)	2	0
10	Nitrogen Compressor	Centrifugal, multi-stage	3,058 m3/min @ 3.4 MPa (108,000 scfm @ 490 psia)	2	0
11	Nitrogen Boost Compressor	Centrifugal, multi-stage	566 m3/min @ 2.3 MPa (20,000 scfm @ 340 psia)	2	0
12	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	71,214 kg/h, 433°C, 1.6 MPa (157,000 lb/h, 811°F, 235 psia)	2	0

ACCOUNT 5A SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	225,436 kg/h (497,000 lb/h) 42°C (107°F) 5.1 MPa (743 psia)	2	0
2	Sulfur Plant	Claus type	147 tonne/day (162 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	301,186 kg/h (664,000 lb/h) 199°C (390°F) 5.5 MPa (793 psia)	2	0
4	Acid Gas Removal Plant	Selexol	225,436 kg/h (497,000 lb/h) 42°C (107°F) 5.1 MPa (733 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	19,504 kg/h (43,000 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	183 m3/min @ 3.0 MPa (6,480 scfm @ 430 psia)	1	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0
3	Sweet Syngas Expansion Turbine/Generator	Turbo expander	198,447 kg/h (437,500 lb/h) Delta P: 2.1 MPa (310 psi) Power output: 3,980 kW	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.3 m (27 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 388,803 kg/h, 12.4 MPa/566°C (857,162 lb/h, 1,800 psig/1,050°F) Reheat steam - 382,124 kg/h, 2.9 MPa/566°C (842,437 lb/h, 420 psig/1,050°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	315 MW 12.4 MPa/566°C/566°C (1800 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,876 MMkJ/h (1,780 MMBtu/h) heat duty, Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	370,973 lpm @ 30 m (98,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,066 MMkJ/h (1,960 MMBtu/h) heat load	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	257,410 liters (68,000 gal)	2	0
2	Slag Crusher	Roll	14 tonne/h (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	14 tonne/h (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	166,559 liters (44,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	79,494 liters (21,000 gal)	2	0
6	Slag Conveyor	Drag chain	14 tonne/h (15 tph)	2	0
7	Slag Separation Screen	Vibrating	14 tonne/h (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	14 tonne/h (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	249,839 liters (66,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	76 lpm @ 14 m H2O (20 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	79,494 liters (21,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	303 lpm @ 564 m H2O (80 gpm @ 1,850 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	998 tonne (1,100 tons)	2	0
14	Unloading Equipment	Telescoping chute	109 tonne/h (120 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 200 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 142 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 21 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.7 CASE 1 - COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-29 shows the total plant capital cost summary organized by cost account and Exhibit 3-30 shows a more detailed breakdown of the capital costs. Exhibit 3-31 shows the initial and annual O&M costs.

The estimated TPC of the GEE gasifier with no CO_2 capture is $1,813/kW. Process contingency represents 2.5 percent of the TPC and project contingency represents 13.3 percent. The 20-year LCOE is 78.0 mills/kWh

Exhibit 3-29 Case 1 Total Plant Cost Summary

Client:	USDOE/NETL
Project:	Bituminous Baseline Study
Report Date:	05-Apr-07
Case:	Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size:	640.3 MW,net
Estimate Type:	Conceptual
Cost Base (Dec)	2006 ($x1000)

TOTAL PLANT COST SUMMARY

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,505	$2,518	$10,582	$0	$0	**$26,606**	$2,410	$0	$5,803	**$34,819**	$54
2	COAL & SORBENT PREP & FEED	$23,112	$4,213	$13,999	$0	$0	**$41,324**	$3,748	$1,500	$9,315	**$55,887**	$87
3	FEEDWATER & MISC. BOP SYSTEMS	$9,975	$8,740	$9,353	$0	$0	**$28,067**	$2,620	$0	$6,893	**$37,580**	$59
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$101,906	$0	$56,569	$0	$0	**$158,475**	$14,508	$21,881	$29,920	**$224,784**	$351
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$152,787	$0	w/equip.	$0	$0	**$152,787**	$14,542	$0	$16,733	**$184,063**	$287
4.4-4.9	Other Gasification Equipment	$12,116	$11,603	$12,827	$0	$0	**$36,546**	$3,471	$0	$8,277	**$48,294**	$75
	SUBTOTAL 4	**$266,809**	**$11,603**	**$69,396**	**$0**	**$0**	**$347,808**	**$32,521**	**$21,881**	**$54,930**	**$457,140**	**$714**
5A	Gas Cleanup & Piping	$46,447	$4,978	$47,184	$0	$0	**$98,610**	$9,456	$89	$21,825	**$129,980**	$203
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	**$87,072**	$8,192	$4,354	$9,962	**$109,578**	$171
6.2-6.9	Combustion Turbine Other	$5,440	$752	$1,598	$0	$0	**$7,791**	$733	$0	$1,539	**$10,063**	$16
	SUBTOTAL 6	**$87,441**	**$752**	**$6,670**	**$0**	**$0**	**$94,862**	**$8,925**	**$4,354**	**$11,501**	**$119,642**	**$187**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,012	$0	$4,840	$0	$0	**$38,851**	$3,667	$0	$4,252	**$46,771**	$73
7.2-7.9	Ductwork and Stack	$3,127	$2,201	$2,922	$0	$0	**$8,249**	$762	$0	$1,465	**$10,476**	$16
	SUBTOTAL 7	**$37,138**	**$2,201**	**$7,761**	**$0**	**$0**	**$47,101**	**$4,429**	**$0**	**$5,717**	**$57,247**	**$89**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$29,570	$0	$5,065	$0	$0	**$34,635**	$3,319	$0	$3,795	**$41,750**	$65
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,895	$1,003	$7,554	$0	$0	**$19,452**	$1,756	$0	$4,243	**$25,451**	$40
	SUBTOTAL 8	**$40,465**	**$1,003**	**$12,619**	**$0**	**$0**	**$54,087**	**$5,075**	**$0**	**$8,039**	**$67,201**	**$105**
9	COOLING WATER SYSTEM	$7,199	$7,656	$6,445	$0	$0	**$21,301**	$1,957	$0	$4,774	**$28,032**	$44
10	ASH/SPENT SORBENT HANDLING SYS	$14,077	$7,868	$14,278	$0	$0	**$36,223**	$3,463	$0	$4,274	**$43,960**	$69
11	ACCESSORY ELECTRIC PLANT	$23,161	$10,196	$20,591	$0	$0	**$53,947**	$4,678	$0	$11,201	**$69,826**	$109
12	INSTRUMENTATION & CONTROL	$9,437	$1,767	$6,335	$0	$0	**$17,538**	$1,616	$877	$3,351	**$23,382**	$37
13	IMPROVEMENTS TO SITE	$3,211	$1,892	$7,981	$0	$0	**$13,084**	$1,285	$0	$4,311	**$18,681**	$29
14	BUILDINGS & STRUCTURES	$0	$6,373	$7,450	$0	$0	**$13,823**	$1,257	$0	$2,462	**$17,541**	$27
	TOTAL COST	**$581,977**	**$71,760**	**$240,644**	**$0**	**$0**	**$894,382**	**$83,439**	**$28,701**	**$154,397**	**$1,160,919**	**$1,813**

Exhibit 3-30 Case 1 Total Plant Cost Details

Client: USDOE/NETL — Report Date: 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size: 640.3 MW,net — Estimate Type: Conceptual — Cost Base (Dec) 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,547	$0	$1,751	$0	$0	$5,298	$474	$0	$1,154	$6,926	$11
1.2	Coal Stackout & Reclaim	$4,583	$0	$1,123	$0	$0	$5,706	$500	$0	$1,241	$7,447	$12
1.3	Coal Conveyors	$4,261	$0	$1,111	$0	$0	$5,372	$472	$0	$1,169	$7,012	$11
1.4	Other Coal Handling	$1,115	$0	$257	$0	$0	$1,372	$120	$0	$298	$1,790	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,518	$6,341	$0	$0	$8,859	$844	$0	$1,941	$11,643	$18
	SUBTOTAL 1.	**$13,505**	**$2,518**	**$10,582**	**$0**	**$0**	**$26,606**	**$2,410**	**$0**	**$5,803**	**$34,819**	**$54**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	incl. w/ 2.3	incl. w/ 2.3	incl. w/ 2.3	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,515	$361	$240	$0	$0	$2,116	$181	$0	$459	$2,757	$4
2.3	Slurry Prep & Feed	$20,764	$0	$9,236	$0	$0	$30,000	$2,719	$1,500	$6,844	$41,063	$64
2.4	Misc.Coal Prep & Feed	$833	$603	$1,837	$0	$0	$3,273	$300	$0	$715	$4,288	$7
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,249	$2,686	$0	$0	$5,936	$548	$0	$1,297	$7,780	$12
	SUBTOTAL 2.	**$23,112**	**$4,213**	**$13,999**	**$0**	**$0**	**$41,324**	**$3,748**	**$1,500**	**$9,315**	**$55,887**	**$87**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,484	$6,058	$3,201	$0	$0	$12,743	$1,176	$0	$2,784	$16,703	$26
3.2	Water Makeup & Pretreating	$532	$55	$297	$0	$0	$884	$83	$0	$290	$1,258	$2
3.3	Other Feedwater Subsystems	$1,924	$652	$587	$0	$0	$3,164	$283	$0	$689	$4,136	$6
3.4	Service Water Systems	$306	$625	$2,172	$0	$0	$3,104	$300	$0	$1,021	$4,426	$7
3.5	Other Boiler Plant Systems	$1,646	$632	$1,567	$0	$0	$3,845	$360	$0	$841	$5,046	$8
3.6	FO Supply Sys & Nat Gas	$306	$577	$539	$0	$0	$1,421	$136	$0	$311	$1,868	$3
3.7	Waste Treatment Equipment	$739	$0	$453	$0	$0	$1,192	$116	$0	$392	$1,700	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,038	$139	$537	$0	$0	$1,715	$165	$0	$564	$2,444	$4
	SUBTOTAL 3.	**$9,975**	**$8,740**	**$9,353**	**$0**	**$0**	**$28,067**	**$2,620**	**$0**	**$6,893**	**$37,580**	**$59**
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$101,906	$0	$56,569	$0	$0	$158,475	$14,508	$21,881	$29,920	$224,784	$351
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$152,787	$0	w/equip.	$0	$0	$152,787	$14,542	$0	$16,733	$184,063	$287
4.4	Scrubber & Low Temperature Cooling	$9,253	$7,518	$7,846	$0	$0	$24,617	$2,346	$0	$5,393	$32,356	$51
4.5	Black Water & Sour Gas Section	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$2,863	$1,359	$2,689	$0	$0	$6,911	$661	$0	$1,514	$9,087	$14
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$2,726	$2,292	$0	$0	$5,018	$463	$0	$1,370	$6,851	$11
	SUBTOTAL 4.	**$266,809**	**$11,603**	**$69,396**	**$0**	**$0**	**$347,808**	**$32,521**	**$21,881**	**$54,930**	**$457,140**	**$714**

Exhibit 3-30 Case 1 Total Plant Costs (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size: 640.3 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
5A	GAS CLEANUP & PIPING											
5A.1	Single Stage Selexol	$33,056	$0	$28,354	$0	$0	$61,411	$5,895	$0	$13,461	$80,767	$126
5A.2	Elemental Sulfur Plant	$9,860	$1,957	$12,731	$0	$0	$24,548	$2,367	$0	$5,383	$32,299	$50
5A.3	Mercury Removal	$1,016	$0	$774	$0	$0	$1,790	$172	$89	$410	$2,461	$4
5A.4	COS Hydrolysis	$2,515	$0	$3,286	$0	$0	$5,801	$560	$0	$1,272	$7,633	$12
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$1,942	$1,338	$0	$0	$3,280	$299	$0	$716	$4,294	$7
5A.9	HGCU Foundations	$0	$1,079	$701	$0	$0	$1,780	$163	$0	$583	$2,527	$4
	SUBTOTAL 5A.	**$46,447**	**$4,978**	**$47,184**	**$0**	**$0**	**$98,610**	**$9,456**	**$89**	**$21,825**	**$129,980**	**$203**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	$87,072	$8,192	$4,354	$9,962	$109,578	$171
6.2	Syngas Expander	$5,440	$0	$760	$0	$0	$6,200	$585	$0	$1,018	$7,803	$12
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$752	$838	$0	$0	$1,591	$148	$0	$522	$2,260	$4
	SUBTOTAL 6.	**$87,441**	**$752**	**$6,670**	**$0**	**$0**	**$94,862**	**$8,925**	**$4,354**	**$11,501**	**$119,642**	**$187**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,012	$0	$4,840	$0	$0	$38,851	$3,667	$0	$4,252	$46,771	$73
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,579	$1,144	$0	$0	$2,723	$239	$0	$592	$3,555	$6
7.4	Stack	$3,127	$0	$1,175	$0	$0	$4,302	$409	$0	$471	$5,182	$8
7.9	HRSG,Duct & Stack Foundations	$0	$622	$602	$0	$0	$1,225	$114	$0	$401	$1,739	$3
	SUBTOTAL 7.	**$37,138**	**$2,201**	**$7,761**	**$0**	**$0**	**$47,101**	**$4,429**	**$0**	**$5,717**	**$57,247**	**$89**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$29,570	$0	$5,065	$0	$0	$34,635	$3,319	$0	$3,795	$41,750	$65
8.2	Turbine Plant Auxiliaries	$204	$0	$467	$0	$0	$670	$65	$0	$74	$809	$1
8.3	Condenser & Auxiliaries	$5,181	$0	$1,496	$0	$0	$6,678	$634	$0	$731	$8,042	$13
8.4	Steam Piping	$5,510	$0	$3,883	$0	$0	$9,393	$801	$0	$2,549	$12,744	$20
8.9	TG Foundations	$0	$1,003	$1,707	$0	$0	$2,711	$256	$0	$890	$3,856	$6
	SUBTOTAL 8.	**$40,465**	**$1,003**	**$12,619**	**$0**	**$0**	**$54,087**	**$5,075**	**$0**	**$8,039**	**$67,201**	**$105**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,704	$0	$1,034	$0	$0	$5,738	$543	$0	$942	$7,223	$11
9.2	Circulating Water Pumps	$1,481	$0	$95	$0	$0	$1,575	$135	$0	$257	$1,967	$3
9.3	Circ.Water System Auxiliaries	$122	$0	$17	$0	$0	$139	$13	$0	$23	$175	$0
9.4	Circ.Water Piping	$0	$5,160	$1,316	$0	$0	$6,476	$573	$0	$1,410	$8,460	$13
9.5	Make-up Water System	$299	$0	$424	$0	$0	$723	$69	$0	$158	$949	$1
9.6	Component Cooling Water Sys	$594	$711	$502	$0	$0	$1,808	$167	$0	$395	$2,370	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,785	$3,057	$0	$0	$4,842	$457	$0	$1,590	$6,889	$11
	SUBTOTAL 9.	**$7,199**	**$7,656**	**$6,445**	**$0**	**$0**	**$21,301**	**$1,957**	**$0**	**$4,774**	**$28,032**	**$44**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$11,592	$6,392	$12,995	$0	$0	$30,979	$2,968	$0	$3,395	$37,341	$58
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$562	$0	$612	$0	$0	$1,174	$113	$0	$193	$1,480	$2
10.7	Ash Transport & Feed Equipment	$759	$0	$182	$0	$0	$941	$87	$0	$154	$1,182	$2
10.8	Misc. Ash Handling Equipment	$1,164	$1,427	$426	$0	$0	$3,017	$285	$0	$495	$3,798	$6
10.9	Ash/Spent Sorbent Foundation	$0	$49	$62	$0	$0	$112	$10	$0	$37	$159	$0
	SUBTOTAL 10.	**$14,077**	**$7,868**	**$14,278**	**$0**	**$0**	**$36,223**	**$3,463**	**$0**	**$4,274**	**$43,960**	**$69**

Exhibit 3-30 Case 1 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 01 - GEE Radiant Only IGCC w/o CO2
Plant Size: 640.3 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$921	$0	$918	$0	$0	$1,839	$175	$0	$201	$2,215	$3
11.2	Station Service Equipment	$3,646	$0	$342	$0	$0	$3,988	$379	$0	$437	$4,804	$8
11.3	Switchgear & Motor Control	$6,967	$0	$1,277	$0	$0	$8,245	$764	$0	$1,351	$10,360	$16
11.4	Conduit & Cable Tray	$0	$3,315	$10,762	$0	$0	$14,077	$1,346	$0	$3,856	$19,279	$30
11.5	Wire & Cable	$0	$6,088	$4,095	$0	$0	$10,184	$744	$0	$2,732	$13,660	$21
11.6	Protective Equipment	$0	$640	$2,427	$0	$0	$3,067	$300	$0	$505	$3,872	$6
11.7	Standby Equipment	$218	$0	$222	$0	$0	$441	$43	$0	$72	$556	$1
11.8	Main Power Transformers	$11,408	$0	$142	$0	$0	$11,550	$875	$0	$1,864	$14,288	$22
11.9	Electrical Foundations	$0	$153	$404	$0	$0	$557	$53	$0	$183	$793	$1
	SUBTOTAL 11.	**$23,161**	**$10,196**	**$20,591**	**$0**	**$0**	**$53,947**	**$4,678**	**$0**	**$11,201**	**$69,826**	**$109**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$932	$0	$648	$0	$0	$1,580	$152	$79	$272	$2,082	$3
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$214	$0	$143	$0	$0	$357	$34	$18	$82	$491	$1
12.7	Computer & Accessories	$4,969	$0	$166	$0	$0	$5,135	$487	$257	$588	$6,466	$10
12.8	Instrument Wiring & Tubing	$0	$1,767	$3,697	$0	$0	$5,464	$463	$273	$1,550	$7,751	$12
12.9	Other I & C Equipment	$3,322	$0	$1,681	$0	$0	$5,002	$480	$250	$860	$6,592	$10
	SUBTOTAL 12.	**$9,437**	**$1,767**	**$6,335**	**$0**	**$0**	**$17,538**	**$1,616**	**$877**	**$3,351**	**$23,382**	**$37**
13	Improvements to Site											
13.1	Site Preparation	$0	$101	$2,169	$0	$0	$2,270	$224	$0	$748	$3,242	$5
13.2	Site Improvements	$0	$1,792	$2,399	$0	$0	$4,190	$412	$0	$1,381	$5,983	$9
13.3	Site Facilities	$3,211	$0	$3,413	$0	$0	$6,624	$650	$0	$2,182	$9,457	$15
	SUBTOTAL 13.	**$3,211**	**$1,892**	**$7,981**	**$0**	**$0**	**$13,084**	**$1,285**	**$0**	**$4,311**	**$18,681**	**$29**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,410	$3,479	$0	$0	$5,888	$540	$0	$964	$7,393	$12
14.3	Administration Building	$0	$802	$590	$0	$0	$1,392	$124	$0	$227	$1,743	$3
14.4	Circulation Water Pumphouse	$0	$158	$85	$0	$0	$243	$21	$0	$40	$304	$0
14.5	Water Treatment Buildings	$0	$423	$418	$0	$0	$842	$76	$0	$138	$1,055	$2
14.6	Machine Shop	$0	$411	$285	$0	$0	$695	$62	$0	$114	$871	$1
14.7	Warehouse	$0	$663	$434	$0	$0	$1,097	$97	$0	$179	$1,373	$2
14.8	Other Buildings & Structures	$0	$397	$313	$0	$0	$710	$63	$0	$155	$929	$1
14.9	Waste Treating Building & Str.	$0	$888	$1,719	$0	$0	$2,607	$242	$0	$570	$3,419	$5
	SUBTOTAL 14.	**$0**	**$6,373**	**$7,450**	**$0**	**$0**	**$13,823**	**$1,257**	**$0**	**$2,462**	**$17,541**	**$27**
	TOTAL COST	**$581,977**	**$71,760**	**$240,644**	**$0**	**$0**	**$894,382**	**$83,439**	**$28,701**	**$154,397**	**$1,160,919**	**$1,813**

Exhibit 3-31 Case 1 Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 01 - GEE Radiant Only IGCC w/o CO2					Heat Rate-net(Btu/kWh):	8,922
					MWe-net:	640
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	15.0		15.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$5,637,060	$8.804
Maintenance Labor Cost					$12,434,373	$19.421
Administrative & Support Labor					$4,517,858	$7.056
TOTAL FIXED OPERATING COSTS					**$22,589,291**	**$35.282**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$23,111,454**	**$0.00515**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	5,874	1.03	**$0**	**$1,766,592**	**$0.00039**
Chemicals						
MU & WT Chem.(lb)	122,480	17,497	0.16	$20,185	$841,987	$0.00019
Carbon (Mercury Removal) (lb)	59,493	81	1.00	$59,493	$23,652	$0.00001
COS Catalyst (m3)	410	0.28	2,308.40	$946,446	$189,160	$0.00004
Water Gas Shift Catalyst(ft3)	0	0	475.00	$0	$0	$0.00000
Selexol Solution (gal)	378	54	12.90	$4,877	$203,424	$0.00005
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.21	125.00	$0	$80,745	$0.00002
Subtotal Chemicals				**$1,031,000**	**$1,338,968**	**$0.00030**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	81	0.40	$0	$9,499	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	645	15.45	$0	$2,909,636	$0.00065
Subtotal-Waste Disposal				**$0**	**$2,919,135**	**$0.00065**
By-products & Emissions						
Sulfur(tons)	0	147	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,031,000**	**$29,136,149**	**$0.00649**
Fuel(ton)	176,276	5,876	42.11	**$7,422,978**	**$72,250,323**	**$0.01610**

3.2.8 CASE 2 - GEE IGCC WITH CO_2 CAPTURE

Case 2 is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 1, namely two gasifier trains, two advanced F Class turbines, two HRSGs and one steam turbine. The gross power output from the plant is constrained by the capacity of the two combustion turbines, and since the CO_2 capture process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 1.

The process description for Case 2 is similar to Case 1 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 2 are shown in Exhibit 3-32 and Exhibit 3-33, respectively. Instead of repeating the entire process description, only differences from Case 1 are reported here.

Gasification

The gasification process is the same as Case 1 with the exception that total coal feed to the two gasifiers is 5,448 tonnes/day (6,005 TPD) (stream 6) and the ASU provides 4,635 tonnes/day (5,110 TPD) of 95 percent oxygen to the gasifier and Claus plant (streams 3 and 5).

Raw Gas Cooling/Particulate Removal

Raw gas cooling and particulate removal are the same as Case 1 with the exception that approximately 548,122 kg/h (1,208,400 lb/h) of saturated steam at 13.8 MPa (2,000 psia) is generated in the radiant SGCs.

Syngas Scrubber/Sour Water Stripper

No differences from Case 1.

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 2 steam (stream 10) is added to the syngas exiting the scrubber to adjust the H_2O:CO molar ratio to 2:1 prior to the first SGS reactor. The hot syngas exiting the first stage of SGS is used to generate the steam that is added in stream 10. A second stage of SGS results in 96 percent overall conversion of the CO to CO_2. The warm syngas from the second stage of SGS (stream 11) is cooled to 232°C (450°F) by producing IP steam that is sent to the reheater in the HRSG. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the second SGS cooler the syngas is further cooled to 39°C (103°F) prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 1.

The AGR process in Case 2 is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption as previously described in Section 3.1.5. The process results in three product streams, the clean syngas, a CO_2-rich stream and an acid gas feed to the Claus plant. The acid gas (stream 17) contains 41 percent H_2S and 45 percent CO_2 with the balance primarily N_2. The CO_2-rich stream is discussed further in the CO_2 compression section.

Exhibit 3-32 Case 2 Process Flow Diagram, GEE IGCC with CO_2 Capture

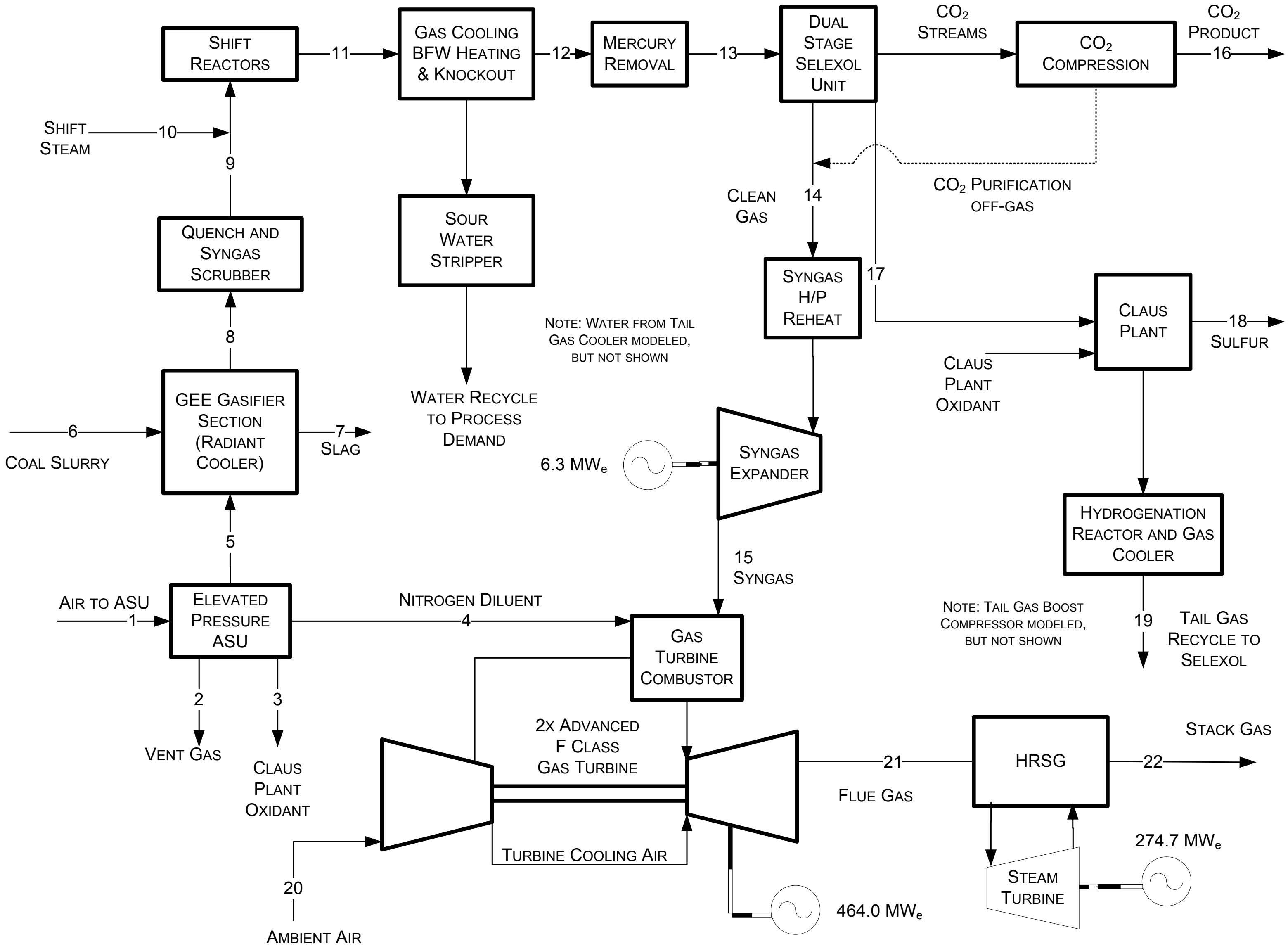

Exhibit 3-33 Case 2 Stream Table, GEE IGCC with CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0094	0.0089	0.0360	0.0024	0.0320	0.0000	0.0000	0.0079	0.0062	0.0000	0.0051
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0010	0.0008	0.0000	0.0006
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3442	0.2666	0.0000	0.0090
CO_2	0.0003	0.0023	0.0000	0.0000	0.0000	0.0000	0.0000	0.1511	0.1166	0.0000	0.3113
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0001	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3349	0.2594	0.0000	0.4305
H_2O	0.0108	0.0836	0.0000	0.0000	0.0000	1.0000	0.0000	0.1429	0.3365	1.0000	0.2317
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0056	0.0000	0.0048
N_2	0.7719	0.8367	0.0140	0.9922	0.0180	0.0000	0.0000	0.0089	0.0069	0.0000	0.0058
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0013	0.0000	0.0011
O_2	0.2076	0.0685	0.9500	0.0054	0.9500	0.0000	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	64,331	8,321	214	42,780	13,015	14,511	0	52,422	67,674	13,313	80,987
V-L Flowrate (lb/hr)	1,855,930	229,617	6,904	1,200,560	418,847	261,198	0	1,069,860	1,343,900	239,846	1,583,740
Solids Flowrate (lb/hr)	0	0	0	0	0	444,737	54,925	0	0	0	0
Temperature (°F)	232	60	90	385	206	141	410	1,100	410	615	519
Pressure (psia)	190.6	16.4	145.0	460.0	980.0	1,050.0	797.7	799.7	797.7	875.0	777.2
Enthalpy (BTU/lb)[B]	55.6	18.0	12.5	87.8	37.7	---	1,710	535.5	474.7	1275.0	433.3
Density (lb/ft^3)	0.741	0.087	0.792	1.424	4.416	---	---	0.975	1.697	1.367	1.447
Molecular Weight	28.849	27.594	32.229	28.063	32.181	---	---	20.409	19.858	18.015	19.555

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

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-33 Case 2 Stream Table (continued)

	12	13	14	15	16	17	18	19	20	21	22
V-L Mole Fraction											
Ar	0.0067	0.0067	0.0111	0.0111	0.0000	0.0000	0.0000	0.0182	0.0094	0.0092	0.0092
CH_4	0.0008	0.0008	0.0022	0.0022	0.0000	0.0000	0.0000	0.0577	0.0000	0.0000	0.0000
CO	0.0117	0.0117	0.0190	0.0190	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000
CO_2	0.4057	0.4057	0.0448	0.0448	1.0000	0.4488	0.0000	0.6784	0.0003	0.0085	0.0085
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.5609	0.5609	0.9095	0.9095	0.0000	0.0000	0.0000	0.0170	0.0000	0.0000	0.0000
H_2O	0.0009	0.0009	0.0000	0.0000	0.0000	0.0394	0.0000	0.0005	0.0108	0.1226	0.1226
H_2S	0.0054	0.0054	0.0000	0.0000	0.0000	0.4102	0.0000	0.0228	0.0000	0.0000	0.0000
N_2	0.0075	0.0075	0.0134	0.0134	0.0000	0.0807	0.0000	0.2051	0.7719	0.7527	0.7527
NH_3	0.0003	0.0003	0.0000	0.0000	0.0000	0.0203	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1071	0.1071
SO_2	0.0000	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	1.0000
V-L Flowrate (lb_{mol}/hr)	62,118	62,118	38,323	38,323	23,493	855	0	576	243,972	307,285	307,285
V-L Flowrate (lb/hr)	1,243,070	1,243,070	198,981	198,981	1,033,930	31,703	0	21,951	7,038,470	8,438,010	8,438,010
Solids Flowrate (lb/hr)	0	0	0	0	0	0	12,514	0	0	0	0
Temperature (°F)	103	103	100	386	155	120	373	95	59	1,052	270
Pressure (psia)	736.7	726.7	696.2	460.0	2,214.7	30.5	25.4	776.1	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	28.0	28.0	91.4	480.6	-46.5	39.7	-96.5	14.0	13.8	361.5	148.2
Density (lb/ft^3)	2.443	2.410	0.602	0.263	30.975	0.184	---	4.966	0.076	0.026	0.053
Molecular Weight	20.012	20.012	5.192	5.192	44.010	37.082	---	38.086	28.849	27.460	27.460

B - Reference conditions are 32.02 F & 0.089 PSIA

CO_2 Compression and Dehydration

CO_2 from the AGR process is generated at three pressure levels. The LP stream is compressed from 0.15 MPa (22 psia) to 1.1 MPa (160 psia) and then combined with the MP stream. The HP stream is combined between compressor stages at 2.1 MPa (300 psia). The combined stream is compressed from 2.1 MPa (300 psia) to a supercritical condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 93 percent CO_2 with the balance primarily nitrogen. For modeling purposes it was assumed that the impurities were separated from the CO_2 and combined with the clean syngas stream from the Selexol process. The pure CO_2 (stream 16) is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.7.

Claus Unit

The Claus plant is the same as Case 1 with the following exceptions:

- 5,676 kg/h (12,514 lb/h) of sulfur (stream 18) are produced
- The waste heat boiler generates 13,555 (29,884 lb/h) of 4.0 MPa (575 psia) steam of which 9,603 kg/h (21,172 lb/h) is available to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is combined with a small amount of clean gas from the CO_2 compression process (stream 14) and heated to 465°F using HP boiler feedwater before passing through an expansion turbine. The clean syngas (stream 15) is diltuted with nitrogen (stream 4) and then enters the CT burner. There is no integration between the CT and the ASU in this case. The exhaust gas (stream 21) exits the CT at 567°C (1052°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) (stream 22) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced commercially available steam turbine using a 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle.

Air Separation Unit

The same elevated pressure ASU is used in Case 2 and produces 4,635 tonnes/day (5,110 TPD) of 95 mole percent oxygen and 13,070 tonnes/day (14,410 TPD) of nitrogen. There is no integration between the ASU and the combustion turbine.

3.2.9 Case 2 Performance Results

The Case 2 modeling assumptions were presented previously in Section 3.2.3.

The plant produces a net output of 556 MW at a net plant efficiency of 32.5 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-34 which includes auxiliary power requirements. The ASU accounts for nearly 64 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 24 percent of the auxiliary power load. The BFW pumps and cooling water system (circulating water pumps and cooling tower fan) comprise over 5 percent of the load, leaving 7 percent of the auxiliary load for all other systems.

Exhibit 3-34 Case 2 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,010
Sweet Gas Expander Power	6,260
Steam Turbine Power	274,690
TOTAL POWER, kWe	**744,960**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	460
Coal Milling	2,330
Coal Slurry Pumps	760
Slag Handling and Dewatering	1,200
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	72,480
Oxygen Compressor	11,520
Nitrogen Compressor	35,870
Claus Plant Tail Gas Recycle Compressor	990
CO_2 Compressor	27,400
Boiler Feedwater Pumps	4,580
Condensate Pump	265
Flash Bottoms Pump	200
Circulating Water Pumps	3,580
Cooling Tower Fans	1,850
Scrubber Pumps	420
Selexol Unit Auxiliaries	17,320
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,760
TOTAL AUXILIARIES, kWe	**189,285**
NET POWER, kWe	**555,675**
Net Plant Efficiency, % (HHV)	32.5
Net Plant Heat Rate (Btu/kWh)	10,505
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,509 (1,431)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	226,968 (500,379)
Thermal Input, kWt	1,710,780
Raw Water Usage, m^3/min (gpm)	8.7 (4,578)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO2, and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 2 is presented in Exhibit 3-35.

Exhibit 3-35 Case 2 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (tons/year) @ 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.004 (0.010)	178 (196)	0.034 (0.075)
NO_X	0.020 (0.047)	867 (955)	0.166 (0.366)
Particulates	0.003 (0.0071)	132 (145)	0.025 (0.056)
Hg	0.25×10^{-6} (0.57×10^{-6})	0.011 (0.012)	2.0×10^{-6} (4.5×10^{-6})
CO_2	8.4 (19.6)	364,000 (401,000)	70 (154)
CO_2[1]			93 (206)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. As a result of achieving the 90 percent CO_2 removal target, the sulfur compounds are removed to an extent that exceeds the environmental target in Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 23 ppmv. This results in a concentration in the flue gas of less than 3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S and then recycled back to the Selexol process, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by nitrogen dilution to 15 ppmvd (as NO_2 @15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration.

The carbon balance for the plant is shown in Exhibit 3-36. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the AspenPlus model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and as CO_2 in the stack gas, ASU vent gas, and the captured CO_2 product. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in CO_2 Product)/[(Carbon in the Coal)-(Carbon in Slag)] or
281,981/(318,992-6,404) *100 or
90.2 percent

Exhibit 3-36 Case 2 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	144,692 (318,992)	**Slag**	2,905 (6,404)
Air (CO_2)	495 (1,091)	**Stack Gas**	14,162 (31,221)
		CO_2 Product	127,904 (281,981)
		ASU Vent	103 (228)
		Wastewater	113 (249)
Total	145,187 (320,083)	**Total**	145,187 (320,083)

Exhibit 3-37 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(12,514/12,560) or
99.6 percent

Exhibit 3-37 Case 2 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,697 (12,560)	**Elemental Sulfur**	5,676 (12,514)
		Stack Gas	13 (28)
		Wastewater	8 (18)
Total	5,697 (12,560)	**Total**	5,697 (12,560)

Exhibit 3-38 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-38 Case 2 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.6 (411)	1.6 (411)	0
Slag Handling	0.5 (143)	0	0.5 (143)
Quench/Scrubber	2.5 (665)	1.2 (315)	1.3 (350)
Shift Steam	1.8 (479)	0	1.8 (479)
BFW Makeup	0.2 (45)	0	0.2 (45)
Cooling Tower Makeup	13.9 (3,679)	0.4 (118)	13.5 (3,561)
Total	**20.5 (5,422)**	**3.2 (844)**	**17.3 (4,578)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-39 through Exhibit 3-43:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is presented in tabular form in Exhibit 3-44. The power out is the combined combustion turbine, steam turbine and expander power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-34) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-39 Case 2 Coal Gasification and Air Separation Units Heat and Mass Balance Schematic

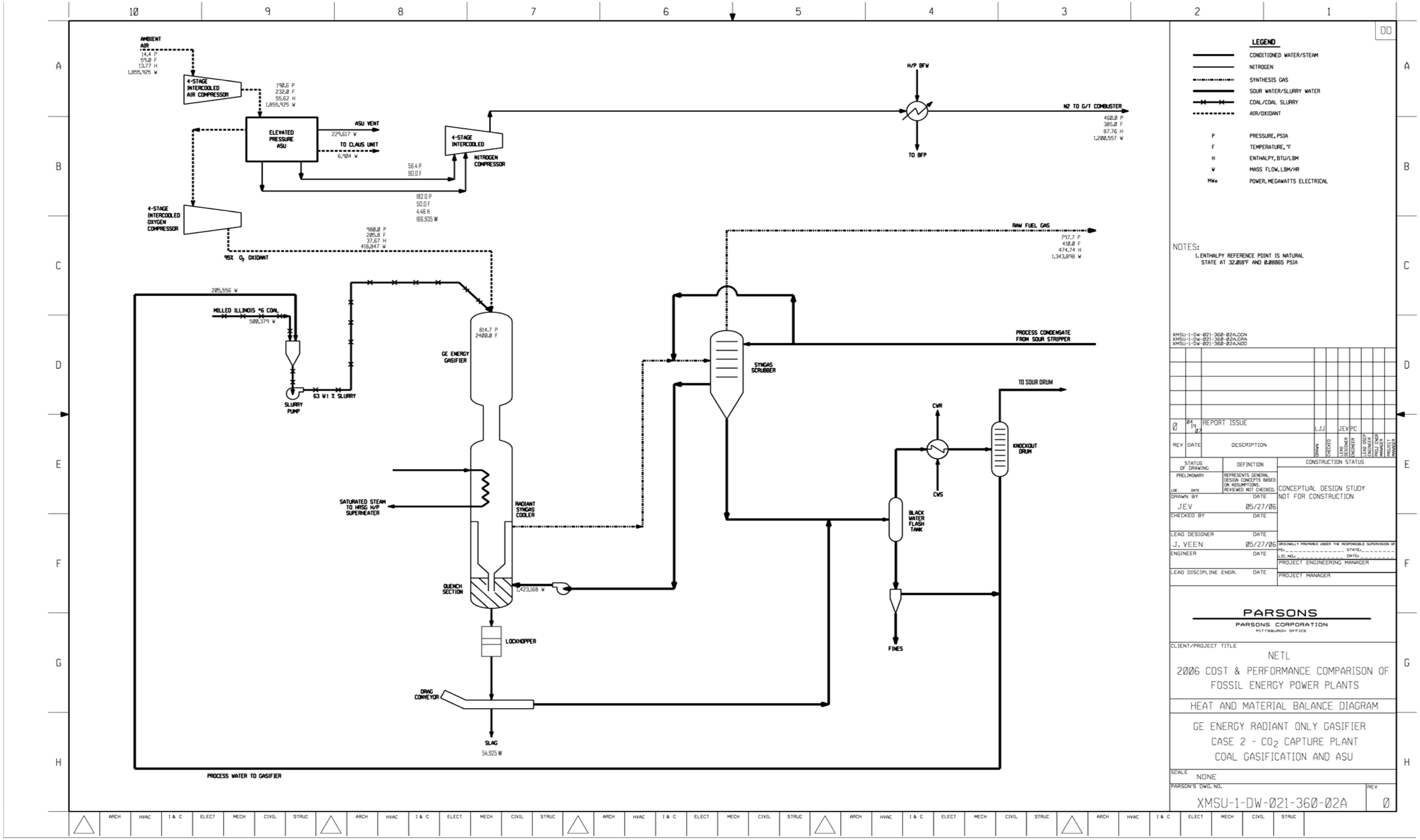

Exhibit 3-40 Case 2 Syngas Cleanup Heat and Mass Balance Schematic

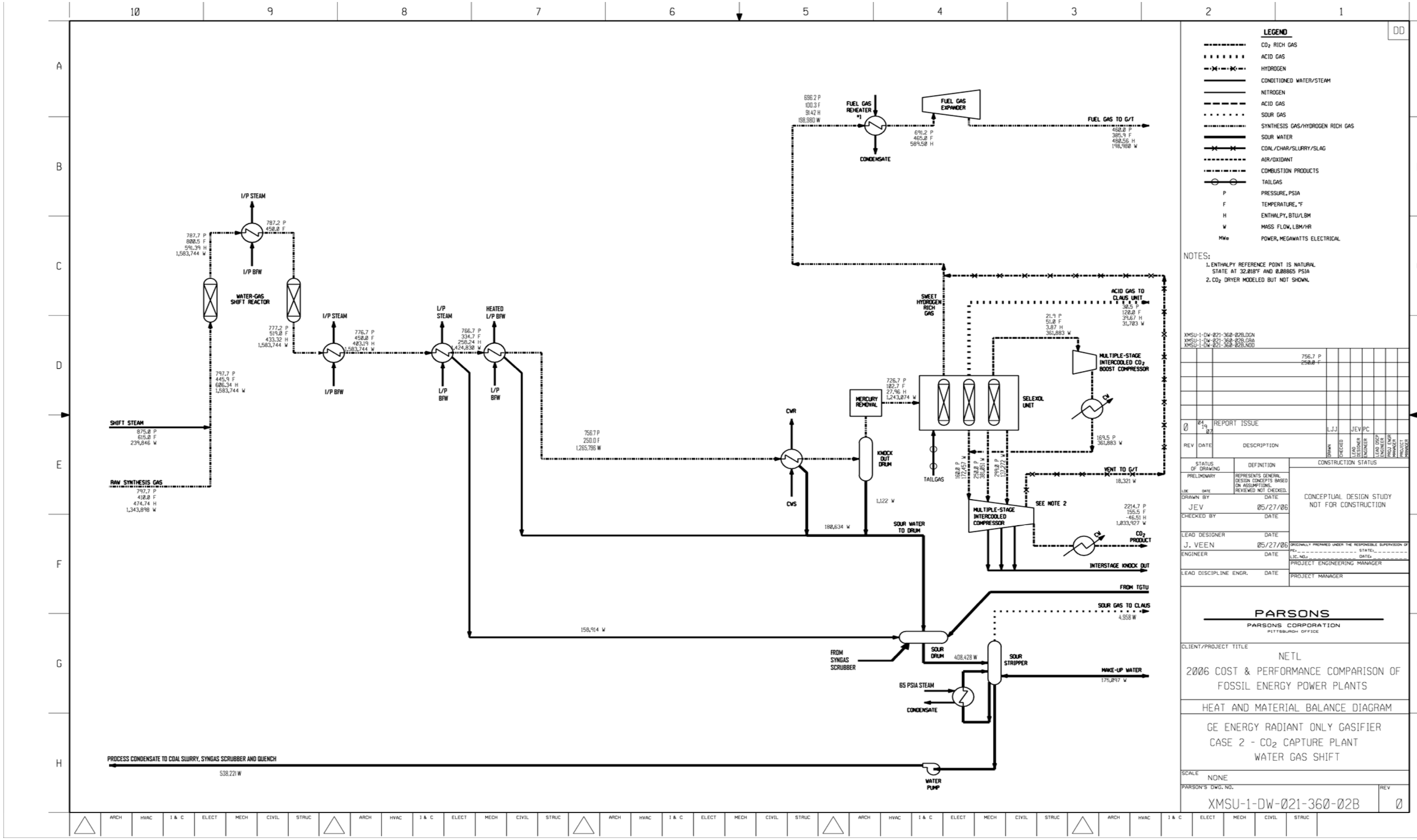

Exhibit 3-41 Case 2 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

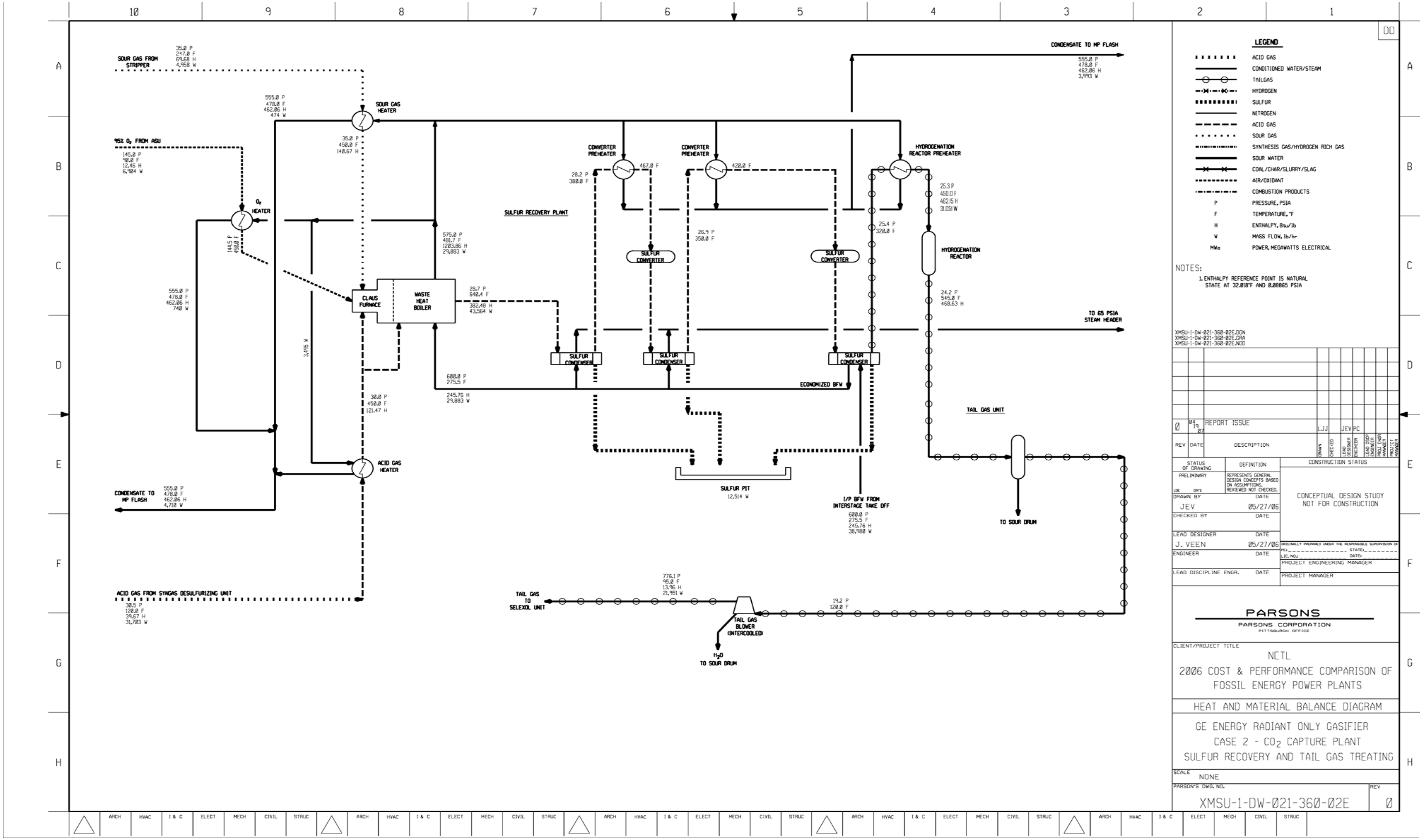

Exhibit 3-42 Case 2 Combined-Cycle Power Generation Heat and Mass Balance Schematic

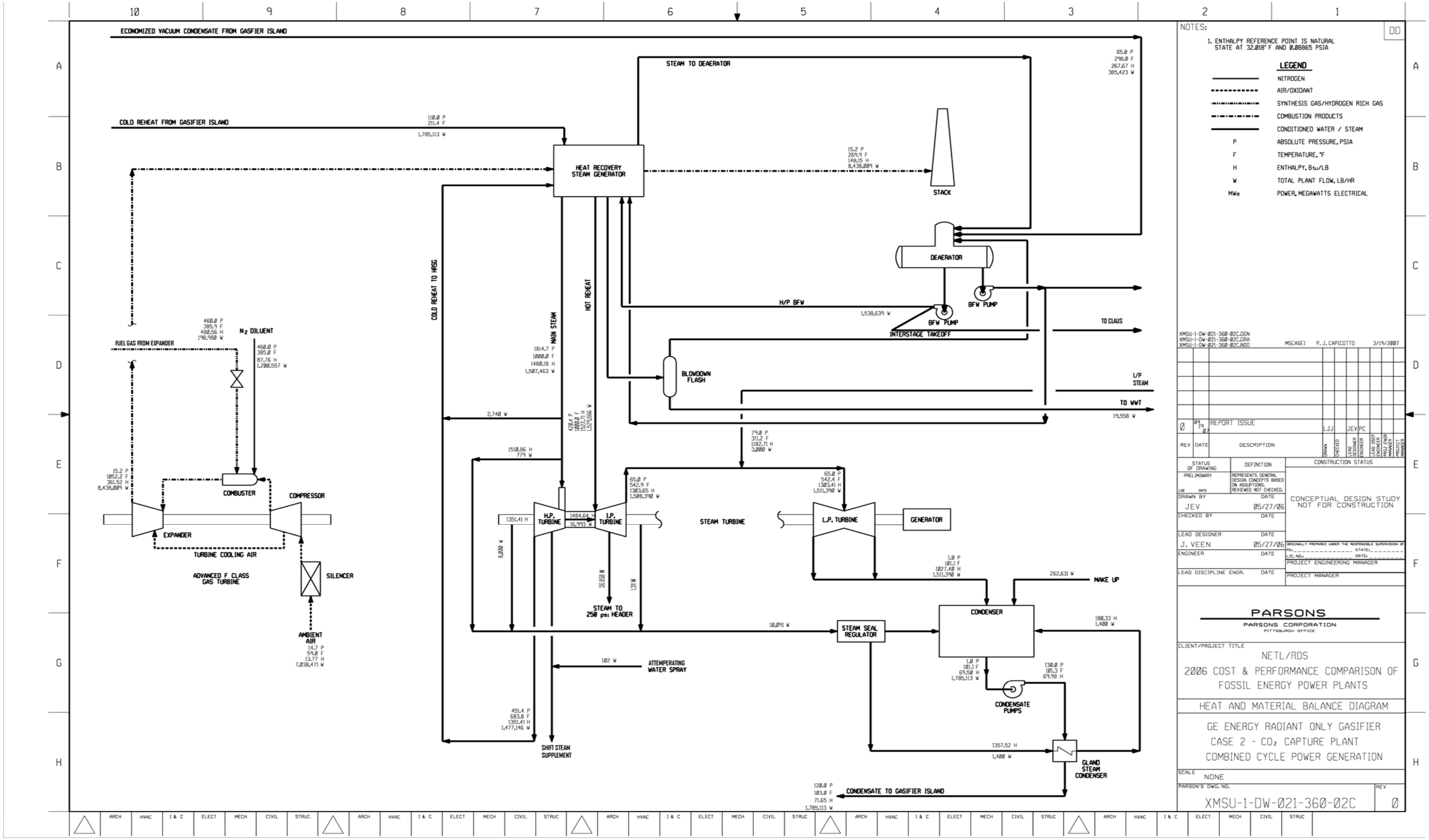

Exhibit 3-43 Case 2 Steam and Feedwater Heat and Mass Balance Schematic

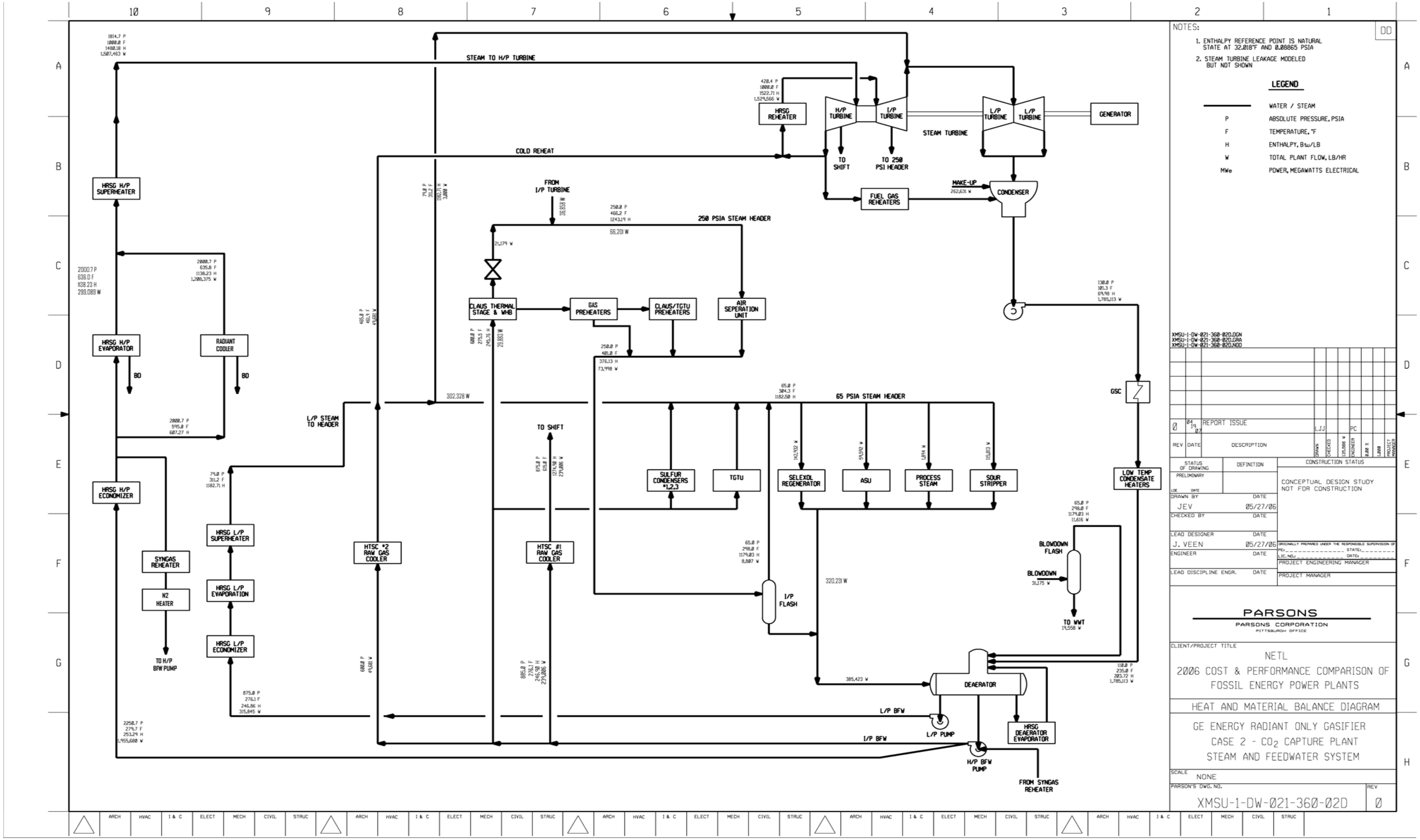

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Exhibit 3-44 Case 2 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,837.4	4.9		5,842.3
ASU Air		25.6		25.6
CT Air		96.9		96.9
Water		13.3		13.3
Auxiliary Power			646.0	646.0
Totals	**5,837.4**	**140.7**	**646.0**	**6,624.1**
Heat Out (MMBtu/hr)				
ASU Intercoolers		269.0		269.0
ASU Vent		4.1		4.1
Slag	90.2	3.7		93.9
Sulfur	49.8	(1.2)		48.6
Tail Gas Compressor Intercoolers		3.5		3.5
CO_2 Compressor Intercoolers		138.0		138.0
CO_2 Product		(48.1)		(48.1)
HRSG Flue Gas		1,250.1		1,250.1
Condenser		1,431.0		1,431.0
Process Losses		847.4		847.4
Power			2,586.5	2,586.5
Totals	**140.0**	**3,897.5**	**2,586.5**	**6,624.1**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.2.10 CASE 2 - MAJOR EQUIPMENT LIST

Major equipment items for the GEE gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.11. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	191 tonne/h (210 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	372 tonne/h (410 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	191 tonne (210 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	372 tonne/h (410 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	372 tonne/h (410 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	254 tonne/h (280 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	499 tonne (550 ton)	1	0
4	Weigh Feeder	Belt	127 tonne/h (140 tph)	2	0
5	Rod Mill	Rotary	127 tonne/h (140 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	306,621 liters (81,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	871 lpm (230 gpm)	2	2
10	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	327,441 liters (86,500 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,726 lpm (720 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	984,215 liters (260,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,451 lpm (1,440 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,726 lpm (720 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,037,211 liters (274,000 gal)	3	0
2	Condensate Pumps	Vertical canned	7,457 lpm @ 91 m H2O (1,970 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	544,311 kg/h (1,200,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,363 lpm @ 707 m H2O (360 gpm @ 2320 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,662 lpm @ 1,890 m H2O (1,760 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,817 lpm @ 223 m H2O (480 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	9,615 lpm @ 18 m H2O (2,540 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	3,710 lpm @ 49 m H2O (980 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,786,728 liter (472,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,173 lpm (310 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,994 tonne/day, 5.6 MPa (3,300 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	280,774 kg/h (619,000 lb/h)	2	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	335,205 kg/h (739,000 lb/h)	2	0
4	Raw Gas Coolers	Shell and tube with condensate drain	395,079 kg/h (871,000 lb/h)	6	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	297,103 kg/h, 38°C, 5.2 MPa (655,000 lb/h, 100°F, 747 psia)	2	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	335,205 kg/h (739,000 lb/h) syngas	2	0
7	ASU Main Air Compressor	Centrifugal, multi-stage	6,343 m3/min @ 1.3 MPa (224,000 scfm @ 190 psia)	2	0
8	Cold Box	Vendor design	2,540 tonne/day (2,800 tpd) of 95% purity oxygen	2	0
9	Oxygen Compressor	Centrifugal, multi-stage	1,274 m3/min @ 7.1 MPa (45,000 scfm @ 1,030 psia)	2	0
10	Nitrogen Compressor	Centrifugal, multi-stage	3,625 m3/min @ 3.4 MPa (128,000 scfm @ 490 psia)	2	0
11	Nitrogen Boost Compressor	Centrifugal, multi-stage	595 m3/min @ 2.3 MPa (21,000 scfm @ 340 psia)	2	0

ACCOUNT 5A SOUR GAS SHIFT AND SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	310,258 kg/h (684,000 lb/h) 39°C (103°F) 5.1 MPa (737 psia)	2	0
2	Sulfur Plant	Claus type	150 tonne/day (165 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	395,079 kg/h (871,000 lb/h) 232°C (450°F) 5.5 MPa (798 psia)	4	0
4	Shift Reactor Heat Recovery Exhchangers	Shell and Tube	Exchanger 1: 148 MMkJ/h (140 MMBtu/h) Exchanger 2: 32 MMkJ/h (30 MMBtu/h)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	310,258 kg/h (684,000 lb/h) 39°C (103°F) 5.0 MPa (727 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	15,513 kg/h (34,200 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	11,431 kg/h @ 6.4 MPa (25,200 lb/h @ 930 psi)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,157 m3/min @ 15.3 MPa (40,859 scfm @ 2,215 psia)	4	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0
3	Syngas Expansion Turbine/Generator	Turbo expander	49,641 kg/h (109,440 lb/h) 4.8 MPa (691 psia) Inlet 3.2 MPa (460 psia) Outlet	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 376,049 kg/h, 12.4 MPa/538°C (829,045 lb/h, 1,800 psig/1,000°F) Reheat steam - 381,590 kg/h, 2.9 MPa/538°C (841,261 lb/h, 420 psig/1,000°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	298 MW 12.4 MPa/538°C/538°C (1800 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	330 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,676 MMkJ/h (1,590 MMBtu/h) heat duty, Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	359,617 lpm @ 30 m (95,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,003 MMkJ/h (1,900 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	261,195 liters (69,000 gal)	2	0
2	Slag Crusher	Roll	14 tonne/h (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	14 tonne/h (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	170,345 liters (45,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	79,494 liters (21,000 gal)	2	0
6	Slag Conveyor	Drag chain	14 tonne/h (15 tph)	2	0
7	Slag Separation Screen	Vibrating	14 tonne/h (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	14 tonne/h (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	253,625 liters (67,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	76 lpm @ 14 m H2O (20 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	83,280 liters (22,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	303 lpm @ 564 m H2O (80 gpm @ 1,850 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	998 tonne (1,100 tons)	2	0
14	Unloading Equipment	Telescoping chute	118 tonne/h (130 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 110 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 207 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 31 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.11 CASE 2 - COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-45 shows the total plant cost summary organized by cost account and Exhibit 3-46 shows a more detailed breakdown of the capital costs. Exhibit 3-47 shows the initial and annual O&M costs.

The estimated TPC of the GEE gasifier with CO_2 capture is $2,390/kW. Process contingency represents 4.2 percent of the TPC and project contingency represents 13.6 percent. The 20-year LCOE, including CO_2 TS&M costs of 3.9 mills/kWh, is 102.9 mills/kWh.

Exhibit 3-45 Case 2 Total Plant Cost Summary

Client:	USDOE/NETL	**Report Date:**	05-Apr-07
Project:	Bituminous Baseline Study		
	TOTAL PLANT COST SUMMARY		
Case:	Case 02 - GEE Radiant Only IGCC w/ CO2		
Plant Size:	555.7 MW,net **Estimate Type:** Conceptual	**Cost Base (Dec)**	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,688	$2,552	$10,726	$0	$0	**$26,966**	$2,443	$0	$5,882	**$35,291**	$64
2	COAL & SORBENT PREP & FEED	$23,455	$4,274	$14,205	$0	$0	**$41,934**	$3,803	$1,522	$9,452	**$56,712**	$102
3	FEEDWATER & MISC. BOP SYSTEMS	$10,144	$8,686	$9,657	$0	$0	**$28,487**	$2,661	$0	$7,040	**$38,188**	$69
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$103,362	$0	$57,380	$0	$0	**$160,742**	$14,715	$22,192	$30,349	**$227,999**	$410
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$157,723	$0	w/equip.	$0	$0	**$157,723**	$15,012	$0	$17,274	**$190,009**	$342
4.4-4.9	Other Gasification Equipment	$12,297	$11,735	$12,985	$0	$0	**$37,018**	$3,516	$0	$8,381	**$48,914**	$88
	SUBTOTAL 4	**$273,383**	**$11,735**	**$70,365**	**$0**	**$0**	**$355,484**	**$33,243**	**$22,192**	**$56,003**	**$466,922**	**$840**
5A	Gas Cleanup & Piping	$79,047	$4,945	$70,370	$0	$0	**$154,363**	$14,797	$22,231	$38,475	**$229,866**	$414
5B	CO_2 REMOVAL & COMPRESSION	$17,712	$0	$10,865	$0	$0	**$28,577**	$2,732	$0	$6,262	**$37,572**	$68
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	**$93,325**	$8,779	$9,332	$11,144	**$122,580**	$221
6.2-6.9	Combustion Turbine Other	$5,270	$752	$1,575	$0	$0	**$7,598**	$715	$0	$1,508	**$9,820**	$18
	SUBTOTAL 6	**$93,270**	**$752**	**$6,900**	**$0**	**$0**	**$100,922**	**$9,494**	**$9,332**	**$12,651**	**$132,400**	**$238**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,193	$0	$4,581	$0	$0	**$36,774**	$3,471	$0	$4,025	**$44,270**	$80
7.2-7.9	Ductwork and Stack	$3,222	$2,268	$3,011	$0	$0	**$8,501**	$785	$0	$1,510	**$10,795**	$19
	SUBTOTAL 7	**$35,415**	**$2,268**	**$7,592**	**$0**	**$0**	**$45,275**	**$4,256**	**$0**	**$5,534**	**$55,065**	**$99**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,444	$0	$4,847	$0	$0	**$33,291**	$3,190	$0	$3,648	**$40,130**	$72
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,439	$943	$7,306	$0	$0	**$18,688**	$1,684	$0	$4,109	**$24,481**	$44
	SUBTOTAL 8	**$38,883**	**$943**	**$12,153**	**$0**	**$0**	**$51,979**	**$4,875**	**$0**	**$7,757**	**$64,611**	**$116**
9	COOLING WATER SYSTEM	$7,074	$7,437	$6,229	$0	$0	**$20,740**	$1,905	$0	$4,628	**$27,273**	$49
10	ASH/SPENT SORBENT HANDLING SYS	$14,265	$7,973	$14,470	$0	$0	**$36,708**	$3,509	$0	$4,331	**$44,548**	$80
11	ACCESSORY ELECTRIC PLANT	$23,997	$11,838	$23,440	$0	$0	**$59,275**	$5,162	$0	$12,496	**$76,933**	$138
12	INSTRUMENTATION & CONTROL	$10,469	$1,960	$7,028	$0	$0	**$19,457**	$1,793	$973	$3,718	**$25,942**	$47
13	IMPROVEMENTS TO SITE	$3,318	$1,956	$8,248	$0	$0	**$13,522**	$1,328	$0	$4,455	**$19,305**	$35
14	BUILDINGS & STRUCTURES	$0	$6,410	$7,441	$0	$0	**$13,851**	$1,259	$0	$2,474	**$17,583**	$32
	TOTAL COST	**$644,121**	**$73,729**	**$279,690**	**$0**	**$0**	**$997,540**	**$93,261**	**$56,251**	**$181,157**	**$1,328,209**	**$2,390**

Exhibit 3-46 Case 2 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 02 - GEE Radiant Only IGCC w/ CO2
Plant Size: 555.7 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,595	$0	$1,775	$0	$0	$5,370	$481	$0	$1,170	$7,020	$13
1.2	Coal Stackout & Reclaim	$4,645	$0	$1,138	$0	$0	$5,783	$507	$0	$1,258	$7,548	$14
1.3	Coal Conveyors	$4,319	$0	$1,126	$0	$0	$5,445	$478	$0	$1,185	$7,107	$13
1.4	Other Coal Handling	$1,130	$0	$260	$0	$0	$1,390	$122	$0	$302	$1,815	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,552	$6,427	$0	$0	$8,979	$856	$0	$1,967	$11,801	$21
	SUBTOTAL 1.	**$13,688**	**$2,552**	**$10,726**	**$0**	**$0**	**$26,966**	**$2,443**	**$0**	**$5,882**	**$35,291**	**$64**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	incl. w/ 2.3	incl. w/ 2.3	incl. w/ 2.3	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,537	$366	$244	$0	$0	$2,146	$184	$0	$466	$2,796	$5
2.3	Slurry Prep & Feed	$21,073	$0	$9,373	$0	$0	$30,446	$2,760	$1,522	$6,946	$41,674	$75
2.4	Misc.Coal Prep & Feed	$845	$612	$1,863	$0	$0	$3,320	$304	$0	$725	$4,350	$8
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,296	$2,725	$0	$0	$6,021	$555	$0	$1,315	$7,892	$14
	SUBTOTAL 2.	**$23,455**	**$4,274**	**$14,205**	**$0**	**$0**	**$41,934**	**$3,803**	**$1,522**	**$9,452**	**$56,712**	**$102**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,396	$5,905	$3,119	$0	$0	$12,420	$1,146	$0	$2,713	$16,280	$29
3.2	Water Makeup & Pretreating	$577	$60	$322	$0	$0	$960	$91	$0	$315	$1,365	$2
3.3	Other Feedwater Subsystems	$1,875	$636	$573	$0	$0	$3,084	$276	$0	$672	$4,031	$7
3.4	Service Water Systems	$333	$679	$2,358	$0	$0	$3,370	$326	$0	$1,109	$4,805	$9
3.5	Other Boiler Plant Systems	$1,787	$686	$1,701	$0	$0	$4,173	$391	$0	$913	$5,478	$10
3.6	FO Supply Sys & Nat Gas	$306	$577	$539	$0	$0	$1,421	$136	$0	$311	$1,868	$3
3.7	Waste Treatment Equipment	$802	$0	$492	$0	$0	$1,294	$125	$0	$426	$1,845	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,068	$144	$553	$0	$0	$1,765	$170	$0	$581	$2,516	$5
	SUBTOTAL 3.	**$10,144**	**$8,686**	**$9,657**	**$0**	**$0**	**$28,487**	**$2,661**	**$0**	**$7,040**	**$38,188**	**$69**
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$103,362	$0	$57,380	$0	$0	$160,742	$14,715	$22,192	$30,349	$227,999	$410
4.2	Syngas Cooler(w/ Gasifier - 4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$157,723	$0	w/equip.	$0	$0	$157,723	$15,012	$0	$17,274	$190,009	$342
4.4	Scrubber & Low Temperature Cooling	$9,391	$7,629	$7,963	$0	$0	$24,983	$2,381	$0	$5,473	$32,838	$59
4.5	Black Water & Sour Gas Section	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$2,907	$1,380	$2,730	$0	$0	$7,017	$671	$0	$1,538	$9,226	$17
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$2,726	$2,292	$0	$0	$5,018	$463	$0	$1,370	$6,851	$12
	SUBTOTAL 4.	**$273,383**	**$11,735**	**$70,365**	**$0**	**$0**	**$355,484**	**$33,243**	**$22,192**	**$56,003**	**$466,922**	**$840**

Exhibit 3-46 Case 2 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 02 - GEE Radiant Only IGCC w/ CO2
Plant Size: 555.7 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$59,515	$0	$51,050	$0	$0	$110,564	$10,614	$22,113	$28,658	$171,950	$309
5A.2	Elemental Sulfur Plant	$10,010	$1,987	$12,925	$0	$0	$24,922	$2,403	$0	$5,465	$32,790	$59
5A.3	Mercury Removal	$1,340	$0	$1,020	$0	$0	$2,360	$226	$118	$541	$3,245	$6
5A.4	Shift Reactors	$8,183	$0	$3,380	$0	$0	$11,563	$1,101	$0	$2,533	$15,196	$27
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$1,862	$1,283	$0	$0	$3,146	$287	$0	$686	$4,119	$7
5A.9	HGCU Foundations	$0	$1,096	$712	$0	$0	$1,808	$166	$0	$592	$2,565	$5
	SUBTOTAL 5A.	**$79,047**	**$4,945**	**$70,370**	**$0**	**$0**	**$154,363**	**$14,797**	**$22,231**	**$38,475**	**$229,866**	**$414**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$17,712	$0	$10,865	$0	$0	$28,577	$2,732	$0	$6,262	$37,572	$68
	SUBTOTAL 5B.	**$17,712**	**$0**	**$10,865**	**$0**	**$0**	**$28,577**	**$2,732**	**$0**	**$6,262**	**$37,572**	**$68**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	$93,325	$8,779	$9,332	$11,144	$122,580	$221
6.2	Syngas Expander	$5,270	$0	$737	$0	$0	$6,007	$567	$0	$986	$7,560	$14
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$752	$838	$0	$0	$1,591	$148	$0	$522	$2,260	$4
	SUBTOTAL 6.	**$93,270**	**$752**	**$6,900**	**$0**	**$0**	**$100,922**	**$9,494**	**$9,332**	**$12,651**	**$132,400**	**$238**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,193	$0	$4,581	$0	$0	$36,774	$3,471	$0	$4,025	$44,270	$80
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,627	$1,179	$0	$0	$2,806	$246	$0	$610	$3,663	$7
7.4	Stack	$3,222	$0	$1,211	$0	$0	$4,433	$422	$0	$485	$5,340	$10
7.9	HRSG,Duct & Stack Foundations	$0	$641	$620	$0	$0	$1,262	$117	$0	$414	$1,792	$3
	SUBTOTAL 7.	**$35,415**	**$2,268**	**$7,592**	**$0**	**$0**	**$45,275**	**$4,256**	**$0**	**$5,534**	**$55,065**	**$99**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,444	$0	$4,847	$0	$0	$33,291	$3,190	$0	$3,648	$40,130	$72
8.2	Turbine Plant Auxiliaries	$195	$0	$449	$0	$0	$645	$63	$0	$71	$778	$1
8.3	Condenser & Auxiliaries	$4,788	$0	$1,407	$0	$0	$6,195	$588	$0	$678	$7,461	$13
8.4	Steam Piping	$5,455	$0	$3,844	$0	$0	$9,299	$793	$0	$2,523	$12,616	$23
8.9	TG Foundations	$0	$943	$1,605	$0	$0	$2,548	$240	$0	$837	$3,625	$7
	SUBTOTAL 8.	**$38,883**	**$943**	**$12,153**	**$0**	**$0**	**$51,979**	**$4,875**	**$0**	**$7,757**	**$64,611**	**$116**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,602	$0	$1,012	$0	$0	$5,614	$531	$0	$922	$7,067	$13
9.2	Circulating Water Pumps	$1,448	$0	$92	$0	$0	$1,540	$132	$0	$251	$1,923	$3
9.3	Circ.Water System Auxiliaries	$119	$0	$17	$0	$0	$136	$13	$0	$22	$172	$0
9.4	Circ.Water Piping	$0	$5,063	$1,292	$0	$0	$6,354	$563	$0	$1,383	$8,300	$15
9.5	Make-up Water System	$320	$0	$454	$0	$0	$774	$73	$0	$170	$1,017	$2
9.6	Component Cooling Water Sys	$584	$698	$493	$0	$0	$1,775	$164	$0	$388	$2,327	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,676	$2,870	$0	$0	$4,546	$429	$0	$1,492	$6,467	$12
	SUBTOTAL 9.	**$7,074**	**$7,437**	**$6,229**	**$0**	**$0**	**$20,740**	**$1,905**	**$0**	**$4,628**	**$27,273**	**$49**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$11,749	$6,479	$13,172	$0	$0	$31,400	$3,008	$0	$3,441	$37,849	$68
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$569	$0	$619	$0	$0	$1,188	$114	$0	$195	$1,498	$3
10.7	Ash Transport & Feed Equipment	$768	$0	$184	$0	$0	$953	$88	$0	$156	$1,196	$2
10.8	Misc. Ash Handling Equipment	$1,178	$1,444	$432	$0	$0	$3,054	$289	$0	$501	$3,844	$7
10.9	Ash/Spent Sorbent Foundation	$0	$50	$63	$0	$0	$113	$11	$0	$37	$161	$0
	SUBTOTAL 10.	**$14,265**	**$7,973**	**$14,470**	**$0**	**$0**	**$36,708**	**$3,509**	**$0**	**$4,331**	**$44,548**	**$80**

Exhibit 3-46 Case 2 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 02 - GEE Radiant Only IGCC w/ CO2
Plant Size: 555.7 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$903	$0	$900	$0	$0	$1,803	$171	$0	$197	$2,172	$4
11.2	Station Service Equipment	$4,284	$0	$402	$0	$0	$4,686	$445	$0	$513	$5,644	$10
11.3	Switchgear & Motor Control	$8,187	$0	$1,501	$0	$0	$9,687	$897	$0	$1,588	$12,172	$22
11.4	Conduit & Cable Tray	$0	$3,895	$12,645	$0	$0	$16,540	$1,581	$0	$4,530	$22,652	$41
11.5	Wire & Cable	$0	$7,154	$4,812	$0	$0	$11,966	$875	$0	$3,210	$16,050	$29
11.6	Protective Equipment	$0	$640	$2,427	$0	$0	$3,067	$300	$0	$505	$3,872	$7
11.7	Standby Equipment	$215	$0	$219	$0	$0	$434	$42	$0	$71	$547	$1
11.8	Main Power Transformers	$10,409	$0	$139	$0	$0	$10,548	$799	$0	$1,702	$13,048	$23
11.9	Electrical Foundations	$0	$149	$395	$0	$0	$544	$52	$0	$179	$775	$1
	SUBTOTAL 11.	**$23,997**	**$11,838**	**$23,440**	**$0**	**$0**	**$59,275**	**$5,162**	**$0**	**$12,496**	**$76,933**	**$138**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,034	$0	$719	$0	$0	$1,752	$169	$88	$301	$2,310	$4
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$238	$0	$159	$0	$0	$396	$38	$20	$91	$545	$1
12.7	Computer & Accessories	$5,513	$0	$184	$0	$0	$5,697	$540	$285	$652	$7,174	$13
12.8	Instrument Wiring & Tubing	$0	$1,960	$4,102	$0	$0	$6,062	$514	$303	$1,720	$8,599	$15
12.9	Other I & C Equipment	$3,685	$0	$1,864	$0	$0	$5,550	$533	$277	$954	$7,314	$13
	SUBTOTAL 12.	**$10,469**	**$1,960**	**$7,028**	**$0**	**$0**	**$19,457**	**$1,793**	**$973**	**$3,718**	**$25,942**	**$47**
13	Improvements to Site											
13.1	Site Preparation	$0	$104	$2,242	$0	$0	$2,346	$231	$0	$773	$3,350	$6
13.2	Site Improvements	$0	$1,851	$2,479	$0	$0	$4,330	$425	$0	$1,427	$6,182	$11
13.3	Site Facilities	$3,318	$0	$3,527	$0	$0	$6,845	$672	$0	$2,255	$9,773	$18
	SUBTOTAL 13.	**$3,318**	**$1,956**	**$8,248**	**$0**	**$0**	**$13,522**	**$1,328**	**$0**	**$4,455**	**$19,305**	**$35**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,290	$3,307	$0	$0	$5,597	$514	$0	$917	$7,028	$13
14.3	Administration Building	$0	$833	$612	$0	$0	$1,446	$129	$0	$236	$1,810	$3
14.4	Circulation Water Pumphouse	$0	$156	$84	$0	$0	$240	$21	$0	$39	$301	$1
14.5	Water Treatment Buildings	$0	$460	$454	$0	$0	$914	$82	$0	$149	$1,146	$2
14.6	Machine Shop	$0	$426	$296	$0	$0	$722	$64	$0	$118	$904	$2
14.7	Warehouse	$0	$688	$450	$0	$0	$1,139	$101	$0	$186	$1,426	$3
14.8	Other Buildings & Structures	$0	$412	$325	$0	$0	$738	$66	$0	$161	$964	$2
14.9	Waste Treating Building & Str.	$0	$922	$1,785	$0	$0	$2,707	$252	$0	$592	$3,550	$6
	SUBTOTAL 14.	**$0**	**$6,410**	**$7,441**	**$0**	**$0**	**$13,851**	**$1,259**	**$0**	**$2,474**	**$17,583**	**$32**
	TOTAL COST	**$644,121**	**$73,729**	**$279,690**	**$0**	**$0**	**$997,540**	**$93,261**	**$56,251**	**$181,157**	**$1,328,209**	**$2,390**

Exhibit 3-47 Case 2 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES

Case 02 - GEE Radiant Only IGCC w/ CO2

Cost Base (Dec)	2006
Heat Rate-net(Btu/kWh):	10,505
MWe-net:	556
Capacity Factor: (%):	80

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	33.00	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

		Total
Skilled Operator	2.0	2.0
Operator	10.0	10.0
Foreman	1.0	1.0
Lab Tech's, etc.	3.0	3.0
TOTAL-O.J.'s	16.0	16.0

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost	$6,012,864	$10.820
Maintenance Labor Cost	$13,432,424	$24.172
Administrative & Support Labor	$4,861,322	$8.748
TOTAL FIXED OPERATING COSTS	**$24,306,610**	**$43.741**

VARIABLE OPERATING COSTS

	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost	Annual Cost	$/kWh-net
Maintenance Material Cost					**$24,602,924**	**$0.00632**
Water(/1000 gallons)	0	6,594	1.03	**$0**	**$1,983,139**	**$0.00051**
Chemicals						
MU & WT Chem.(lb)	137,493	19,642	0.16	$22,659	$945,198	$0.00024
Carbon (Mercury Removal) (lb)	84,811	116	1.00	$84,811	$33,872	$0.00001
COS Catalyst (m3)	0	0	2,308.40	$0	$0	$0.00000
Water Gas Shift Catalyst(ft3)	6,288	4.30	475.00	$2,986,800	$596,410	$0.00015
Selexol Solution (gal)	504	72	12.90	$6,502	$271,232	$0.00007
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip	2.25	125.00	$0	$82,125	$0.00002
Subtotal Chemicals				**$3,100,772**	**$1,928,837**	**$0.00050**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	116	0.40	$0	$13,603	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	659	15.45	$0	$2,973,464	$0.00076
Subtotal-Waste Disposal				**$0**	**$2,987,067**	**$0.00077**
By-products & Emissions	0	0	0.00		$0	$0.00000
Sulfur(tons)	0	150	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$3,100,772**	**$31,501,967**	**$0.00809**
Fuel(ton)	180,143	6,005	42.11	**$7,585,825**	**$73,835,368**	**$0.01896**

3.3 CONOCOPHILLIPS E-GAS™ IGCC CASES

This section contains an evaluation of plant designs for Cases 3 and 4, which are based on the ConocoPhillips (CoP) E-Gas™ gasifier. Cases 3 and 4 are very similar in terms of process, equipment, scope and arrangement, except that Case 4 includes sour gas shift reactors, CO_2 absorption/regeneration and compression/transport systems. There are no provisions for CO_2 removal in Case 3.

The balance of this section is organized in an analogous manner to Section 3.2:

- Gasifier Background
- Process System Description for Case 3
- Key Assumptions for Cases 3 and 4
- Sparing Philosophy for Cases 3 and 4
- Performance Results for Case 3
- Equipment List for Case 3
- Cost Estimates for Case 3
- Process and System Description, Performance Results, Equipment List and Cost Estimate for Case 4

3.3.1 GASIFIER BACKGROUND

Dow Chemical (the former principal stockholder of Destec Energy, which was bought by Global Energy, Inc., the gasifier business that was purchased by ConocoPhillips) is a major producer of chemicals. They began coal gasification development work in 1976 with bench-scale (2 kg/h [4 lb/h]) reactor testing. Important fundamental data were obtained for conversion and yields with various coals and operating conditions. This work led to the construction of a pilot plant at Dow's large chemical complex in Plaquemine, Louisiana. The pilot plant was designed for a capacity of 11 tonnes/day (12 TPD) (dry lignite basis) and was principally operated with air as the oxidant. The plant also operated with oxygen at an increased capacity of 33 tonnes/day (36 TPD) (dry lignite basis). This pilot plant operated from 1978 through 1983.

Following successful operation of the pilot plant, Dow built a larger 499 tonnes/day (550 TPD) (dry lignite basis) gasifier at Plaquemine. In 1984, Dow Chemical and the U.S. Synthetic Fuels Corporation (SFC) announced a price guarantee contract which allowed the building of the first commercial-scale Dow coal gasification unit. The Louisiana Gasification Technology, Inc. (LGTI) plant, sometimes called the Dow Syngas Project, was also located in the Dow Plaquemine chemical complex. The plant gasified about 1,451 tonnes/day (1,600 TPD) (dry basis) of subbituminous coal to generate 184 MW (gross) of combined-cycle electricity. To ensure continuous power output to the petrochemical complex, a minimum of 20 percent of natural gas was co-fired with the syngas. LGTI was operated from 1987 through 1995.

In September 1991, DOE selected the Wabash River coal gasification repowering project, which used the Destec Energy process, for funding under the Clean Coal Technology Demonstration Program. The project was a joint venture of Destec and Public Service of Indiana (PSI Energy, Inc.). Its purpose was to repower a unit at PSI's Wabash River station in West Terre Haute, Indiana to produce 265 MW of net power from local high-sulfur bituminous coal. The design of the project gasifier was based on the Destec LGTI gasifier. Experience gained in that project provided significant input to the design of the Wabash River coal gasification facility and eliminated much of the risk associated with scale-up and process variables.

Gasifier Capacity – The gasifier originally developed by Dow is now known as the CoP E-Gas™ gasifier. The daily coal-handling capacity of the E-Gas gasifier operating at Plaquemine was in the range of 1,270 tonnes (1,400 tons) (moisture/ash-free [MAF] basis) for bituminous coal to 1,497 tonnes (1,650 tons) for lignite. The dry gas production rate was 141,600 Nm^3/h (5 million scf/h) with an energy content of about 1,370 MMkJ/h (1,300 MMBtu/h) (HHV). The daily coal-handling capacity of the gasifier at Wabash River is about 1,678 tonnes (1,850 tons) (MAF basis) for high-sulfur bituminous coal. The dry gas production rate is about 189,724 Nm^3/h (6.7 million scf/h) with an energy content of about 1,950 MMkJ/h (1,850 MMBtu/h) (HHV). This size matches the combustion turbine, which is a GE 7FA.

With increased power and fuel gas turbine demand, the gasifier coal feed increases proportionately. CoP has indicated that the gasifier can readily handle the increased demand.

Distinguishing Characteristics - A key advantage of the CoP coal gasification technology is the current operating experience with subbituminous coal at full commercial scale at the Plaquemine plant and bituminous coal at the Wabash plant. The two-stage operation improves the efficiency, reduces oxygen requirements, and enables more effective operation on slurry feeds relative to a single stage gasifier. The fire-tube SGC used by E-Gas has a lower capital cost than a water-tube design, an added advantage for the CoP technology at this time. However, this experience may spur other developers to try fire-tube designs.

Entrained-flow gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag.

The key disadvantages of the CoP coal gasification technology are the relatively short refractory life and the high waste heat recovery (SGC) duty. As with the other entrained-flow slagging gasifiers, these disadvantages result from high operating temperature. However, the two-stage operation results in a quenched syngas that is higher in CH_4 content than other gasifiers. This becomes a disadvantage in CO_2 capture cases since the CH_4 passes through the SGS reactors without change, and is also not separated by the AGR thus limiting the amount of carbon that can be captured.

Important Coal Characteristics - The slurry feeding system and the recycle of process condensate water as the principal slurrying liquid make low levels of ash and soluble salts desirable coal characteristics for use in the E-Gas™ coal gasification process. High ash levels increase the ratio of water to carbon in the coal in the feed slurry, thereby increasing the oxygen requirements. Soluble salts affect the processing cost and amount of water blowdown required to avoid problems associated with excessive buildup of salts in the slurry water recycle loop.

Bituminous coals with lower inherent moisture improve the slurry concentration and reduce oxygen requirements. The two-stage operation reduces the negative impact of low-rank coal use in slurry feed, entrained-flow gasification. Low to moderate ash fusion-temperature coals are preferred for slagging gasifiers. Coals with high ash fusion temperatures may require flux addition for optimal gasification operation.

3.3.2 PROCESS DESCRIPTION

In this section the overall CoP gasification process is described. The system description follows the BFD in Exhibit 3-48 and stream numbers reference the same Exhibit. The tables in Exhibit 3-49 provide process data for the numbered streams in the BFD.

Coal Grinding and Slurry Preparation

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. Coal grinding and slurry preparation is similar to the GEE cases but repeated here for completeness.

Coal from the coal silo is fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which in turn feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62-68 percent using bituminous coal and CoP presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent. [41, 49]

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

Gasification

This plant utilizes two gasification trains to process a total of 5,050 tonnes/day (5,567 TPD) of Illinois No. 6 coal. Each of the 2 x 50 percent gasifiers operate at maximum capacity. The E-Gas™ two-stage coal gasification technology features an oxygen-blown, entrained-flow, refractory-lined gasifier with continuous slag removal. About 78 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All oxygen for gasification is fed to this stage of the gasifier at a pressure of 4.2 MPa (615 psia). This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 1,316 to 1,427°C (2,400 to 2,600°F). The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 22 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1,010°C (1,850°F). Total slurry to both stages is shown as stream 6 in Exhibit 3-48.

Exhibit 3-48 Case 3 Process Flow Diagram, E-Gas™ IGCC without CO_2 Capture

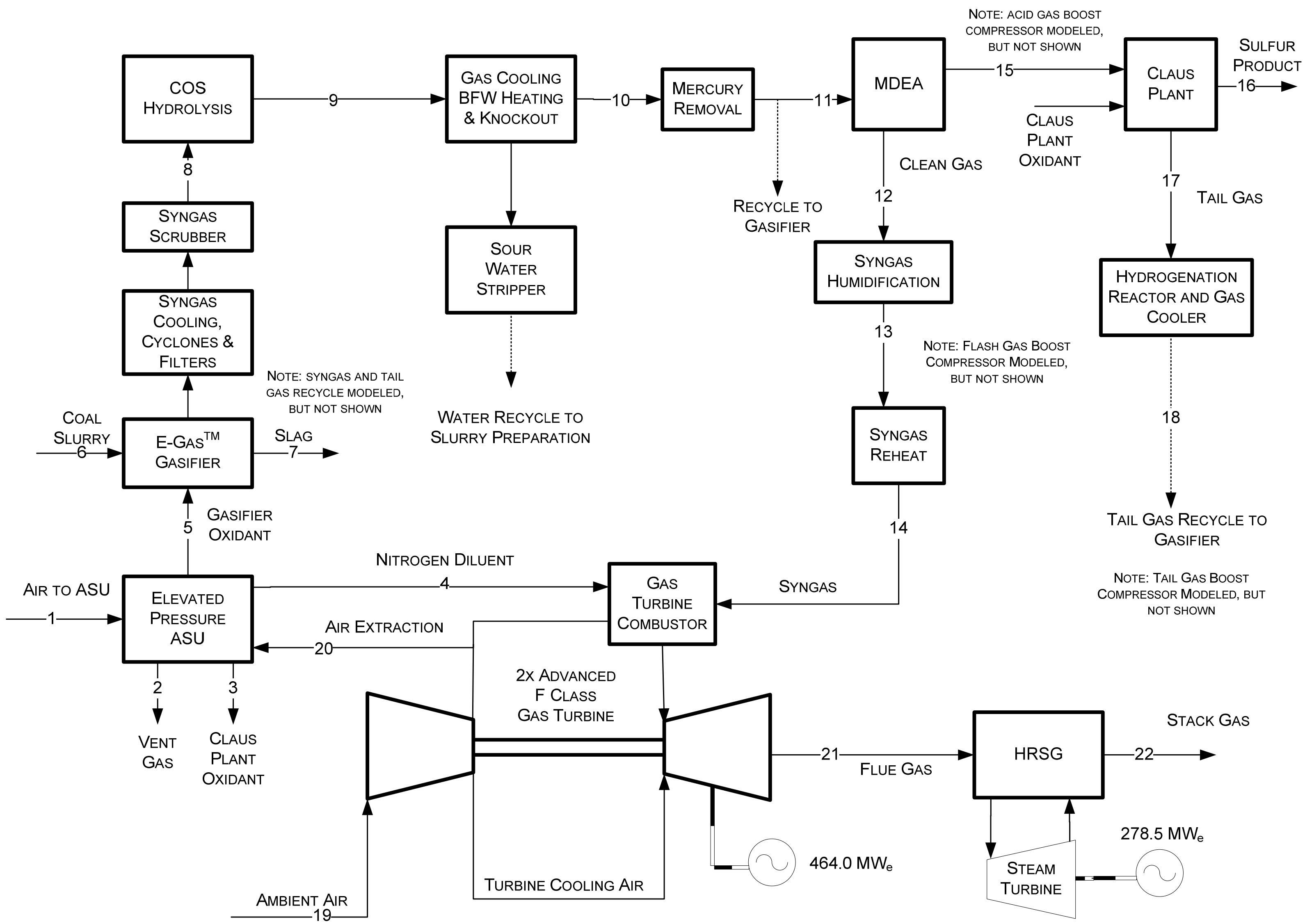

Exhibit 3-49 Case 3 Stream Table, E-Gas™ IGCC without CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0262	0.0360	0.0024	0.0320	0.0000	0.0000	0.0080	0.0080	0.0092	0.0092
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0400	0.0400	0.0457	0.0457
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3851	0.3851	0.4403	0.4403
CO_2	0.0003	0.0090	0.0000	0.0000	0.0000	0.0000	0.0000	0.1468	0.1473	0.1685	0.1685
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2738	0.2738	0.3134	0.3134
H_2O	0.0099	0.2756	0.0000	0.0004	0.0000	1.0000	0.0000	0.1251	0.1246	0.0018	0.0018
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0079	0.0084	0.0092	0.0092
N_2	0.7732	0.4638	0.0140	0.9919	0.0180	0.0000	0.0000	0.0102	0.0102	0.0117	0.0117
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0026	0.0002	0.0002
O_2	0.2074	0.2254	0.9500	0.0054	0.9500	0.0000	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	41,839	1,917	242	40,619	10,830	13,452	0	55,289	55,289	48,292	38,633
V-L Flowrate (lb/hr)	1,207,360	51,005	7,811	1,139,740	348,539	242,145	0	1,196,610	1,196,610	1,070,040	856,032
Solids Flowrate (lb/hr)	0	0	0	0	0	412,305	47,201	0	0	0	0
Temperature (°F)	235	70	90	385	191	140	1,850	400	401	103	103
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	850.0	850.0	554.7	544.7	504.7	494.7
Enthalpy (BTU/lb)[B]	55.7	26.8	12.5	88.0	34.4	---	1,120	241.5	241.4	25.0	25.0
Density (lb/ft^3)	0.735	0.104	0.683	1.424	3.412	---	---	1.302	1.277	1.852	1.815
Molecular Weight	28.857	26.613	32.229	28.060	32.181	---	---	21.643	21.643	22.158	22.158

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

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-49 Case 3 Stream Table Continued

	12	13	14	15	16	17	18	19	20	21	22
V-L Mole Fraction											
Ar	0.0095	0.0088	0.0088	0.0000	0.0000	0.0059	0.0092	0.0094	0.0094	0.0088	0.0088
CH_4	0.0471	0.0434	0.0434	0.0001	0.0000	0.0000	0.0383	0.0000	0.0000	0.0000	0.0000
CO	0.4544	0.4189	0.4189	0.0014	0.0000	0.0910	0.0003	0.0000	0.0000	0.0000	0.0000
CO_2	0.1513	0.1395	0.1395	0.7034	0.0000	0.4812	0.8551	0.0003	0.0003	0.0822	0.0822
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.3235	0.2982	0.2982	0.0010	0.0000	0.0186	0.0097	0.0000	0.0000	0.0000	0.0000
H_2O	0.0019	0.0798	0.0798	0.0000	0.0000	0.3490	0.0023	0.0108	0.0108	0.0718	0.0718
H_2S	0.0000	0.0000	0.0000	0.2941	0.0000	0.0068	0.0140	0.0000	0.0000	0.0000	0.0000
N_2	0.0120	0.0111	0.0111	0.0000	0.0000	0.0454	0.0710	0.7719	0.7719	0.7360	0.7360
NH_3	0.0002	0.0002	0.0002	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	0.0000	0.0000	0.0000	0.2076	0.2076	0.1012	0.1012
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	37,428	40,600	40,600	1,205	0	1,596	1,021	243,395	12,038	298,016	298,016
V-L Flowrate (lb/hr)	806,593	863,729	863,729	49,439	0	50,953	42,010	7,021,820	347,293	8,678,000	8,678,000
Solids Flowrate (lb/hr)	0	0	0	0	11,591	0	0	0	0	0	0
Temperature (°F)	99	266	385	187	368	320	251	59	811	1,111	270
Pressure (psia)	494.2	484.2	479.2	30.0	24.9	24.9	804.1	14.7	234.9	15.2	15.2
Enthalpy (BTU/lb)[B]	24.2	153.9	197.6	33.3	-97.5	288.6	49.1	13.8	200.3	330.6	106.9
Density (lb/ft^3)	1.776	1.324	1.125	0.177	---	0.095	4.340	0.076	0.497	0.026	0.057
Molecular Weight	21.550	21.274	21.274	41.022	---	31.929	41.154	28.849	28.849	29.119	29.119

B - Reference conditions are 32.02 F & 0.089 PSIA

The syngas produced by the CoP gasifier is higher in methane content than either the GEE or Shell gasifier. The two stage design allows for improved cold gas efficiency and lower oxygen consumption, but the quenched second stage allows some CH_4 to remain. The syngas CH_4 concentration exiting the gasifier in Case 3 is 3.9 vol% (compared to 0.10 vol% in Case 1 [GEE] and 0.04 vol% in Case 5 [Shell]). The relatively high CH_4 concentration impacts CO_2 capture efficiency as discussed further in Section 3.3.8.

Raw Gas Cooling/Particulate Removal

The 1,010°C (1,850°F) raw coal gas from the second stage of the gasifier is cooled to 371°C (700°F) in the waste heat recovery (synthesis gas cooler) unit, which consists of a fire-tube boiler and convective superheating and economizing sections. Fire-tube boilers cost markedly less than comparable duty water-tube boilers. This is because of the large savings in high-grade steel associated with containing the hot high-pressure synthesis gas in relatively small tubes.

The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed through a proprietary continuous-pressure letdown/dewatering system (stream 7). Char is produced in the second gasifier stage and is recycled to the hotter first stage, to be gasified.

The cooled gas from the SGC is cleaned of remaining particulate via a cyclone collector followed by a ceramic candle filter. Recycled syngas is used as the pulse gas to clean the candle filters. The recovered fines are pneumatically returned to the first stage of the gasifier. The combination of recycled char and recycled particulate results in high overall carbon conversion (99.2 percent used in this study).

Following particulate removal, additional heat is removed from the syngas to provide syngas re-heat prior to the COS reactor and to generate steam for the LP steam header. In this manner the syngas is cooled to 166°C (330°F) prior to the syngas scrubber.

Syngas Scrubber/Sour Water Stripper

Syngas exiting the second of the two low temperature heat exchangers passes to a syngas scrubber where a water wash is used to remove chlorides and particulate. The syngas exits the scrubber saturated at 152°C (305°F).

The sour water stripper removes NH_3, SO_2, and other impurities from the scrubber and other waste streams. The stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from synthesis gas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

COS Hydryolysis, Mercury Removal and Acid Gas Removal

Syngas exiting the scrubber is reheated to 400°F and enters a COS hydrolysis reactor (stream 8). About 99.5 percent of the COS is converted to CO_2 and H_2O (Section 3.1.5). The gas exiting the COS reactor (stream 9) passes through a series of heat exchangers and knockout drums to lower the syngas temperature to 39°C (103°F) and to separate entrained water. The cooled syngas (stream 10) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

Cool, particulate-free synthesis gas (stream 11) enters the absorber unit at approximately 3.4 MPa (495 psia) and 39°C (103°F). In the absorber, H_2S is preferentially removed from the fuel gas stream by contact with MDEA. The absorber column is operated at 27°C (80°F) by refrigerating the lean MDEA solvent. The lower temperature is required to achieve an outlet H_2S concentration of less than 30 ppmv in the sweet syngas. The stripper acid gas stream (stream 15), consisting of 29 percent H_2S and 70 percent CO_2, is sent to the Claus unit. The acid gas is combined with the sour water stripper off gas and introduced into the Claus plant burner section.

Claus Unit

Acid gas from the MDEA unit is preheated to 232°C (450°F). A portion of the acid gas along with all of the sour gas from the stripper and oxygen from the ASU are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2 at a furnace temperature of 1,316°C (2,400°F), which must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Following the thermal stage and condensation of sulfur, two reheaters and two sulfur converters are used to obtain a per-pass H_2S conversion of approximately 99.5 percent. The Claus Plant tail gas is hydrogenated and recycled back to the gasifier (stream 18). In the furnace waste heat boiler, 14,710 kg/h (32,430 lb/h) of 4.0 MPa (575 psia) steam is generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to provide some steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

A flow rate of 5,258 kg/h (11,591 lb/h) of elemental sulfur (stream 16) is recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.5 percent.

Power Block

Clean syngas exiting the MDEA absorber (stream 12) is partially humidified (stream 13) because there is not sufficient nitrogen from the ASU to provide the level of dilution required to reach the target syngas heating value. The moisturized syngas stream is reheated (stream 14), further diluted with nitrogen from the ASU (stream 4) and enters the advanced F Class combustion turbine (CT) burner. The CT compressor provides combustion air to the burner and also 22 percent of the total ASU air requirement (stream 20). The exhaust gas exits the CT at 599°C (1,111°F) (stream 21) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) (stream 22) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit (ASU)

The elevated pressure ASU was described in Section 3.1.2. In Case 3 the ASU is designed to produce a nominal output of 3,880 tonnes/day (4,275 TPD) of 95 mole percent O_2 for use in the gasifier (stream 5) and Claus plant (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 12,410 tonnes/day (13,680 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor (stream 4). About 4.9 percent of the gas turbine air is used to supply approximately 22 percent of the ASU air requirements (stream 20).

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.3.3 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 3 and 4, CoP IGCC with and without CO_2 capture, are compiled in Exhibit 3-50.

Balance of Plant – Cases 3 and 4

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 3-17.

3.3.4 SPARING PHILOSOPHY

The sparing philosophy for Cases 3 and 4 is provided below. Single trains are utilized throughout with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment.

The plant design consists of the following major subsystems:

- Two air separation units (2 x 50%)
- Two trains of slurry preparation and slurry pumps (2 x 50%)
- Two trains of gasification, including gasifier, synthesis gas cooler, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of refrigerated MDEA acid gas gas removal in Case 3 and two-stage Selexol in Case 4 (2 x 50%),
- One train of Claus-based sulfur recovery (1 x 100%).
- Two combustion turbine/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

Exhibit 3-50 CoP IGCC Plant Study Configuration Matrix

Case	3	4
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.85	0.85
Carbon Conversion, %	99.2	99.2
Syngas HHV at MDEA Outlet, kJ/Nm^3 (Btu/scf)	11,131 (299)	12,918 (347)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1800/1050/1050)	12.4/538/538 (1800/1000/1000)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
Combustion Turbine	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	CoP E-Gas™	CoP E-Gas™
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Slurry Solids Conent, %	63	63
COS Hydrolysis	Yes	Occurs in SGS
Sour Gas Shift	No	Yes
H_2S Separation	Refrigerated MDEA	Selexol 1st Stage
Sulfur Removal, %	99.5	99.7
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Gasifier/ Elemental Sulfur	Claus Plant with Tail Gas Recycle to Gasifier/ Elemental Sulfur
Particulate Control	Cyclone, Candle Filter, Scrubber, and AGR Absorber	Cyclone, Candle Filter, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB), N_2 Dilution and Humidification	MNQC (LNB), N_2 Dilution and Humidification
CO_2 Separation	N/A	Selexol 2nd Stage
CO_2 Capture	N/A	88.4% from Syngas
CO_2 Sequestration	N/A	Off-site Saline Formation

3.3.5 CASE 3 PERFORMANCE RESULTS

The plant produces a net output of 623 MWe at a net plant efficiency of 39.3 percent (HHV basis). CoP recently reported the same efficiency for their gasifier using Illinois No. 6 coal and an amine based AGR. [49]

Overall performance for the entire plant is summarized in Exhibit 3-51 which includes auxiliary power requirements. The ASU accounts for over 76 percent of the total auxiliary load distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The cooling water system, including the circulating water pumps and cooling tower fan, accounts for over 4 percent of the auxiliary load, and the BFW pumps account for an additional 3.6 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-51 Case 3 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,030
Steam Turbine Power	278,480
TOTAL POWER, kWe	**742,510**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,160
Coal Slurry Pumps	570
Slag Handling and Dewatering	1,110
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	47,130
Oxygen Compressor	8,240
Nitrogen Compressor	34,680
Syngas Recycle Blower	2,130
Tail Gas Recycle Blower	1,760
Boiler Feedwater Pumps	4,280
Condensate Pump	220
Flash Bottoms Pump	200
Circulating Water Pumps	3,350
Cooling Tower Fans	1,730
Scrubber Pumps	70
SS Amine Unit Auxiliaries	3,230
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,540
TOTAL AUXILIARIES, kWe	**119,140**
NET POWER, kWe	**623,370**
Net Plant Efficiency, % (HHV)	39.3
Net Plant Heat Rate (Btu/kWh)	8,681
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,468 (1,393)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	210,417 (463,889)
Thermal Input, kWt	1,586,023
Raw Water Usage, m^3/min (gpm)	14.2 (3,757)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 3 is presented in Exhibit 3-52.

Exhibit 3-52 Case 3 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.0054 (0.0125)	215 (237)	0.041 (0.091)
NO_X	0.026 (0.059)	1,021 (1,126)	0.196 (0.433)
Particulates	0.003 (0.0071)	122 (135)	0.023 (0.052)
Hg	0.25×10^{-6} (0.57×10^{-6})	0.010 (0.011)	1.9×10^{-6} (4.2×10^{-6})
CO_2	85.7 (199)	3,427,000 (3,778,000)	659 (1,452)
CO_2[1]			785 (1,730)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the refrigerated Coastal SS Amine AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S and then recycled back to the gasifier, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by the use of nitrogen dilution (primarily) and humidification (to a lesser extent) to 15 ppmvd (as NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-53. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas and ASU vent gas. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance.

Exhibit 3-53 Case 3 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	134,141 (295,729)	**Slag**	1,006 (2,218)
Air (CO_2)	465 (1,026)	**Stack Gas**	133,374 (294,039)
		ASU Vent	94 (207)
		Wastewater	132 (291)
Total	134,606 (296,755)	**Total**	134,606 (296,755)

Exhibit 3-54 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,591/11,644) or
99.5 percent

Exhibit 3-54 Case 3 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,281 (11,644)	**Elemental Sulfur**	5,257 (11,591)
		Stack Gas	15 (34)
		Wastewater	9 (19)
Total	5,281 (11,644)	**Total**	5,281 (11,644)

Exhibit 3-55 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-55 Case 3 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.4 (381)	1.1 (292)	0.3 (89)
Slag Handling	0.5 (123)	0	0.5 (123)
Syngas Humidifier	0.5 (133)	0	0.5 (133)
BFW Makeup	0.2 (40)	0	0.2 (40)
Cooling Tower Makeup	13.0 (3,442)	0.3 (70)	12.7 (3,372)
Total	**15.6 (4,119)**	**1.4 (362)**	**14.2 (3,757)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-56 through Exhibit 3-60:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-61. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-51) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-56 Case 3 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

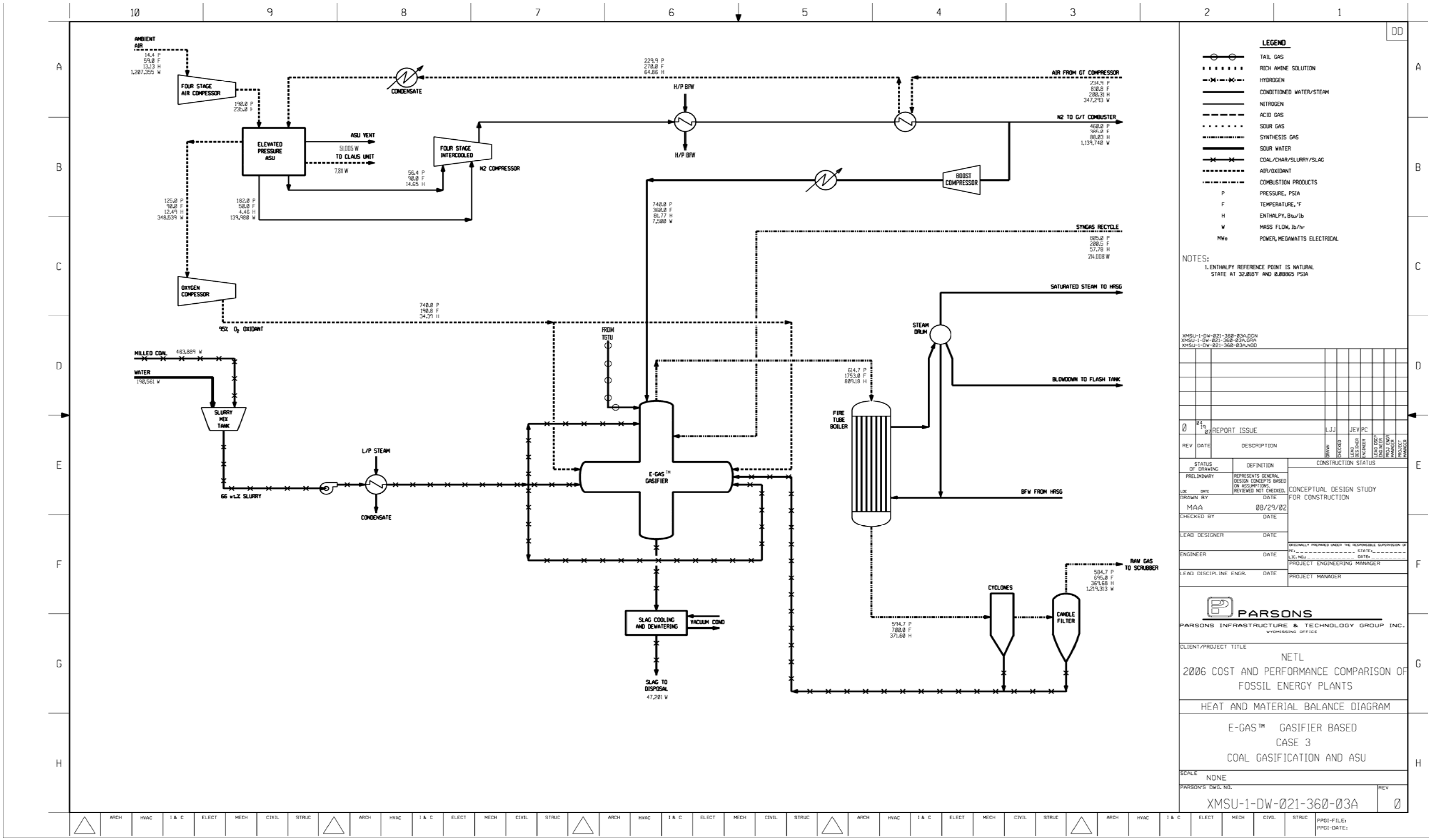

Exhibit 3-57 Case 3 Syngas Cleanup Heat and Mass Balance Schematic

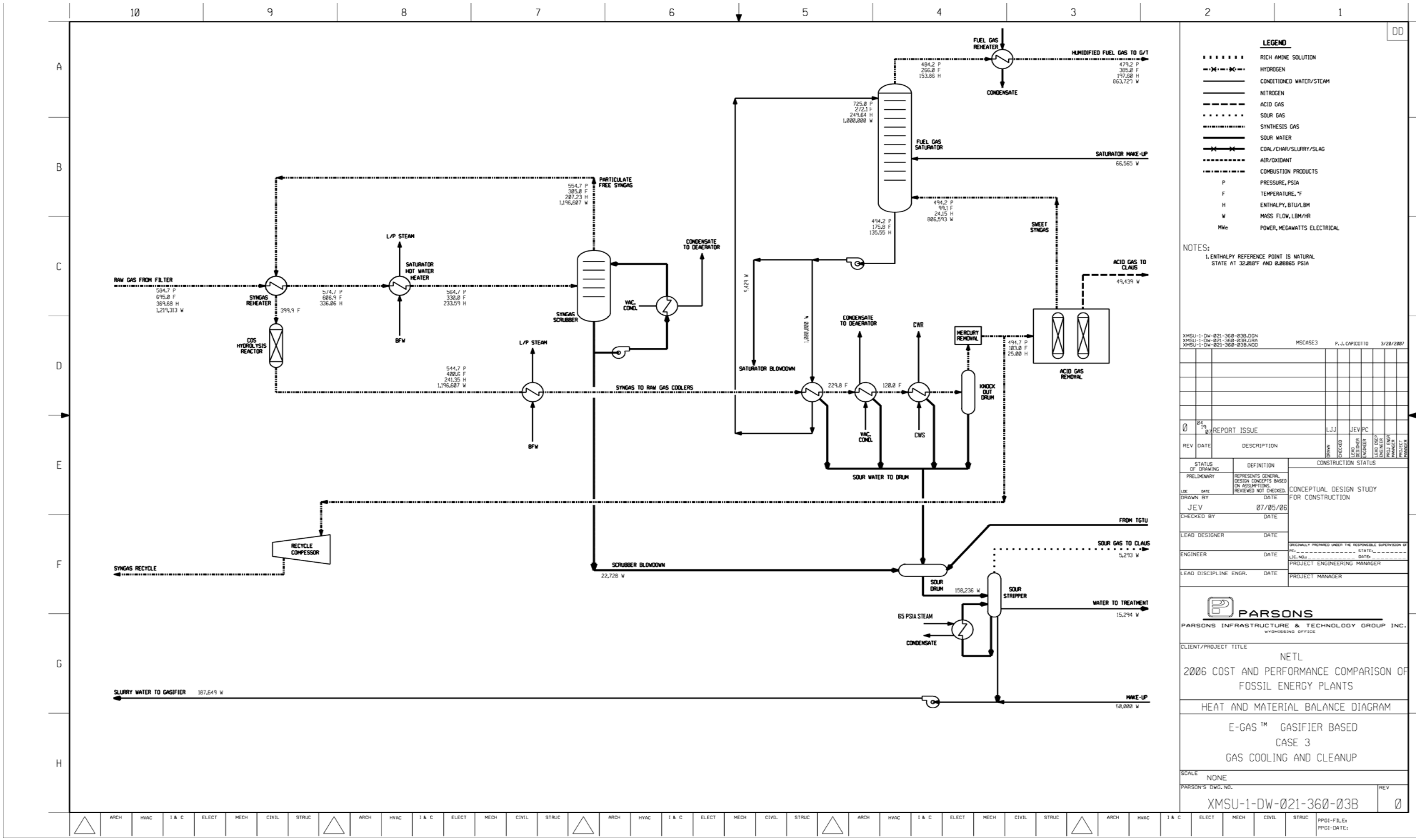

Exhibit 3-58 Case 3 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

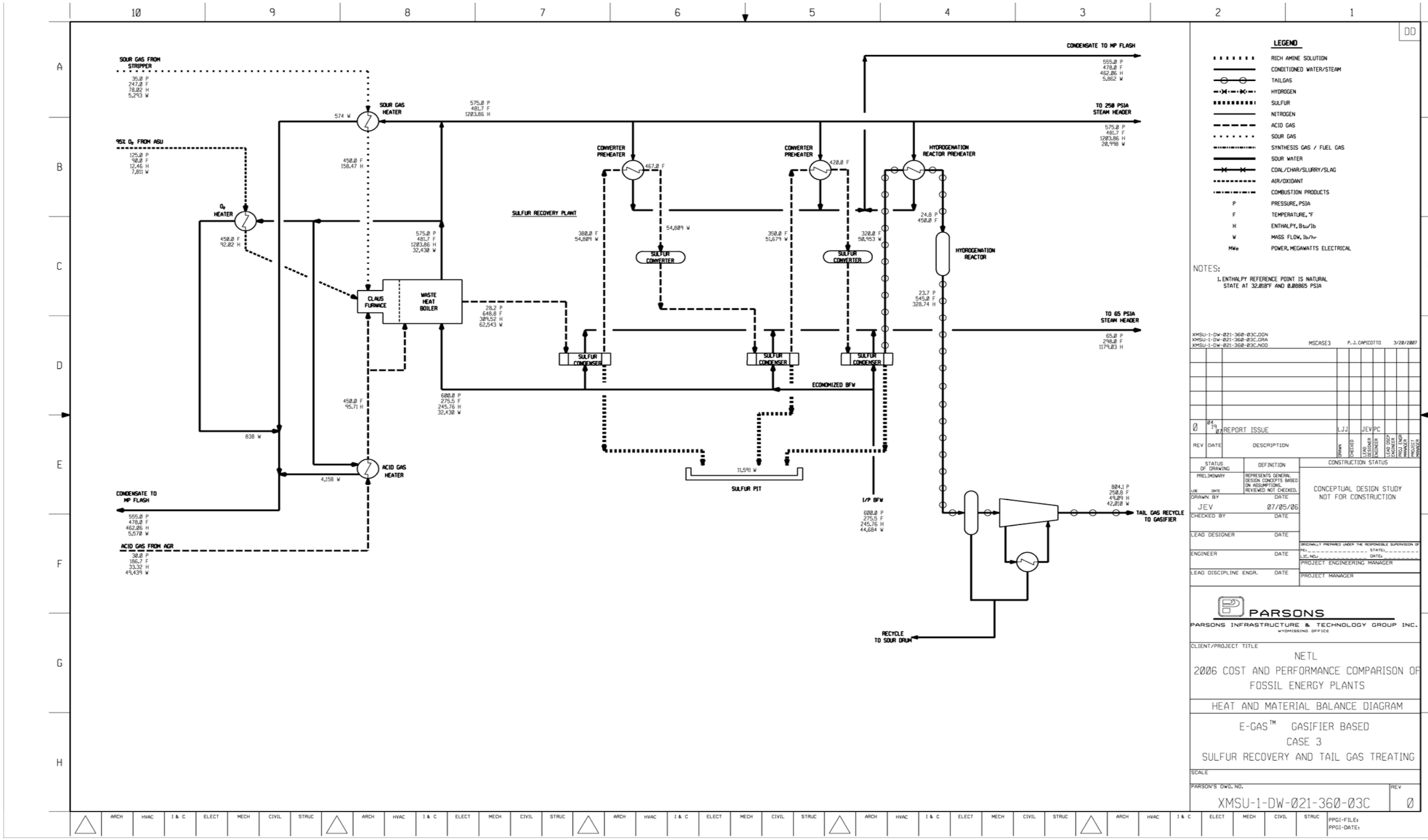

Exhibit 3-59 Case 3 Combined Cycle Power Generation Heat and Mass Balance Schematic

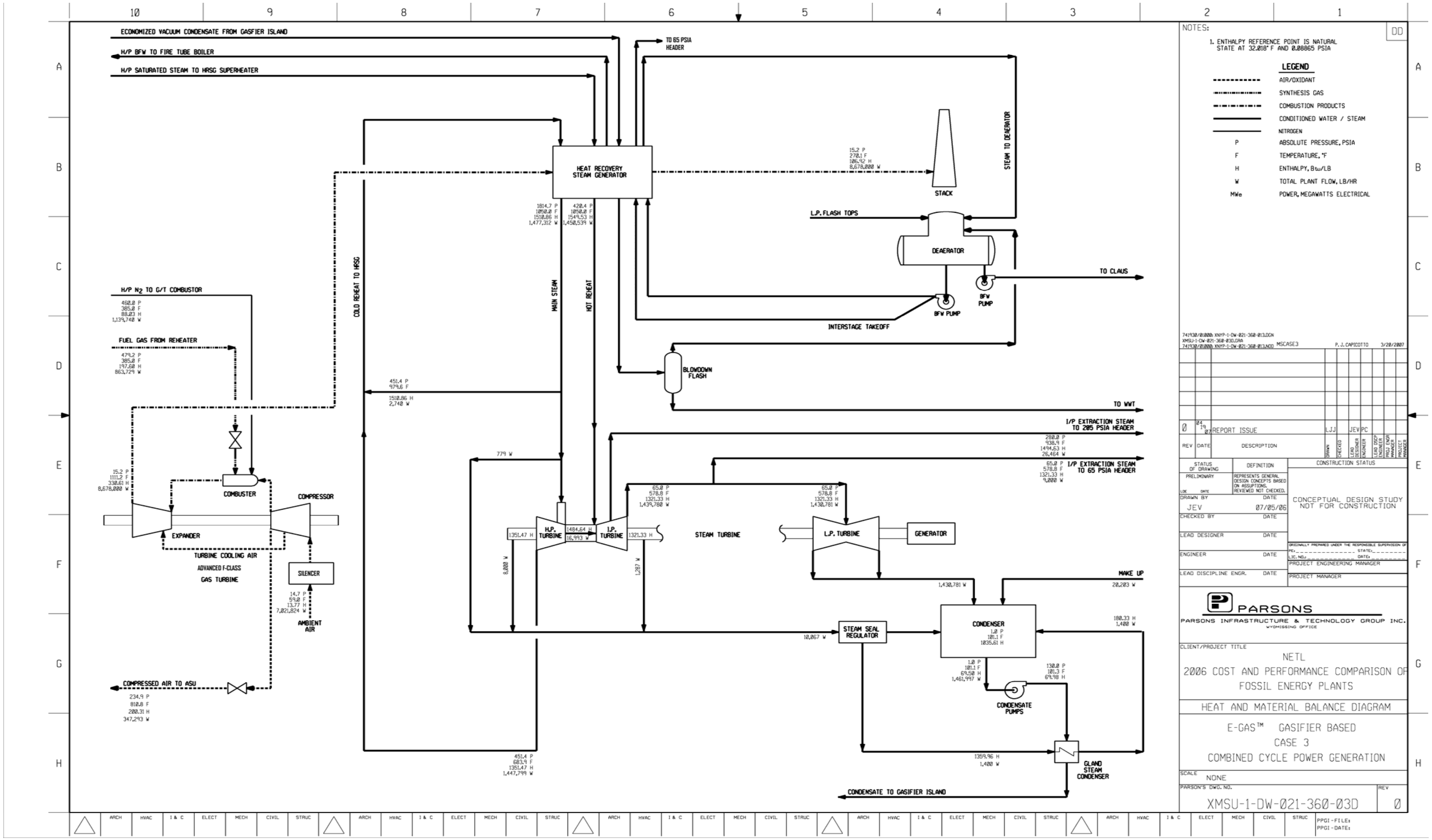

Exhibit 3-60 Case 3 Steam and Feedwater Heat and Mass Balance Schematic

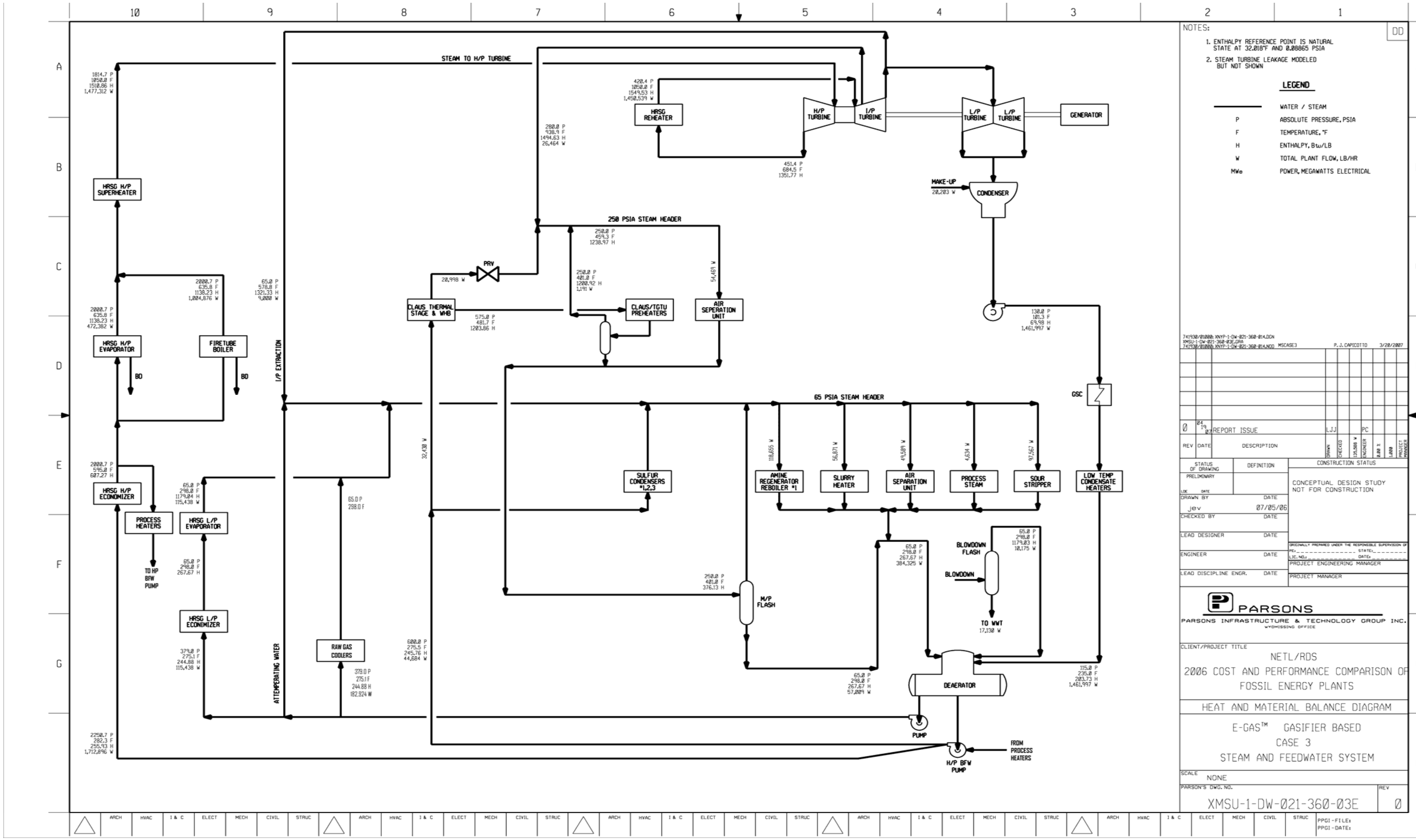

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Exhibit 3-61 Case 3 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,411.7	4.5		5,416.2
ASU Air		15.9		15.9
CT Air		96.7		96.7
Water		4.3		4.3
Auxiliary Power			406.5	406.5
Totals	**5,411.7**	**121.3**	**406.5**	**5,939.6**
Heat Out (MMBtu/hr)				
ASU Intercoolers		203.0		203.0
ASU Vent		1.4		1.4
Slag	31.3	21.6		52.9
Sulfur	46.2	(1.1)		45.0
Tail Gas Compressor Intercoolers		6.3		6.3
HRSG Flue Gas		928.0		928.0
Condenser		1,393.0		1,393.0
Process Losses		732.1		732.1
Power			2,577.9	2,577.9
Totals	**77.5**	**3,284.2**	**2,577.9**	**5,939.6**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.3.6 CASE 3 - MAJOR EQUIPMENT LIST

Major equipment items for the CoP gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.7. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	172 tonne/h (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	345 tonne/h (380 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	345 tonne/h (380 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	345 tonne/h (380 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/h (260 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	463 tonne (510 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	283,908 liters (75,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	795 lpm (210 gpm)	2	2
10	Trommel Screen	Coarse	163 tonne/h (180 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	303,592 liters (80,200 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,536 lpm (670 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	908,506 liters (240,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,072 lpm (1,340 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,536 lpm (670 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,101,563 liters (291,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,132 lpm @ 91 m H2O (1,620 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	463,118 kg/h (1,021,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,325 lpm @ 283 m H2O (350 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,511 lpm @ 1,890 m H2O (1,720 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 909 lpm @ 390 m H2O (240 gpm @ 1,280 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	7,912 lpm @ 18 m H2O (2,090 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	1,476 lpm @ 49 m H2O (390 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	715,448 liter (189,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,812 tonne/day, 4.2 MPa (3,100 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	304,361 kg/h (671,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	291,660 kg/h (643,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	298,464 kg/h (658,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	275,784 kg/h (608,000 lb/h)	6	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	266,259 kg/h, 39°C, 3.6 MPa (587,000 lb/h, 103°F, 515 psia)	2	0
8	Saturation Water Economizers	Shell and tube	275,784 kg/h (608,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	201,395 kg/h, 130°C, 3.3 MPa (444,000 lb/h, 266°F, 484 psia)	2	0
10	Saturator Water Pump	Centrifugal	4,543 lpm @ 201 m H2O (1,200 gpm @ 660 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	215,457 kg/h (475,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	298,464 kg/h (658,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	4,134 m3/min @ 1.3 MPa (146,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,076 m3/min @ 5.1 MPa (38,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,540 m3/min @ 3.4 MPa (125,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	481 m3/min @ 2.3 MPa (17,000 scfm @ 340 psia)	2	0
18	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	86,636 kg/h, 433°C, 1.6 MPa (191,000 lb/h, 811°F, 235 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	234,054 kg/h (516,000 lb/h) 39°C (103°F) 3.4 MPa (495 psia)	2	0
2	Sulfur Plant	Claus type	139 tonne/day (153 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	298,464 kg/h (658,000 lb/h) 204°C (400°F) 3.8 MPa (555 psia)	2	0
4	Acid Gas Removal Plant	MDEA	213,642 kg/h (471,000 lb/h) 39°C (103°F) 3.3 MPa (485 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	25,401 kg/h (56,000 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	21,772 kg/h @ 6.6 MPa (48,000 lb/h @ 950 psia)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, STACK AND DUCTING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.3 m (27 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 368,554 kg/h, 12.4 MPa/566°C (812,522 lb/h, 1,800 psig/1,050°F) Reheat steam - 361,875 kg/h, 2.9 MPa/566°C (797,796 lb/h, 420 psig/1,050°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	293 MW 12.4 MPa/566°C/566°C (1800 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	330 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,613 MMkJ/h (1,530 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	336,904 lpm @ 30 m (89,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT, 1,876 MMkJ/h (1,780 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	223,341 liters (59,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/h (13 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/h (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	147,632 liters (39,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/h (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/h (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/h (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	219,556 liters (58,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	265 lpm @ 433 m H2O (70 gpm @ 1,420 ft H2O)	2	2
13	Grey Water Recycle Heat Exchanger	Shell and tube	15,876 kg/h (35,000 lb/h)	2	0
14	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
15	Unloading Equipment	Telescoping chute	100 tonne/h (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 190 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 130 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.7 CASE 3 - COSTS ESTIMATING RESULTS

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-62 shows the total plant capital cost summary organized by cost account and Exhibit 3-63 shows a more detailed breakdown of the capital costs. Exhibit 3-64 shows the initial and annual O&M costs.

The estimated TPC of the CoP gasifier with no CO_2 capture is $1,733/kW. Process contingency represents 2.5 percent of the TPC and project contingency is 13.3 percent. The 20-year LCOE is 75.3 mills/kWh.

Exhibit 3-62 Case 3 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 03 - ConocoPhillips IGCC w/o CO2
Plant Size: 623.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,060	$2,435	$10,233	$0	$0	**$25,728**	$2,088	$0	$5,563	**$33,379**	$54
2	COAL & SORBENT PREP & FEED	$22,211	$4,065	$13,559	$0	$0	**$39,835**	$3,200	$0	$8,607	**$51,642**	$83
3	FEEDWATER & MISC. BOP SYSTEMS	$9,148	$7,886	$8,644	$0	$0	**$25,678**	$2,149	$0	$6,278	**$34,105**	$55
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$90,425	$0	$55,527	$0	$0	**$145,952**	$11,971	$21,893	$26,972	**$206,789**	$332
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$137,711	$0	w/equip.	$0	$0	**$137,711**	$11,743	$0	$14,945	**$164,399**	$264
4.4-4.9	Other Gasification Equipment	$18,487	$8,580	$11,695	$0	$0	**$38,763**	$3,285	$0	$9,043	**$51,091**	$82
	SUBTOTAL 4	**$246,624**	**$8,580**	**$67,222**	**$0**	**$0**	**$322,427**	**$26,999**	**$21,893**	**$50,961**	**$422,279**	**$677**
5A	Gas Cleanup & Piping	$50,895	$4,805	$38,080	$0	$0	**$93,780**	$8,032	$104	$20,588	**$122,504**	$197
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	**$87,071**	$7,338	$4,354	$9,876	**$108,639**	$174
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$121	$0	$470	**$2,037**	$3
	SUBTOTAL 6	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$7,459**	**$4,354**	**$10,346**	**$110,676**	**$178**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,926	$0	$4,828	$0	$0	**$38,754**	$3,277	$0	$4,203	**$46,234**	$74
7.2-7.9	Ductwork and Stack	$3,123	$2,198	$2,918	$0	$0	**$8,239**	$682	$0	$1,450	**$10,371**	$17
	SUBTOTAL 7	**$37,049**	**$2,198**	**$7,745**	**$0**	**$0**	**$46,992**	**$3,959**	**$0**	**$5,653**	**$56,604**	**$91**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,109	$0	$4,930	$0	$0	**$33,039**	$2,837	$0	$3,588	**$39,463**	$63
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,092	$953	$7,185	$0	$0	**$18,229**	$1,473	$0	$3,969	**$23,671**	$38
	SUBTOTAL 8	**$38,201**	**$953**	**$12,115**	**$0**	**$0**	**$51,268**	**$4,310**	**$0**	**$7,556**	**$63,135**	**$101**
9	COOLING WATER SYSTEM	$6,760	$7,303	$6,124	$0	$0	**$20,187**	$1,661	$0	$4,492	**$26,340**	$42
10	ASH/SPENT SORBENT HANDLING SYS	$18,173	$1,373	$9,021	$0	$0	**$28,568**	$2,437	$0	$3,382	**$34,386**	$55
11	ACCESSORY ELECTRIC PLANT	$22,608	$9,796	$19,825	$0	$0	**$52,229**	$4,054	$0	$10,733	**$67,016**	$108
12	INSTRUMENTATION & CONTROL	$9,358	$1,752	$6,282	$0	$0	**$17,391**	$1,436	$870	$3,296	**$22,992**	$37
13	IMPROVEMENTS TO SITE	$3,155	$1,860	$7,843	$0	$0	**$12,858**	$1,132	$0	$4,197	**$18,186**	$29
14	BUILDINGS & STRUCTURES	$0	$6,209	$7,240	$0	$0	**$13,449**	$1,095	$0	$2,378	**$16,922**	$27
	TOTAL COST	**$559,240**	**$59,898**	**$219,767**	**$0**	**$0**	**$838,905**	**$70,010**	**$27,220**	**$144,031**	**$1,080,166**	**$1,733**

Exhibit 3-63 Total Plant Cost Details

Client: USDOE/NETL　　**Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 03 - ConocoPhillips IGCC w/o CO2
Plant Size: 623.4 MW,net　　**Estimate Type:** Conceptual　　**Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,430	$0	$1,693	$0	$0	$5,123	$411	$0	$1,107	$6,641	$11
1.2	Coal Stackout & Reclaim	$4,432	$0	$1,086	$0	$0	$5,517	$433	$0	$1,190	$7,141	$11
1.3	Coal Conveyors	$4,120	$0	$1,074	$0	$0	$5,195	$409	$0	$1,121	$6,724	$11
1.4	Other Coal Handling	$1,078	$0	$249	$0	$0	$1,327	$104	$0	$286	$1,717	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,435	$6,132	$0	$0	$8,566	$731	$0	$1,860	$11,157	$18
	SUBTOTAL 1.	**$13,060**	**$2,435**	**$10,233**	**$0**	**$0**	**$25,728**	**$2,088**	**$0**	**$5,563**	**$33,379**	**$54**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,462	$348	$232	$0	$0	$2,042	$157	$0	$440	$2,638	$4
2.3	Slurry Prep & Feed	$19,945	$0	$8,962	$0	$0	$28,908	$2,310	$0	$6,244	$37,462	$60
2.4	Misc.Coal Prep & Feed	$804	$582	$1,772	$0	$0	$3,158	$259	$0	$684	$4,101	$7
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,135	$2,592	$0	$0	$5,727	$473	$0	$1,240	$7,441	$12
	SUBTOTAL 2.	**$22,211**	**$4,065**	**$13,559**	**$0**	**$0**	**$39,835**	**$3,200**	**$0**	**$8,607**	**$51,642**	**$83**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,088	$5,369	$2,836	$0	$0	$11,293	$934	$0	$2,445	$14,672	$24
3.2	Water Makeup & Pretreating	$502	$52	$280	$0	$0	$834	$71	$0	$271	$1,176	$2
3.3	Other Feedwater Subsystems	$1,705	$578	$521	$0	$0	$2,804	$225	$0	$606	$3,634	$6
3.4	Service Water Systems	$289	$590	$2,049	$0	$0	$2,928	$254	$0	$955	$4,137	$7
3.5	Other Boiler Plant Systems	$1,553	$596	$1,478	$0	$0	$3,626	$305	$0	$786	$4,717	$8
3.6	FO Supply Sys & Nat Gas	$299	$565	$527	$0	$0	$1,391	$119	$0	$302	$1,812	$3
3.7	Waste Treatment Equipment	$697	$0	$427	$0	$0	$1,124	$98	$0	$367	$1,588	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,015	$136	$526	$0	$0	$1,678	$145	$0	$547	$2,369	$4
	SUBTOTAL 3.	**$9,148**	**$7,886**	**$8,644**	**$0**	**$0**	**$25,678**	**$2,149**	**$0**	**$6,278**	**$34,105**	**$55**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$90,425	$0	$55,527	$0	$0	$145,952	$11,971	$21,893	$26,972	$206,789	$332
4.2	Syngas Cooling (w/ 4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$137,711	$0	w/equip.	$0	$0	$137,711	$11,743	$0	$14,945	$164,399	$264
4.4	LT Heat Recovery & FG Saturation	$18,487	$0	$6,956	$0	$0	$25,443	$2,191	$0	$5,527	$33,160	$53
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,142	$465	$0	$0	$1,607	$137	$0	$349	$2,092	$3
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$7,439	$4,275	$0	$0	$11,713	$957	$0	$3,168	$15,838	$25
	SUBTOTAL 4.	**$246,624**	**$8,580**	**$67,222**	**$0**	**$0**	**$322,427**	**$26,999**	**$21,893**	**$50,961**	**$422,279**	**$677**

Exhibit 3-63 Total Plant Cost Details (continued)

Client:	USDOE/NETL			**Report Date:**	05-Apr-07
Project:	Bituminous Baseline Study				
	TOTAL PLANT COST SUMMARY				
Case:	Case 03 - ConocoPhillips IGCC w/o CO2				
Plant Size:	623.4 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Dec)**	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	MDEA-LT AGR	$34,245	$0	$16,003	$0	$0	$50,248	$4,291	$0	$10,908	$65,447	$105
5A.2	Elemental Sulfur Plant	$11,411	$2,265	$14,734	$0	$0	$28,410	$2,454	$0	$6,173	$37,037	$59
5A.3	Mercury Removal	$1,177	$0	$897	$0	$0	$2,074	$178	$104	$471	$2,827	$5
5A.4	COS Hydrolysis	$3,651	$0	$4,771	$0	$0	$8,422	$728	$0	$1,830	$10,980	$18
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$410	$230	$130	$0	$0	$770	$65	$0	$167	$1,002	$2
5A.7	Fuel Gas Piping	$0	$1,161	$800	$0	$0	$1,961	$160	$0	$424	$2,546	$4
5A.9	HGCU Foundations	$0	$1,149	$746	$0	$0	$1,895	$155	$0	$615	$2,666	$4
	SUBTOTAL 5A.	**$50,895**	**$4,805**	**$38,080**	**$0**	**$0**	**$93,780**	**$8,032**	**$104**	**$20,588**	**$122,504**	**$197**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	$87,071	$7,338	$4,354	$9,876	$108,639	$174
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$121	$0	$470	$2,037	$3
	SUBTOTAL 6.	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$7,459**	**$4,354**	**$10,346**	**$110,676**	**$178**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,926	$0	$4,828	$0	$0	$38,754	$3,277	$0	$4,203	$46,234	$74
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,577	$1,143	$0	$0	$2,719	$214	$0	$587	$3,520	$6
7.4	Stack	$3,123	$0	$1,174	$0	$0	$4,296	$366	$0	$466	$5,129	$8
7.9	HRSG,Duct & Stack Foundations	$0	$622	$601	$0	$0	$1,223	$102	$0	$397	$1,722	$3
	SUBTOTAL 7.	**$37,049**	**$2,198**	**$7,745**	**$0**	**$0**	**$46,992**	**$3,959**	**$0**	**$5,653**	**$56,604**	**$91**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,109	$0	$4,930	$0	$0	$33,039	$2,837	$0	$3,588	$39,463	$63
8.2	Turbine Plant Auxiliaries	$198	$0	$455	$0	$0	$654	$57	$0	$71	$782	$1
8.3	Condenser & Auxiliaries	$4,660	$0	$1,421	$0	$0	$6,082	$517	$0	$660	$7,259	$12
8.4	Steam Piping	$5,233	$0	$3,687	$0	$0	$8,920	$682	$0	$2,400	$12,002	$19
8.9	TG Foundations	$0	$953	$1,621	$0	$0	$2,574	$217	$0	$837	$3,629	$6
	SUBTOTAL 8.	**$38,201**	**$953**	**$12,115**	**$0**	**$0**	**$51,268**	**$4,310**	**$0**	**$7,556**	**$63,135**	**$101**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,397	$0	$967	$0	$0	$5,364	$455	$0	$873	$6,692	$11
9.2	Circulating Water Pumps	$1,383	$0	$86	$0	$0	$1,469	$113	$0	$237	$1,819	$3
9.3	Circ.Water System Auxiliaries	$116	$0	$17	$0	$0	$132	$11	$0	$22	$165	$0
9.4	Circ.Water Piping	$0	$4,910	$1,253	$0	$0	$6,163	$489	$0	$1,330	$7,982	$13
9.5	Make-up Water System	$284	$0	$403	$0	$0	$688	$58	$0	$149	$895	$1
9.6	Component Cooling Water Sys	$579	$693	$490	$0	$0	$1,762	$146	$0	$382	$2,290	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,699	$2,909	$0	$0	$4,608	$389	$0	$1,499	$6,497	$10
	SUBTOTAL 9.	**$6,760**	**$7,303**	**$6,124**	**$0**	**$0**	**$20,187**	**$1,661**	**$0**	**$4,492**	**$26,340**	**$42**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,861	$0	$7,828	$0	$0	$23,688	$2,024	$0	$2,571	$28,283	$45
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$523	$0	$569	$0	$0	$1,092	$94	$0	$178	$1,365	$2
10.7	Ash Transport & Feed Equipment	$706	$0	$169	$0	$0	$876	$72	$0	$142	$1,090	$2
10.8	Misc. Ash Handling Equipment	$1,083	$1,327	$397	$0	$0	$2,807	$238	$0	$457	$3,502	$6
10.9	Ash/Spent Sorbent Foundation	$0	$46	$58	$0	$0	$104	$9	$0	$34	$147	$0
	SUBTOTAL 10.	**$18,173**	**$1,373**	**$9,021**	**$0**	**$0**	**$28,568**	**$2,437**	**$0**	**$3,382**	**$34,386**	**$55**

Exhibit 3-63 Total Plant Cost Details (continued)

	Client:	USDOE/NETL								**Report Date:**	05-Apr-07		
	Project:	Bituminous Baseline Study											
				TOTAL PLANT COST SUMMARY									
	Case:	Case 03 - ConocoPhillips IGCC w/o CO2											
	Plant Size:	623.4 MW,net		**Estimate Type:**		Conceptual				**Cost Base (Dec)**	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$901	$0	$899	$0	$0	$1,800	$153	$0	$195	$2,148	$3
11.2	Station Service Equipment	$3,498	$0	$328	$0	$0	$3,827	$326	$0	$415	$4,568	$7
11.3	Switchgear & Motor Control	$6,686	$0	$1,226	$0	$0	$7,911	$657	$0	$1,285	$9,853	$16
11.4	Conduit & Cable Tray	$0	$3,181	$10,327	$0	$0	$13,508	$1,157	$0	$3,666	$18,331	$29
11.5	Wire & Cable	$0	$5,842	$3,930	$0	$0	$9,772	$640	$0	$2,603	$13,015	$21
11.6	Protective Equipment	$0	$624	$2,365	$0	$0	$2,989	$262	$0	$488	$3,739	$6
11.7	Standby Equipment	$215	$0	$218	$0	$0	$433	$37	$0	$71	$541	$1
11.8	Main Power Transformers	$11,308	$0	$138	$0	$0	$11,446	$776	$0	$1,833	$14,056	$23
11.9	Electrical Foundations	$0	$149	$394	$0	$0	$543	$46	$0	$177	$766	$1
	SUBTOTAL 11.	**$22,608**	**$9,796**	**$19,825**	**$0**	**$0**	**$52,229**	**$4,054**	**$0**	**$10,733**	**$67,016**	**$108**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$924	$0	$643	$0	$0	$1,566	$135	$78	$267	$2,047	$3
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$212	$0	$142	$0	$0	$354	$31	$18	$80	$483	$1
12.7	Computer & Accessories	$4,928	$0	$164	$0	$0	$5,092	$432	$255	$578	$6,357	$10
12.8	Instrument Wiring & Tubing	$0	$1,752	$3,666	$0	$0	$5,418	$412	$271	$1,525	$7,626	$12
12.9	Other I & C Equipment	$3,294	$0	$1,666	$0	$0	$4,960	$426	$248	$845	$6,480	$10
	SUBTOTAL 12.	**$9,358**	**$1,752**	**$6,282**	**$0**	**$0**	**$17,391**	**$1,436**	**$870**	**$3,296**	**$22,992**	**$37**
13	Improvements to Site											
13.1	Site Preparation	$0	$99	$2,132	$0	$0	$2,231	$197	$0	$728	$3,156	$5
13.2	Site Improvements	$0	$1,761	$2,357	$0	$0	$4,118	$362	$0	$1,344	$5,824	$9
13.3	Site Facilities	$3,155	$0	$3,354	$0	$0	$6,509	$572	$0	$2,124	$9,206	$15
	SUBTOTAL 13.	**$3,155**	**$1,860**	**$7,843**	**$0**	**$0**	**$12,858**	**$1,132**	**$0**	**$4,197**	**$18,186**	**$29**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$27	$0	$75	$451	$1
14.2	Steam Turbine Building	$0	$2,309	$3,334	$0	$0	$5,643	$464	$0	$916	$7,024	$11
14.3	Administration Building	$0	$793	$583	$0	$0	$1,375	$110	$0	$223	$1,708	$3
14.4	Circulation Water Pumphouse	$0	$156	$84	$0	$0	$240	$19	$0	$39	$298	$0
14.5	Water Treatment Buildings	$0	$399	$395	$0	$0	$794	$64	$0	$129	$987	$2
14.6	Machine Shop	$0	$406	$281	$0	$0	$687	$55	$0	$111	$853	$1
14.7	Warehouse	$0	$655	$428	$0	$0	$1,083	$86	$0	$175	$1,345	$2
14.8	Other Buildings & Structures	$0	$392	$310	$0	$0	$702	$56	$0	$152	$910	$1
14.9	Waste Treating Building & Str.	$0	$877	$1,698	$0	$0	$2,575	$214	$0	$558	$3,348	$5
	SUBTOTAL 14.	**$0**	**$6,209**	**$7,240**	**$0**	**$0**	**$13,449**	**$1,095**	**$0**	**$2,378**	**$16,922**	**$27**
	TOTAL COST	**$559,240**	**$59,898**	**$219,767**	**$0**	**$0**	**$838,905**	**$70,010**	**$27,220**	**$144,031**	**$1,080,166**	**$1,733**

Exhibit 3-64 Case 3 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 03 - ConocoPhillips 600MW IGCC w/o CO2					Heat Rate-net(Btu/kWh):	8,681
					MWe-net:	623
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	15.0		15.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$5,637,060	$9.043
Maintenance Labor Cost					$11,924,540	$19.129
Administrative & Support Labor					$4,390,400	$7.043
TOTAL FIXED OPERATING COSTS					**$21,951,999**	**$35.215**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$22,346,706**	**$0.00512**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	5,410.08	1.03	**$0**	**$1,627,136**	**$0.00037**
Chemicals						
MU & WT Chem.(lb)	112,811	16,116	0.16	$18,591	$775,520	$0.00018
Carbon (Mercury Removal) (lb)	84,449	116	1.00	$84,449	$33,872	$0.00001
COS Catalyst (m3)	375	0.26	2,308.40	$865,651	$173,030	$0.00004
Water Gas Shift Catalyst(ft3)	0	0	475.00	$0	$0	$0.00000
Selexol Solution (gal.)	0	0	12.90	$0	$0	$0.00000
MDEA Solution (gal)	280	40	8.38	$2,345	$97,820	$0.00002
Sulfinol Solution (gal)	0	0	9.68	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.10	125.00	$0	$76,650	$0.00002
Subtotal Chemicals				**$971,037**	**$1,156,892**	**$0.00026**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	116	0.40	$0	$13,603	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	566	15.45	$0	$2,555,311	$0.00058
Subtotal-Waste Disposal				**$0**	**$2,568,914**	**$0.00059**
By-products & Emissions						
Sulfur(tons)	0	139	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$971,037**	**$27,699,648**	**$0.00634**
Fuel(ton)	166,992	5,566	42.11	**$7,032,052**	**$68,445,302**	**$0.01567**

3.3.8 CASE 4 - E-GAS™ IGCC POWER PLANT WITH CO_2 CAPTURE

This case is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 3, namely two gasifier trains, two advanced F class turbines, two HRSGs and one steam turbine. The gross power output from the plant is constrained by the capacity of the two combustion turbines, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 3.

The process description for Case 4 is similar to Case 2 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 4 are shown in Exhibit 3-65 and Exhibit 3-66, respectively. Instead of repeating the entire process description, only differences from Case 3 are reported here.

Coal Preparation and Feed Systems

No differences from Case 3.

Gasification

The gasification process is the same as Case 3 with the exception that total coal feed to the two gasifiers is 5,203 tonnes/day (5,735 TPD) (stream 6) and the ASU provides 4,000 tonnes/day (4,420 TPD) of 95 mole percent oxygen to the gasifier and Claus plant (streams 5 and 3).

Raw Gas Cooling/Particulate Removal

Raw gas cooling and particulate removal are the same as Case 3 with the exception that approximately 483,170 kg/h (1,065,206 lb/h) of saturated steam at 13.8 MPa (2,000 psia) is generated in the SGC.

Syngas Scrubber/Sour Water Stripper

No differences from Case 3.

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 4 steam (stream 8) is added to the syngas exiting the scrubber to adjust the H_2O:CO molar ratio to approximately 2:1 prior to the first WGS reactor. The hot syngas exiting the first stage of SGS is used to generate a portion of the steam that is added in stream 8. Two more stages of SGS (for a total of three) result in 97.6 percent overall conversion of the CO to CO_2. The syngas exiting the final stage of SGS still contains 2.4 vol% CH_4 which is subsequently oxidized to CO_2 in the CT and limits overall carbon capture to 88.4 percent. The warm syngas from the second stage of SGS is cooled to 232°C (450°F) by producing IP steam that is sent to the reheater in the HRSG. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the third stage of SGS, the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 3.

Exhibit 3-65 Case 4 Process Flow Diagram, E-Gas™ IGCC with CO_2 Capture

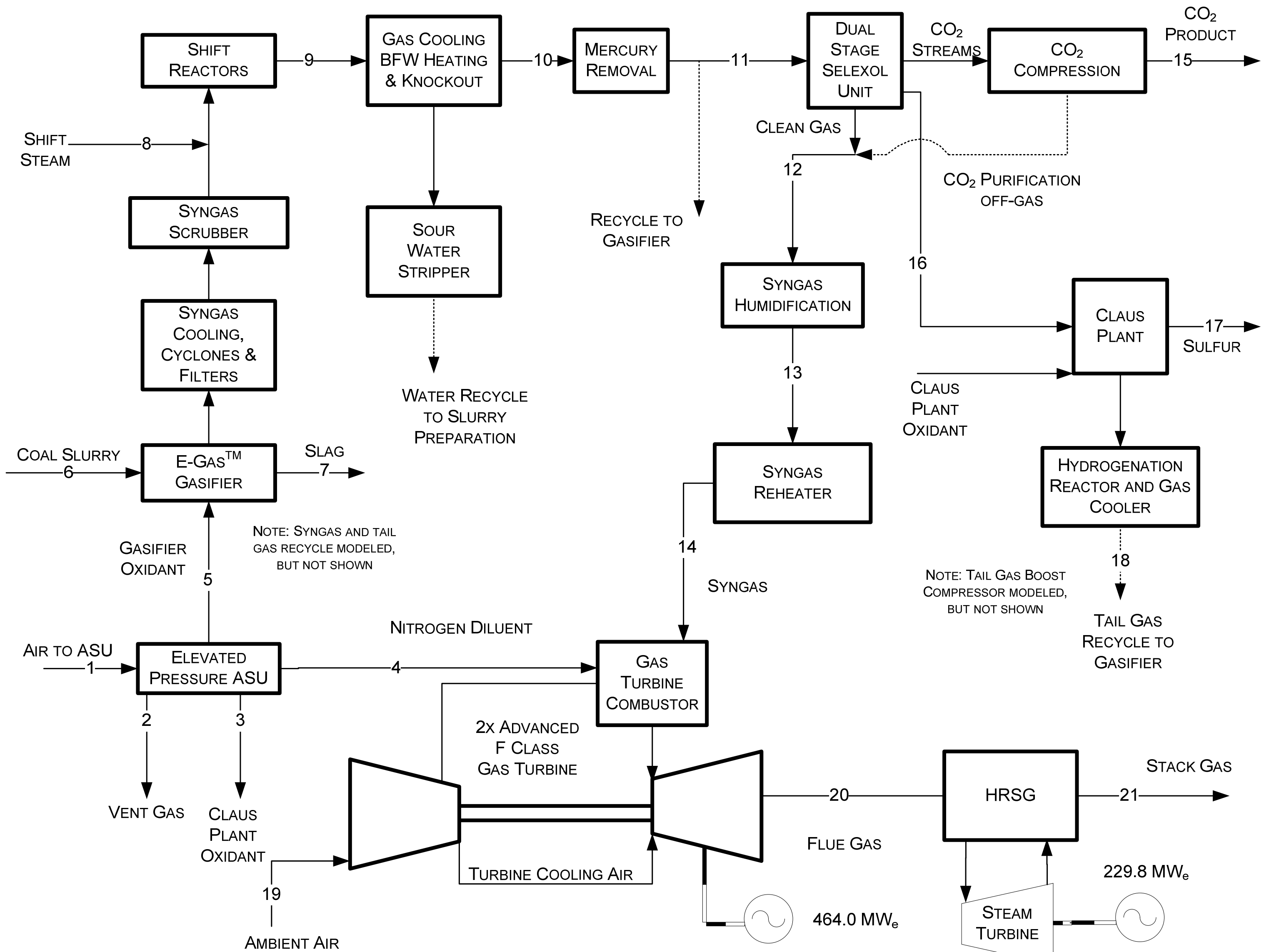

Exhibit 3-66 Case 4 Stream Table, E-Gas™ IGCC with CO_2 Capture

	1	2	3	4	5	6[A]	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0263	0.0360	0.0023	0.0320	0.0000	0.0000	0.0000	0.0051	0.0065	0.0065
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0238	0.0302	0.0302
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0052	0.0067	0.0067
CO_2	0.0003	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3214	0.4122	0.4122
COS	0.0000	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	0.0000	0.4116	0.5275	0.5275
H_2O	0.0099	0.2713	0.0000	0.0004	0.0000	1.0000	0.0000	1.0000	0.2185	0.0014	0.0014
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0051	0.0058	0.0058
N_2	0.7732	0.4665	0.0140	0.9919	0.0180	0.0000	0.0000	0.0000	0.0073	0.0094	0.0094
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0004	0.0004
O_2	0.2074	0.2266	0.9500	0.0054	0.9500	0.0000	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	55,654	1,969	278	41,984	11,156	25,799	0	31,642	91,106	71,043	56,835
V-L Flowrate (lb/hr)	1,606,000	52,498	8,944	1,178,060	359,031	249,436	0	570,044	1,827,120	1,465,320	1,172,260
Solids Flowrate (lb/hr)	0	0	0	0	0	424,717	48,622	0	0	0	0
Temperature (°F)	242	70	90	385	191	140	1,850	615	457	93	93
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	850.0	850.0	600.0	516.0	481.0	471.0
Enthalpy (BTU/lb)[B]	57.3	26.7	12.5	88.0	34.4	---	1,120	1300.1	384.8	24.1	24.1
Density (lb/ft^3)	0.729	0.103	0.683	1.424	3.412	---	---	0.937	1.052	1.672	1.638
Molecular Weight	28.86	26.67	32.23	28.06	32.18	---	---	18.02	20.05	20.63	20.63

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

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-66 Case 4 Stream Table (Continued)

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0109	0.0093	0.0093	0.0000	0.0000	0.0000	0.0205	0.0094	0.0089	0.0089
CH_4	0.0508	0.0436	0.0436	0.0000	0.0000	0.0000	0.0880	0.0000	0.0000	0.0000
CO	0.0112	0.0096	0.0096	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000
CO_2	0.0243	0.0208	0.0208	1.0000	0.4321	0.0000	0.6024	0.0003	0.0097	0.0097
COS	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.8888	0.7620	0.7620	0.0000	0.0000	0.0000	0.0215	0.0000	0.0000	0.0000
H_2O	0.0001	0.1427	0.1427	0.0000	0.0554	0.0000	0.0006	0.0108	0.1350	0.1350
H_2S	0.0000	0.0000	0.0000	0.0000	0.4035	0.0000	0.0180	0.0000	0.0000	0.0000
N_2	0.0139	0.0119	0.0119	0.0000	0.0774	0.0000	0.2486	0.7719	0.7429	0.7429
NH_3	0.0000	0.0000	0.0000	0.0000	0.0312	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1035	0.1035
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	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	33,733	39,346	39,346	22,257	813	47	628	242,512	308,662	308,662
V-L Flowrate (lb/hr)	162,487	263,603	263,603	979,537	29,677	11,954	22,868	6,996,340	8,438,000	8,438,000
Solids Flowrate (lb/hr)	0	0	0	0	0	11,954	0	0	0	0
Temperature (°F)	99	299	385	156	120	375	95	59	1052	270
Pressure (psia)	468.5	458.5	453.5	2214.7	30.5	25.4	767.5	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	97.3	699.4	795.2	-46.0	48.7	-96.2	14.5	13.8	372.8	157.8
Density (lb/ft^3)	0.376	0.378	0.335	30.793	0.179	---	4.692	0.076	0.026	0.053
Molecular Weight	4.82	6.70	6.70	44.01	36.49	---	36.39	28.85	27.34	27.34

B - Reference conditions are 32.02 F & 0.089 PSIA

The AGR process in Case 4 is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption as previously described in Section 3.1.5. The process results in three product streams, the clean syngas, a CO_2-rich stream and an acid gas feed to the Claus plant. The acid gas (stream 16) contains 40 percent H_2S and 43 percent CO_2 with the balance primarily N_2. The CO_2-rich stream is discussed further in the CO_2 compression section.

CO_2 Compression and Dehydration

CO_2 from the AGR process is generated at three pressure levels. The LP stream is compressed from 0.15 MPa (22 psia) to 1.1 MPa (160 psia) and then combined with the MP stream. The HP stream is combined between compressor stages at 2.1 MPa (300 psia). The combined stream is compressed from 2.1 MPa (300 psia) to a supercritical condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 93 percent CO_2 with the balance primarily nitrogen. For modeling purposes it was assumed that the impurities were separated from the CO_2 and combined with the clean syngas stream from the Selexol process. The pure CO_2 (stream 15) is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.7.

Claus Unit

The Claus plant is the same as Case 3 with the following exceptions:

- 5,423 kg/h (11,955 lb/h) of sulfur (stream 17) are produced
- The waste heat boiler generates 17,296 kg/h (38,131 lb/h) of 4.0 MPa (585 psia) steam, which provides all of the Claus plant process needs and provides some additional steam to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is combined with a small amount of clean gas from the CO_2 compression process (stream 12) and partially humidified because the nitrogen available from the ASU is insufficient to provide adequate dilution. The moisturized syngas is reheated (stream 14) to 196°C (385°F) using HP boiler feedwater, diltuted with nitrogen (stream 4), and then enters the CT burner. There is no integration between the CT and the ASU in this case. The exhaust gas (stream 20) exits the CT at 567°C (1052°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) (stream 21) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced commercially available steam turbine using a 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle.

Air Separation Unit

The elevated pressure ASU is the same as in other cases and produces 4,000 tonnes/day (4,420 TPD) of 95 mole percent oxygen and 12,830 tonnes/day (14,140 TPD) of nitrogen. There is no integration between the ASU and the combustion turbine.

3.3.9 CASE 4 PERFORMANCE RESULTS

The Case 4 modeling assumptions were presented previously in Section 3.3.3.

The plant produces a net output of 518 MWe at a net plant efficiency of 31.7 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-67 which includes auxiliary power requirements. The ASU accounts for nearly 62 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 23 percent of the auxiliary power load. The BFW pumps and cooling water system (circulating water pumps and cooling tower fan) comprise nearly 6 percent of the load, leaving 9 percent of the auxiliary load for all other systems.

Exhibit 3-67 Case 4 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Steam Turbine Power	229,840
TOTAL POWER, kWe	**693,840**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,230
Coal Slurry Pumps	580
Slag Handling and Dewatering	1,140
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	62,760
Oxygen Compressor	8,490
Nitrogen Compressor	36,330
Syngas Recycle Blower	3,400
Tail Gas Recycle Blower	1,090
CO_2 Compressor	25,970
Boiler Feedwater Pumps	5,340
Condensate Pump	270
Flash Bottoms Pump	200
Circulating Water Pumps	3,020
Cooling Tower Fans	1,560
Scrubber Pumps	70
Double Stage Selexol Unit Auxiliaries	14,840
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	200
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,570
TOTAL AUXILIARIES, kWe	**175,600**
NET POWER, kWe	**518,240**
Net Plant Efficiency, % (HHV)	31.7
Net Plant Heat Rate (Btu/kWh)	10,757
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,224 (1,161)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	216,752 (477,855)
Thermal Input, kWt	1,633,771
Raw Water Usage, m^3/min (gpm)	15.6 (4,135)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NO_X, SO_2, CO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 4 is presented in Exhibit 3-68.

Exhibit 3-68 Case 4 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (tons/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.004 (0.0085)	151 (167)	0.031 (0.069)
NO_X	0.021 (0.050)	882 (972)	0.181 (0.400)
Particulates	0.003 (0.0071)	126 (139)	0.026 (0.057)
Hg	0.25×10^{-6} (0.57×10^{-6})	0.010 (0.011)	2.1×10^{-6} (4.6×10^{-6})
CO_2	10.1 (23.6)	417,000 (460,000)	86 (189)
CO_2[1]			115 (253)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The CO_2 capture target results in the sulfur compounds being removed to a greater extent than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 22 ppmv. This results in a concentration in the flue gas of less than 3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated to convert all sulfur species to H_2S, and then recycled back to the gasifier, thereby eliminating the need for a tail gas treatment unit.

NO_X emissions are limited by the use of humidification and nitrogen dilution to 15 ppmvd (NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and ultimately destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration. Because of the relatively high CH_4 content in the syngas, this results in an overall carbon removal of 88.4 percent.

The carbon balance for the plant is shown in Exhibit 3-69. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected in the carbon balance below since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas, ASU vent gas and the captured CO_2 product. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
267,147/(304,632-2,285) *100 or
88.4 percent

Exhibit 3-69 Case 4 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	138,180 (304,632)	**Slag**	1,037 (2,285)
Air (CO_2)	488 (1,077)	**Stack Gas**	16,246 (35,817)
		CO_2 Product	121,176 (267,147)
		ASU Vent	99 (218)
		Wastewater	110 (242)
Total	138,668 (305,709)	**Total**	138,668 (305,709)

Exhibit 3-70 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,954/11,994) or
99.7 percent

Exhibit 3-70 Case 4 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,440 (11,994)	**Elemental Sulfur**	5,422 (11,954)
		Stack Gas	11 (24)
		Wastewater	7 (16)
Total	5,440 (11,994)	**Total**	5,440 (11,994)

Exhibit 3-71 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-71 Case 4 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Slurry	1.5 (392)	1.5 (392)	0
Slag Handling	0.5 (126)	0.5 (126)	0
Humidifier	0.8 (219)	0.8 (219)	0
Shift Steam	4.3 (1,140)	0	4.3 (1,140)
BFW Makeup	0.2 (46)	0	0.2 (46)
Cooling Tower Makeup	11.7 (3,098)	0.6 (149)	11.1 (2,949)
Total	**19.0 (5,021)**	**3.4 (886)**	**15.6 (4,135)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-72 through Exhibit 3-76:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-77. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-67) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 3-72 Case 4 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

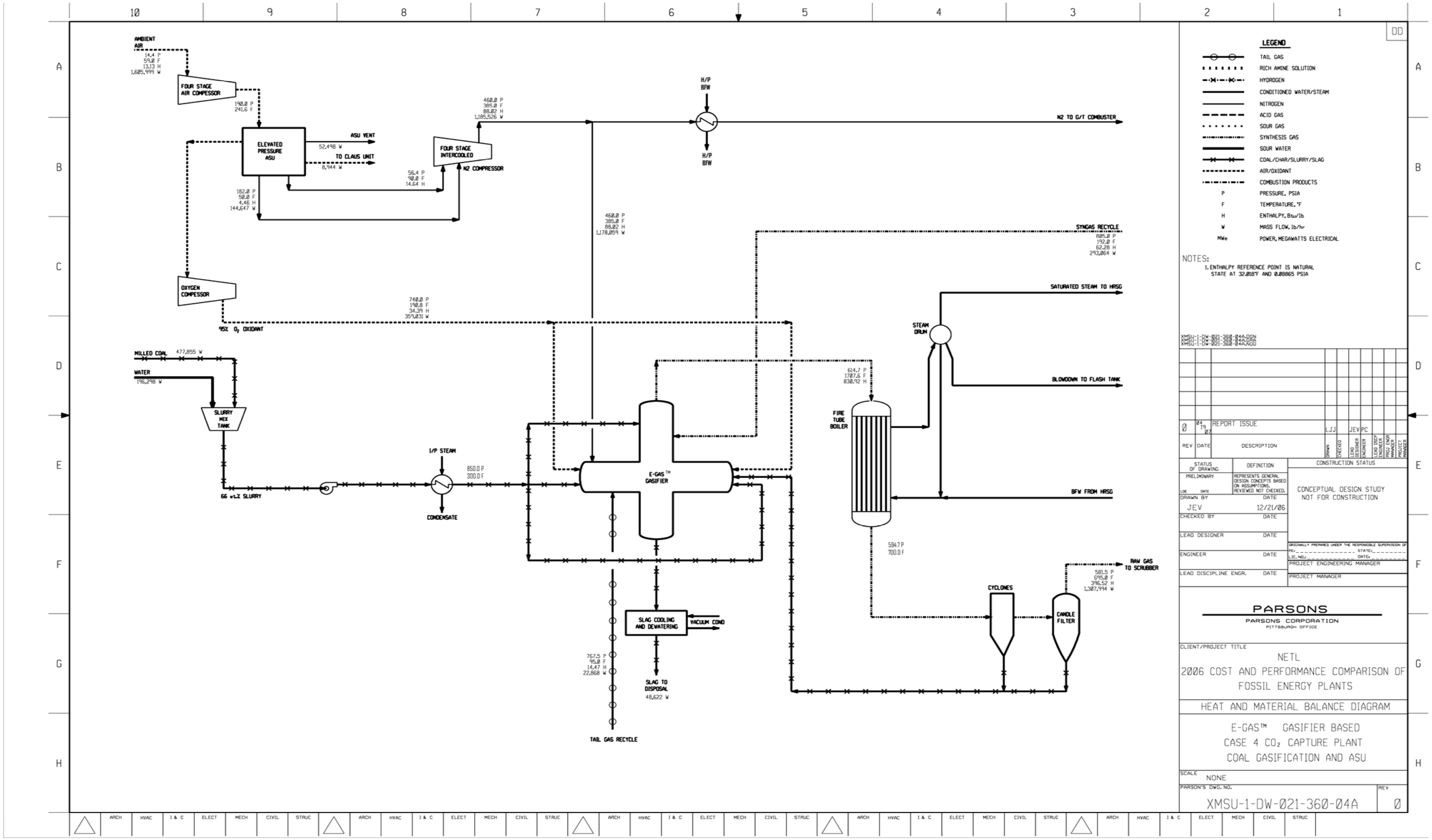

Exhibit 3-73 Case 4 Syngas Cleanup Heat and Mass Balance Schematic

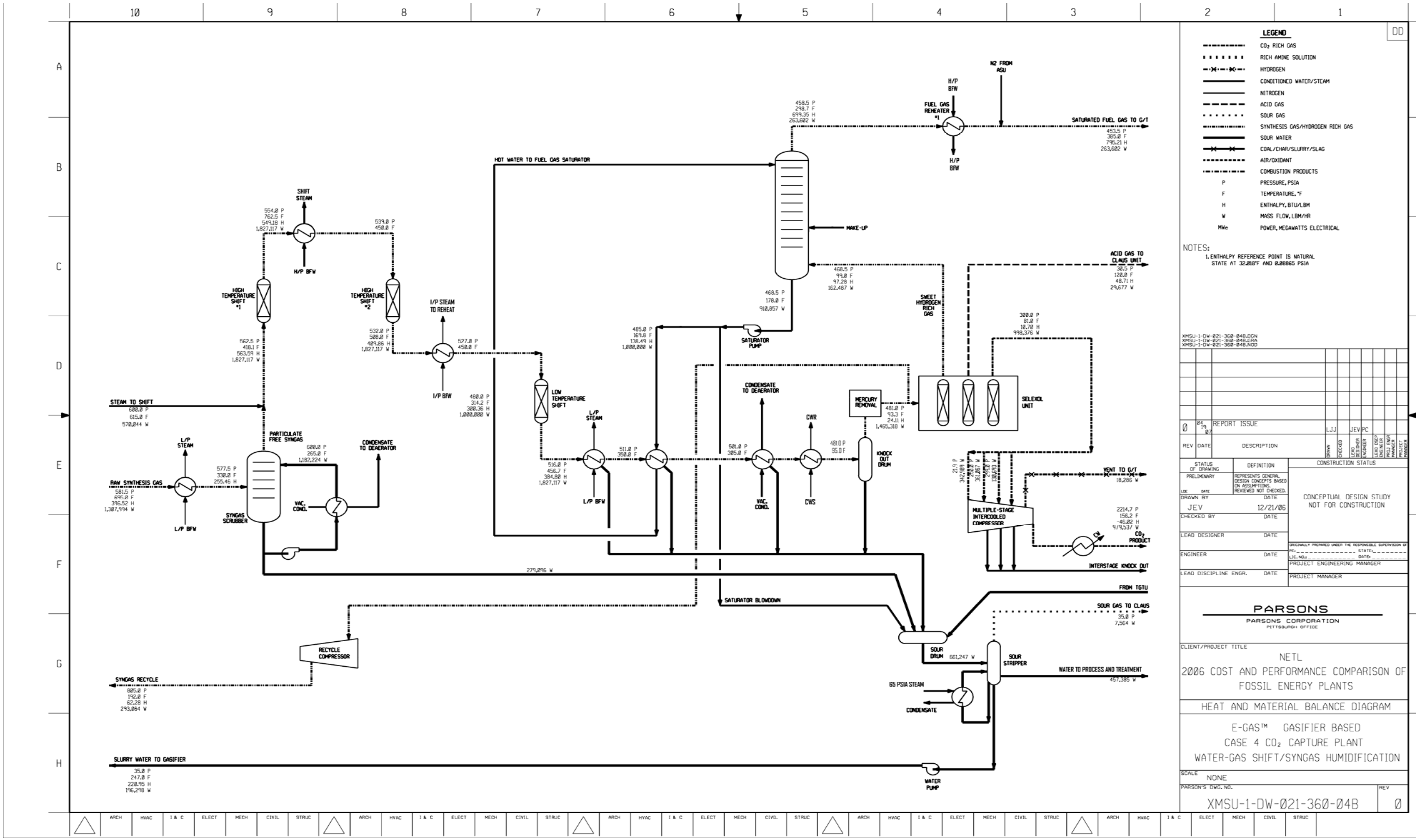

Exhibit 3-74 Case 4 Sulfur Recover and Tail Gas Recycle Heat and Mass Balance Schematic

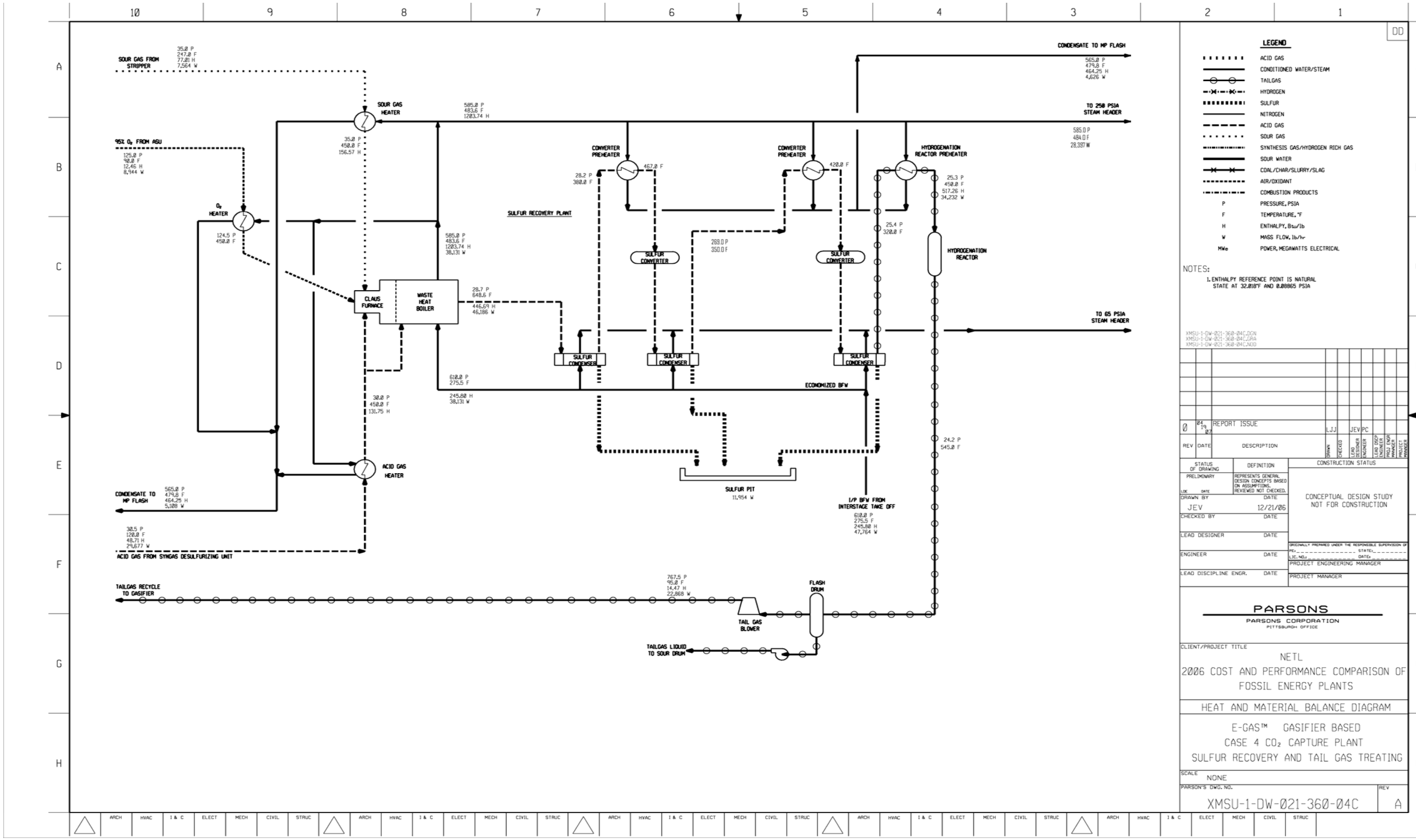

Exhibit 3-75 Case 4 Combined Cycle Power Generation Heat and Mass Balance Schematic

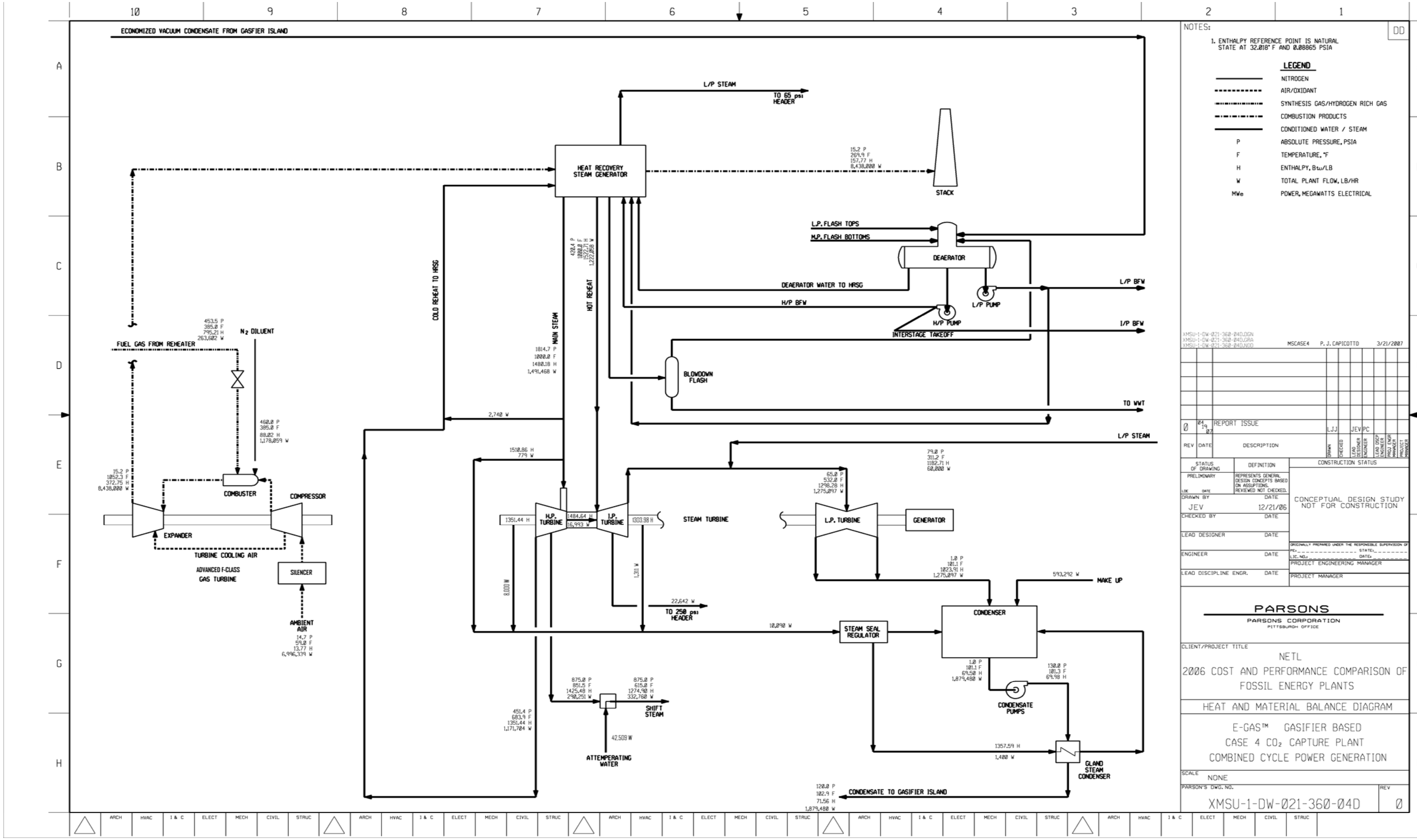

Exhibit 3-76 Case 4 Steam and Feedwater Heat and Mass Balance Schematic

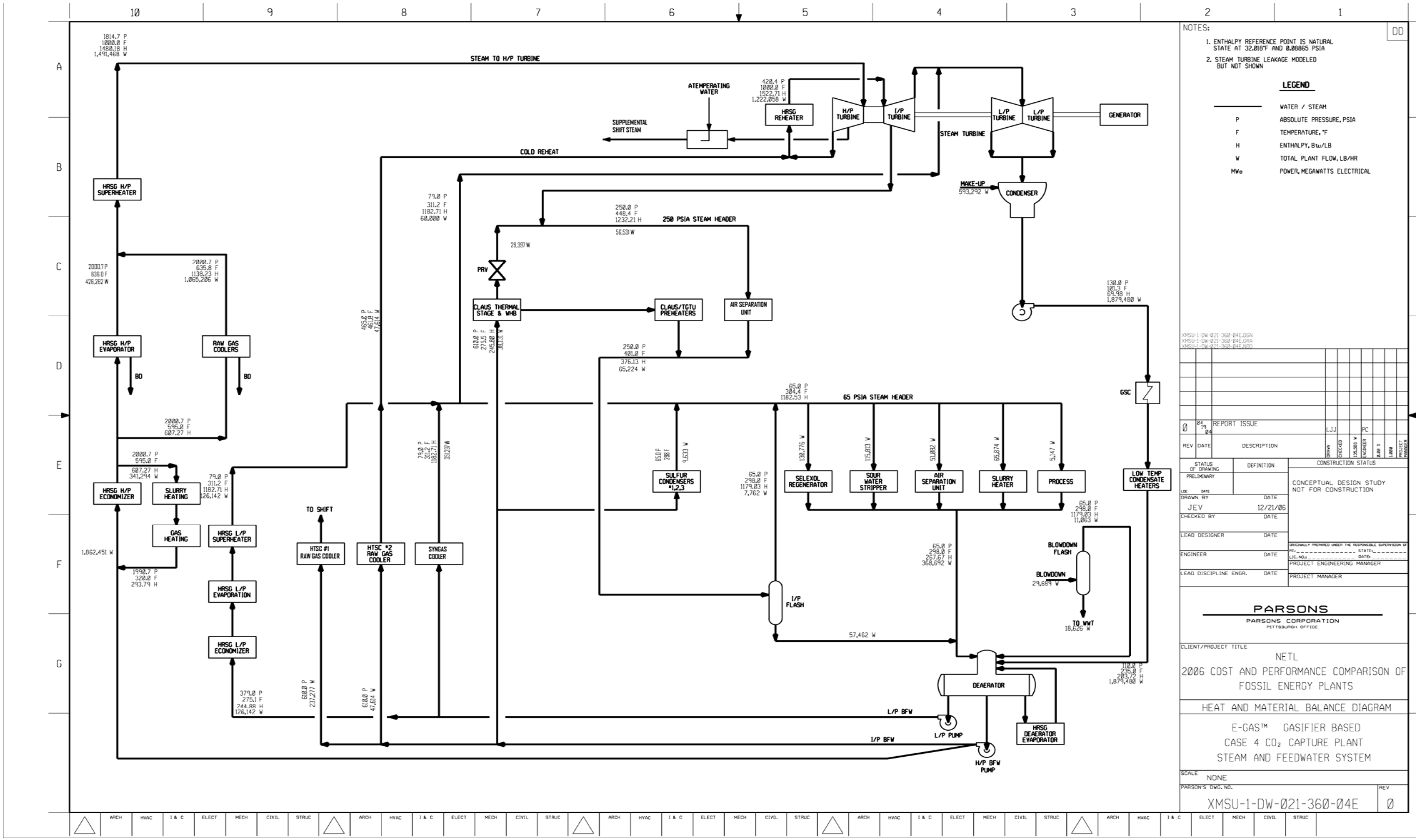

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Exhibit 3-77 Case 4 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,575.1	4.7		5,579.8
ASU Air		21.1		21.1
CT Air		96.3		96.3
Water		16.9		16.9
Auxiliary Power			599.2	599.2
Totals	**5,575.1**	**138.9**	**599.2**	**6,313.2**
Heat Out (MMBtu/hr)				
ASU Intercoolers		240.9		240.9
ASU Vent		1.4		1.4
Slag	32.2	22.2		54.4
Sulfur	47.6	(1.1)		46.4
Tail Gas Compressor Intercoolers		3.9		3.9
CO_2 Compressor Intercoolers		130.7		130.7
CO_2 Product		(45.1)		(45.1)
HRSG Flue Gas		1,335.7		1,335.7
Condenser		1,161.0		1,161.0
Process Losses		980.4		980.4
Power			2,403.5	2,403.5
Totals	**79.8**	**3,830.0**	**2,403.5**	**6,313.2**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.3.10 CASE 4 - MAJOR EQUIPMENT LIST

Major equipment items for the CoP gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.11. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/h (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	354 tonne/h (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	354 tonne/h (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	354 tonne/h (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/h (260 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	481 tonne (530 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	295,264 liters (78,000 gal)	2	0
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	2	2
10	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
11	Rod Mill Discharge Tank with Agitator	Field erected	312,678 liters (82,600 gal)	2	0
12	Rod Mill Product Pumps	Centrifugal	2,612 lpm (690 gpm)	2	2
13	Slurry Storage Tank with Agitator	Field erected	946,361 liters (250,000 gal)	2	0
14	Slurry Recycle Pumps	Centrifugal	5,224 lpm (1,380 gpm)	2	2
15	Slurry Product Pumps	Positive displacement	2,612 lpm (690 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2,237,196 liters (591,000 gal)	3	0
2	Condensate Pumps	Vertical canned	7,874 lpm @ 91 m H2O (2,080 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	577,877 kg/h (1,274,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	2,006 lpm @ 283 m H2O (530 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,587 lpm @ 1,890 m H2O (1,740 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,476 lpm @ 223 m H2O (390 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	8,707 lpm @ 18 m H2O (2,300 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	4,088 lpm @ 49 m H2O (1,080 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,968,429 liter (520,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	2,574 lpm (680 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,903 tonne/day, 4.2 MPa (3,200 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	326,133 kg/h (719,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	313,433 kg/h (691,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	299,825 kg/h (661,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	455,861 kg/h (1,005,000 lb/h)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	351,988 kg/h, 38°C, 5.1 MPa (776,000 lb/h, 100°F, 737 psia)	2	0
8	Saturation Water Economizers	Shell and tube	455,861 kg/h (1,005,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	62,596 kg/h, 149°C, 3.2 MPa (138,000 lb/h, 300°F, 458 psia)	2	0
10	Saturator Water Pump	Centrifugal	3,785 lpm @ 15 m H2O (1,000 gpm @ 50 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	65,771 kg/h (145,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	299,825 kg/h (661,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	5,493 m3/min @ 1.3 MPa (194,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,104 m3/min @ 5.1 MPa (39,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,653 m3/min @ 3.4 MPa (129,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	510 m3/min @ 2.3 MPa (18,000 scfm @ 340 psia)	2	0

ACCOUNT 5A SOUR GAS SHIFT AND SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	320,690 kg/h (707,000 lb/h) 34°C (93°F) 3.3 MPa (481 psia)	2	0
2	Sulfur Plant	Claus type	143 tonne/day (158 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	455,861 kg/h (1,005,000 lb/h) 232°C (450°F) 3.9 MPa (562 psia)	6	0
4	Shift Reactor Heat Recovery Exhchangers	Shell and Tube	Exchanger 1: 148 MMkJ/h (140 MMBtu/h) Exchanger 2: 32 MMkJ/h (30 MMBtu/h)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	292,567 kg/h (645,000 lb/h) 35°C (95°F) 3.2 MPa (471 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	17,100 kg/h (37,700 lb/h) 232°C (450°F) 0.2 MPa (25 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	11,975 kg/h @ 6.4 MPa (26,400 lb/h @ 930 psia)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,096 m3/min @ 15.3 MPa (38,715 scfm @ 2,215 psia)	4	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 372,086 kg/h, 12.4 MPa/538°C (820,307 lb/h, 1,800 psig/1,000°F) Reheat steam - 304,874 kg/h, 2.9 MPa/538°C (672,132 lb/h, 420 psig/1,000°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	251 MW 12.4 MPa/538°C/538°C (1800 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	280 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,392 MMkJ/h (1,320 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	302,835 lpm @ 30 m (80,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT, 1,687 MMkJ/h (1,600 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	230,912 liters (61,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/h (13 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/h (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	151,418 liters (40,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	71,923 liters (19,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/h (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/h (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/h (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	227,126 liters (60,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	265 lpm @ 433 m H2O (70 gpm @ 1,420 ft H2O)	2	2
13	Grey Water Recycle Heat Exchanger	Shell and tube	15,876 kg/h (35,000 lb/h)	2	0
14	Slag Storage Bin	Vertical, field erected	907 tonne (1,000 tons)	2	0
15	Unloading Equipment	Telescoping chute	100 tonne/h (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 80 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 191 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 29 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.11 CASE 4 - COST ESTIMATING RESULTS

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-78 shows the total plant capital cost summary organized by cost account and Exhibit 3-79 shows a more detailed breakdown of the capital costs. Exhibit 3-80 shows the initial and annual O&M costs.

The estimated TPC of the CoP gasifier with CO_2 capture is $2,431/kW. Process contingency represents 4.3 percent of the TPC and project contingency represents 13.7 percent. The 20-year LCOE, including CO_2 TS&M costs of 4.1 mills/kWh, is 105.7 mills/kWh.

Exhibit 3-78 Case 4 Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	05-Apr-07			
	Project:	Bituminous Baseline Study												
		TOTAL PLANT COST SUMMARY												
	Case:	Case 04 - ConocoPhillips IGCC w/ CO2												
	Plant Size:	518.2 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)		

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,303	$2,480	$10,424	$0	$0	**$26,207**	$2,127	$0	$5,667	**$34,000**	$66
2	COAL & SORBENT PREP & FEED	$22,651	$4,146	$13,827	$0	$0	**$40,624**	$3,263	$0	$8,777	**$52,665**	$102
3	FEEDWATER & MISC. BOP SYSTEMS	$9,371	$7,975	$8,947	$0	$0	**$26,292**	$2,201	$0	$6,451	**$34,944**	$67
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$93,113	$0	$57,142	$0	$0	**$150,256**	$12,324	$22,538	$27,768	**$212,885**	$411
4.2	Syngas Cooling (w/ 4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$142,779	$0	w/equip.	$0	$0	**$142,779**	$12,175	$0	$15,495	**$170,449**	$329
4.4-4.9	Other Gasification Equipment	$24,864	$8,707	$14,165	$0	$0	**$47,736**	$4,057	$0	$11,002	**$62,795**	$121
	SUBTOTAL 4	**$260,756**	**$8,707**	**$71,307**	**$0**	**$0**	**$340,771**	**$28,555**	**$22,538**	**$54,265**	**$446,129**	**$861**
5A	Gas Cleanup & Piping	$81,314	$4,446	$69,562	$0	$0	**$155,321**	$13,338	$21,481	$38,231	**$228,370**	$441
5B	CO_2 REMOVAL & COMPRESSION	$17,010	$0	$10,435	$0	$0	**$27,445**	$2,351	$0	$5,959	**$35,754**	$69
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	**$93,325**	$7,865	$9,333	$11,052	**$121,575**	$235
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$121	$0	$470	**$2,037**	$4
	SUBTOTAL 6	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$7,986**	**$9,333**	**$11,522**	**$123,611**	**$239**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,356	$0	$4,604	$0	$0	**$36,960**	$3,125	$0	$4,009	**$44,094**	$85
7.2-7.9	Ductwork and Stack	$3,222	$2,268	$3,011	$0	$0	**$8,501**	$703	$0	$1,496	**$10,700**	$21
	SUBTOTAL 7	**$35,577**	**$2,268**	**$7,615**	**$0**	**$0**	**$45,461**	**$3,829**	**$0**	**$5,505**	**$54,794**	**$106**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,224	$0	$4,105	$0	$0	**$29,328**	$2,518	$0	$3,185	**$35,030**	$68
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$9,243	$828	$6,527	$0	$0	**$16,598**	$1,338	$0	$3,645	**$21,581**	$42
	SUBTOTAL 8	**$34,466**	**$828**	**$10,632**	**$0**	**$0**	**$45,926**	**$3,856**	**$0**	**$6,829**	**$56,611**	**$109**
9	COOLING WATER SYSTEM	$6,318	$6,821	$5,729	$0	$0	**$18,867**	$1,553	$0	$4,194	**$24,614**	$47
10	ASH/SPENT SORBENT HANDLING SYS	$18,516	$1,396	$9,191	$0	$0	**$29,103**	$2,482	$0	$3,445	**$35,031**	$68
11	ACCESSORY ELECTRIC PLANT	$23,064	$11,396	$22,575	$0	$0	**$57,035**	$4,450	$0	$11,923	**$73,409**	$142
12	INSTRUMENTATION & CONTROL	$10,183	$1,906	$6,836	$0	$0	**$18,925**	$1,562	$946	$3,586	**$25,021**	$48
13	IMPROVEMENTS TO SITE	$3,208	$1,891	$7,974	$0	$0	**$13,073**	$1,151	$0	$4,267	**$18,490**	$36
14	BUILDINGS & STRUCTURES	$0	$6,066	$6,992	$0	$0	**$13,057**	$1,063	$0	$2,319	**$16,439**	$32
	TOTAL COST	**$623,738**	**$61,009**	**$268,131**	**$0**	**$0**	**$952,878**	**$79,766**	**$54,298**	**$172,940**	**$1,259,883**	**$2,431**

Exhibit 3-79 Case 4 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 04 - ConocoPhillips IGCC w/ CO2
Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,493	$0	$1,725	$0	$0	$5,218	$418	$0	$1,127	$6,764	$13
1.2	Coal Stackout & Reclaim	$4,514	$0	$1,106	$0	$0	$5,620	$441	$0	$1,212	$7,274	$14
1.3	Coal Conveyors	$4,197	$0	$1,094	$0	$0	$5,291	$416	$0	$1,141	$6,849	$13
1.4	Other Coal Handling	$1,098	$0	$253	$0	$0	$1,351	$106	$0	$291	$1,749	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,480	$6,246	$0	$0	$8,726	$745	$0	$1,894	$11,365	$22
	SUBTOTAL 1.	**$13,303**	**$2,480**	**$10,424**	**$0**	**$0**	**$26,207**	**$2,127**	**$0**	**$5,667**	**$34,000**	**$66**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,491	$355	$236	$0	$0	$2,082	$160	$0	$448	$2,690	$5
2.3	Slurry Prep & Feed	$20,340	$0	$9,140	$0	$0	$29,480	$2,356	$0	$6,367	$38,204	$74
2.4	Misc.Coal Prep & Feed	$820	$593	$1,807	$0	$0	$3,221	$265	$0	$697	$4,182	$8
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,197	$2,644	$0	$0	$5,841	$483	$0	$1,265	$7,588	$15
	SUBTOTAL 2.	**$22,651**	**$4,146**	**$13,827**	**$0**	**$0**	**$40,624**	**$3,263**	**$0**	**$8,777**	**$52,665**	**$102**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,088	$5,369	$2,836	$0	$0	$11,293	$934	$0	$2,445	$14,672	$28
3.2	Water Makeup & Pretreating	$537	$56	$300	$0	$0	$893	$76	$0	$290	$1,259	$2
3.3	Other Feedwater Subsystems	$1,705	$578	$521	$0	$0	$2,804	$225	$0	$606	$3,634	$7
3.4	Service Water Systems	$309	$632	$2,194	$0	$0	$3,135	$272	$0	$1,022	$4,428	$9
3.5	Other Boiler Plant Systems	$1,662	$638	$1,582	$0	$0	$3,882	$326	$0	$842	$5,050	$10
3.6	FO Supply Sys & Nat Gas	$299	$565	$527	$0	$0	$1,391	$119	$0	$302	$1,812	$3
3.7	Waste Treatment Equipment	$746	$0	$457	$0	$0	$1,203	$104	$0	$392	$1,700	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,024	$138	$531	$0	$0	$1,693	$146	$0	$552	$2,390	$5
	SUBTOTAL 3.	**$9,371**	**$7,975**	**$8,947**	**$0**	**$0**	**$26,292**	**$2,201**	**$0**	**$6,451**	**$34,944**	**$67**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$93,113	$0	$57,142	$0	$0	$150,256	$12,324	$22,538	$27,768	$212,885	$411
4.2	Syngas Cooling (w/ 4.1	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$142,779	$0	w/equip.	$0	$0	$142,779	$12,175	$0	$15,495	$170,449	$329
4.4	LT Heat Recovery & FG Saturation	$24,864	$0	$9,355	$0	$0	$34,219	$2,946	$0	$7,433	$44,598	$86
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,157	$471	$0	$0	$1,629	$139	$0	$354	$2,121	$4
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$7,550	$4,339	$0	$0	$11,889	$972	$0	$3,215	$16,075	$31
	SUBTOTAL 4.	**$260,756**	**$8,707**	**$71,307**	**$0**	**$0**	**$340,771**	**$28,555**	**$22,538**	**$54,265**	**$446,129**	**$861**

Exhibit 3-79 Case 4 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 04 - ConocoPhillips IGCC w/ CO2
Plant Size: 518.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$57,451	$0	$49,279	$0	$0	$106,730	$9,179	$21,346	$27,451	$164,707	$318
5A.2	Elemental Sulfur Plant	$9,709	$1,927	$12,535	$0	$0	$24,170	$2,088	$0	$5,252	$31,510	$61
5A.3	Mercury Removal	$1,531	$0	$1,166	$0	$0	$2,697	$232	$135	$613	$3,676	$7
5A.4	Shift Reactors	$12,213	$0	$4,919	$0	$0	$17,133	$1,461	$0	$3,719	$22,312	$43
5A.5	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$410	$230	$130	$0	$0	$770	$65	$0	$167	$1,002	$2
5A.7	Fuel Gas Piping	$0	$1,150	$793	$0	$0	$1,943	$159	$0	$420	$2,522	$5
5A.9	HGCU Foundations	$0	$1,138	$739	$0	$0	$1,878	$154	$0	$609	$2,641	$5
	SUBTOTAL 5A.	**$81,314**	**$4,446**	**$69,562**	**$0**	**$0**	**$155,321**	**$13,338**	**$21,481**	**$38,231**	**$228,370**	**$441**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$17,010	$0	$10,435	$0	$0	$27,445	$2,351	$0	$5,959	$35,754	$69
	SUBTOTAL 5B.	**$17,010**	**$0**	**$10,435**	**$0**	**$0**	**$27,445**	**$2,351**	**$0**	**$5,959**	**$35,754**	**$69**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	$93,325	$7,865	$9,333	$11,052	$121,575	$235
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$121	$0	$470	$2,037	$4
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$7,986**	**$9,333**	**$11,522**	**$123,611**	**$239**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,356	$0	$4,604	$0	$0	$36,960	$3,125	$0	$4,009	$44,094	$85
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,627	$1,179	$0	$0	$2,806	$221	$0	$605	$3,632	$7
7.4	Stack	$3,222	$0	$1,211	$0	$0	$4,433	$378	$0	$481	$5,292	$10
7.9	HRSG,Duct & Stack Foundations	$0	$641	$620	$0	$0	$1,262	$105	$0	$410	$1,777	$3
	SUBTOTAL 7.	**$35,577**	**$2,268**	**$7,615**	**$0**	**$0**	**$45,461**	**$3,829**	**$0**	**$5,505**	**$54,794**	**$106**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,224	$0	$4,105	$0	$0	$29,328	$2,518	$0	$3,185	$35,030	$68
8.2	Turbine Plant Auxiliaries	$168	$0	$385	$0	$0	$553	$48	$0	$60	$662	$1
8.3	Condenser & Auxiliaries	$4,112	$0	$1,235	$0	$0	$5,348	$455	$0	$580	$6,382	$12
8.4	Steam Piping	$4,962	$0	$3,497	$0	$0	$8,459	$647	$0	$2,276	$11,382	$22
8.9	TG Foundations	$0	$828	$1,409	$0	$0	$2,237	$189	$0	$728	$3,154	$6
	SUBTOTAL 8.	**$34,466**	**$828**	**$10,632**	**$0**	**$0**	**$45,926**	**$3,856**	**$0**	**$6,829**	**$56,611**	**$109**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,081	$0	$897	$0	$0	$4,978	$422	$0	$810	$6,210	$12
9.2	Circulating Water Pumps	$1,284	$0	$77	$0	$0	$1,361	$104	$0	$220	$1,685	$3
9.3	Circ.Water System Auxiliaries	$108	$0	$15	$0	$0	$123	$10	$0	$20	$154	$0
9.4	Circ.Water Piping	$0	$4,606	$1,175	$0	$0	$5,781	$459	$0	$1,248	$7,488	$14
9.5	Make-up Water System	$301	$0	$427	$0	$0	$729	$62	$0	$158	$949	$2
9.6	Component Cooling Water Sys	$544	$650	$459	$0	$0	$1,653	$137	$0	$358	$2,148	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,564	$2,678	$0	$0	$4,242	$358	$0	$1,380	$5,981	$12
	SUBTOTAL 9.	**$6,318**	**$6,821**	**$5,729**	**$0**	**$0**	**$18,867**	**$1,553**	**$0**	**$4,194**	**$24,614**	**$47**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$16,165	$0	$7,978	$0	$0	$24,143	$2,063	$0	$2,621	$28,826	$56
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$532	$0	$579	$0	$0	$1,111	$96	$0	$181	$1,387	$3
10.7	Ash Transport & Feed Equipment	$718	$0	$172	$0	$0	$890	$73	$0	$145	$1,108	$2
10.8	Misc. Ash Handling Equipment	$1,101	$1,350	$403	$0	$0	$2,854	$242	$0	$464	$3,560	$7
10.9	Ash/Spent Sorbent Foundation	$0	$47	$59	$0	$0	$106	$9	$0	$34	$149	$0
	SUBTOTAL 10.	**$18,516**	**$1,396**	**$9,191**	**$0**	**$0**	**$29,103**	**$2,482**	**$0**	**$3,445**	**$35,031**	**$68**

Exhibit 3-79 Case 4 Total Plant Cost Details (Continued)

Client:	USDOE/NETL				Report Date:	05-Apr-07	
Project:	Bituminous Baseline Study						
	TOTAL PLANT COST SUMMARY						
Case:	Case 04 - ConocoPhillips IGCC w/ CO2						
Plant Size:	518.2 MW,net	Estimate Type:	Conceptual		Cost Base (Dec)	2006	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$866	$0	$864	$0	$0	$1,730	$147	$0	$188	$2,065	$4
11.2	Station Service Equipment	$4,122	$0	$387	$0	$0	$4,509	$384	$0	$489	$5,381	$10
11.3	Switchgear & Motor Control	$7,876	$0	$1,444	$0	$0	$9,320	$773	$0	$1,514	$11,608	$22
11.4	Conduit & Cable Tray	$0	$3,748	$12,166	$0	$0	$15,914	$1,363	$0	$4,319	$21,596	$42
11.5	Wire & Cable	$0	$6,883	$4,630	$0	$0	$11,512	$754	$0	$3,067	$15,333	$30
11.6	Protective Equipment	$0	$624	$2,365	$0	$0	$2,989	$262	$0	$488	$3,739	$7
11.7	Standby Equipment	$208	$0	$211	$0	$0	$419	$36	$0	$68	$524	$1
11.8	Main Power Transformers	$9,992	$0	$132	$0	$0	$10,124	$687	$0	$1,622	$12,432	$24
11.9	Electrical Foundations	$0	$142	$376	$0	$0	$518	$44	$0	$169	$730	$1
	SUBTOTAL 11.	**$23,064**	**$11,396**	**$22,575**	**$0**	**$0**	**$57,035**	**$4,450**	**$0**	**$11,923**	**$73,409**	**$142**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,005	$0	$699	$0	$0	$1,705	$147	$85	$291	$2,227	$4
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$231	$0	$154	$0	$0	$385	$33	$19	$88	$525	$1
12.7	Computer & Accessories	$5,362	$0	$179	$0	$0	$5,541	$470	$277	$629	$6,918	$13
12.8	Instrument Wiring & Tubing	$0	$1,906	$3,990	$0	$0	$5,896	$448	$295	$1,660	$8,299	$16
12.9	Other I & C Equipment	$3,584	$0	$1,813	$0	$0	$5,398	$464	$270	$920	$7,052	$14
	SUBTOTAL 12.	**$10,183**	**$1,906**	**$6,836**	**$0**	**$0**	**$18,925**	**$1,562**	**$946**	**$3,586**	**$25,021**	**$48**
13	Improvements to Site											
13.1	Site Preparation	$0	$101	$2,167	$0	$0	$2,268	$200	$0	$740	$3,209	$6
13.2	Site Improvements	$0	$1,790	$2,397	$0	$0	$4,187	$368	$0	$1,367	$5,922	$11
13.3	Site Facilities	$3,208	$0	$3,410	$0	$0	$6,618	$582	$0	$2,160	$9,360	$18
	SUBTOTAL 13.	**$3,208**	**$1,891**	**$7,974**	**$0**	**$0**	**$13,073**	**$1,151**	**$0**	**$4,267**	**$18,490**	**$36**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$27	$0	$75	$451	$1
14.2	Steam Turbine Building	$0	$2,058	$2,971	$0	$0	$5,030	$414	$0	$816	$6,260	$12
14.3	Administration Building	$0	$814	$598	$0	$0	$1,412	$113	$0	$229	$1,753	$3
14.4	Circulation Water Pumphouse	$0	$153	$82	$0	$0	$235	$18	$0	$38	$291	$1
14.5	Water Treatment Buildings	$0	$427	$423	$0	$0	$850	$69	$0	$138	$1,057	$2
14.6	Machine Shop	$0	$417	$289	$0	$0	$705	$56	$0	$114	$876	$2
14.7	Warehouse	$0	$672	$440	$0	$0	$1,112	$88	$0	$180	$1,381	$3
14.8	Other Buildings & Structures	$0	$403	$318	$0	$0	$721	$58	$0	$156	$934	$2
14.9	Waste Treating Building & Str.	$0	$900	$1,744	$0	$0	$2,644	$220	$0	$573	$3,437	$7
	SUBTOTAL 14.	**$0**	**$6,066**	**$6,992**	**$0**	**$0**	**$13,057**	**$1,063**	**$0**	**$2,319**	**$16,439**	**$32**
	TOTAL COST	**$623,738**	**$61,009**	**$268,131**	**$0**	**$0**	**$952,878**	**$79,766**	**$54,298**	**$172,940**	**$1,259,883**	**$2,431**

Exhibit 3-80 Case 4 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 04 - ConocoPhillips IGCC w/ CO2					Heat Rate-net(Btu/kWh):	10,757
					MWe-net:	518
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	10.0		10.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	16.0		16.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$6,012,864	$11.602
Maintenance Labor Cost					$13,171,520	$25.416
Administrative & Support Labor					$4,796,096	$9.255
TOTAL FIXED OPERATING COSTS					**$23,980,481**	**$46.273**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$24,211,567**	**$0.00667**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	5,954	1.03	**$0**	**$1,790,845**	**$0.00049**
Chemicals						
MU & WT Chem.(lb)	124,161	17,737	0.16	$20,462	$853,547	$0.00024
Carbon (Mercury Removal) (lb)	128,090	175	1.00	$128,090	$51,100	$0.00001
COS Catalyst (m3)	0	0	2,308.40	$0	$0	$0.00000
Water Gas Shift Catalyst(ft3)	11,053	7.57	475.00	$5,250,175	$1,049,363	$0.00029
Selexol Solution (gal.)	462	66	12.90	$5,960	$248,630	$0.00007
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.16	125.00	$0	$78,840	$0.00002
Subtotal Chemicals				**$5,404,687**	**$2,281,480**	**$0.00063**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	$0.00000
Waste Disposal						
Spent Mercury Catalyst (lb)	0	175	0.40	$0	$20,522	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	583	15.45	$0	$2,632,348	$0.00072
Subtotal-Waste Disposal				**$0**	**$2,652,870**	**$0.00073**
By-products & Emissions						
Sulfur(tons)	0	143	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$5,404,687**	**$30,936,762**	**$0.00852**
Fuel(ton)	172,030	5,734	42.11	**$7,244,210**	**$70,510,306**	**$0.01941**

3.4 SHELL GLOBAL SOLUTIONS IGCC CASES

This section contains an evaluation of plant designs for Cases 5 and 6, which are based on the Shell Global Solutions (Shell) gasifier. Cases 5 and 6 are very similar in terms of process, equipment, scope and arrangement, except that Case 6 employs a syngas quench and includes sour gas shift reactors, CO_2 absorption/regeneration and compression/transport systems. There are no provisions for CO_2 removal in Case 5.

The balance of this section is organized in an analogous manner to Sections 3.2 and 3.3:

- Gasifier Background
- Process System Decscription for Case 5
- Key Assumptions for Cases 5 and 6
- Sparing Philosophy for Cases 5 and 6
- Performance Results for Case 5
- Equipment List for Case 5
- Cost Estimates For Case 5
- Process and System Description, Performance Results, Equipment List and Cost Estimate for Case 6

3.4.1 GASIFIER BACKGROUND

Development and Current Status – Development of the Shell gasification process for partial oxidation of oil and gas began in the early 1950s. More than 75 commercial Shell partial-oxidation plants have been built worldwide to convert a variety of hydrocarbon liquids and gases to carbon monoxide and hydrogen.

Shell Internationale Petroleum Maatschappij B.V. began work on coal gasification in 1972. The coal gasifier is significantly different than the oil and gas gasifiers developed earlier. A pressurized, entrained-flow, slagging coal gasifier was built at Shell's Amsterdam laboratories. This 5 tonnes/day (6 TPD) process development unit has operated for approximately 12,000 hours since 1976. A larger 150 tonnes/day (165 TPD) pilot plant was built at Shell's Hamburg refinery in Hamburg, Germany. This larger unit operated for approximately 6,000 hours from 1978 to 1983, and successfully gasified over 27,216 tonnes (30,000 tons) of coal.

From 1974 until mid-1981, Heinrich Koppers GmbH (now Krupp Koppers) cooperated with Shell in the development work for the coal gasification technology at the 150 tonnes/day (165 TPD) pilot plant in Hamburg. Krupp Koppers is the licensor of the commercially proven Koppers-Totzek coal gasification technology, an entrained-flow slagging gasification system operated at atmospheric pressure.

In June 1981, the partnership between Shell and Krupp Koppers was terminated. Since that time, this gasification technology has been developed solely by Shell as the Shell Coal Gasification Process. Krupp Koppers continued its own development of a similar pressurized, dry feed, entrained-flow gasification technology called PRENFLO. Krupp Koppers has built and successfully operated a small 45 tonnes/day (50 TPD) PRENFLO pilot plant at Fuerstenhausen, Germany. In 2000 Shell and Krupp Uhde agreed to join forces again in gasification and jointly offer the Shell coal gasification process.

Based on the experience it gained with the Hamburg unit, Shell built a demonstration unit at its oil refinery and chemical complex in Deer Park, Texas, near Houston. This new unit, commonly called SCGP-1 (for Shell Coal Gasification Plant-1), was designed to gasify bituminous coal at the rate of 227 tonnes/day (250 TPD) and to gasify high-moisture, high-ash lignite at the rate of 363 tonnes/day (400 TPD). The relatively small difference in size between the Hamburg and Deer Park units reflects design changes and improvements.

The Deer Park demonstration plant operated successfully after startup in July 1987. Before the end of the program in 1991, after 15,000 hours of operation, 18 different feedstocks were gasified at the plant, including domestic coals ranging from lignite to high-sulfur bituminous, three widely traded foreign coals, and petroleum coke. The Deer Park unit produced superheated high-pressure steam in the waste heat recovery boiler. The plant also had facilities for extensive environmental monitoring and for sidestream testing of several AGR processes, including Sulfinol-D, Sulfinol-M, highly loaded MDEA, and various wastewater treatment schemes.

In spring 1989, Shell announced that its technology had been selected for the large commercial-scale Demkolec B.V. IGCC plant at Buggenum, near Roermond, in The Netherlands. This plant generates 250 MW of IGCC electricity with a single Shell gasifier consuming 1,814 tonnes/day (2,000 TPD) (dry basis) of coal. The plant was originally owned and operated by Samenwerkende Electriciteits-Productiebedrijven NV (SEP), a consortium of Dutch utilities, and began operation in 1994. In 2000 the plant was purchased by Nuon. Shell was extensively involved in the design, startup, and initial operation of this plant. A key feature of this design is the use of extraction air from the combustion turbine air compressor to feed the oxygen plant.

Gasifier Capacity – The large gasifier operating in The Netherlands has a bituminous coal-handling capacity of 1,633 tonnes/day (1,800 TPD) and produces dry gas at a rate of 158,575 Nm^3/h (5.6 million scf/h) with an energy content of about 1,792 MMkJ/h (1,700 MMBtu/h) (HHV). This gasifier was sized to match the fuel gas requirements for the Siemens/Kraftwerk Union V-94.2 combustion turbine and could easily be scaled up to match advanced F Class turbine requirements.

Distinguishing Characteristics – The key advantage of the Shell coal gasification technology is its lack of feed coal limitations. One of the major achievements of the Shell development program has been the successful gasification of a wide variety of coals ranging from anthracite to brown coal. The dry pulverized feed system developed by Shell uses all coal types with essentially no operating and design modifications (provided the drying pulverizers are appropriately sized). The dry fed Shell gasifier also has the advantage of lower oxygen requirement than comparable slurry fed entrained flow gasifiers.

Entrained-flow slagging gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag. The dry feed entrained-flow gasifiers also have minor environmental advantages over the slurry feed entrained-flow gasifiers. They produce a higher H_2S/CO_2 ratio acid gas, which improves sulfur recovery and lessens some of the gray water processing and the fixed-salts blowdown problems associated with slurry feeding.

A disadvantage of the Shell coal gasification technology is the high waste heat recovery (synthesis gas cooler) duty. As with the other slagging gasifiers, the Shell process has this disadvantage due to its high operating temperature. The ability to feed dry solids minimizes the oxygen requirement and makes the Shell gasifier somewhat more efficient than entrained flow gasifiers employing slurry feed systems. The penalty paid for this increase in efficiency is a coal feed system that is more costly and operationally more complex. Demonstration of the reliability and safety of the dry coal feeding system was essential for the successful development of the Shell technology. The high operating temperature required by all entrained-flow slagging processes can result in relatively high capital and maintenance costs. However, the Shell gasifier employs a cooled refractory, which requires fewer changeouts than an uncooled refractory. Life of a water wall is determined by metallurgy and temperature and can provide a significant O&M cost benefit over refractory lined gasifiers.

Important Coal Characteristics – Characteristics desirable for coal considered for use in the Shell gasifier include moderate ash fusion temperature and relatively low ash content. The Shell gasifier is extremely flexible; it can handle a wide variety of different coals, including lignite. High-ash fusion-temperature coals may require flux addition for optimal gasifier operation. The ash content, fusion temperature, and composition affect the required gasifier operating temperature level, oxygen requirements, heat removal, slag management, and maintenance. However, dry feeding reduces the negative effects of high ash content relative to slurry feed gasifiers.

3.4.2 PROCESS DESCRIPTION

In this section the overall Shell gasification process for Case 5 is described. The system description follows the BFD in Exhibit 3-81 and stream numbers reference the same Exhibit. The tables in Exhibit 3-82 provide process data for the numbered streams in the BFD.

Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. The Shell process uses a dry feed system which is sensitive to the coal moisture content. Coal moisture consists of two parts, surface moisture and inherent moisture. For coal to flow smoothly through the lock hoppers, the surface moisture must be removed. The Illinois No. 6 coal used in this study contains 11.12 percent total moisture on an as-received basis (stream 9). It was assumed that the coal must be dried to 5 percent moisture to allow for smooth flow through the dry feed system (stream 10).

The coal is simultaneously crushed and dried in the coal mill then delivered to a surge hopper with an approximate 2-hour capacity. The drying medium is provided by combining the off-gas from the Claus plant TGTU and a slipstream of clean syngas (stream 8) and passing them through an incinerator. The incinerator flue gas, with an oxygen content of 6 vol%, is then used to dry the coal in the mill.

The coal is drawn from the surge hoppers and fed through a pressurization lock hopper system to a dense phase pneumatic conveyor, which uses nitrogen from the ASU to convey the coal to the gasifiers.

Exhibit 3-81 Case 5 Process Flow Diagram, Shell IGCC without CO_2 Capture

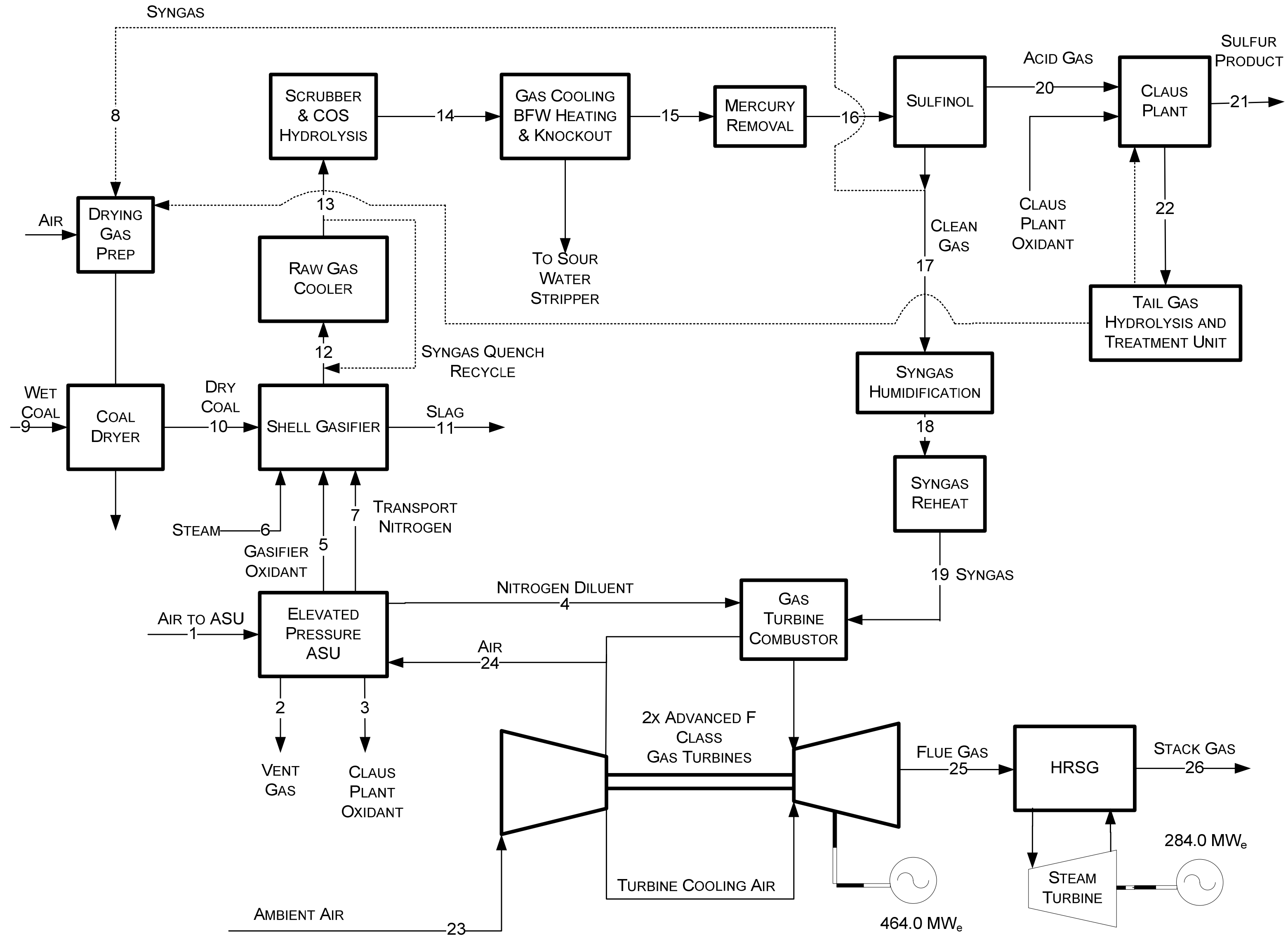

Exhibit 3-82 Case 5 Stream Table, Shell IGCC without CO_2 Capture

	1	2	3	4	5	6	7	8	9[A]	10[A]	11	12	13
V-L Mole Fraction													
Ar	0.0094	0.0263	0.0360	0.0024	0.0360	0.0000	0.0000	0.0105	0.0000	0.0000	0.0000	0.0097	0.0097
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0004	0.0004
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6151	0.0000	0.0000	0.0000	0.5716	0.5716
CO_2	0.0003	0.0091	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.0211	0.0211
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0007
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3122	0.0000	0.0000	0.0000	0.2901	0.2901
H_2O	0.0104	0.2820	0.0000	0.0004	0.0000	1.0000	0.0000	0.0014	1.0000	1.0000	0.0000	0.0364	0.0364
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081	0.0081
N_2	0.7722	0.4591	0.0140	0.9918	0.0140	0.0000	1.0000	0.0599	0.0000	0.0000	0.0000	0.0585	0.0585
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0033	0.0033
O_2	0.2077	0.2235	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	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	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	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	37,250	1,938	225	38,900	10,865	2,424	2,019	447	2,796	1,165	0	75,202	40,232
V-L Flowrate (lb/hr)	1,074,830	51,432	7,250	1,091,540	350,168	43,673	56,553	8,949	50,331	20,982	0	1,548,350	828,347
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	402,289	402,289	45,315	0	0
Temperature (°F)	232	70	90	385	518	650	560	124	59	215	2,600	1,635	398
Pressure (psia)	190.6	16.4	125.0	460.0	740.0	740.0	815.0	516.7	14.7	14.7	614.7	614.7	574.7
Enthalpy (BTU/lb)[B]	55.3	26.8	12.5	88.0	107.7	1311.5	132.2	33.1	11,676	---	1,167	619.8	160.2
Density (lb/ft^3)	0.741	0.104	0.683	1.424	2.272	1.119	2.086	1.651	---	---	---	0.563	1.286
Molecular Weight	28.854	26.545	32.229	28.060	32.229	18.015	28.013	20.011	---	---	---	20.589	20.589

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

B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-82 Case 5 Stream Table, Shell IGCC without CO_2 Capture (continued)

	14	15	16	17	18	19	20	21	22	23	24	25	26
V-L Mole Fraction													
Ar	0.0097	0.0101	0.0101	0.0105	0.0086	0.0086	0.0003	0.0000	0.0041	0.0094	0.0094	0.0088	0.0088
CH_4	0.0004	0.0004	0.0004	0.0004	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.5699	0.5940	0.5940	0.6151	0.5080	0.5080	0.0112	0.0000	0.0674	0.0000	0.0000	0.0000	0.0000
CO_2	0.0217	0.0226	0.0226	0.0006	0.0005	0.0005	0.6315	0.0000	0.4947	0.0003	0.0003	0.0755	0.0755
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000
H_2	0.2893	0.3015	0.3015	0.3122	0.2579	0.2579	0.0062	0.0000	0.0179	0.0000	0.0000	0.0000	0.0000
H_2O	0.0387	0.0015	0.0015	0.0014	0.1752	0.1752	0.0042	0.0000	0.3199	0.0108	0.0108	0.0847	0.0847
H_2S	0.0088	0.0091	0.0091	0.0000	0.0000	0.0000	0.2596	0.0000	0.0015	0.0000	0.0000	0.0000	0.0000
N_2	0.0583	0.0608	0.0608	0.0599	0.0494	0.0494	0.0870	0.0000	0.0898	0.7719	0.7719	0.7277	0.7277
NH_3	0.0032	0.0000	0.0000	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.2076	0.1033	0.1033
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0045	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	40,353	38,715	38,715	36,914	44,695	44,695	1,353	0	2,088	248,660	16,712	302,092	302,092
V-L Flowrate (lb/hr)	830,529	801,076	801,076	738,696	878,868	878,868	53,431	0	67,836	7,173,720	482,146	8,728,000	8,728,000
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	11,307	0	0	0	0	0
Temperature (°F)	351	95	95	124	312	385	124	344	280	59	811	1,105	270
Pressure (psia)	549.7	529.7	519.7	516.7	465.0	460.0	60.0	23.6	23.6	14.7	234.9	15.2	15.2
Enthalpy (BTU/lb)[B]	146.2	22.6	22.6	33.1	269.4	301.3	21.9	-102.1	255.2	13.8	200.3	340.0	116.4
Density (lb/ft^3)	1.300	1.841	1.807	1.651	1.111	0.998	0.378	---	0.097	0.076	0.497	0.026	0.056
Molecular Weight	20.581	20.692	20.692	20.011	19.664	19.664	39.490	---	32.491	28.849	28.849	28.892	28.892

B - Reference conditions are 32.02 F & 0.089 PSIA

Gasifier

There are two Shell dry feed, pressurized, upflow, entrained, slagging gasifiers, operating at 4.2 MPa (615 psia) and processing a total of 4,927 tonnes/day (5,431 TPD) of as-received coal. Coal reacts with oxygen and steam at a temperature of 1427°C (2600°F) to produce principally hydrogen and carbon monoxide with little carbon dioxide formed.

The gasifier includes a refractory-lined water wall that is also protected by molten slag that solidifies on the cooled walls.

Raw Gas Cooling/Particulate Removal

High-temperature heat recovery in each gasifier train is accomplished in three steps, including the gasifier jacket, which cools the syngas by maintaining the reaction temperature at 1427°C (2600°F). The product gas from the gasifier is cooled to 891°C (1635°F) by adding cooled recycled fuel gas to lower the temperature below the ash melting point. Gas (stream 12) then goes through a raw gas cooler, which lowers the gas temperature from 891°C (1635°F) to 316°C (600°F), and produces high-pressure steam for use in the steam cycle. The syngas is further cooled to 203°C (398°F) (stream 13) by heating water that is used to humidify the sweet syngas prior to the combustion turbine.

After passing through the raw gas cooler, the syngas passes through a cyclone and a raw gas candle filter where a majority of the fine particles are removed and returned to the gasifier with the coal fuel. The filter consists of an array of ceramic candle elements in a pressure vessel. Fines produced by the gasification system are recirculated to extinction. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form. The slag is solidified in a quench tank for disposal (stream 11). Lockhoppers are used to reduce the pressure of the solids from 4.2 to 0.1 MPa (615 to 15 psia). The syngas scrubber removes additional particulate matter further downstream.

Quench Gas Compressor

About 45 percent of the raw gas from the filter is recycled back to the gasifier as quench gas. A single-stage compressor is utilized to boost the pressure of a cooled fuel gas stream from 4.0 MPa (575 psia) to 4.2 MPa (615 psia) to provide quench gas to cool the gas stream from the gasifier.

Syngas Scrubber/Sour Water Stripper

The raw synthesis gas exiting the ceramic particulate filter at 203°C (398°F) (stream 13) then enters the scrubber for removal of chlorides and remaining particulate. The quench scrubber washes the syngas in a counter-current flow in two packed beds. The syngas leaves the scrubber saturated at a temperature of 110°C (230ºF). The quench scrubber removes essentially all traces of entrained particles, principally unconverted carbon, slag, and metals. The bottoms from the scrubber are sent to the slag removal and handling system for processing.

The sour water stripper removes NH_3, SO_2, and other impurities from the waste stream of the scrubber. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from synthesis gas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

COS Hydrolysis, Mercury Removal and Acid Gas Removal

H_2S and COS are at significant concentrations, requiring removal for the power plant to achieve the low design level of SO_2 emissions. H_2S is removed in an acid gas removal process; however, because COS is not readily removable, it is first catalytically converted to H_2S in a COS hydrolysis unit.

Following the water scrubber, the gas is reheated to 177°C (350°F) and fed to the COS hydrolysis reactor. The COS in the sour gas is hydrolyzed with steam over a catalyst bed to H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the AGR process (stream 14), it must be cooled to about 35°C (95°F). During this cooling through a series of heat exchangers, part of the water vapor condenses. This water, which contains some NH_3, is sent to the sour water stripper. The cooled syngas (stream 15) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

The Sulfinol process, developed by Shell in the early 1960s, is a combination process that uses a mixture of amines and a physical solvent. The solvent consists of an aqueous amine and sulfolane. Sulfinol-D uses diisopropanolamine (DIPA), while Sulfinol-M uses MDEA. The mixed solvents allow for better solvent loadings at high acid gas partial pressures and higher solubility of COS and organic sulfur compounds than straight aqueous amines. Sulfinol-M was selected for this application.

The sour syngas is fed directly into an HP contactor. The HP contactor is an absorption column in which the H_2S, COS, CO_2, and small amounts of H_2 and CO are removed from the gas by the Sulfinol solvent. The overhead gas stream from the HP contactor is then washed with water in the sweet gas scrubber before leaving the unit as the feed gas to the sulfur polishing unit.

The rich solvent from the bottom of the HP contactor flows through a hydraulic turbine and is flashed in the rich solvent flash vessel. The flashed gas is then scrubbed in the LP contactor with lean solvent to remove H_2S and COS. The overhead from the LP contactor is flashed in the LP KO drum. This gas can be used as a utility fuel gas, consisting primarily of H_2 and CO, at 0.8 MPa (118 psia) and 38°C (101°F). The solvent from the bottom of the LP contactor is returned to the rich solvent flash vessel.

Hot, lean solvent in the lean/rich solvent exchanger then heats the flashed rich solvent before entering the stripper. The stripper strips the H_2S, COS, and CO_2 from the solvent at low pressure with heat supplied through the stripper reboiler. The acid gas stream to sulfur recovery/tail gas cleanup is recovered as the flash gas from the stripper accumulator. The lean solvent from the bottom of the stripper is cooled in the lean/rich solvent exchanger and the lean solvent cooler. Most of the lean solvent is pumped to the HP contactor. A small amount goes to the LP contactor.

The Sulfinol process removes essentially all of the CO_2 along with the H_2S and COS. The acid gas fed to the SRU contains 26 vol% H_2S and 63 vol% CO_2. The CO_2 passes through the SRU, the TGTU and ultimately is vented through the coal dryer. Since the amount of CO_2 in the syngas is small initially, this does not have a significant effect on the mass flow reaching the gas turbine. However, the costs of the sulfur recovery/tail gas cleanup are higher than for a sulfur removal process producing an acid gas stream with a higher sulfur concentration.

Claus Unit

The sulfur recovery unit is a Claus bypass type sulfur recovery unit utilizing oxygen (stream 3) instead of air and followed by an amine-based SCOT tail gas unit. The Claus plant produces molten sulfur (stream 21) by reacting approximately one third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. The combination of Claus technology and SCOT tail gas technology results in an overall sulfur recovery exceeding 99 percent.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant produces approximately 123 tonnes/day (136 TPD) of elemental sulfur. Feed for this case consists of acid gas from both the acid gas cleanup unit (stream 20) and a vent stream from the sour water stripper in the gasifier section. Vent gas from the tail gas treatment unit is combined with a slipstream of clean syngas (stream 8), passed through an incinerator, and the hot, nearly inert incinerator off gas is used to dry coal before being vented to the atmosphere.

In the furnace waste heat boiler, 12,283 kg/h (27,080 lb/h) of 3.6 MPa (525 psia) steam are generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to provide some steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

Power Block

Clean syngas exiting the Sulfinol absorber (stream 17) is humidified because there is not sufficient nitrogen from the ASU to provide the level of dilution required. The moisturized syngas (stream 18) is reheated (stream 19), further diluted with nitrogen from the ASU (stream 4) and steam, and enters the advanced F Class combustion turbine (CT) burner. The CT compressor provides combustion air to the burner and also 31 percent of the air requirements in the ASU (stream 24). The exhaust gas exits the CT at 596°C (1,105°F) (stream 25) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) (stream 26) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit (ASU)

The ASU is designed to produce a nominal output of 3,900 tonnes/day (4,290 TPD) of 95 mole percent O_2 for use in the gasifier (stream 5) and sulfur recovery unit (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 11,900 tonnes/day (13,100 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor. About 6.7 percent of the gas turbine air is used to supply approximately 31 percent of the ASU air requirements.

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.4.3 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 5 and 6, Shell IGCC with and without CO_2 capture, are compiled in Exhibit 3-83.

Balance of Plant – Cases 5 and 6

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 3-17.

Exhibit 3-83 Shell IGCC Plant Study Configuration Matrix

Case	5	6
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.827	0.827
Carbon Conversion, %	99.5	99.5
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	10,610 (285)	10,610 (285)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1800/1050/1050)	12.4/538/538 (1800/1000/1000)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
Combustion Turbine	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	Shell	Shell
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Feed Moisture Content, %	5	5
COS Hydrolysis	Yes	Occurs in SGS
Sour Gas Shift	No	Yes
H_2S Separation	Sulfinol-M	Selexol 1st Stage
Sulfur Removal, %	99.5	99.7
Sulfur Recovery	Claus Plant with Tail Gas Treatment / Elemental Sulfur	Claus Plant with Tail Gas Treatment / Elemental Sulfur
Particulate Control	Cyclone, Candle Filter, Scrubber, and AGR Absorber	Cyclone, Candle Filter, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB), N_2 Dilution, Humidification and steam dilution	MNQC (LNB), N_2 Dilution and Humidification
CO_2 Separation	N/A	Selexol 2nd Stage
CO_2 Capture	N/A	90.8% from Syngas
CO_2 Sequestration	N/A	Off-site Saline Formation

3.4.4 SPARING PHILOSOPHY

The sparing philosophy for Cases 5 and 6 is provided below. Single trains are utilized throughout with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment.

The plant design consists of the following major subsystems:

- Two air separation units (2 x 50%)
- Two trains of coal drying and dry feed systems (2 x 50%)
- Two trains of gasification, including gasifier, synthesis gas cooler, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Sulfinol-M acid gas gas removal in Case 5 and two-stage Selexol in Case 6 (2 x 50%),
- One train of Claus-based sulfur recovery (1 x 100%).
- Two combustion turbine/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.4.5 CASE 5 PERFORMANCE RESULTS

The plant produces a net output of 636 MWe at a net plant efficiency of 41.1 percent (HHV basis). Shell has reported expected efficiencies using bituminous coal of around 44-45 percent (HHV basis), although this value excluded the net power impact of coal drying. [52] Accounting for coal drying would reduce the efficiency by only about 0.5-1 percentage points so the efficency results for the Shell case are still lower in this study than reported by the vendor.

Overall performance for the entire plant is summarized in Exhibit 3-84 which includes auxiliary power requirements. The ASU accounts for over 76 percent of the total auxiliary load distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The cooling water system, including the circulating water pumps and cooling tower fan, accounts for over 4 percent of the auxiliary load, and the BFW pumps account for an additional 3.6 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-84 Case 5 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,030
Steam Turbine Power	283,990
TOTAL POWER, kWe	**748,020**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	430
Coal Milling	2,110
Slag Handling	540
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	41,630
Oxygen Compressor	10,080
Nitrogen Compressor	37,010
Syngas Recycle Compressor	1,650
Incinerator Air Blower	160
Boiler Feedwater Pumps	4,670
Condensate Pump	230
Flash Bottoms Pump	200
Circulating Water Pumps	3,150
Cooling Tower Fans	1,630
Scrubber Pumps	120
Sulfinol Unit Auxiliaries	660
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,550
TOTAL AUXILIARIES, kWe	**112,170**
NET POWER, kWe	**635,850**
Net Plant Efficiency, % (HHV)	41.1
Net Plant Heat Rate (Btu/kWh)	8,306
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,401 (1,329)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	205,305 (452,620)
Thermal Input, kWt	1,547,493
Raw Water Usage, m^3/min (gpm)	14.4 (3,792)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 5 is presented in Exhibit 3-85.

Exhibit 3-85 Case 5 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.0053 (0.0124)	209 (230)	0.040 (0.088)
NO_X	0.025 (0.058)	982 (1,082)	0.187 (0.413)
Particulates	0.003 (0.0071)	119 (131)	0.023 (0.050)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.010 (0.011)	$1.8x10^{-6}$ ($4.0x10^{-6}$)
CO_2	85.9 (200)	3,351,000 (3,694,000)	639 (1,409)
CO_2[1]			752 (1,658)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 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 less than 30 ppmv. This results in a concentration in the flue gas of less than 4 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is treated using an amine based system to capture most of the remaining sulfur. The cleaned gas from the tail gas treatment unit is combined with a slipstream of clean syngas, passed through an incinerator, and the hot, inert incinerator offgas is used to dry coal prior to being vented to atmosphere. The SO_2 emissions in Exhibit 3-85 include both the stack emissions and the coal dryer emissions.

NO_X emissions are limited by the use of nitrogen dilution, humidification and steam dilution to 15 ppmvd (as NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-86. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and as CO_2 in the stack gas, ASU vent gas and coal dryer vent gas. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance.

Exhibit 3-86 Case 5 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	130,882 (288,545)	**Slag**	656 (1,446)
Air (CO_2)	471 (1,039)	**Stack Gas**	124,162 (273,731)
		ASU Vent	96 (212)
		Coal Dryer	6,252 (13,783)
		Wastewater	187 (412)
Total	131,353 (289,584)	**Total**	131,353 (289,584)

Exhibit 3-87 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, sulfur in the coal drying gas, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,307/11,361) or
99.5 percent

Exhibit 3-87 Case 5 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,153 (11,361)	**Elemental Sulfur**	5,129 (11,307)
		Stack Gas	14 (30)
		Coal Dryer Vent	1 (3)
		Wastewater	9 (21)
Total	5,153 (11,361)	**Total**	5,153 (11,361)

Exhibit 3-88 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-88 Case 5 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Gasifier Steam	0.3 (87)	0	0.3 (87)
Humidifier	1.1 (293)	0	1.1 (293)
Slag Handling	0.5 (118)	0.5 (118)	0
Scrubber	0.2 (61)	0	0.2 (61)
CT Steam Dilution	0.5 (132)	0	0.5 (132)
BFW Makeup	0.2 (39)	0	0.2 (39)
Cooling Tower Makeup	12.2 (3,233)	0.2 (54)	12.0 (3,180)
Total	**15.0 (3,963)**	**0.7 (171)**	**14.3 (3,792)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-89 through Exhibit 3-93:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-61. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-84) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-89 Case 5 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

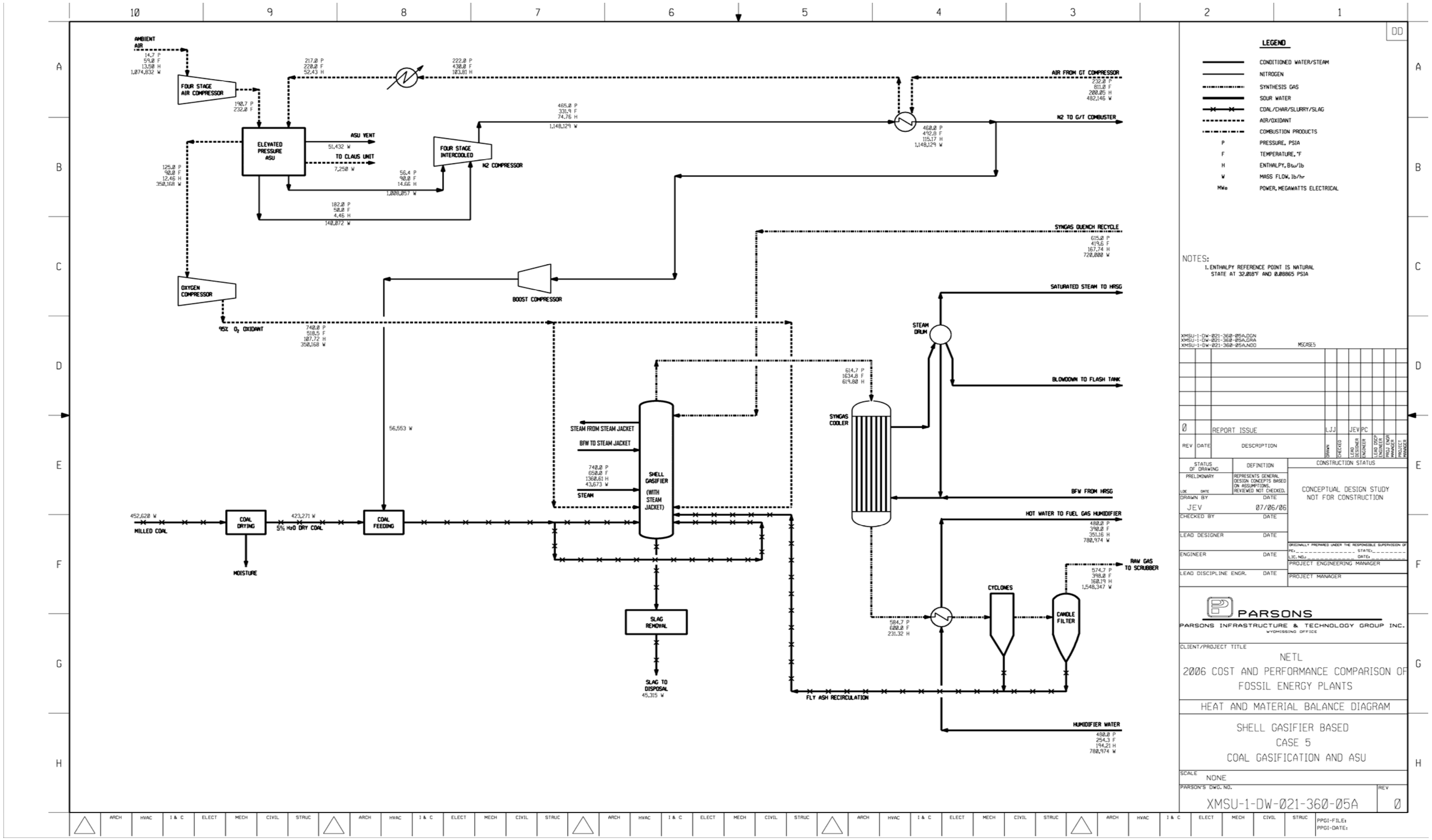

Exhibit 3-90 Case 5 Syngas Cleanup Heat and Mass Balance Schematic

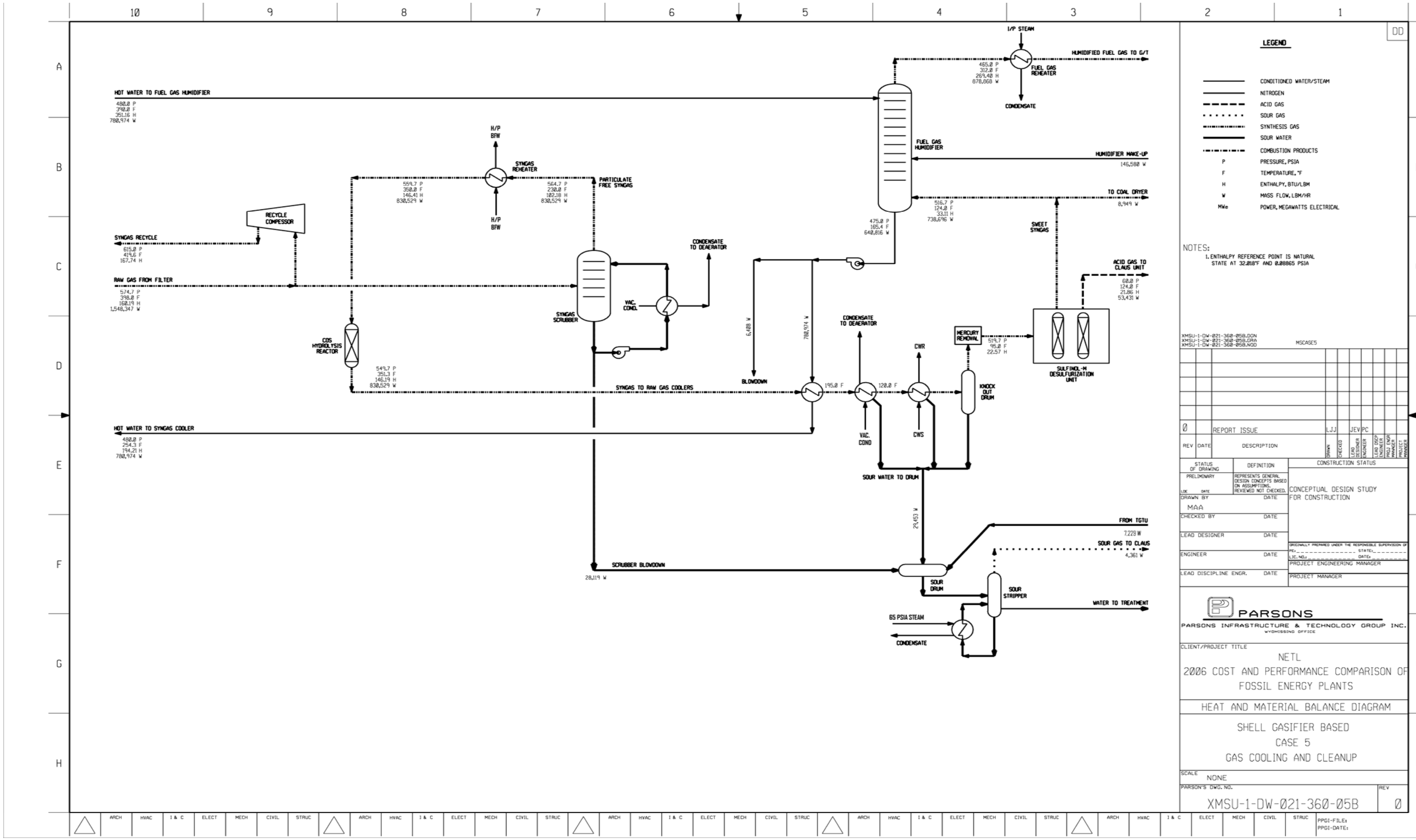

Exhibit 3-91 Case 5 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

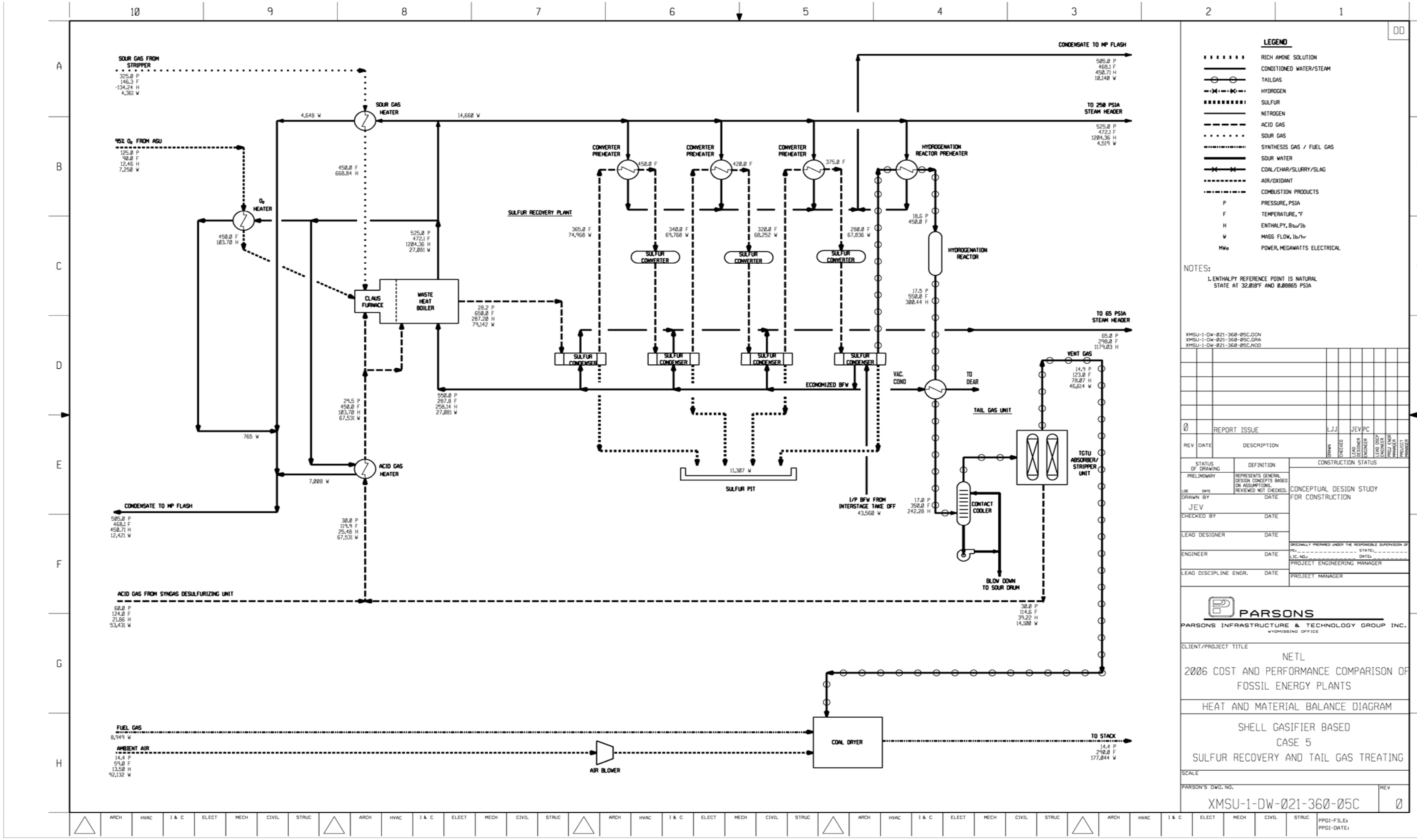

Exhibit 3-92 Case 5 Combined Cycle Power Generation Heat and Mass Balance Schematic

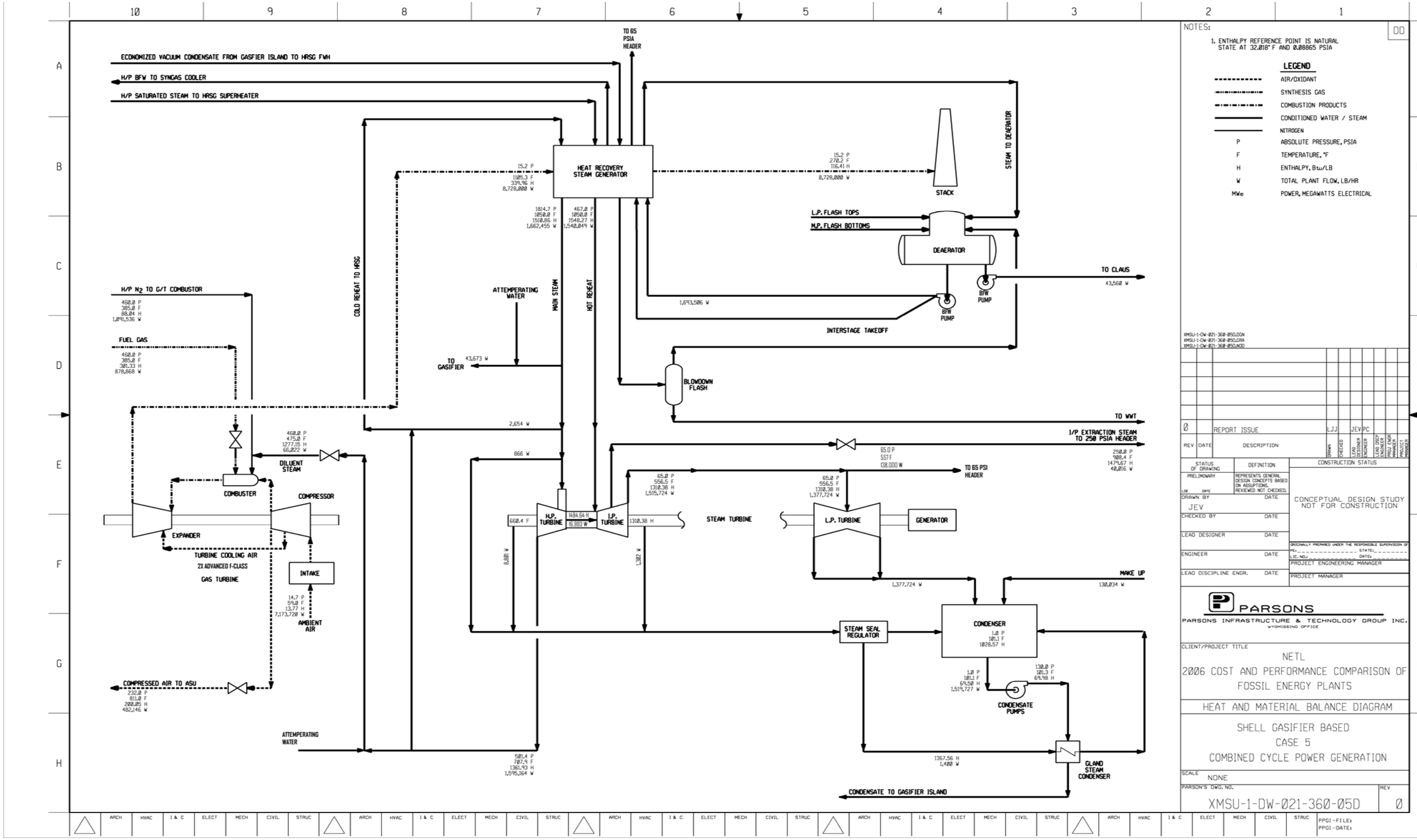

Exhibit 3-93 Case 5 Steam and Feedwater Heat and Mass Balance Schematic

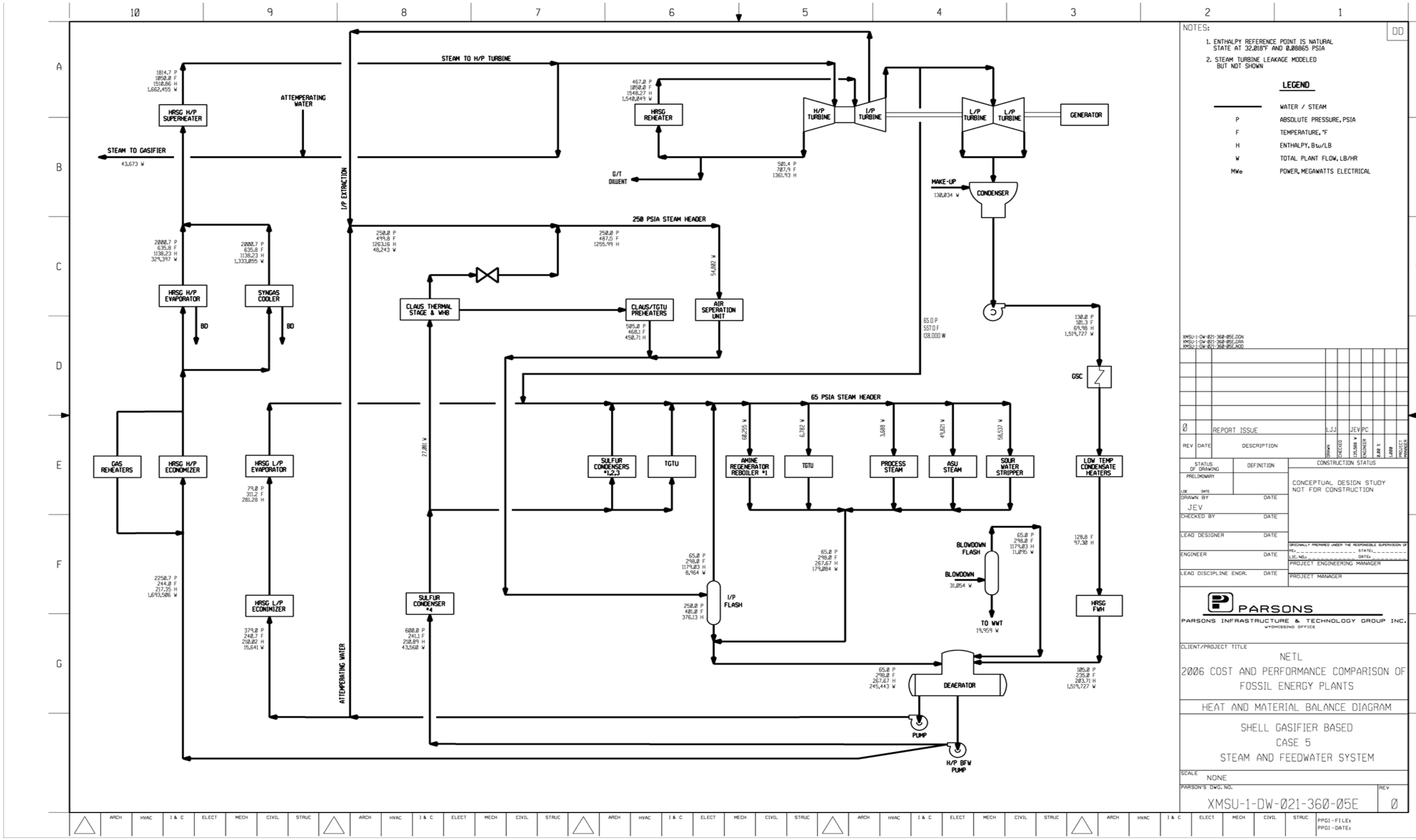

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Exhibit 3-94 Case 5 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,280.2	4.4		5,284.6
ASU Air		14.5		14.5
CT Air		98.8		98.8
Incinerator Air		1.2		1.2
Water		9.4		9.4
Auxiliary Power			382.7	382.7
Totals	**5,280.2**	**128.4**	**382.7**	**5,791.3**
Heat Out (MMBtu/hr)				
ASU Intercoolers		171.4		171.4
ASU Vent		1.4		1.4
Slag	20.4	32.5		52.9
Sulfur	45.0	(1.2)		43.8
Dryer Stack Gas		53.1		53.1
HRSG Flue Gas		1015.9		1,015.9
Condenser		1,329.0		1,329.0
Process Losses		526.1		520.2
Power			2,597.6	2,597.6
Totals	**65.4**	**3,128.3**	**2,597.6**	**5,791.3**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.4.6 CASE 5 - MAJOR EQUIPMENT LIST

Major equipment items for the Shell gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.4.7. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	172 tonne/h (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	336 tonne/h (370 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	336 tonne/h (370 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	336 tonne/h (370 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	73 tonne/h (80 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	227 tonne/h (250 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	454 tonne (500 ton)	1	0
4	Weigh Feeder	Belt	109 tonne/h (120 tph)	2	0
5	Coal Drying and Pulverization	Rotary	109 tonne/h (120 tph)	2	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	590,529 liters (156,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,360 lpm @ 91 m H2O (1,680 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	443,160 kg/h (977,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	151 lpm @ 302 m H2O (40 gpm @ 990 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 7,344 lpm @ 1,890 m H2O (1,940 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,060 lpm @ 223 m H2O (280 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	7,987 lpm @ 18 m H2O (2,110 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	1,590 lpm @ 49 m H2O (420 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	768,445 liter (203,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,722 tonne/day, 4.2 MPa (3,000 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	386,461 kg/h (852,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	207,292 kg/h (457,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	206,838 kg/h (456,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	276,238 kg/h (609,000 lb/h)	6	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	200,488 kg/h, 35°C, 3.7 MPa (442,000 lb/h, 95°F, 530 psia)	2	0
8	Saturation Water Economizers	Shell and tube	207,292 kg/h (457,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	219,085 kg/h, 154°C, 3.2 MPa (483,000 lb/h, 309°F, 465 psia)	2	0
10	Saturator Water Pump	Centrifugal	2,650 lpm @ 12 m H2O (700 gpm @ 40 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	219,085 kg/h (483,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	206,838 kg/h (456,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	3,681 m3/min @ 1.3 MPa (130,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,076 m3/min @ 5.1 MPa (38,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,540 m3/min @ 3.4 MPa (125,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	481 m3/min @ 2.3 MPa (17,000 scfm @ 340 psia)	2	0
18	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	120,202 kg/h, 433°C, 1.6 MPa (265,000 lb/h, 811°F, 232 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	200,034 kg/h (441,000 lb/h) 35°C (95°F) 3.7 MPa (530 psia)	2	0
2	Sulfur Plant	Claus type	135 tonne/day (149 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	207,292 kg/h (457,000 lb/h) 177°C (350°F) 3.9 MPa (560 psia)	2	0
4	Acid Gas Removal Plant	Sulfinol	200,034 kg/h (441,000 lb/h) 51°C (124°F) 3.6 MPa (520 psia)	2	0
5	Tail Gas Treatment Unit	Proprietary amine, absorber/stripper	30,255 kg/h (66,700 lb/h) 49°C (120°F) 0.1 MPa (16.4 psia)	1	0
6	Tail Gas Treatment Incinerator	N/A	64 MMkJ/h (61 MMBtu/h)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.
1	Gas Turbine	Advanced F class	232 MW	2
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.4 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 414,742 kg/h, 12.4 MPa/566°C (914,348 lb/h, 1,800 psig/1,050°F) Reheat steam - 384,205 kg/h, 3.1 MPa/566°C (847,027 lb/h, 452 psig/1,050°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	299 MW 12.4 MPa/566°C/566°C (1800 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	330 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,539 MMkJ/h (1,460 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	314,192 lpm @ 30 m (83,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 1760 MMkJ/h (1670 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	215,770 liters (57,000 gal)	2	0
2	Slag Crusher	Roll	11 tonne/h (12 tph)	2	0
3	Slag Depressurizer	Lock Hopper	11 tonne/h (12 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	140,061 liters (37,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	11 tonne/h (12 tph)	2	0
7	Slag Separation Screen	Vibrating	11 tonne/h (12 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	11 tonne/h (12 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	211,985 liters (56,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	68,138 liters (18,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 433 m H2O (60 gpm @ 1,420 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	91 tonne/h (100 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 200 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 124 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.4.7 CASE 5 - COST ESTIMATING

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-95 shows the total plant capital cost summary organized by cost account and Exhibit 3-96 shows a more detailed breakdown of the capital costs. Exhibit 3-97 shows the initial and annual O&M costs.

The estimated TPC of the Shell gasifier with no CO_2 capture is $1,977/kW. Process contingency represents 2.6 percent of the TPC and project contingency represents 13.7 percent. The 20-year LCOE is 80.5 mills/kWh.

Exhibit 3-95 Case 5 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 05 - Shell IGCC w/o CO2
Plant Size: 635.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$12,864	$2,398	$10,080	$0	$0	**$25,343**	$2,296	$0	$5,528	**$33,166**	$52
2	COAL & SORBENT PREP & FEED	$101,770	$8,108	$17,105	$0	$0	**$126,983**	$11,023	$0	$27,601	**$165,607**	$260
3	FEEDWATER & MISC. BOP SYSTEMS	$9,612	$8,441	$8,983	$0	$0	**$27,035**	$2,523	$0	$6,636	**$36,194**	$57
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$133,051	$0	$58,510	$0	$0	**$191,560**	$17,125	$26,889	$36,009	**$271,583**	$427
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$135,222	$0	w/equip.	$0	$0	**$135,222**	$12,870	$0	$14,809	**$162,901**	$256
4.4-4.9	Other Gasification Equipment	$15,596	$8,787	$10,765	$0	$0	**$35,147**	$3,316	$0	$8,369	**$46,833**	$74
	SUBTOTAL 4	**$283,868**	**$8,787**	**$69,274**	**$0**	**$0**	**$361,929**	**$33,312**	**$26,889**	**$59,188**	**$481,317**	**$757**
5A	Gas Cleanup & Piping	$52,340	$6,552	$37,224	$0	$0	**$96,117**	$9,164	$82	$21,477	**$126,839**	$199
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	**$87,071**	$8,191	$4,354	$9,962	**$109,578**	$172
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$135	$0	$474	**$2,055**	$3
	SUBTOTAL 6	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$8,326**	**$4,354**	**$10,436**	**$111,632**	**$176**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,073	$0	$4,848	$0	$0	**$38,921**	$3,674	$0	$4,260	**$46,855**	$74
7.2-7.9	Ductwork and Stack	$3,174	$2,235	$2,996	$0	$0	**$8,405**	$776	$0	$1,494	**$10,675**	$17
	SUBTOTAL 7	**$37,247**	**$2,235**	**$7,844**	**$0**	**$0**	**$47,326**	**$4,450**	**$0**	**$5,753**	**$57,529**	**$90**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,510	$0	$4,862	$0	$0	**$33,372**	$3,198	$0	$3,657	**$40,227**	$63
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,015	$966	$7,277	$0	$0	**$18,258**	$1,646	$0	$4,035	**$23,939**	$38
	SUBTOTAL 8	**$38,525**	**$966**	**$12,138**	**$0**	**$0**	**$51,630**	**$4,844**	**$0**	**$7,692**	**$64,166**	**$101**
9	COOLING WATER SYSTEM	$6,512	$7,397	$6,140	$0	$0	**$20,049**	$1,841	$0	$4,525	**$26,415**	$42
10	ASH/SPENT SORBENT HANDLING SYS	$17,384	$1,343	$8,631	$0	$0	**$27,357**	$2,605	$0	$3,274	**$33,236**	$52
11	ACCESSORY ELECTRIC PLANT	$21,331	$6,784	$19,452	$0	$0	**$47,567**	$4,373	$0	$9,764	**$61,704**	$97
12	INSTRUMENTATION & CONTROL	$9,443	$1,768	$6,339	$0	$0	**$17,551**	$1,617	$878	$3,354	**$23,399**	$37
13	IMPROVEMENTS TO SITE	$3,166	$1,866	$7,871	$0	$0	**$12,903**	$1,268	$0	$4,251	**$18,422**	$29
14	BUILDINGS & STRUCTURES	$0	$6,247	$7,291	$0	$0	**$13,537**	$1,231	$0	$2,414	**$17,182**	$27
	TOTAL COST	**$676,062**	**$63,575**	**$224,205**	**$0**	**$0**	**$963,842**	**$88,874**	**$32,202**	**$171,892**	**$1,256,810**	**$1,977**

Exhibit 3-96 Case 5 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 05 - Shell IGCC w/o CO2
Plant Size: 635.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,378	$0	$1,668	$0	$0	$5,046	$452	$0	$1,100	$6,598	$10
1.2	Coal Stackout & Reclaim	$4,365	$0	$1,069	$0	$0	$5,435	$477	$0	$1,182	$7,094	$11
1.3	Coal Conveyors	$4,059	$0	$1,058	$0	$0	$5,117	$449	$0	$1,113	$6,679	$11
1.4	Other Coal Handling	$1,062	$0	$245	$0	$0	$1,307	$114	$0	$284	$1,705	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,398	$6,040	$0	$0	$8,438	$804	$0	$1,848	$11,091	$17
	SUBTOTAL 1.	**$12,864**	**$2,398**	**$10,080**	**$0**	**$0**	**$25,343**	**$2,296**	**$0**	**$5,528**	**$33,166**	**$52**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$38,663	$2,310	$5,692	$0	$0	$46,666	$4,033	$0	$10,140	$60,838	$96
2.2	Prepared Coal Storage & Feed	$1,831	$436	$290	$0	$0	$2,557	$219	$0	$555	$3,332	$5
2.3	Dry Coal Injection System	$60,268	$706	$5,655	$0	$0	$66,630	$5,747	$0	$14,475	$86,852	$137
2.4	Misc.Coal Prep & Feed	$1,007	$729	$2,220	$0	$0	$3,956	$363	$0	$864	$5,182	$8
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$3,927	$3,247	$0	$0	$7,174	$662	$0	$1,567	$9,403	$15
	SUBTOTAL 2.	**$101,770**	**$8,108**	**$17,105**	**$0**	**$0**	**$126,983**	**$11,023**	**$0**	**$27,601**	**$165,607**	**$260**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$3,370	$5,859	$3,095	$0	$0	$12,325	$1,137	$0	$2,692	$16,154	$25
3.2	Water Makeup & Pretreating	$505	$53	$282	$0	$0	$839	$79	$0	$276	$1,194	$2
3.3	Other Feedwater Subsystems	$1,861	$631	$568	$0	$0	$3,060	$274	$0	$667	$4,000	$6
3.4	Service Water Systems	$291	$594	$2,063	$0	$0	$2,948	$285	$0	$970	$4,203	$7
3.5	Other Boiler Plant Systems	$1,563	$600	$1,487	$0	$0	$3,650	$342	$0	$799	$4,791	$8
3.6	FO Supply Sys & Nat Gas	$300	$567	$529	$0	$0	$1,397	$134	$0	$306	$1,836	$3
3.7	Waste Treatment Equipment	$702	$0	$430	$0	$0	$1,132	$110	$0	$372	$1,614	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,020	$137	$528	$0	$0	$1,685	$162	$0	$554	$2,402	$4
	SUBTOTAL 3.	**$9,612**	**$8,441**	**$8,983**	**$0**	**$0**	**$27,035**	**$2,523**	**$0**	**$6,636**	**$36,194**	**$57**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$133,051	$0	$58,510	$0	$0	$191,560	$17,125	$26,889	$36,009	$271,583	$427
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$135,222	$0	w/equip.	$0	$0	$135,222	$12,870	$0	$14,809	$162,901	$256
4.4	LT Heat Recovery & FG Saturation	$15,596	$0	$5,868	$0	$0	$21,464	$2,063	$0	$4,705	$28,232	$44
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$910	$371	$0	$0	$1,281	$122	$0	$281	$1,684	$3
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$7,876	$4,526	$0	$0	$12,402	$1,131	$0	$3,383	$16,917	$27
	SUBTOTAL 4.	**$283,868**	**$8,787**	**$69,274**	**$0**	**$0**	**$361,929**	**$33,312**	**$26,889**	**$59,188**	**$481,317**	**$757**

Exhibit 3-96 Case 5 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								**Report Date:**	05-Apr-07	
	Project:	Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case 05 - Shell IGCC w/o CO2										
	Plant Size:	635.9 MW,net		**Estimate Type:**		Conceptual				**Cost Base (Dec)**	2006	($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
5A	GAS CLEANUP & PIPING											
5A.1	Sulfinol Sustem	$38,450	$0	$17,968	$0	$0	$56,417	$5,378	$0	$12,359	$74,154	$117
5A.2	Elemental Sulfur Plant	$9,353	$1,856	$12,076	$0	$0	$23,285	$2,246	$0	$5,106	$30,636	$48
5A.3	Mercury Removal	$926	$0	$705	$0	$0	$1,631	$156	$82	$374	$2,243	$4
5A.4	COS Hydrolysis	$2,564	$0	$3,351	$0	$0	$5,916	$571	$0	$1,297	$7,784	$12
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,047	$176	$99	$0	$0	$1,323	$125	$0	$289	$1,737	$3
5A.6	Fuel Gas Piping	$0	$2,272	$1,566	$0	$0	$3,838	$350	$0	$837	$5,025	$8
5A.9	HGCU Foundations	$0	$2,248	$1,460	$0	$0	$3,708	$339	$0	$1,214	$5,261	$8
	SUBTOTAL 5A.	**$52,340**	**$6,552**	**$37,224**	**$0**	**$0**	**$96,117**	**$9,164**	**$82**	**$21,477**	**$126,839**	**$199**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$82,000	$0	$5,071	$0	$0	$87,071	$8,191	$4,354	$9,962	$109,578	$172
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$135	$0	$474	$2,055	$3
	SUBTOTAL 6.	**$82,000**	**$684**	**$5,833**	**$0**	**$0**	**$88,517**	**$8,326**	**$4,354**	**$10,436**	**$111,632**	**$176**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,073	$0	$4,848	$0	$0	$38,921	$3,674	$0	$4,260	$46,855	$74
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,603	$1,191	$0	$0	$2,794	$246	$0	$608	$3,648	$6
7.4	Stack	$3,174	$0	$1,193	$0	$0	$4,367	$415	$0	$478	$5,261	$8
7.9	HRSG,Duct & Stack Foundations	$0	$632	$611	$0	$0	$1,243	$115	$0	$408	$1,766	$3
	SUBTOTAL 7.	**$37,247**	**$2,235**	**$7,844**	**$0**	**$0**	**$47,326**	**$4,450**	**$0**	**$5,753**	**$57,529**	**$90**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,510	$0	$4,862	$0	$0	$33,372	$3,198	$0	$3,657	$40,227	$63
8.2	Turbine Plant Auxiliaries	$196	$0	$450	$0	$0	$646	$63	$0	$71	$779	$1
8.3	Condenser & Auxiliaries	$4,511	$0	$1,442	$0	$0	$5,952	$565	$0	$652	$7,169	$11
8.4	Steam Piping	$5,308	$0	$3,741	$0	$0	$9,048	$772	$0	$2,455	$12,276	$19
8.9	TG Foundations	$0	$966	$1,645	$0	$0	$2,611	$246	$0	$857	$3,714	$6
	SUBTOTAL 8.	**$38,525**	**$966**	**$12,138**	**$0**	**$0**	**$51,630**	**$4,844**	**$0**	**$7,692**	**$64,166**	**$101**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,206	$0	$924	$0	$0	$5,130	$486	$0	$842	$6,458	$10
9.2	Circulating Water Pumps	$1,317	$0	$79	$0	$0	$1,397	$119	$0	$227	$1,743	$3
9.3	Circ.Water System Auxiliaries	$117	$0	$17	$0	$0	$134	$13	$0	$22	$169	$0
9.4	Circ.Water Piping	$0	$4,978	$1,270	$0	$0	$6,248	$553	$0	$1,360	$8,162	$13
9.5	Make-up Water System	$288	$0	$409	$0	$0	$697	$66	$0	$153	$916	$1
9.6	Component Cooling Water Sys	$582	$697	$492	$0	$0	$1,771	$164	$0	$387	$2,322	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,723	$2,949	$0	$0	$4,672	$441	$0	$1,534	$6,646	$10
	SUBTOTAL 9.	**$6,512**	**$7,397**	**$6,140**	**$0**	**$0**	**$20,049**	**$1,841**	**$0**	**$4,525**	**$26,415**	**$42**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,123	$0	$7,464	$0	$0	$22,587	$2,154	$0	$2,474	$27,215	$43
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$511	$0	$557	$0	$0	$1,068	$103	$0	$176	$1,346	$2
10.7	Ash Transport & Feed Equipment	$691	$0	$166	$0	$0	$856	$79	$0	$140	$1,075	$2
10.8	Misc. Ash Handling Equipment	$1,059	$1,298	$388	$0	$0	$2,745	$259	$0	$451	$3,454	$5
10.9	Ash/Spent Sorbent Foundation	$0	$45	$57	$0	$0	$102	$10	$0	$33	$145	$0
	SUBTOTAL 10.	**$17,384**	**$1,343**	**$8,631**	**$0**	**$0**	**$27,357**	**$2,605**	**$0**	**$3,274**	**$33,236**	**$52**

Exhibit 3-96 Case 5 Total Plant Cost Details (Continued)

	Client:	USDOE/NETL									Report Date:	05-Apr-07	
	Project:	Bituminous Baseline Study											
		TOTAL PLANT COST SUMMARY											
	Case:	Case 05 - Shell IGCC w/o CO2											
	Plant Size:	635.9 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)	
Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW	
11	ACCESSORY ELECTRIC PLANT												
11.1	Generator Equipment	$905	$0	$902	$0	$0	$1,808	$172	$0	$198	$2,177	$3	
11.2	Station Service Equipment	$3,411	$0	$320	$0	$0	$3,732	$354	$0	$409	$4,495	$7	
11.3	Switchgear & Motor Control	$6,519	$0	$1,195	$0	$0	$7,714	$715	$0	$1,264	$9,693	$15	
11.4	Conduit & Cable Tray	$0	$310	$10,070	$0	$0	$10,380	$1,259	$0	$2,910	$14,549	$23	
11.5	Wire & Cable	$0	$5,697	$3,832	$0	$0	$9,529	$697	$0	$2,556	$12,782	$20	
11.6	Protective Equipment	$0	$627	$2,378	$0	$0	$3,005	$294	$0	$495	$3,793	$6	
11.7	Standby Equipment	$215	$0	$219	$0	$0	$434	$42	$0	$71	$548	$1	
11.8	Main Power Transformers	$10,280	$0	$139	$0	$0	$10,419	$789	$0	$1,681	$12,889	$20	
11.9	Electrical Foundations	$0	$150	$396	$0	$0	$546	$52	$0	$179	$777	$1	
	SUBTOTAL 11.	**$21,331**	**$6,784**	**$19,452**	**$0**	**$0**	**$47,567**	**$4,373**	**$0**	**$9,764**	**$61,704**	**$97**	
12	INSTRUMENTATION & CONTROL												
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0	
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0	
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0	
12.4	Other Major Component Control	$932	$0	$649	$0	$0	$1,581	$152	$79	$272	$2,084	$3	
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0	
12.6	Control Boards,Panels & Racks	$214	$0	$143	$0	$0	$357	$34	$18	$82	$492	$1	
12.7	Computer & Accessories	$4,973	$0	$166	$0	$0	$5,139	$487	$257	$588	$6,471	$10	
12.8	Instrument Wiring & Tubing	$0	$1,768	$3,700	$0	$0	$5,468	$464	$273	$1,551	$7,756	$12	
12.9	Other I & C Equipment	$3,324	$0	$1,682	$0	$0	$5,006	$480	$250	$860	$6,597	$10	
	SUBTOTAL 12.	**$9,443**	**$1,768**	**$6,339**	**$0**	**$0**	**$17,551**	**$1,617**	**$878**	**$3,354**	**$23,399**	**$37**	
13	Improvements to Site												
13.1	Site Preparation	$0	$99	$2,139	$0	$0	$2,238	$221	$0	$738	$3,197	$5	
13.2	Site Improvements	$0	$1,767	$2,366	$0	$0	$4,132	$406	$0	$1,361	$5,900	$9	
13.3	Site Facilities	$3,166	$0	$3,366	$0	$0	$6,532	$641	$0	$2,152	$9,325	$15	
	SUBTOTAL 13.	**$3,166**	**$1,866**	**$7,871**	**$0**	**$0**	**$12,903**	**$1,268**	**$0**	**$4,251**	**$18,422**	**$29**	
14	Buildings & Structures												
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1	
14.2	Steam Turbine Building	$0	$2,337	$3,373	$0	$0	$5,710	$524	$0	$935	$7,169	$11	
14.3	Administration Building	$0	$794	$584	$0	$0	$1,379	$123	$0	$225	$1,727	$3	
14.4	Circulation Water Pumphouse	$0	$157	$84	$0	$0	$241	$21	$0	$39	$301	$0	
14.5	Water Treatment Buildings	$0	$402	$398	$0	$0	$800	$72	$0	$131	$1,003	$2	
14.6	Machine Shop	$0	$407	$282	$0	$0	$689	$61	$0	$112	$862	$1	
14.7	Warehouse	$0	$657	$430	$0	$0	$1,086	$96	$0	$177	$1,360	$2	
14.8	Other Buildings & Structures	$0	$393	$310	$0	$0	$704	$63	$0	$153	$920	$1	
14.9	Waste Treating Building & Str.	$0	$879	$1,703	$0	$0	$2,582	$240	$0	$564	$3,386	$5	
	SUBTOTAL 14.	**$0**	**$6,247**	**$7,291**	**$0**	**$0**	**$13,537**	**$1,231**	**$0**	**$2,414**	**$17,182**	**$27**	
	TOTAL COST	**$676,062**	**$63,575**	**$224,205**	**$0**	**$0**	**$963,842**	**$88,874**	**$32,202**	**$171,892**	**$1,256,810**	**$1,977**	

Exhibit 3-97 Case 5 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 05 - Shell IGCC w/o CO2					Heat Rate-net(Btu/kWh):	8,306
					MWe-net:	636
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	15.0		15.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$5,637,060	$8.865
Maintenance Labor Cost					$12,260,125	$19.281
Administrative & Support Labor					$4,474,296	$7.037
TOTAL FIXED OPERATING COSTS					**$22,371,481**	**$35.184**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$22,850,084**	**$0.00513**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	5,460	1.03	**$0**	**$1,642,294**	**$0.00037**
Chemicals						
MU & WT Chem.(lb)	113,862	16,266	0.16	$18,764	$782,745	$0.00018
Carbon (Mercury Removal) (lb)	72,509	99	1.00	$72,509	$28,908	$0.00001
COS Catalyst (m3)	1	0.19	2,308.40	$3,042	$126,875	$0.00003
Water Gas Shift Catalyst(ft3)	0	0	475.00	$0	$0	$0.00000
Selexol Solution (gal.)	0	0	12.90	$0	$0	$0.00000
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	525	75	9.68	$5,080	$211,900	$0.00005
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.05	125.00	$0	$74,825	$0.00002
Subtotal Chemicals				**$99,395**	**$1,225,254**	**$0.00027**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	99	0.40	$0	$11,609	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	544	15.45	$0	$2,453,209	$0.00055
Subtotal-Waste Disposal				**$0**	**$2,464,819**	**$0.00055**
By-products & Emissions						
Sulfur(tons)	0	136	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$99,395**	**$28,182,450**	**$0.00632**
Fuel(ton)	162,977	5,433	42.11	**$6,862,984**	**$66,799,712**	**$0.01499**

3.4.8 CASE 6 - SHELL IGCC POWER PLANT WITH CO_2 CAPTURE

This case is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 5, namely two Shell gasifier trains, two advanced F class turbines, two HRSGs and one steam turbine. The gross power output is constrained by the capacity of the two combustion turbines, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 5 (517 MW versus 636 MW).

The process description for Case 6 is similar to Case 5 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 6 are shown in Exhibit 3-98 and Exhibit 3-99, respectively. Instead of repeating the entire process description, only differences from Case 5 are reported here.

Coal Preparation and Feed Systems

No differences from Case 5.

Gasification

The gasification process is the same as Case 5 with the following exceptions:

- The syngas exiting the gasifier (stream 12) is quenched to 399°C (750°F) with water rather than recycled syngas to provide a portion of the water required for water gas shift
- Total coal feed (as-received) to the two gasifiers is 5,151 tonnes/day (5,678 TPD) (stream 9)
- The ASU provides 4,070 tonnes/day (4,480 TPD) of 95 mole percent oxygen to the gasifier and Claus plant (streams 5 and 3)

Raw Gas Cooling/Particulate Removal

Following the water quench and particulate removal the syngas is cooled to 260°C (500°F) prior to the syngas scrubber (stream 13) by vaporizing HP BFW and pre-heating IP BFW.

Syngas Scrubber/Sour Water Stripper

Syngas exits the scrubber at 204°C (400°F).

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 6 the syngas after the scrubber is reheated to 285°C (545°F) and then steam (stream 14) is added to adjust the H_2O:CO molar ratio to approximately 2:1 prior to the first SGS reactor. The hot syngas exiting the first stage of SGS is used to generate the steam that is added in stream 14. One more stage of SGS (for a total of two) results in 95.6 percent overall conversion of the CO to CO_2. The warm syngas from the second stage of SGS is cooled to 241°C (465°F) by preheating the syngas prior to the first stage of SGS. The SGS catalylst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the second stage of SGS, the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 5

Exhibit 3-98 Case 6 Process Flow Diagram, Shell IGCC with CO_2 Capture

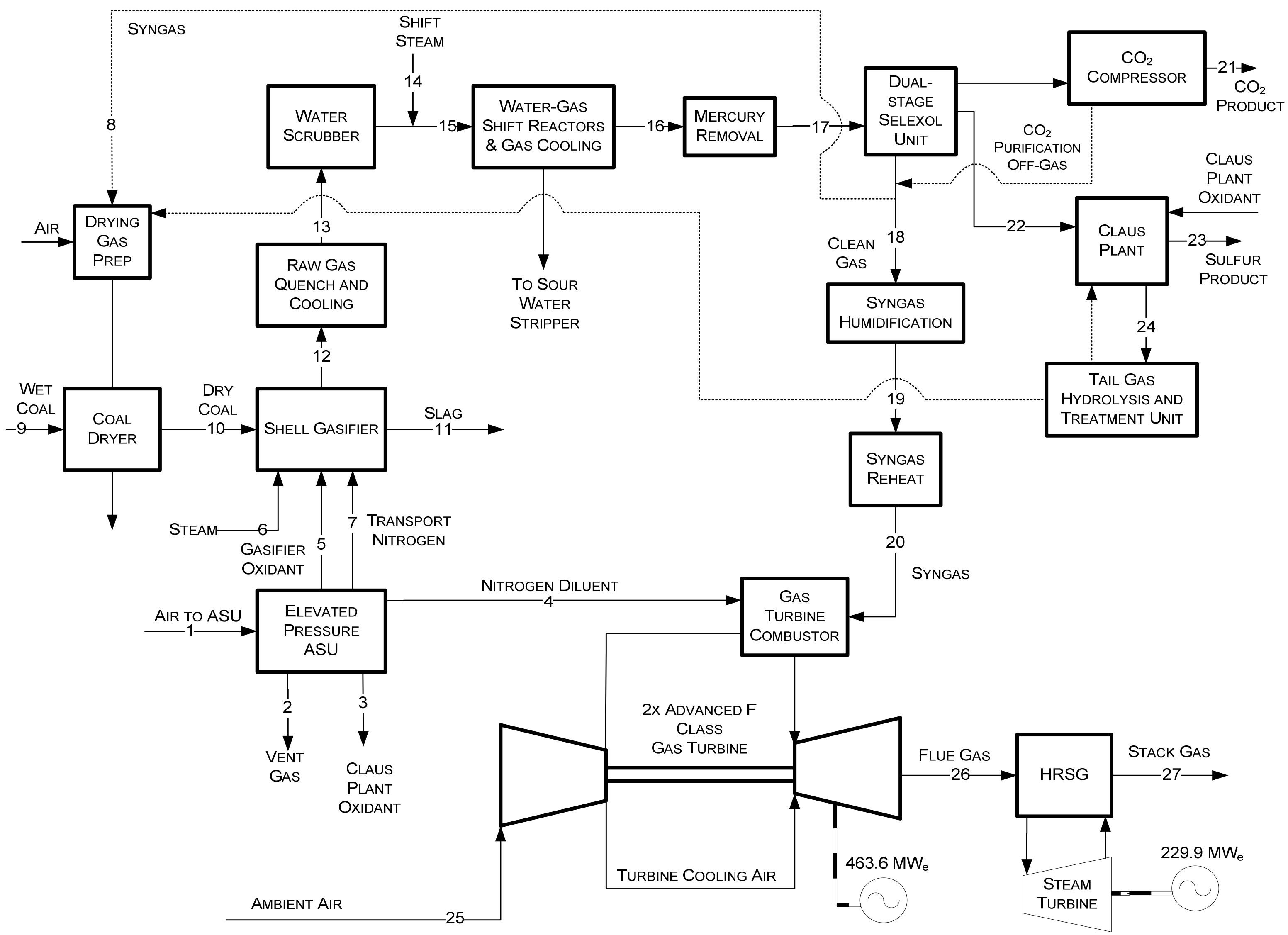

Exhibit 3-99 Case 6 Stream Table, Shell IGCC with CO_2 Capture

	1	2	3	4	5	6	7	8	9[A]	10[A]	11	12	13	14
V-L Mole Fraction														
Ar	0.0094	0.0263	0.0360	0.0024	0.0360	0.0000	0.0000	0.0102	0.0000	0.0000	0.0000	0.0097	0.0052	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0000	0.0000	0.0000	0.0004	0.0002	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0265	0.0000	0.0000	0.0000	0.5716	0.3070	0.0000
CO_2	0.0003	0.0091	0.0000	0.0000	0.0000	0.0000	0.0000	0.0211	0.0000	0.0000	0.0000	0.0211	0.0113	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0004	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.8874	0.0000	0.0000	0.0000	0.2901	0.1558	0.0000
H_2O	0.0104	0.2820	0.0000	0.0004	0.0000	1.0000	0.0000	0.0001	1.0000	1.0000	0.0000	0.0364	0.4826	1.0000
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081	0.0043	0.0000
N_2	0.7722	0.4591	0.0140	0.9918	0.0140	0.0000	1.0000	0.0543	0.0000	0.0000	0.0000	0.0585	0.0314	0.0000
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0033	0.0018	0.0000
O_2	0.2077	0.2235	0.9500	0.0054	0.9500	0.0000	0.0000	0.0000	0.0000	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	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	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	56,388	2,025	230	40,650	11,358	2,534	2,110	491	2,923	1,218	0	42,059	78,325	11,679
V-L Flowrate (lb/hr)	1,627,030	53,746	7,428	1,140,640	366,070	45,657	59,121	2,651	52,617	21,935	0	865,967	1,519,300	210,400
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	420,559	420,559	47,374	0	0	0
Temperature (°F)	238	70	90	385	518	750	560	121	59	215	2,595	2,595	500	750
Pressure (psia)	190.0	16.4	125.0	460.0	740.0	740.0	815.0	469.6	14.7	14.7	614.7	604.7	564.7	825.0
Enthalpy (BTU/lb)[B]	56.9	26.8	11.4	88.0	107.7	1409.5	132.2	113.8	---	---	---	1012.8	665.9	1,368.5
Density (lb/ft^3)	0.732	0.104	0.688	1.424	2.272	1.027	2.086	0.407	---	---	---	0.378	1.064	1.145
Molecular Weight	28.854	26.545	32.229	28.060	32.229	18.015	28.013	5.399	---	---	---	20.589	19.397	18.015

A - Solids flowrate includes dry coal; V-L flowrate includes water from coal
B - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-99 Case 6 Stream Table (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27
V-L Mole Fraction													
Ar	0.0046	0.0064	0.0064	0.0102	0.0099	0.0099	0.0000	0.0000	0.0000	0.0074	0.0094	0.0091	0.0091
CH_4	0.0002	0.0002	0.0002	0.0004	0.0004	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.2697	0.0166	0.0166	0.0265	0.0256	0.0256	0.0000	0.0000	0.0000	0.0792	0.0000	0.0000	0.0000
CO_2	0.0100	0.3771	0.3771	0.0211	0.0204	0.0204	1.0000	0.3526	0.0000	0.2293	0.0003	0.0063	0.0063
COS	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0003	0.0000	0.0000	0.0000
H_2	0.1369	0.5547	0.5547	0.8874	0.8584	0.8584	0.0000	0.0000	0.0000	0.0417	0.0000	0.0000	0.0000
H_2O	0.5455	0.0014	0.0014	0.0001	0.0327	0.0327	0.0000	0.0502	0.0000	0.4003	0.0108	0.1258	0.1258
H_2S	0.0038	0.0050	0.0050	0.0000	0.0000	0.0000	0.0000	0.3122	0.0000	0.0013	0.0000	0.0000	0.0000
N_2	0.0276	0.0385	0.0385	0.0543	0.0526	0.0526	0.0000	0.2845	0.0000	0.2379	0.7719	0.7513	0.7513
NH_3	0.0016	0.0000	0.0000	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2076	0.1075	0.1075
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0026	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	89,158	63,376	63,376	39,127	40,448	40,448	22,707	1,017	0	1,603	244,799	308,019	308,019
V-L Flowrate (lb/hr)	1,714,460	1,249,470	1,249,470	211,226	235,031	235,031	999,309	35,657	0	42,962	7,062,330	8,438,000	8,438,000
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	11,825	0	0	0	0
Temperature (°F)	574	95	95	121	213	385	156	124	352	280	59	1,051	270
Pressure (psia)	544.7	482.6	472.6	469.6	453.9	448.9	2,214.7	60.0	23.6	23.6	14.7	15.2	15.2
Enthalpy (BTU/lb)[B]	767.7	25.6	25.6	113.8	327.0	535.7	-46.4	37.9	-100.6	362.5	13.8	364.1	150.8
Density (lb/ft^3)	0.944	1.598	1.565	0.407	0.365	0.288	30.929	0.343	329.618	0.080	0.076	0.026	0.053
Molecular Weight	19.229	19.715	19.715	5.399	5.811	5.811	44.010	35.063	256.528	26.798	28.849	27.394	27.394

B - Reference conditions are 32.02 F & 0.089 PSIA

The AGR process in Case 6 is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption. The process results in three product streams, the clean syngas (stream 18), a CO_2-rich stream and an acid gas feed to the Claus plant (stream 22). The acid gas contains 31 percent H_2S and 35 percent CO_2 with the balance primarily N_2. The CO_2-rich stream is discussed further in the CO_2 compression section.

CO_2 Compression and Dehydration

CO_2 from the AGR process is generated at three pressure levels. The LP stream is compressed from 0.15 MPa (22 psia) to 1.1 MPa (160 psia) and then combined with the MP stream. The HP stream is combined between compressor stages at 2.1 MPa (300 psia). The combined stream is compressed from 2.1 MPa (300 psia) to a supercritical condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 93 percent CO_2 with the balance primarily nitrogen. For modeling purposes it was assumed that the impurities were separated from the CO_2 and combined with the clean syngas stream from the Selexol process. The pure CO_2 (stream 21) is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.7.

Claus Unit

The Claus plant is the same as Case 5 with the following exceptions:

- 5,364 kg/h (11,825 lb/h) of sulfur (stream 23) are produced
- The waste heat boiler generates 14,099 kg/h (31,082 lb/h) of 4.7 MPa (679 psia) steam, which provides all of the Claus plant process needs and provides some additional steam to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is combined with a small amount of clean gas from the CO_2 compression process (stream 18) and partially humidified because the nitrogen available from the ASU is insufficient to provide adequate dilution. The moisturized syngas is reheated to 196°C (385°F) using HP boiler feedwater, diluted with nitrogen (stream 4), and then enters the CT burner. The exhaust gas (stream 26) exits the CT at 566°C (1051°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) (stream 27) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced commercially available steam turbine using a 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle. There is no integration between the CT and the ASU in this case.

Air Separation Unit

The same elevated pressure ASU is used as in Case 5 and produces 4,070 tonnes/day (4,480 TPD) of 95 mole percent oxygen and 12,420 tonnes/day (13,690 TPD) of nitrogen. There is no integration between the ASU and the combustion turbine.

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.4.9 CASE 6 PERFORMANCE RESULTS

The Case 6 modeling assumptions were presented previously in Section 3.4.3.

The plant produces a net output of 517 MWe at a net plant efficiency of 32.0 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-100 which includes auxiliary power requirements. The ASU accounts for approximately 64 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 25 percent of the auxiliary power load. The BFW and circulating water system (circulating water pumps and cooling tower fan) comprise about 5 percent of the load, leaving 6 percent of the auxiliary load for all other systems.

Exhibit 3-100 Case 6 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	463,630
Steam Turbine Power	229,925
TOTAL POWER, kWe	**693,555**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,210
Slag Handling	570
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	62,970
Oxygen Compressor	10,540
Nitrogen Compressor	38,670
Syngas Recycle Compressor	0
Incinerator Air Blower	160
CO_2 Compressor	28,050
Boiler Feedwater Pumps	3,290
Condensate Pump	310
Flash Bottoms Pump	200
Circulating Water Pumps	3,440
Cooling Tower Fans	1,780
Scrubber Pumps	390
Double Stage Selexol Unit Auxiliaries	15,500
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Miscellaneous Balance of Plant (Note 1)	3,000
Transformer Loss	2,550
TOTAL AUXILIARIES, kWe	**176,420**
NET POWER, kWe	**517,135**
Net Plant Efficiency, % (HHV)	32.0
Net Plant Heat Rate (Btu/kWh)	10,674
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	**1,465 (1,390)**
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	214,629 (473,176)
Thermal Input, kWt	1,617,772
Raw Water Usage, m^3/min (gpm)	17.3 (4,563)

Note 1: Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NO_X, SO_2, CO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 6 is presented in Exhibit 3-101.

Exhibit 3-101 Case 6 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.0045 (0.0105)	185 (204)	0.038 (0.084)
NO_X	0.021 (0.049)	856 (944)	0.176 (0.388)
Particulates	0.003 (0.0071)	125 (137)	0.026 (0.057)
Hg	$0.25x10^{-6}$ ($0.57x10^{-6}$)	0.010 (0.011)	$2.1x10^{-6}$ ($4.5x10^{-6}$)
CO_2	8.0 (18.7)	328,000 (361,000)	67.4 (149)
CO_2[1]			90.4 (199)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The CO_2 capture target results in the sulfur compounds being removed to a greater extent than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 22 ppmv. This results in a concentration in the flue gas of about 3 ppmv. 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 inlet. The clean gas from the tail gas treatment unit is sent to the coal dryer prior to being vented to atmosphere.

NO_X emissions are limited by the use of nitrogen dilution and humidification to 15 ppmvd (as NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and subsequently destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of mercury is captured from the syngas by an activated carbon bed. Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration. Because not all of the CO is converted to CO_2 in the shift reactors, the overall CO_2 removal is 90.2 percent.

The carbon balance for the plant is shown in Exhibit 3-102. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not used in the carbon capture equation below, but it is not neglected in the balance since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and CO_2 in the stack gas, coal dryer vent gas, ASU vent gas and the captured CO_2 product. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
272,478/(301,649-1,511) *100 or
90.8 percent

Exhibit 3-102 Case 6 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	136,826 (301,649)	**Slag**	685 (1,511)
Air (CO_2)	500 (1,102)	**Stack Gas**	10,610 (23,390)
		CO_2 Product	123,595 (272,478)
		ASU Vent	101 (222)
		Coal Dryer	2,137 (4,712)
		Wastewater	198 (438)
Total	137,326 (302,751)	**Total**	137,326 (302,751)

Exhibit 3-103 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, dissolved SO_2 in the wastewater blowdown stream, sulfur emitted in the stack gas and sulfur from the tail gas unit that is vented through the coal dryer. Sulfur in the slag is considered negligible, and the sulfur content of the blowdown stream is calculated by difference to close the material balance. The total sulfur capture is represented by the following fraction:

(Sulfur byproduct/Sulfur in the coal) or
(11,825/11,877) or
99.6 percent

Exhibit 3-103 Case 6 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,387 (11,877)	**Elemental Sulfur**	5,364 (11,825)
		Stack Gas	12 (27)
		Dryer Gas	1 (2)
		Wastewater	10 (23)
Total	5,387 (11,877)	**Total**	5,387 (11,877)

Exhibit 3-104 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and that water is re-used as internal recycle. Raw water makeup is the difference between water demand and internal recycle.

Exhibit 3-104 Case 6 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
Gasifier Steam	0.3 (91)	0	0.3 (91)
Shift Steam	1.6 (420)	0	1.6 (420)
Humidifier	0.3 (67)	0.3 (67)	0
Slag Handling	0.4 (123)	0.4 (123)	0
Quench/Scrubber	4.9 (1,306)	2.6 (693)	2.3 (612)
BFW Makeup	0.2 (45)	0	0.2 (45)
Cooling Tower Makeup	13.4 (3,528)	0.5 (133)	12.9 (3,395)
Total	**21.1 (5,581)**	**3.8 (1,017)**	**17.3 (4,564)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-105 through Exhibit 3-109:

- Coal gasification and air separation unit
- Syngas cleanup
- Sulfur recovery and tail gas recycle
- Combined cycle power generation
- Steam and feedwater

An overall plant energy balance is provided in tabular form in Exhibit 3-110. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-100) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 3-105 Case 6 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

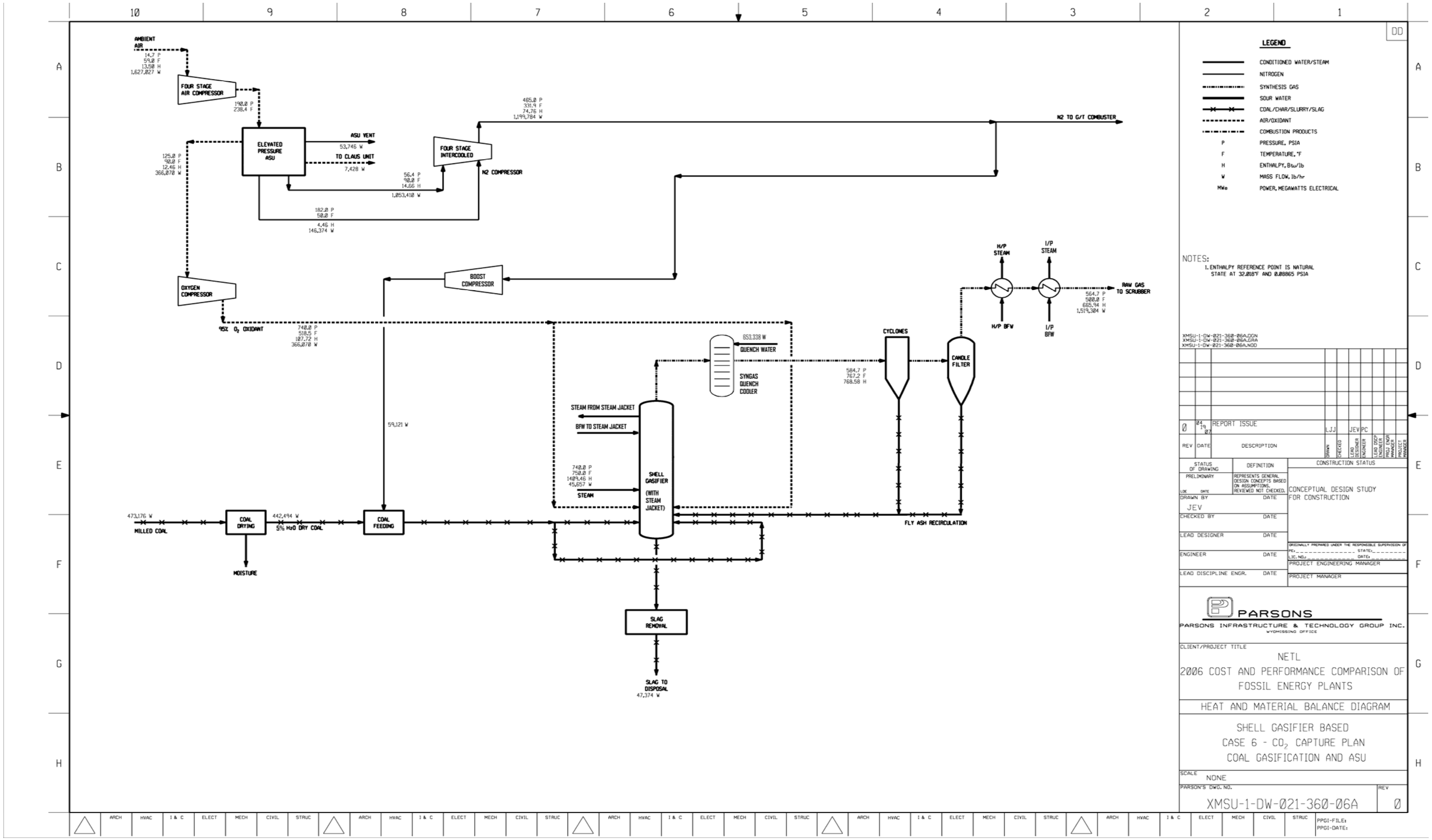

Exhibit 3-106 Case 6 Syngas Cleanup Heat and Mass Balance Schematic

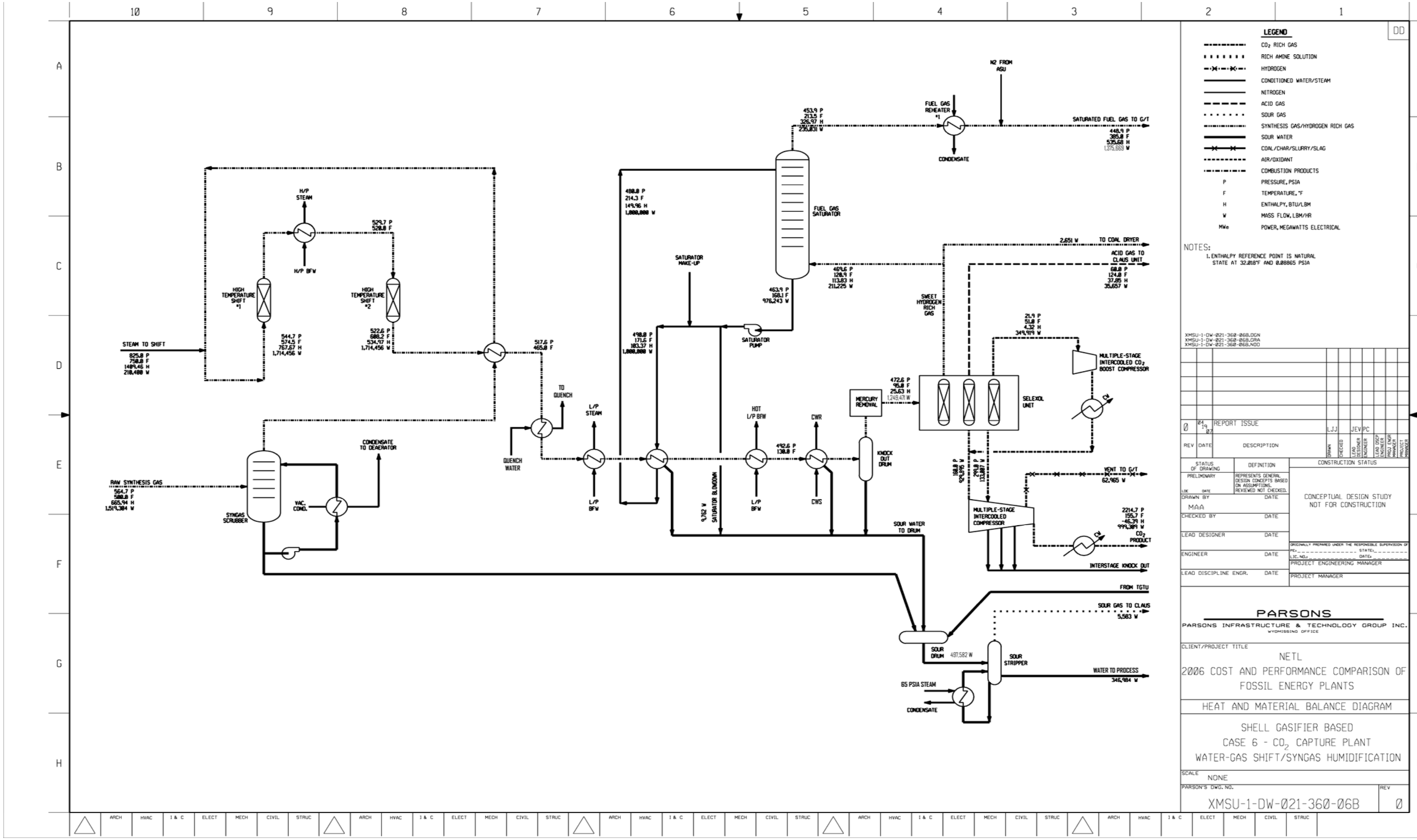

Exhibit 3-107 Case 6 Sulfur Recovery and Tail Gas Recycle Heat and Mass Balance Schematic

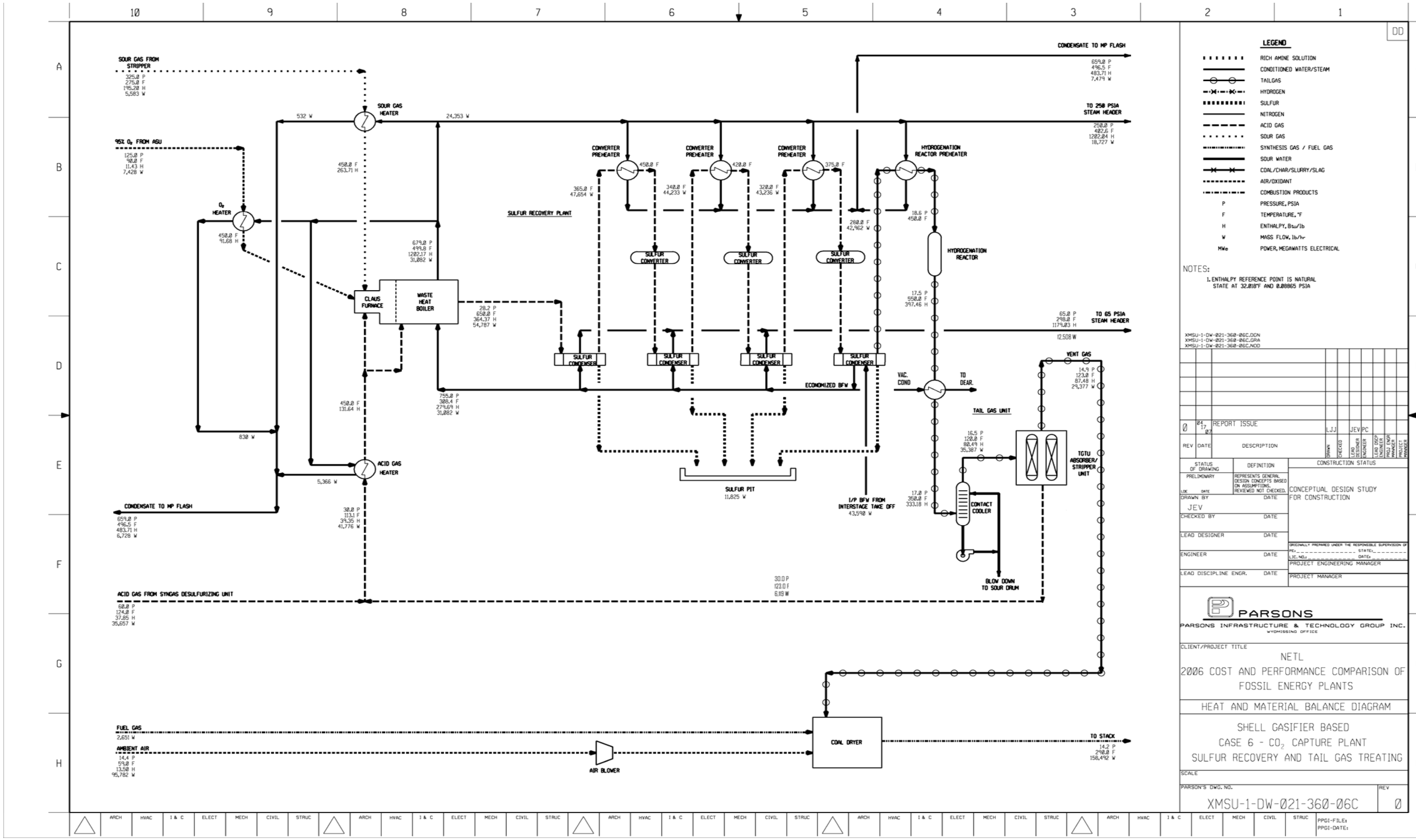

Exhibit 3-108 Case 6 Combined Cycle Power Generation Heat and Mass Balance Schematic

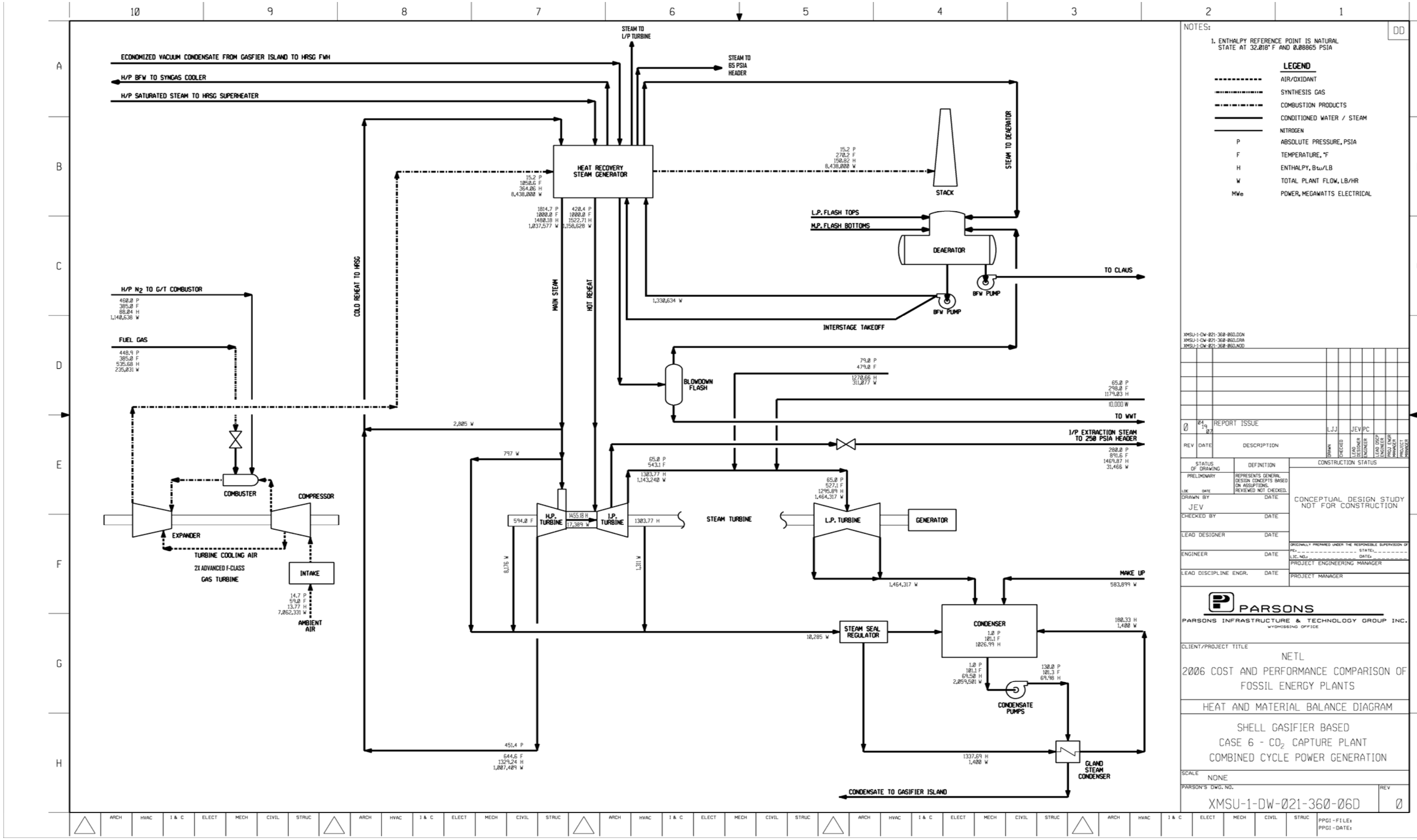

Exhibit 3-109 Case 6 Steam and Feedwater Heat and Mass Balance Schematic

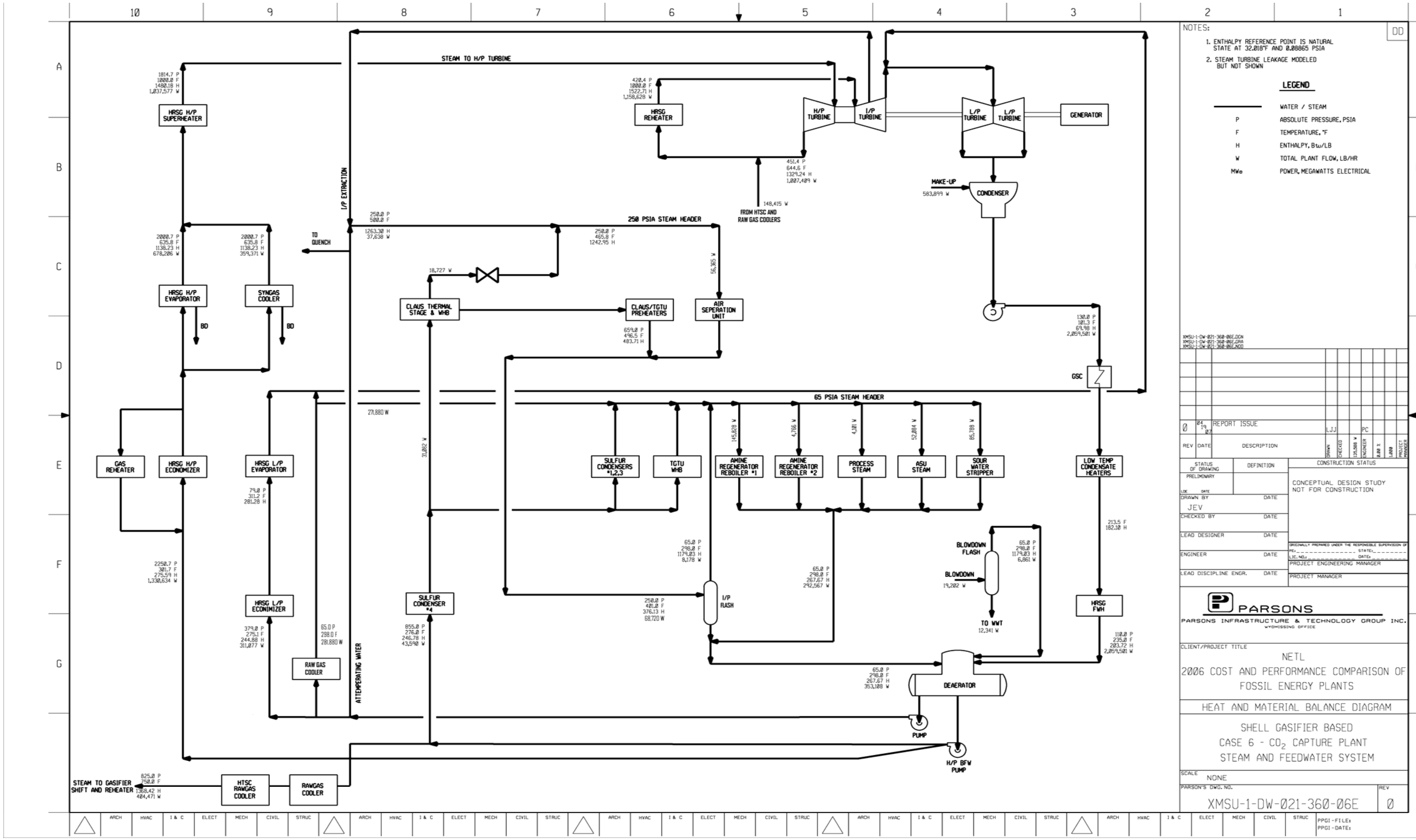

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Exhibit 3-110 Case 6 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,520.2	4.6		5,524.8
ASU Air		22.0		22.0
CT Air		97.2		97.2
Incinerator Air		1.3		1.3
Water		23.2		23.2
Auxiliary Power			602.0	602.0
Totals	**5,520.2**	**148.4**	**602.0**	**6,270.5**
Heat Out (MMBtu/hr)				
ASU Intercoolers		222.8		222.8
ASU Vent		1.4		1.4
Slag	21.3	33.9		55.2
Sulfur	47.1	(1.2)		45.9
Dryer Stack Gas		59.5		59.5
CO_2 Compressor Intercoolers		115.4		115.4
CO_2 Product		(46.4)		(46.4)
HRSG Flue Gas		1,273.3		1,273.3
Condenser		1,390.0		1,390.0
Process Losses		748.8		748.8
Power			2,404.6	2,404.6
Totals	**68.4**	**3,797.5**	**2,404.6**	**6,270.5**

(1) Process Losses are calculated by difference and reflect various gasification, turbine, HRSG and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

3.4.10 CASE 6 - MAJOR EQUIPMENT LIST

Major equipment items for the Shell gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.4.11. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/h (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	354 tonne/h (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	354 tonne/h (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	354 tonne/h (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/h (260 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	472 tonne (520 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Coal Drying and Pulverization	Rotary	118 tonne/h (130 tph)	2	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	927,433 liters (245,000 gal)	3	0
2	Condensate Pumps	Vertical canned	8,631 lpm @ 91 m H2O (2,280 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	603,732 kg/h (1,331,000 lb/h)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	3,975 lpm @ 283 m H2O (1,050 gpm @ 930 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 4,580 lpm @ 1,890 m H2O (1,210 gpm @ 6,200 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,173 lpm @ 223 m H2O (310 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	58 MMkJ/h (55 MMBtu/h) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 21 m H2O (5,500 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	9,577 lpm @ 18 m H2O (2,530 gpm @ 60 ft H2O)	2	1
15	Filtered Water Pumps	Stainless steel, single suction	4,353 lpm @ 49 m H2O (1,150 gpm @ 160 ft H2O)	2	1
16	Filtered Water Tank	Vertical, cylindrical	1,048,567 liter (277,000 gal)	2	0
17	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,060 lpm (280 gpm)	2	0
18	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY AND FUEL GAS SATURATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,812 tonne/day, 4.2 MPa (3,100 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	379,204 kg/h (836,000 lb/h)	2	0
3	Synthesis Gas Cyclone	High efficiency	375,121 kg/h (827,000 lb/h) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	375,121 kg/h (827,000 lb/h)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	713,048 kg/h (1,572,000 lb/h)	6	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	312,072 kg/h, 35°C, 3.4 MPa (688,000 lb/h, 95°F, 488 psia)	2	0
8	Saturation Water Economizers	Shell and tube	427,738 kg/h (943,000 lb/h)	2	0
9	Fuel Gas Saturator	Vertical tray tower	58,513 kg/h, 101°C, 3.2 MPa (129,000 lb/h, 213°F, 470 psia)	2	0
10	Saturator Water Pump	Centrifugal	4,164 lpm @ 21 m H2O (1,100 gpm @ 70 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	58,513 kg/h (129,000 lb/h)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	375,121 kg/h (827,000 lb/h) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	5,550 m3/min @ 1.3 MPa (196,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,268 tonne/day (2,500 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,133 m3/min @ 5.1 MPa (40,000 scfm @ 740 psia)	2	0
16	Nitrogen Compressor	Centrifugal, multi-stage	3,710 m3/min @ 3.4 MPa (131,000 scfm @ 490 psia)	2	0
17	Nitrogen Boost Compressor	Centrifugal, multi-stage	510 m3/min @ 2.3 MPa (18,000 scfm @ 340 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	311,618 kg/h (687,000 lb/h) 35°C (95°F) 3.3 MPa (483 psia)	2	0
2	Sulfur Plant	Claus type	142 tonne/day (156 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	427,738 kg/h (943,000 lb/h) 302°C (575°F) 3.8 MPa (545 psia)	4	0
4	Shift Reactor Heat Recovery Exhchangers	Shell and Tube	Exchanger 1: 211 MMkJ/h (200 MMBtu/h) Exchanger 2: 63 MMkJ/h (60 MMBtu/h)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	311,618 kg/h (687,000 lb/h) 51°C (124°F) 3.3 MPa (473 psia)	2	0
6	Tail Gas Treatment Unit	Proprietary amine, absorber/stripper	17,645 kg/h (38,900 lb/h) 49°C (120°F) 0.1 MPa (16.4 psia)	1	0
7	Tail Gas Treatment Incinerator	N/A	67 MMkJ/h (64 MMBtu/h)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compression	Integrally geared, multi-stage centrifugal	1,119 m3/min @ 15.3 MPa (39,500 scfm @ 2,215 psia)	4	1

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 258,851 kg/h, 12.4 MPa/538°C (570,667 lb/h, 1,800 psig/1,000°F) Reheat steam - 289,050 kg/h, 2.9 MPa/538°C (637,245 lb/h, 420 psig/1,000°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	242 MW 12.4 MPa/538°C/538°C (1800 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	270 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,613 MMkJ/h (1,530 MMBtu/h), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	344,475 lpm @ 30 m (91,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 1,919 MMkJ/h (1,820 MMBtu/h) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	227,126 liters (60,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/h (13 tph)	2	0
3	Slag Depressurizer	Lock Hopper	12 tonne/h (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	147,632 liters (39,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,138 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/h (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/h (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/h (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	219,556 liters (58,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	71,923 liters (19,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	265 lpm @ 433 m H2O (70 gpm @ 1,420 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/h (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 70 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 193 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 29 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.4.11 CASE 6 - COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-111 shows the total plant capital cost summary organized by cost account and Exhibit 3-112 shows a more detailed breakdown of the capital costs. Exhibit 3-113 shows the initial and annual O&M costs.

The estimated TPC of the Shell gasifier with CO_2 capture is $2,668/kW. The gasifier in Case 6 is slightly larger than Case 5, but the syngas cooler is much smaller in Case 6 (because of the quench configuration), which results in a lower overall cost for the Gasifier Account in Case 6. Process contingency represents 3.8 percent of the TPC and project contingency represents 14.0 percent. The 20-year LCOE, including CO_2 TS&M costs of 4.1 mills/kWh, is 110.4 mills/kWh.

Exhibit 3-111 Case 6 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 06 - Shell IGCC w/ CO2
Plant Size: 517.1 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,222	$2,465	$10,360	$0	$0	**$26,046**	$2,360	$0	$5,681	**$34,087**	$66
2	COAL & SORBENT PREP & FEED	$104,780	$8,348	$17,611	$0	$0	**$130,739**	$11,350	$0	$28,418	**$170,507**	$330
3	FEEDWATER & MISC. BOP SYSTEMS	$8,804	$7,082	$8,709	$0	$0	**$24,596**	$2,304	$0	$6,179	**$33,079**	$64
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$102,271	$0	$44,114	$0	$0	**$146,384**	$13,107	$20,012	$27,635	**$207,139**	$401
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$144,337	$0	w/equip.	$0	$0	**$144,337**	$13,738	$0	$15,808	**$173,883**	$336
4.4-4.9	Other Gasification Equipment	$25,903	$9,641	$15,020	$0	$0	**$50,564**	$4,796	$0	$11,764	**$67,123**	$130
	SUBTOTAL 4	**$272,511**	**$9,641**	**$59,134**	**$0**	**$0**	**$341,285**	**$31,641**	**$20,012**	**$55,207**	**$448,145**	**$867**
5A	Gas Cleanup & Piping	$80,918	$4,433	$69,321	$0	$0	**$154,672**	$14,826	$22,300	$38,565	**$230,362**	$445
5B	CO_2 REMOVAL & COMPRESSION	$17,265	$0	$10,209	$0	$0	**$27,475**	$2,626	$0	$6,020	**$36,121**	$70
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	**$93,325**	$8,779	$9,332	$11,144	**$122,580**	$237
6.2-6.9	Combustion Turbine Other	$0	$684	$762	$0	$0	**$1,446**	$135	$0	$474	**$2,055**	$4
	SUBTOTAL 6	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$8,914**	**$9,332**	**$11,618**	**$124,635**	**$241**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,181	$0	$4,579	$0	$0	**$36,760**	$3,470	$0	$4,023	**$44,253**	$86
7.2-7.9	Ductwork and Stack	$3,222	$2,268	$3,041	$0	$0	**$8,531**	$788	$0	$1,516	**$10,835**	$21
	SUBTOTAL 7	**$35,402**	**$2,268**	**$7,620**	**$0**	**$0**	**$45,291**	**$4,258**	**$0**	**$5,539**	**$55,087**	**$107**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$24,587	$0	$4,106	$0	$0	**$28,693**	$2,750	$0	$3,144	**$34,587**	$67
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$8,905	$828	$6,089	$0	$0	**$15,822**	$1,435	$0	$3,347	**$20,604**	$40
	SUBTOTAL 8	**$33,492**	**$828**	**$10,195**	**$0**	**$0**	**$44,515**	**$4,184**	**$0**	**$6,491**	**$55,191**	**$107**
9	COOLING WATER SYSTEM	$6,933	$7,764	$6,432	$0	$0	**$21,129**	$1,940	$0	$4,752	**$27,821**	$54
10	ASH/SPENT SORBENT HANDLING SYS	$17,865	$1,375	$8,869	$0	$0	**$28,109**	$2,676	$0	$3,363	**$34,149**	$66
11	ACCESSORY ELECTRIC PLANT	$22,955	$8,041	$22,625	$0	$0	**$53,621**	$4,967	$0	$11,178	**$69,766**	$135
12	INSTRUMENTATION & CONTROL	$10,193	$1,908	$6,843	$0	$0	**$18,945**	$1,746	$947	$3,620	**$25,258**	$49
13	IMPROVEMENTS TO SITE	$3,207	$1,890	$7,973	$0	$0	**$13,070**	$1,284	$0	$4,306	**$18,660**	$36
14	BUILDINGS & STRUCTURES	$0	$6,095	$7,021	$0	$0	**$13,117**	$1,192	$0	$2,349	**$16,657**	$32
	TOTAL COST	**$715,547**	**$62,824**	**$259,009**	**$0**	**$0**	**$1,037,381**	**$96,266**	**$52,591**	**$193,286**	**$1,379,524**	**$2,668**

Exhibit 3-112 Case 6 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 06 - Shell IGCC w/ CO2
Plant Size: 517.1 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,472	$0	$1,714	$0	$0	$5,186	$464	$0	$1,130	$6,781	$13
1.2	Coal Stackout & Reclaim	$4,487	$0	$1,099	$0	$0	$5,586	$490	$0	$1,215	$7,291	$14
1.3	Coal Conveyors	$4,171	$0	$1,087	$0	$0	$5,259	$462	$0	$1,144	$6,865	$13
1.4	Other Coal Handling	$1,091	$0	$252	$0	$0	$1,343	$118	$0	$292	$1,753	$3
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,465	$6,207	$0	$0	$8,672	$826	$0	$1,900	$11,399	$22
	SUBTOTAL 1.	**$13,222**	**$2,465**	**$10,360**	**$0**	**$0**	**$26,046**	**$2,360**	**$0**	**$5,681**	**$34,087**	**$66**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$39,807	$2,378	$5,861	$0	$0	$48,046	$4,152	$0	$10,440	$62,638	$121
2.2	Prepared Coal Storage & Feed	$1,885	$449	$299	$0	$0	$2,633	$226	$0	$572	$3,430	$7
2.3	Dry Coal Injection System	$62,051	$727	$5,823	$0	$0	$68,601	$5,917	$0	$14,904	$89,421	$173
2.4	Misc.Coal Prep & Feed	$1,037	$750	$2,286	$0	$0	$4,073	$373	$0	$889	$5,336	$10
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$4,043	$3,343	$0	$0	$7,386	$681	$0	$1,614	$9,681	$19
	SUBTOTAL 2.	**$104,780**	**$8,348**	**$17,611**	**$0**	**$0**	**$130,739**	**$11,350**	**$0**	**$28,418**	**$170,507**	**$330**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,575	$4,477	$2,365	$0	$0	$9,417	$869	$0	$2,057	$12,344	$24
3.2	Water Makeup & Pretreating	$575	$60	$321	$0	$0	$955	$90	$0	$314	$1,359	$3
3.3	Other Feedwater Subsystems	$1,422	$482	$434	$0	$0	$2,338	$209	$0	$509	$3,057	$6
3.4	Service Water Systems	$331	$676	$2,347	$0	$0	$3,354	$324	$0	$1,104	$4,782	$9
3.5	Other Boiler Plant Systems	$1,779	$682	$1,693	$0	$0	$4,154	$389	$0	$909	$5,452	$11
3.6	FO Supply Sys & Nat Gas	$300	$567	$529	$0	$0	$1,397	$134	$0	$306	$1,837	$4
3.7	Waste Treatment Equipment	$798	$0	$489	$0	$0	$1,288	$125	$0	$424	$1,836	$4
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,024	$138	$530	$0	$0	$1,692	$163	$0	$557	$2,412	$5
	SUBTOTAL 3.	**$8,804**	**$7,082**	**$8,709**	**$0**	**$0**	**$24,596**	**$2,304**	**$0**	**$6,179**	**$33,079**	**$64**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$102,271	$0	$44,114	$0	$0	$146,384	$13,107	$20,012	$27,635	$207,139	$401
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$144,337	$0	w/equip.	$0	$0	$144,337	$13,738	$0	$15,808	$173,883	$336
4.4	LT Heat Recovery & FG Saturation	$25,903	$0	$9,746	$0	$0	$35,649	$3,426	$0	$7,815	$46,890	$91
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,589	$647	$0	$0	$2,236	$213	$0	$490	$2,938	$6
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$8,052	$4,627	$0	$0	$12,679	$1,157	$0	$3,459	$17,295	$33
	SUBTOTAL 4.	**$272,511**	**$9,641**	**$59,134**	**$0**	**$0**	**$341,285**	**$31,641**	**$20,012**	**$55,207**	**$448,145**	**$867**

Exhibit 3-112 Case 6 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 06 - Shell IGCC w/ CO2
Plant Size: 517.1 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$59,698	$0	$51,207	$0	$0	$110,905	$10,647	$22,181	$28,747	$172,480	$334
5A.2	Elemental Sulfur Plant	$9,156	$1,817	$11,821	$0	$0	$22,794	$2,198	$0	$4,999	$29,991	$58
5A.3	Mercury Removal	$1,346	$0	$1,025	$0	$0	$2,371	$227	$119	$543	$3,260	$6
5A.4	Shift Reactors	$8,816	$0	$3,551	$0	$0	$12,367	$1,177	$0	$2,709	$16,253	$31
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,903	$320	$180	$0	$0	$2,403	$226	$0	$526	$3,155	$6
5A.6	Fuel Gas Piping	$0	$1,154	$795	$0	$0	$1,949	$178	$0	$425	$2,552	$5
5A.9	HGCU Foundations	$0	$1,142	$741	$0	$0	$1,883	$172	$0	$617	$2,672	$5
	SUBTOTAL 5A.	**$80,918**	**$4,433**	**$69,321**	**$0**	**$0**	**$154,672**	**$14,826**	**$22,300**	**$38,565**	**$230,362**	**$445**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$17,265	$0	$10,209	$0	$0	$27,475	$2,626	$0	$6,020	$36,121	$70
	SUBTOTAL 5B.	**$17,265**	**$0**	**$10,209**	**$0**	**$0**	**$27,475**	**$2,626**	**$0**	**$6,020**	**$36,121**	**$70**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	$93,325	$8,779	$9,332	$11,144	$122,580	$237
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$135	$0	$474	$2,055	$4
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$8,914**	**$9,332**	**$11,618**	**$124,635**	**$241**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,181	$0	$4,579	$0	$0	$36,760	$3,470	$0	$4,023	$44,253	$86
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,627	$1,209	$0	$0	$2,836	$249	$0	$617	$3,702	$7
7.4	Stack	$3,222	$0	$1,211	$0	$0	$4,433	$422	$0	$485	$5,340	$10
7.9	HRSG,Duct & Stack Foundations	$0	$641	$620	$0	$0	$1,262	$117	$0	$414	$1,792	$3
	SUBTOTAL 7.	**$35,402**	**$2,268**	**$7,620**	**$0**	**$0**	**$45,291**	**$4,258**	**$0**	**$5,539**	**$55,087**	**$107**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$24,587	$0	$4,106	$0	$0	$28,693	$2,750	$0	$3,144	$34,587	$67
8.2	Turbine Plant Auxiliaries	$168	$0	$385	$0	$0	$554	$54	$0	$61	$668	$1
8.3	Condenser & Auxiliaries	$4,661	$0	$1,421	$0	$0	$6,082	$577	$0	$666	$7,325	$14
8.4	Steam Piping	$4,076	$0	$2,873	$0	$0	$6,949	$593	$0	$1,886	$9,428	$18
8.9	TG Foundations	$0	$828	$1,410	$0	$0	$2,238	$211	$0	$735	$3,184	$6
	SUBTOTAL 8.	**$33,492**	**$828**	**$10,195**	**$0**	**$0**	**$44,515**	**$4,184**	**$0**	**$6,491**	**$55,191**	**$107**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,467	$0	$981	$0	$0	$5,448	$516	$0	$895	$6,858	$13
9.2	Circulating Water Pumps	$1,405	$0	$88	$0	$0	$1,494	$128	$0	$243	$1,864	$4
9.3	Circ.Water System Auxiliaries	$124	$0	$18	$0	$0	$141	$13	$0	$23	$178	$0
9.4	Circ.Water Piping	$0	$5,260	$1,342	$0	$0	$6,602	$584	$0	$1,437	$8,624	$17
9.5	Make-up Water System	$322	$0	$456	$0	$0	$777	$74	$0	$170	$1,021	$2
9.6	Component Cooling Water Sys	$615	$736	$520	$0	$0	$1,871	$173	$0	$409	$2,453	$5
9.9	Circ.Water System Foundations& Structures	$0	$1,768	$3,027	$0	$0	$4,795	$452	$0	$1,574	$6,822	$13
	SUBTOTAL 9.	**$6,933**	**$7,764**	**$6,432**	**$0**	**$0**	**$21,129**	**$1,940**	**$0**	**$4,752**	**$27,821**	**$54**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,549	$0	$7,674	$0	$0	$23,223	$2,215	$0	$2,544	$27,981	$54
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$524	$0	$570	$0	$0	$1,094	$105	$0	$180	$1,379	$3
10.7	Ash Transport & Feed Equipment	$707	$0	$170	$0	$0	$877	$81	$0	$144	$1,101	$2
10.8	Misc. Ash Handling Equipment	$1,085	$1,329	$397	$0	$0	$2,811	$266	$0	$462	$3,539	$7
10.9	Ash/Spent Sorbent Foundation	$0	$46	$58	$0	$0	$104	$10	$0	$34	$148	$0
	SUBTOTAL 10.	**$17,865**	**$1,375**	**$8,869**	**$0**	**$0**	**$28,109**	**$2,676**	**$0**	**$3,363**	**$34,149**	**$66**

Exhibit 3-112 Case 6 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 05-Apr-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 06 - Shell IGCC w/ CO2
Plant Size: 517.1 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$866	$0	$863	$0	$0	$1,729	$164	$0	$189	$2,083	$4
11.2	Station Service Equipment	$4,130	$0	$388	$0	$0	$4,518	$429	$0	$495	$5,442	$11
11.3	Switchgear & Motor Control	$7,893	$0	$1,447	$0	$0	$9,340	$865	$0	$1,531	$11,735	$23
11.4	Conduit & Cable Tray	$0	$376	$12,191	$0	$0	$12,567	$1,524	$0	$3,523	$17,614	$34
11.5	Wire & Cable	$0	$6,897	$4,639	$0	$0	$11,536	$843	$0	$3,095	$15,474	$30
11.6	Protective Equipment	$0	$627	$2,378	$0	$0	$3,005	$294	$0	$495	$3,793	$7
11.7	Standby Equipment	$208	$0	$211	$0	$0	$419	$40	$0	$69	$529	$1
11.8	Main Power Transformers	$9,858	$0	$132	$0	$0	$9,990	$757	$0	$1,612	$12,358	$24
11.9	Electrical Foundations	$0	$142	$376	$0	$0	$518	$49	$0	$170	$737	$1
	SUBTOTAL 11.	**$22,955**	**$8,041**	**$22,625**	**$0**	**$0**	**$53,621**	**$4,967**	**$0**	**$11,178**	**$69,766**	**$135**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,006	$0	$700	$0	$0	$1,706	$164	$85	$293	$2,249	$4
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$231	$0	$154	$0	$0	$386	$37	$19	$88	$531	$1
12.7	Computer & Accessories	$5,368	$0	$179	$0	$0	$5,547	$526	$277	$635	$6,985	$14
12.8	Instrument Wiring & Tubing	$0	$1,908	$3,994	$0	$0	$5,902	$500	$295	$1,674	$8,372	$16
12.9	Other I & C Equipment	$3,588	$0	$1,815	$0	$0	$5,403	$518	$270	$929	$7,121	$14
	SUBTOTAL 12.	**$10,193**	**$1,908**	**$6,843**	**$0**	**$0**	**$18,945**	**$1,746**	**$947**	**$3,620**	**$25,258**	**$49**
13	Improvements to Site											
13.1	Site Preparation	$0	$101	$2,167	$0	$0	$2,267	$223	$0	$747	$3,238	$6
13.2	Site Improvements	$0	$1,790	$2,396	$0	$0	$4,186	$411	$0	$1,379	$5,976	$12
13.3	Site Facilities	$3,207	$0	$3,410	$0	$0	$6,617	$650	$0	$2,180	$9,446	$18
	SUBTOTAL 13.	**$3,207**	**$1,890**	**$7,973**	**$0**	**$0**	**$13,070**	**$1,284**	**$0**	**$4,306**	**$18,660**	**$36**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,059	$2,972	$0	$0	$5,031	$462	$0	$824	$6,316	$12
14.3	Administration Building	$0	$814	$598	$0	$0	$1,412	$126	$0	$231	$1,768	$3
14.4	Circulation Water Pumphouse	$0	$153	$82	$0	$0	$235	$21	$0	$38	$294	$1
14.5	Water Treatment Buildings	$0	$457	$452	$0	$0	$909	$82	$0	$149	$1,140	$2
14.6	Machine Shop	$0	$416	$289	$0	$0	$705	$63	$0	$115	$883	$2
14.7	Warehouse	$0	$672	$440	$0	$0	$1,112	$98	$0	$182	$1,392	$3
14.8	Other Buildings & Structures	$0	$403	$318	$0	$0	$721	$64	$0	$157	$942	$2
14.9	Waste Treating Building & Str.	$0	$900	$1,744	$0	$0	$2,644	$246	$0	$578	$3,467	$7
	SUBTOTAL 14.	**$0**	**$6,095**	**$7,021**	**$0**	**$0**	**$13,117**	**$1,192**	**$0**	**$2,349**	**$16,657**	**$32**
	TOTAL COST	**$715,547**	**$62,824**	**$259,009**	**$0**	**$0**	**$1,037,381**	**$96,266**	**$52,591**	**$193,286**	**$1,379,524**	**$2,668**

Exhibit 3-113 Case 6 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						
Case 06 - Shell IGCC w/ CO2					Cost Base (Dec)	2006
					Heat Rate-net(Btu/kWh):	10,674
					MWe-net:	517
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	10.0		10.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	16.0		16.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$6,012,864	$11.627
Maintenance Labor Cost					$12,084,712	$23.369
Administrative & Support Labor					$4,524,394	$8.749
TOTAL FIXED OPERATING COSTS					**$22,621,970**	**$43.745**

VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost					**$22,581,355**	**$0.00623**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	6,551	1.03	**$0**	**$1,970,146**	**$0.00054**
Chemicals						
MU & WT Chem.(lb)	136,592	19,513	0.16	$22,510	$939,005	$0.00026
Carbon (Mercury Removal) (lb)	130,280	178	1.00	$130,280	$51,976	$0.00001
COS Catalyst (m3)	0	0	0.96	$0	$0	$0.00000
Water Gas Shift Catalyst(ft3)	6,922	4.74	475.00	$3,287,950	$657,438	$0.00018
Selexol Solution (gal.)	469	67	12.90	$6,051	$252,397	$0.00007
MDEA Solution (gal)	0	0	0.96	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	9.68	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	2.14	125.00	$0	$78,110	$0.00002
Subtotal Chemicals				**$3,446,791**	**$1,978,926**	**$0.00055**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	178	0.40	$0	$20,874	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	568	15.45	$0	$2,561,970	$0.00071
Subtotal-Waste Disposal				**$0**	**$2,582,844**	**$0.00071**
By-products & Emissions						
Sulfur(tons)	0	142	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$3,446,791**	**$29,113,271**	**$0.00803**
Fuel(ton)	170,338	5,678	42.11	**$7,172,945**	**$69,816,668**	**$0.01926**

3.5 IGCC CASE SUMMARY

The performance results of the six IGCC plant configurations modeled in this study are summarized in Exhibit 3-114.

Exhibit 3-114 Estimated Performance and Cost Results for IGCC Cases

	Integrated Gasification Combined Cycle					
	GEE		CoP		Shell	
	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CO_2 Capture	No	Yes	No	Yes	No	Yes
Gross Power Output (kW_e)	770,350	744,960	742,510	693,840	748,020	693,555
Auxiliary Power Requirement (kW_e)	130,100	189,285	119,140	175,600	112,170	176,420
Net Power Output (kW_e)	640,250	555,675	623,370	518,240	635,850	517,135
Coal Flowrate (lb/hr)	489,634	500,379	463,889	477,855	452,620	473,176
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kW_{th})	1,674,044	1,710,780	1,586,023	1,633,771	1,547,493	1,617,772
Net Plant HHV Efficiency (%)	38.2%	32.5%	39.3%	31.7%	41.1%	32.0%
Net Plant HHV Heat Rate (Btu/kW-hr)	8,922	10,505	8,681	10,757	8,304	10,674
Raw Water Usage, gpm	4,003	4,579	3,757	4,135	3,792	4,563
Total Plant Cost ($ x 1,000)	1,160,919	1,328,209	1,080,166	1,259,883	1,256,810	1,379,524
Total Plant Cost ($/kW)	1,813	2,390	1,733	2,431	1,977	2,668
LCOE (mills/kWh)[1]	78.0	102.9	75.3	105.7	80.5	110.4
CO_2 Emissions (lb/MWh)[2]	1,459	154	1,452	189	1,409	149
CO_2 Emissions (lb/MWh)[3]	1,755	206	1,730	253	1,658	199
SO_2 Emissions (lb/MWh)[2]	0.0942	0.0751	0.0909	0.0686	0.0878	0.0837
NOx Emissions (lb/MWh)[2]	0.406	0.366	0.433	0.400	0.413	0.388
PM Emissions (lb/MWh)[2]	0.053	0.056	0.052	0.057	0.050	0.057
Hg Emissions (lb/MWh)[2]	4.24E-06	4.48E-06	4.16E-06	4.59E-06	4.03E-06	4.55E-06

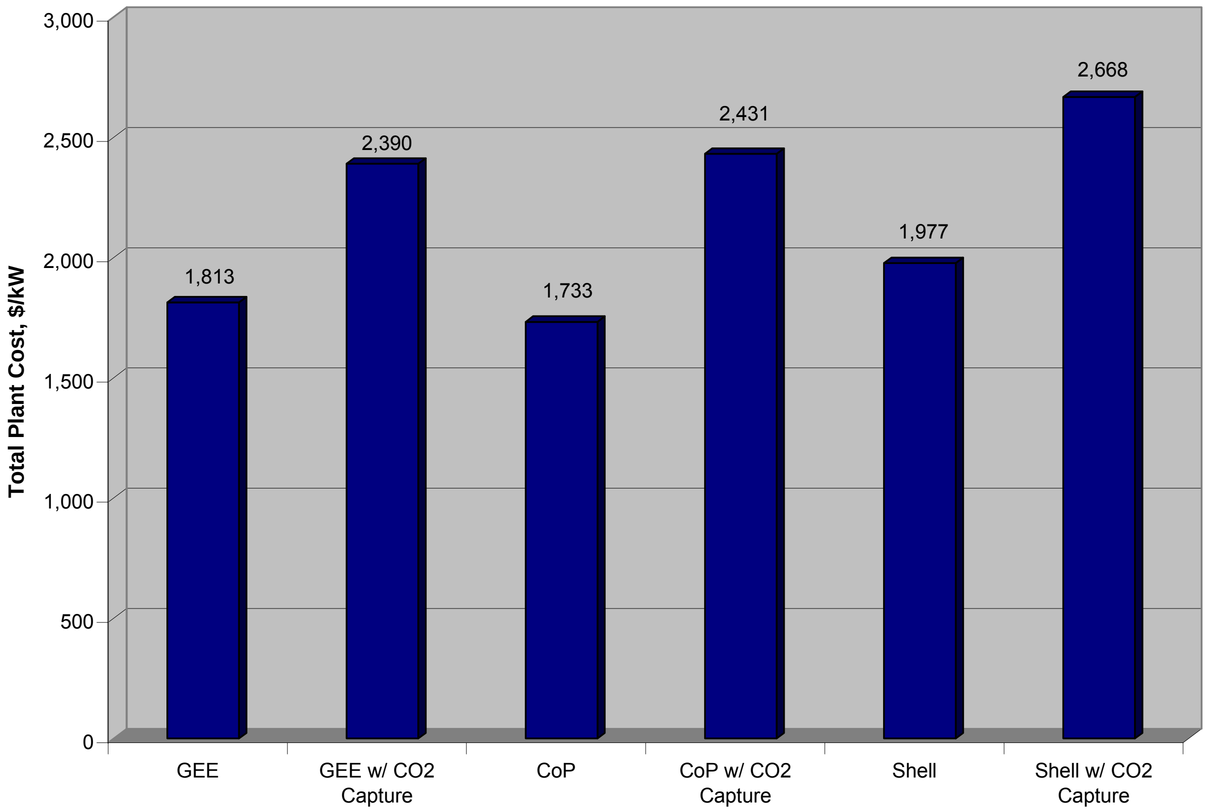
[1] Based on an 80% capacity factor
[2] Value is based on gross output
[3] Value is based on net output

The TPC of the six IGCC cases is shown in Exhibit 3-115. The following observations are made with the caveat that the differences between cases are less than the estimate accuracy (± 30 percent). However, all cases are evaluated using a common set of technical and economic assumptions allowing meaningful comparisons among the cases:

- CoP has the lowest capital cost among the non-capture cases. The E-Gas technology has several features that lend it to being lower cost, such as:
    - The firetube syngas cooler is much smaller and less expensive than a radiant section. E-Gas can use a firetube boiler because the two-stage design reduces the gas temperature (slurry quench) and drops the syngas temperature into a range where a radiant cooler is not needed.
    - The firetube syngas cooler sits next to the gasifier instead of above or below it which reduces the height of the main gasifier structure. The E-Gas proprietary slag removal system, used instead of lock hoppers below the gasifier, also contributes to the lower structure height.

  The TPC of the GEE gasifier is about 5 percent greater than CoP and Shell is about 12 percent higher.

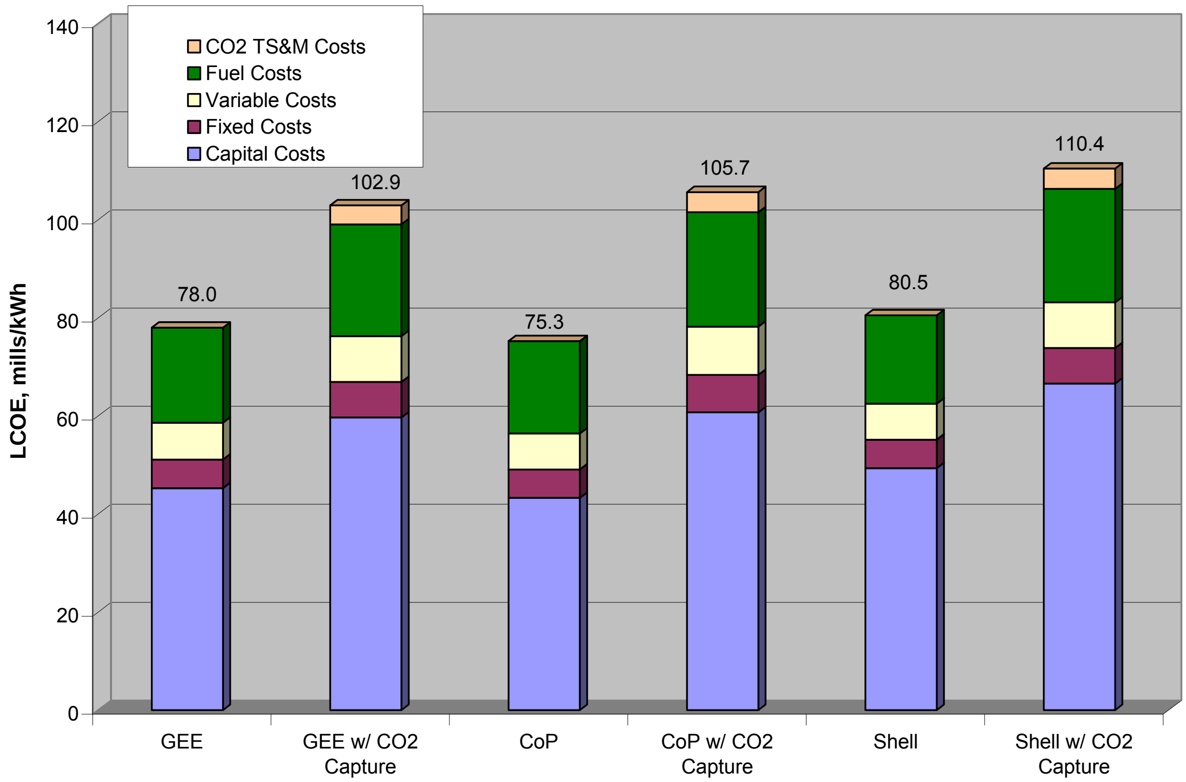
Exhibit 3-115 TPC for IGCC Cases



- The GEE gasifier is the low cost technology in the CO_2 capture cases, with CoP about 2 percent higher and Shell about 12 percent higher. The greatest uncertainty in all of the capital cost estimates is for the Shell capture case which is based on a water quench process (instead of syngas recycle) that has been proposed by Shell in a patent application. [53] However, to date there have been no commercial applications of this configuration.
- The ASU cost represents on average 14 percent of the TPC (range from 12.6-15.8 percent). The ASU cost includes oxygen and nitrogen compression, and in the non-capture cases, also includes the cost of the combustion turbine extraction air heat exchanger. With nitrogen dilution used to the maximum extent possible, nitrogen compression costs are significant.
- The capital cost premium for adding CO_2 capture averages 36 percent ($2,496/kW versus $1,841/kW).

The 20-year LCOE is shown for the IGCC cases in Exhibit 3-116.

Exhibit 3-116 LCOE for IGCC Cases



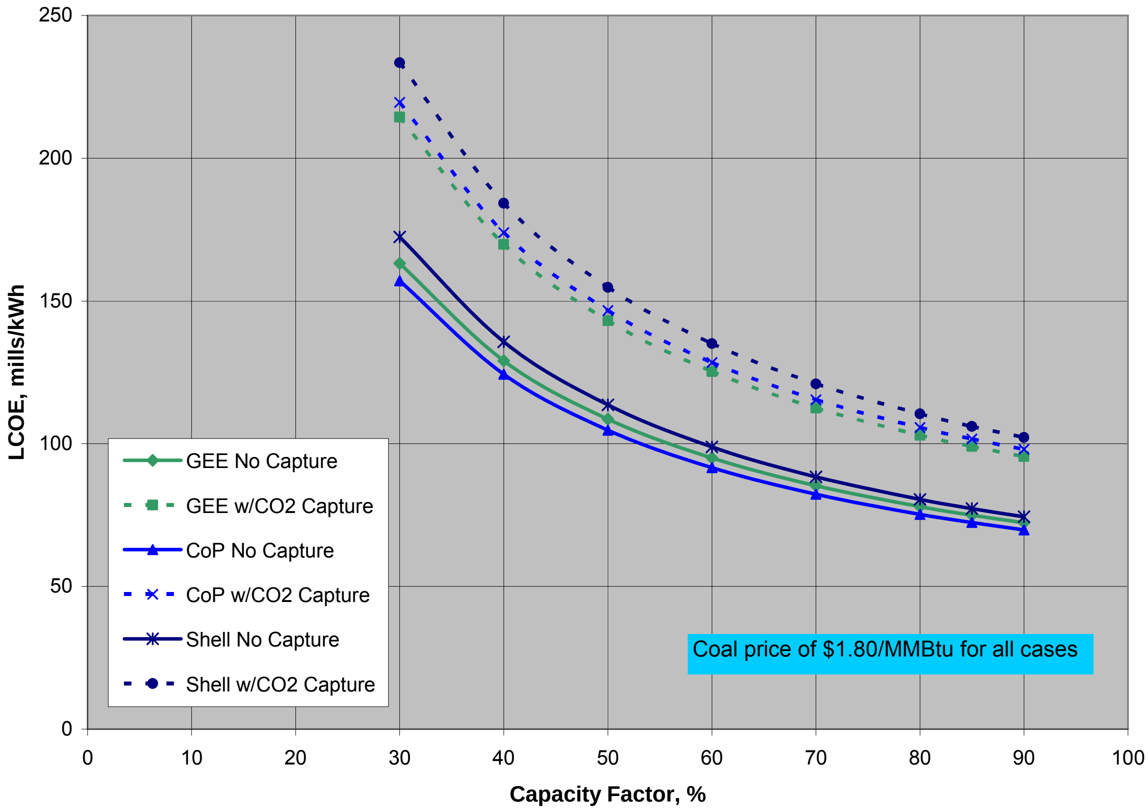
The following observations can be made:

- The LCOE is dominated by capital costs, at least 57 percent of the total in all cases.
- In the non-capture cases the CoP gasifier has the lowest LCOE, but the differential with Shell is reduced (compared to the TPC) primarily because of the higher efficiency of the Shell gasifier. The Shell LCOE is 7 percent higher than CoP (compared to 12 percent higher TPC). The GEE gasifier LCOE is about 3.5 percent higher than CoP.
- In the capture cases the variation in LCOE is small, however the order of the GEE and CoP gasifiers is reversed. The range is from 102.9 mills/kWh for GEE to 110.4 mills/kWh for Shell with CoP intermediate at 105.7 mills/kWh. The LCOE CO_2 capture premium for the IGCC cases averages 36 percent (range of 32 to 40 percent).
- The CO_2 TS&M LCOE component comprises less than 4 percent of the total LCOE in all capture cases.

The effect of capacity factor and coal price on LCOE is shown in Exhibit 3-117 and Exhibit 3-118, respectively.

The assumption implicit in Exhibit 3-117 is that each gasifier technology can achieve a capacity factor of up to 90 percent with no additional capital equipment. The cost differential between technologies decreases as capacity factor increases. At low capacity factor the capital cost differential is more magnified and the spread between technologies increases slightly.

Exhibit 3-117 Capacity Factor Sensitivity of IGCC Cases



LCOE is relatively insensitive to fuel costs for the IGCC cases as shown in Exhibit 3-118. A tripling of coal price from 1 to $3/MMBtu results in an average LCOE increase of only about 26-31 percent for all cases.

As presented in Section 2.4 the cost of CO_2 capture was calculated in two ways, CO_2 removed and CO_2 avoided. The results for the IGCC carbon capture cases are shown in Exhibit 3-119. The cost of CO_2 removed averages $30/ton for the three IGCC cases with a range of $27-$32/ton. The CoP and Shell gasifier cases have nearly identical results but for different reasons. In the CoP case the cost per ton of CO_2 removed is higher than GEE primarily because it has the lowest CO_2 removal efficiency due to the higher syngas CH_4 content. The Shell case is higher than GEE because it has the highest LCOE of the three gasifiers.

The cost of CO_2 avoided averages $39/ton with a range of $32-$42/ton. The cost of CO_2 avoided follows the same trends as CO_2 removed for the same reasons.

Exhibit 3-118 Coal Price Sensitivity of IGCC Cases

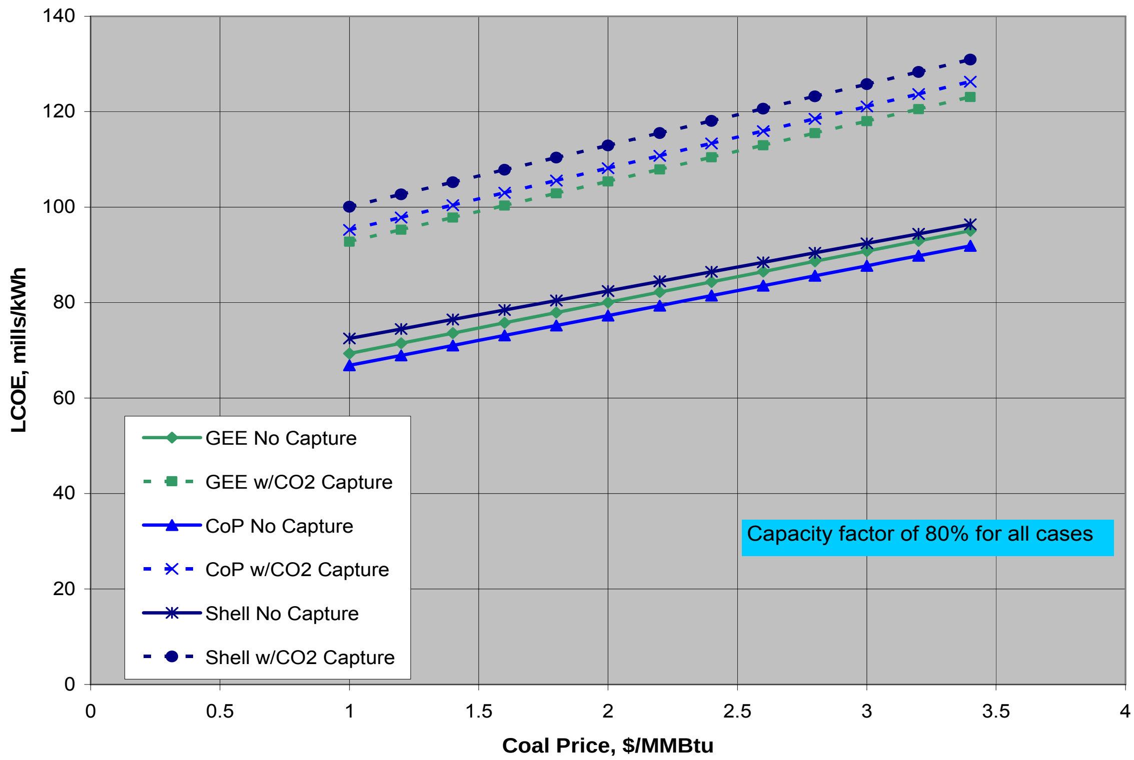
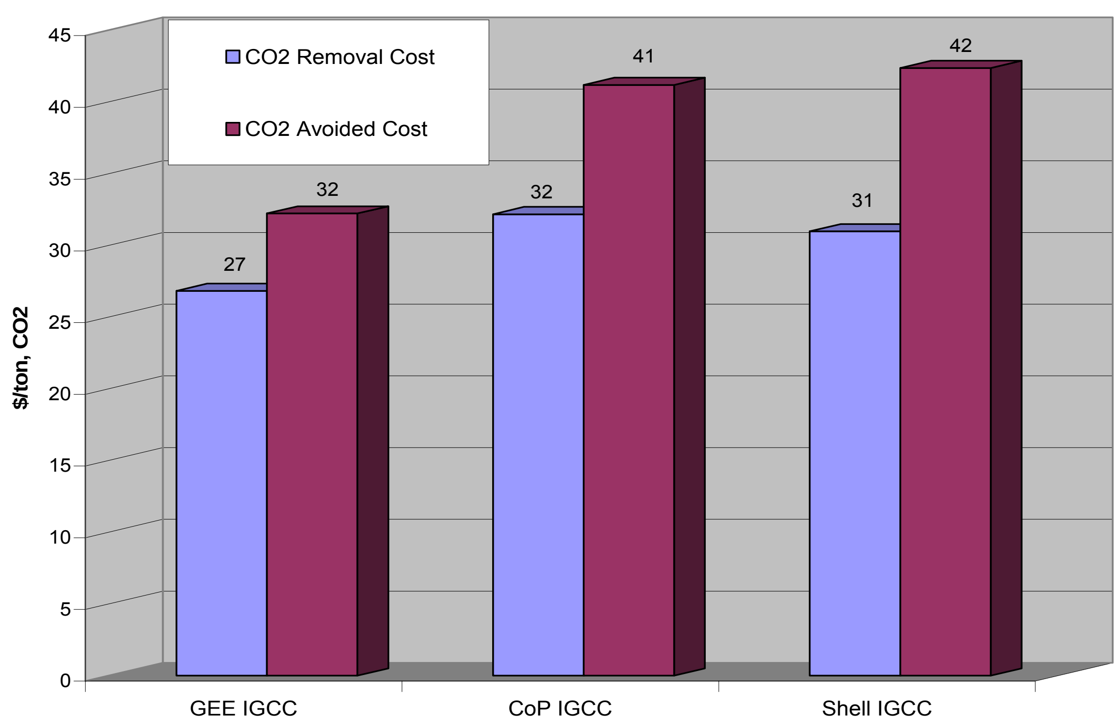


Exhibit 3-119 Cost of CO_2 Captured and Avoided in IGCC Cases



The following observations can be made regarding plant performance:

- In the non-carbon capture cases the dry fed Shell gasifier has the highest net plant efficiency (41.1 percent), followed by the two-stage CoP slurry fed gasifier (39.3 percent) and the single-stage GEE gasifier (38.2 percent). The absolute values of the GEE and CoP gasifiers are close to the reported values per the vendors. [50, 51] The Shell efficiency is slightly lower than reported by the vendor in other recent presentations. [52]
- In the carbon capture cases the efficiency of the three gasifiers is nearly equal, ranging from 31.7 to 32.5 percent.
- The dry fed Shell gasifier experiences the largest energy penalty (9.1 percent) primarily because addition of the steam required for the water gas shift reaction is provided as quench water to reduce the syngas temperature from 1427°C (2600°F) to 399°C (750°F). Quench to 399°C (750°F) reduces the amount of heat recovered in the syngas cooler relative to the non-capture case where syngas recycle reduces the temperature to only 891°C (1635°F) prior to the cooler. The CO_2 capture scheme used in this study for the Shell process is similar to one described in a recent Shell patent application. [53]
- The CoP process experiences the second largest energy penalty (7.6 percent) primarily because, like the Shell case, a significant amount of water must be added to the syngas for the SGS reactions.
- The energy penalty for the GEE gasifier with CO_2 capture is 5.7 percent. The smaller energy penalty results from the large amount of water already in the syngas from the quench step prior to SGS. While the quench limits the efficiency in the non-capture case, it is the primary reason that the net efficiency is slightly greater than CoP and Shell in the CO_2 capture case.
- The assumed carbon conversion efficiency in this study for the three gasifiers results in differing amount of carbon in the slag. Exhibit 3-120 shows carbon conversion and slag carbon content. Carbon capture efficiency is reported based on the amount of carbon entering the system with the coal less the carbon exiting the gasifier with the slag.

Exhibit 3-120 Carbon Conversion Efficiency and Slag Carbon Content

Gasifier Vendor	Carbon Conversion, %	Slag Carbon Content, wt%
GEE	98.0	11.66
CoP	99.2	4.70
Shell	99.5	3.19

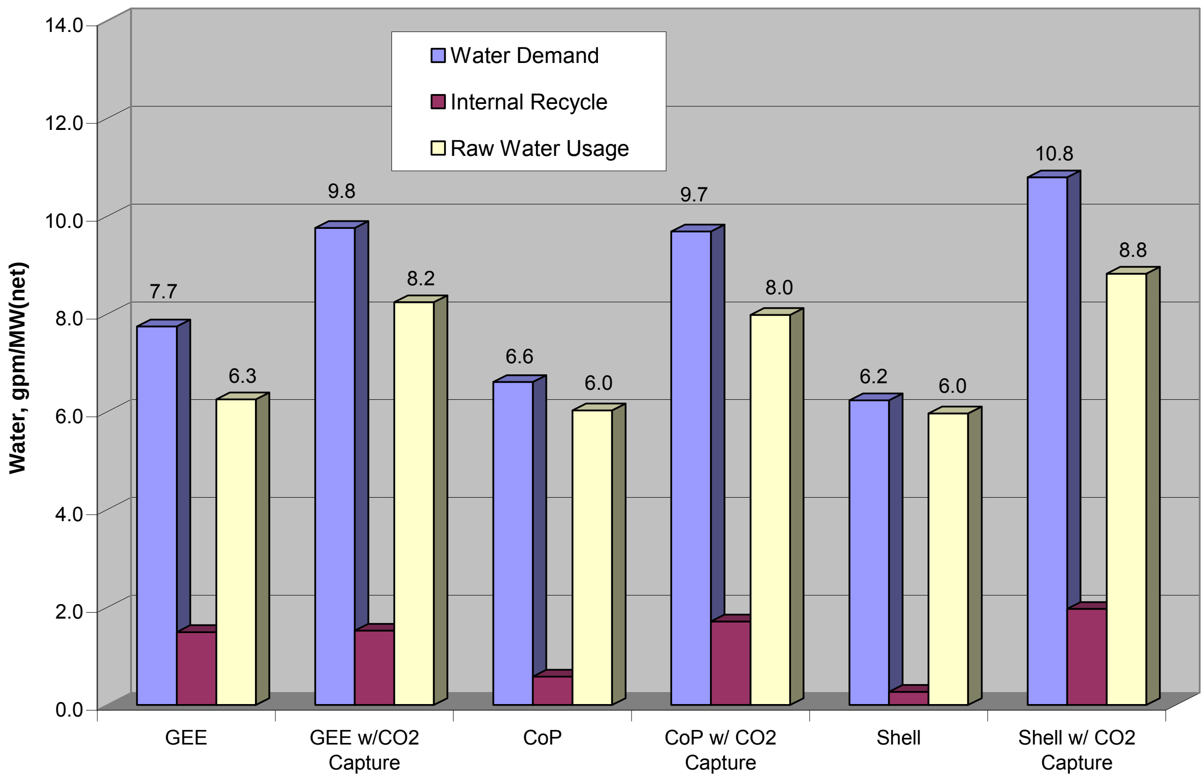
- Particulate emissions and Hg emissions are essentially the same for all six IGCC cases. The environmental target for particulate emissions is 0.0071 lb/MMBtu, and it was assumed that the combination of particulate control used by each technology could meet this limit. Similarly, the carbon beds used for mercury control were uniformly assumed to achieve 95 percent removal. The small variation in Hg emissions is due to a similar small variation in coal feed rate among the six cases. In all cases the Hg emissions are substantially below the NSPS requirement of 20 x 10^{-6} lb/MWh. Had 90 percent been chosen for the Hg removal efficiency, all six cases would still have had emissions less than half of the NSPS limit.

- Based on vendor data, it was assumed that the advanced F class turbine would achieve 15 ppmv NOx emissions at 15 percent O_2 for both "standard" syngas in the non-capture cases and for high hydrogen syngas in the CO_2 capture cases. The NOx emissions are slightly lower in the three capture cases (compared to non-capture) because of the lower syngas volume generated in high hydrogen syngas cases.
- The environmental target for SO_2 emissions is 0.0128 lb/MMBtu. Vendor quotes confirmed that each of the AGR processes, Selexol, refrigerated MDEA and Sulfinol-M, could meet the limit. The two-stage Selexol process used for each of the CO_2 capture cases resulted in lower SO_2 emissions because the unit was designed to meet the CO_2 removal requirement. The CoP gasifier has the lowest SO_2 emissions among CO_2 capture cases because of maximizing CO_2 capture to compensate for the higher CH_4 concentration in the CoP raw syngas.

Water demand, internal recycle and water usage, all normalized by net output, are presented in Exhibit 3-121. The following observations can be made:

- Raw water usage for all cases is dominated by cooling tower makeup requirements, which accounts for 84-92 percent of raw water usage in non-capture cases and 71-78 percent in CO_2 capture cases.
- Normalized water demand for the GEE non-capture case is 17 percent higher than the CoP non-capture case and 24 percent higher than the Shell non-capture case primarily because of the large quench water requirement. However, because much of the quench water is subsequently recovered as condensate as the syngas is cooled, the raw water usage of the GEE process is only 3.7 percent higher than CoP and 4.8 percent higher than Shell.
- The Shell non-capture case has the lowest normalized water demand, but is approximately equal to CoP in normalized raw water usage because very little water is available to recover for internal recycle in the Shell system. The GEE normalized raw water usage is slightly higher than CoP and Shell primarily because the larger steam turbine output leads to higher cooling tower makeup requirements.
- The normalized water demand for the three CO_2 capture cases varies by only 11 percent from the highest to the lowest. The variation between cases is small because each technology requires approximately the same amount of water in the syngas prior to the shift reactors. The difference in technologies is where and how the water is introduced. Much of the water is introduced in the quench sections of the GEE and Shell cases while steam is added in the CoP case.
- The normalized raw water usage in the CO_2 capture cases also shows little variation with CoP the lowest, GEE only 3.3 percent higher and Shell about 10 percent higher. The main reason for the lower CoP water requirement is less cooling tower makeup is required because a significant amount of extraction steam is used for the SGS shift reaction.

Exhibit 3-121 Water Usage in IGCC Cases



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4 PULVERIZED COAL RANKINE CYCLE PLANTS

Four pulverized coal-fired (PC) Rankine cycle power plant configurations were evaluated and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 start up date. All designs employ a one-on-one configuration comprised of a state-of-the art pulverized coal steam generator firing Illinois No. 6 coal and a steam turbine.

The PC cases are evaluated with and without carbon capture on a common 550 MWe net basis. The designs that include carbon capture have a larger gross unit size to compensate for the higher auxiliary loads. The constant net output sizing basis is selected because it provides for a meaningful side-by-side comparison of the results. The boiler and steam turbine industry ability to match unit size to a custom specification has been commercially demonstrated enabling common net output comparison of the PC cases in this study. As discussed in Section 3, this was not possible in the IGCC cases because of the fixed output from the combustion turbine. However, the net output from the PC cases falls in the range of outputs from the IGCC cases, which average 530 MW for CO_2 capture cases and 630 MW for non-capture cases.

Steam conditions for the Rankine cycle cases were selected based on a survey of boiler and steam turbine original equipment manufacturers (OEM), who were asked for the most advanced steam conditions that they would guarantee for a commercial project in the US with subcritical and supercritical PC units rated at nominal 550 MWe net capacities and firing Illinois No. 6 coal [54]. Based on the OEM responses, the following single-reheat steam conditions were selected for the study:

- For subcritical cycle cases (9 and 10) – 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F)
- For supercritical cases (11 and 12) – 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F)

While the current DOE program for the ultra supercritical cycle materials development targets 732°C/760°C (1350ºF/1400ºF) at 34.5 MPa (5000 psi) cycle conditions to be available by 2015, and a similar Thermie program in the European Union (EU) has targeted 700°C/720°C (1292ºF/1328ºF) at about 29.0 MPa (4200 psi) [55], steam temperature selection for boilers depends upon fuel corrosiveness. Most of the contacted OEMs were of the opinion that the steam conditions in this range would be limited to low sulfur coal applications (such as PRB). Their primary concern is that elevated temperature operation while firing high sulfur coal (such as Illinois No. 6) would result in an exponential increase of the material wastage rates of the highest temperature portions of the superheater and reheater due to coal ash corrosion, requiring pressure parts replacement outages approximately every 10 or 15 years. This cost would offset the value of fuel savings and emissions reduction due to the higher efficiency. The availability/reliability of the more exotic materials required to support the elevated temperature environment for high sulfur/chlorine applications, while extensively demonstrated in the laboratory [56], has not been commercially demonstrated. In addition, the three most recently built supercritical units in North America have steam cycles similar to this study's design basis, namely Genesee Phase 3 in Canada, which started operations in 2004 (25.0 MPa/570°C/568°C [3625 psia/1058°F/1054°F]), Council Bluffs 4 in the United States, which is currently under construction (25.4 MPa/566°C/593°C [3690 psia/1050°F/1100°F]), and Oak Creek 1 and 2, which are currently under construction (24.1 MPa/566°C [3500 psig/1050°F]).

The evaluation basis details, including site ambient conditions, fuel composition and the emissions control basis, are provided in Section 2 of this report.

4.1 PC COMMON PROCESS AREAS

The PC cases have process areas which are common to each plant configuration such as coal receiving and storage, emissions control technologies, power generation, etc. As detailed descriptions of these process areas in each case section would be burdensome and repetitious, they are presented in this section for general background information. The performance features of these sections are then presented in the case-specific sections.

4.1.1 COAL AND SORBENT RECEIVING AND STORAGE

The function of the coal portion of the Coal and Sorbent Receiving and Storage system for PC plants is identical to the IGCC facilities. It is to provide the equipment required for unloading, conveying, preparing, and storing the fuel delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the coal storage silos. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

The scope of the sorbent receiving and storage system includes truck roadways, turnarounds, unloading hoppers, conveyors and the day storage bin.

Operation Description - The coal is delivered to the site by 100-car unit trains comprised of 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 2.5 cm x 0 (1" x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six boiler silos.

Limestone is delivered to the site using 23 tonne (25 ton) trucks. The trucks empty into a below grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin.

4.1.2 STEAM GENERATOR AND ANCILLARIES

The steam generator for the subcritical PC plants is a drum-type, wall-fired, balanced draft, natural circulation, totally enclosed dry bottom furnace, with superheater, reheater, economizer and air-heater.

The steam generator for the supercritical plants is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace. It includes superheater, reheater, economizer, and air heater.

It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit but with some consideration for daily or weekly cycling, as can be cost effectively included in the base design.

The combustion systems for both subcritical and supercritical steam conditions are equipped with LNBs and OFA. It is assumed for the purposes of this study that the power plant is designed for operation as a base-load unit.

Scope

The steam generator comprises the following for both subcritical and supercritical PCs:

- Drum-type evaporator (subcritical only)
- Economizer
- Overfire air system
- Once-through type steam generator (supercritical only)
- Spray type desuperheater
- Forced draft (FD) fans
- Startup circuit, including integral separators (supercritical only)
- Soot blower system
- Primary air (PA) fans
- Water-cooled furnace, dry bottom
- Air preheaters (Ljungstrom type)
- Induced draft (ID) fans
- Two-stage superheater
- Coal feeders and pulverizers
- Reheater
- Low NOx Coal burners and light oil ignitors/ warmup system

The steam generator operates as follows:

Feedwater and Steam

For the subcritical steam system feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the boiler drum, from where it is distributed to the water wall circuits enclosing the furnace. After passing through the lower and upper furnace circuits and steam drum in sequence, the steam passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater.

The steam then exits the steam generator en route to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the IP turbine as hot reheat.

For the supercritical steam system feedwater enters the bottom header of the economizer and passes upward through the economizer tube bank, through stringer tubes which support the primary superheater, and discharges to the economizer outlet headers. From the outlet headers, water flows to the furnace hopper inlet headers via external downcomers. Water then flows upward through the furnace hopper and furnace wall tubes. From the furnace, water flows to the steam water separator. During low load operation (operation below the Benson point), the water from the separator is returned to the economizer inlet with the boiler recirculating pump. Operation at loads above the Benson point is once through.

Steam flows from the separator through the furnace roof to the convection pass enclosure walls, primary superheater, through the first stage of water attemperation, to the furnace platens. From the platens, the steam flows through the second stage of attemperation and then to the intermediate superheater. The steam then flows to the final superheater and on to the outlet pipe terminal. Two stages of spray attemperation are used to provide tight temperature control in all high temperature sections during rapid load changes.

Steam returning from the turbine passes through the primary reheater surface, then through crossover piping containing inter-stage attemperation. The crossover piping feeds the steam to the final reheater banks and then out to the turbine. Inter-stage attemperation is used to provide outlet temperature control during load changes.

Air and Combustion Products

Combustion air from the FD fans is heated in Ljungstrom type air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying pulverized coal to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the pulverized coal, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The pulverized coal and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow to the SCR reactor, fabric filter, ID fan, FGD system, and stack.

Fuel Feed

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72% passing 200 mesh and less than 0.5% remaining on 50 mesh [57]. The pulverized coal exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans.

Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to hydrobins, where the ash is dewatered before it is transferred to trucks for offsite disposal. The description of the balance of the bottom ash handling system is presented in Section 4.1.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

A boiler of this capacity employs approximately 24 to 36 coal nozzles arranged at multiple elevations. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, overfire air nozzles are provided to further stage combustion and thereby minimize NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition, warm-up and flame stabilization at startup and low loads.

Air Preheaters

Each steam generator is furnished with two vertical-shaft Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

Soot Blowers

The soot-blowing system utilizes an array of 50 to 150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of high-pressure steam. The blowers are sequenced to provide an effective cleaning cycle depending on the coal quality and design of the furnace and convection surfaces. Electric motors drive the soot blowers through their cycles.

4.1.3 NO_X CONTROL SYSTEM

The plant is designed to achieve the environmental target of 0.07 lb NOx/MMBtu. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The low-NOx burners and overfire air reduce the emissions to about 0.5 lb/MMBtu.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed for 86 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life. This, along with the low-NOx burners, achieves the emission limit of 0.07 lb/MMBtu.

The SCR capital costs are included with the boiler costs, as is the cost for the initial load of catalyst.

Selective non-catalytic reduction (SNCR) was considered for this application. However, with the installation of the low-NOx burners and overfire air system, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions limit of 0.07 lb/MMBtu difficult. SNCR works better in applications that contain medium to high quantities of NOx and require removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

SCR Operation Description

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The operating range for vanadium/titanium-based catalysts is 260°C (500°F) to 455°C (850°F). The boiler is equipped with economizer bypass to provide flue gas to the reactors at the desired temperature during periods of low flow rate, such as low load operation. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and associated dampers for low load temperature control are also included.

4.1.4 PARTICULATE CONTROL

The fabric filter (or baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9-1.5 m/min [3-5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide (PPS) with intrinsic Teflon (PTFE) coating [58]. The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). Each compartment contains a number of gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

4.1.5 MERCURY REMOVAL

Mercury removal is based on a coal Hg content of 0.15 ppmd. The basis for the coal Hg concentration was discussed in Section 2.4. The combination of pollution control technologies used in the PC plants, SCR, fabric filters and FGD, result in significant co-benefit capture of mercury. The SCR promotes the oxidation of elemental mercury, which in turn enhances the mercury removal capability of the fabric filter and FGD unit. The mercury co-benefit capture is assumed to be 90 percent for this combination of control technologies as described in Section 2.4. Co-benefit capture alone is sufficient to meet current NSPS mercury limits so no activated carbon injection is included in the PC cases.

4.1.6 FLUE GAS DESULFURIZATION

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 prior to release to the environment, or entering into the Carbon Dioxide Removal (CDR) facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. For Cases 10 and 12 with CO_2 capture, the SO_2 content of the scrubbed gases must be further reduced to approximately 10 ppmv to minimize formation of amine heat stable salts during the CO_2 absorption process. The CDR unit includes a polishing scrubber to reduce the flue gas SO_2 concentration from about 38 ppmv at the FGD exit to the required 10 ppmv prior to the CDR absorber. The scope of the FGD system is from the outlet of the ID fans to the stack inlet (Cases 9 and 11) or to the CDR process inlet (Cases 10 and 12). The system description is divided into three sections:

- Limestone Handling and Reagent Preparation
- FGD Scrubber

- Byproduct Dewatering

Reagent Preparation System

The function of the limestone reagent preparation system is to grind and slurry the limestone delivered to the plant. The scope of the system is from the day bin up to the limestone feed system. The system is designed to support continuous baseload operation.

Operation Description - Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill slurry tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydrocyclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydrocyclone underflow with oversized limestone is directed back to the mill for further grinding. The hydrocyclone overflow with correctly sized limestone is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

FGD Scrubber

The flue gas exiting the air preheater section of the boiler passes through one of two parallel fabric filter units, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent. Multiple spray elevations with header piping and nozzles maintain a consistent reagent concentration in the spray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed flue gas exits at the top of the absorber vessel and is routed to the plant stack or CDR process.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite contained in the slurry to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of byproduct solids via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The byproduct solids are routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

This FGD system is designed for wet stack operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the FGD discharge temperature of 57°C (135°F) (non-CO_2 capture cases) or 32°C (89°F) (CO_2 capture cases) is not necessary.

Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is gypsum dewatering producing wallboard grade gypsum. The scope of the system is from the bleed pump discharge connections to the gypsum storage pile.

Operation Description - The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO_2 absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off byproduct solids and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The bleed from the absorber contains approximately 20 wt% gypsum. The absorber slurry is pumped by an absorber bleed pump to a primary dewatering hydrocyclone cluster. The primary hydrocyclone performs two process functions. The first function is to dewater the slurry from 20 wt% to 50 wt% solids. The second function of the primary hydrocyclone is to perform a $CaCO_3$ and $CaSO_4{\bullet}2H_2O$ separation. This process ensures a limestone stoichiometry in the absorber vessel of 1.10 and an overall limestone stoichiometry of 1.05. This system reduces the overall operating cost of the FGD system. The underflow from the hydrocyclone flows into the filter feed tank, from which it is pumped to a horizontal belt vacuum filter. Two 100 percent filter systems are provided for redundant capacity.

Hydrocyclones

The hydrocyclone is a simple and reliable device (no moving parts) designed to increase the slurry concentration in one step to approximately 50 wt%. This high slurry concentration is necessary to optimize operation of the vacuum belt filter.

The hydrocyclone feed enters tangentially and experiences centrifugal motion so that the heavy particles move toward the wall and flow out the bottom. Some of the lighter particles collect at the center of the cyclone and flow out the top. The underflow is thus concentrated from 20 wt% at the feed to 50 wt%.

Multiple hydrocyclones are used to process the bleed stream from the absorber. The hydrocyclones are configured in a cluster with a common feed header. The system has two hydrocyclone clusters, each with five 15 cm (6 inch) diameter units. Four cyclones are used to continuously process the bleed stream at design conditions, and one cyclone is spare.

Cyclone overflow and underflow are collected in separate launders. The overflow from the hydrocyclones still contains about 5 wt% solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber. The underflow of the hydrocyclones flows into the filter feed tank from where it is pumped to the horizontal belt vacuum filters.

Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is dewatered to approximately 90 wt% solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

4.1.7 CARBON DIOXIDE RECOVERY FACILITY

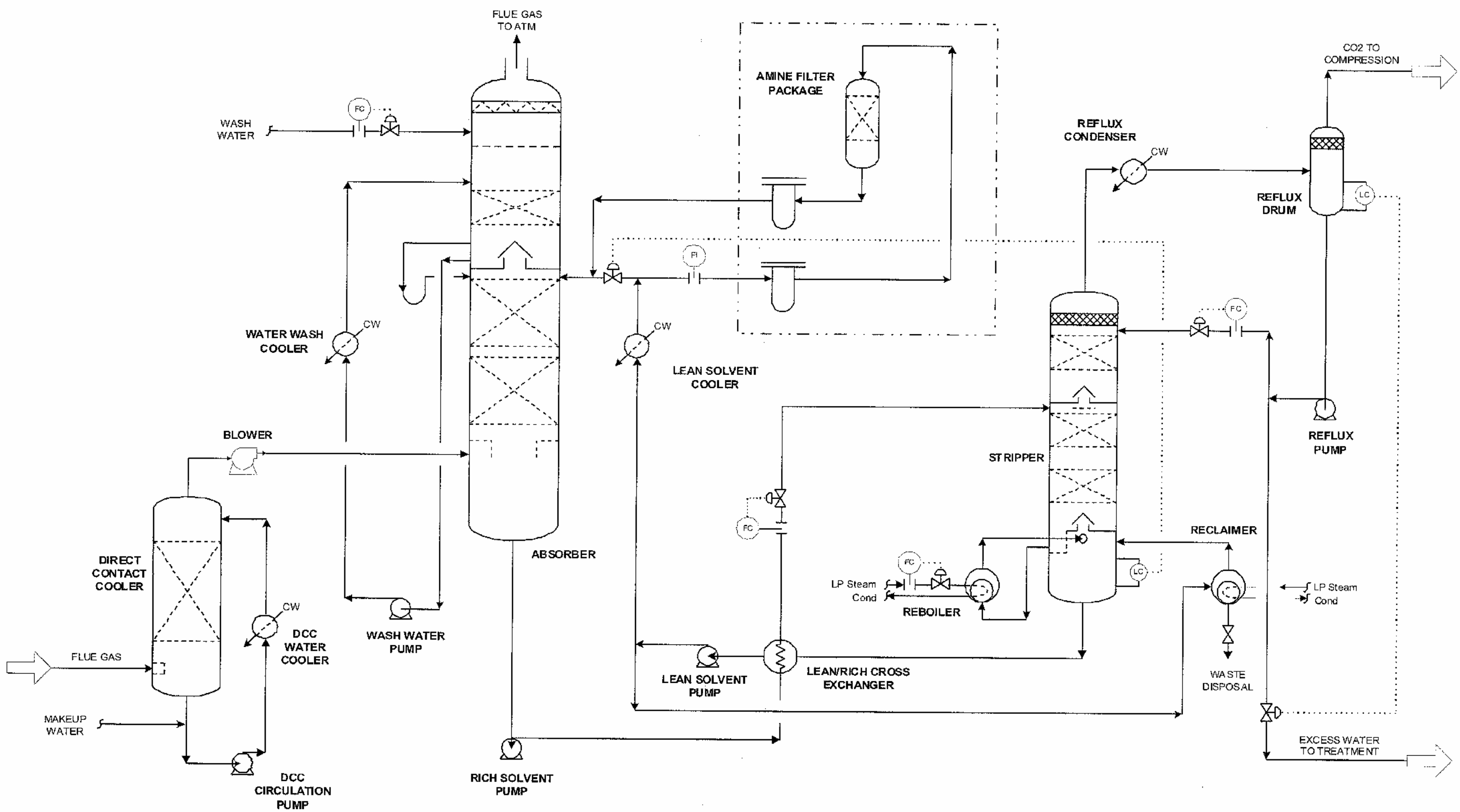
A Carbon Dioxide Recovery (CDR) facility is used in Cases 10 and 12 to remove 90 percent of the CO_2 in the flue gas exiting the FGD unit, purify it, and compress it to a supercritical condition. The flue gas exiting the FGD unit contains about 1 percent more CO_2 than the raw flue gas because of the CO_2 liberated from the limestone in the FGD absorber vessel. The CDR is comprised of the flue gas supply, SO_2 polishing, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for Cases 10 and 12 is based on the Fluor Econamine FG Plus technology. [59] A typical flowsheet is shown in Exhibit 4-1. The Econamine FG Plus process uses a formulation of monoethanolamine (MEA) and a proprietary inhibitor to recover CO_2 from the flue gas. This process is designed to recover high-purity CO_2 from low-pressure streams that contain oxygen, such as flue gas from coal-fired power plants, gas turbine exhaust gas, and other waste gases. The Econamine process used in this study differs from previous studies, including the 2004 IEA study, [59] in the following ways:

- The complexity of the control and operation of the plant is significantly decreased
- Solvent consumption is decreased
- Hard to dispose waste from the plant is eliminated

The above are achieved at the expense of a slightly higher steam requirement in the stripper (3,556 kJ/kg [1,530 Btu/lb] versus 3,242 kJ/kg [1,395 Btu/lb] used in the IEA study). [60]

Exhibit 4-1 Fluor Econamine FG Plus Typical Flow Diagram



SO_2 Polishing and Flue Gas Cooling and Supply

To prevent the accumulation of heat stable salts, the incoming flue gas must have an SO_2 concentration of 10 ppmv or less. The gas exiting the FGD system passes through an SO_2 polishing step to achieve this objective. The polishing step consists of a non-plugging, low-differential-pressure, spray-baffle-type scrubber using a 20 wt% solution of sodium hydroxide (NaOH). A removal efficiency of about 75 percent is necessary to reduce SO_2 emissions from the FGD outlet to 10 ppmv as required by the Econamine process. The polishing scrubber proposed for this application has been demonstrated in numerous industrial applications throughout the world and can achieve removal efficiencies of over 95 percent if necessary.

The polishing scrubber also serves as the flue gas cooling system. Cooling water from the PC plant is used to reduce the temperature and hence moisture content of the saturated flue gas exiting the FGD system. Flue gas is cooled beyond the CO_2 absorption process requirements to 32°C (90°F) to account for the subsequent flue gas temperature increase of about 17°C (30°F) in the flue gas blower. Downstream from the Polishing Scrubber flue gas pressure is boosted in the Flue Gas Blowers by approximately 0.014 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the PC plant circulating water system and returned to the PC plant cooling tower. The CDR facility requires a significant amount of cooling water for flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, the lean solvent cooler, and CO_2 compression interstage cooling. The cooling water requirements for the CDR facility in the two PC capture cases range from 1,514,180-1,703,450 lpm (400,000-450,000 gpm), which greatly exceeds the PC plant cooling water requirement of 719,235-870,650 lpm (190,000-230,000 gpm).

CO_2 Absorption

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent called Econamine FG Plus. Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, and the rest leaves the top of the absorber section and flows into the water wash section of the tower. The lean solvent enters the top of the absorber, absorbs the CO_2 from the flue gases and leaves the bottom of the absorber with the absorbed CO_2.

Water Wash Section

The purpose of the Water Wash section is to minimize solvent losses due to mechanical entrainment and evaporation. The flue gas from the top of the CO_2 Absorption section is contacted with a re-circulating stream of water for the removal of most of the lean solvent. The scrubbed gases, along with unrecovered solvent, exit the top of the wash section for discharge to the atmosphere via the vent stack. The water stream from the bottom of the wash section is collected on a chimney tray. A portion of the water collected on the chimney tray spills over to the absorber section as water makeup for the amine with the remainder pumped via the Wash Water Pump and cooled by the Wash Water Cooler, and recirculated to the top of the CO_2

Absorber. The wash water level is maintained by water makeup from the Wash Water Makeup Pump.

Rich/Lean Amine Heat Exchange System

The rich solvent from the bottom of the CO_2 Absorber is preheated by the lean solvent from the Solvent Stripper in the Rich Lean Solvent Exchanger. The heated rich solvent is routed to the Solvent Stripper for removal of the absorbed CO_2. The stripped solvent from the bottom of the Solvent Stripper is pumped via the Hot Lean Solvent Pumps through the Rich Lean Exchanger to the Solvent Surge Tank. Prior to entering the Solvent Surge Tank, a slipstream of the lean solvent is pumped via the Solvent Filter Feed Pump through the Solvent Filter Package to prevent buildup of contaminants in the solution. From the Solvent Surge Tank the lean solvent is pumped via the Warm Lean Solvent Pumps to the Lean Solvent Cooler for further cooling, after which the cooled lean solvent is returned to the CO_2 Absorber, completing the circulating solvent circuit.

Solvent Stripper

The purpose of the Solvent Stripper is to separate the CO_2 from the rich solvent feed exiting the bottom of the CO_2 Absorber. The rich solvent is collected on a chimney tray below the bottom packed section of the Solvent Stripper and routed to the Solvent Stripper Reboilers where the rich solvent is heated by steam, stripping the CO_2 from the solution. Steam is provided from the LP section of the steam turbine and is between 0.9-1.2 MPa (130-170 psia) and 366-396°C (690-745°F) for the two PC cases. The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Solvent Stripper Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Solvent Stripper Reflux Drum where the vapor and liquid are separated. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Solvent Stripper Reflux Drum is pumped via the Solvent Stripper Reflux Pumps where a portion of condensed overhead liquid is used as make-up water for the Water Wash section of the CO_2 Absorber. The rest of the pumped liquid is routed back to the Solvent Stripper as reflux, which aids in limiting the amount of solvent vapors entering the stripper overhead system.

Solvent Stripper Reclaimer

A small slipstream of the lean solvent from the Solvent Stripper bottoms is fed to the Solvent Stripper Reclaimer for the removal of high-boiling nonvolatile impurities (heat stable salts - HSS), volatile acids and iron products from the circulating solvent solution. The solvent bound in the HSS is recovered by reaction with caustic and heating with steam. The solvent reclaimer system reduces corrosion, foaming and fouling in the solvent system. The reclaimed solvent is returned to the Solvent Stripper and the spent solvent is pumped via the Solvent Reclaimer Drain Pump to the Solvent Reclaimer Drain Tank.

Steam Condensate

Steam condensate from the Solvent Stripper Reclaimer accumulates in the Solvent Reclaimer Condensate Drum and is level controlled to the Solvent Reboiler Condensate Drum. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler Condensate Drum and returned to the the steam cycle between boiler feedwater heaters 4 and 5 via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System

A proprietary corrosion inhibitor is continuously injected into the CO_2 Absorber rich solvent bottoms outlet line, the Solvent Stripper bottoms outlet line and the Solvent Stripper top tray. This constant injection is to help control the rate of corrosion throughout the CO_2 recovery plant system.

Gas Compression and Drying System

In the compression section, the CO_2 is compressed to 15.3 MPa (2,215 psia) by a six-stage centrifugal compressor. The discharge pressures of the stages were balanced to give reasonable power distribution and discharge temperatures across the various stages as shown in Exhibit 4-2.

Exhibit 4-2 CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.36 (52)
2	0.78 (113)
3	1.71 (248)
4	3.76 (545)
5	8.27 (1,200)
6	15.3 (2,215)

Power consumption for this large compressor was estimated assuming an isentropic efficiency of 84 percent. During compression to 15.3 MPa (2,215 psia) in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE using the methodology described in Section 2.7.

4.1.8 POWER GENERATION

The steam turbine is designed for long-term operation (90 days or more) at MCR with throttle control valves 95 percent open. It is also capable of a short-term 5 percent OP/VWO condition (16 hours).

For the subcritical cases, the steam turbine is a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft [61]. The exhaust pressure is 50.8 cm

(2 in) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

The steam-turbine generator systems for the supercritical plants are similar in design to the subcritical systems. The differences include steam cycle conditions and eight extractions points versus seven for the subcritical design.

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a low-pressure steam seal system. The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

Operation Description - The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2400 psig/1050ºF) for the subcritical cases and 24.1MPa /593°C (3500psig/1100°F) for the supercritical cases. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 566°C (1050ºF) in the subcritical cases and 593°C (1100°F) in the supercritical cases. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

The turbine is designed to operate at constant inlet steam pressure over the entire load range.

4.1.9 BALANCE OF PLANT

The balance of plant components consist of the condensate, feedwater, main and reheat steam, extraction steam, ash handling, ducting and stack, waste treatment and miscellaneous systems as described below.

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the LP feedwater heaters. Each system consists of one main condenser; two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity; one gland steam condenser; four LP heaters; and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP feedwater heaters 1 through 4 are 50 percent capacity, parallel flow, and are located in the condenser neck. All remaining feedwater heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Pneumatic level control valves control normal drain levels in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Pneumatic level control valves control dump line flow.

Feedwater

The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the HP feedwater heaters to the economizer. One turbine-driven boiler feedwater pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters. One 25 percent motor-driven boiler feedwater pump is provided for startup. The pumps are provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Pneumatic level control valves control normal drain level in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel vent condenser and storage tank. The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust (1.05 MPa/395°C [153 psig/743°F]) provides steam to the boiler feed pump steam turbine.

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the IP turbine stop valves.

Main steam exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve and is routed in a single line feeding the HP turbine. A branch line off the IP turbine exhaust feeds the boiler feed water pump turbine during unit operation starting at approximately 60 percent load.

Cold reheat steam exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

Circulating Water System

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent circulating water pumps are provided. The circulating water system provides cooling water to the condenser, the auxiliary cooling water system, and the CDR facility in capture cases.

The auxiliary cooling water system is a closed-loop system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc. are included for a complete operable system.

The CDR system in Cases 10 and 12 requires a substantial amount of cooling water that is provided by the PC plant circulating water system. The additional cooling load imposed by the CDR is reflected in the significantly larger circulating water pumps and cooling tower in those cases.

Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the hydrobins (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is sluiced to hydrobins for dewatering and offsite removal by truck.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) is conveyed using water to the economizer/pyrites transfer tank. This material is then sluiced on a periodic basis to the hydrobins.

Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete. The stack is 152 m (500 ft) high for adequate particulate dispersion.

Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash to within the U.S. EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. Waste treatment equipment is housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system, dry lime feeder, lime slurry tank, slurry tank mixer, and lime slurry feed pumps.

The oxidation system consists of an air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed offsite. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water are provided. A storage tank provides a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

Buildings and Structures

Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Fuel oil pump house
- Coal crusher building
- Continuous emissions monitoring building
- Pump house and electrical equipment building
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

4.1.10 ACCESSORY ELECTRIC PLANT

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, required foundations, and standby equipment.

4.1.11 INSTRUMENTATION AND CONTROL

An integrated plant-wide control and monitoring DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual, with operator selection of modular automation routines available.

4.2 SUBCRITICAL PC CASES

This section contains an evalution of plant designs for Cases 9 and 10 which are based on a subcritical PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F) cycle. The only difference between the two plants is that Case 10 includes CO_2 capture while Case 9 does not.

The balance of Section 4.2 is organized as follows:

- Process and System Description provides an overview of the technology operation as applied to Case 9. The systems that are common to all PC cases were covered in Section 4.1 and only features that are unique to Case 9 are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 9 and 10.
- Sparing Philosophy is provided for both Cases 9 and 10.
- Performance Results provides the main modeling results from Case 9, including the performance summary, environmental performance, water balance, mass and energy balance diagrams and energy balance table.
- Equipment List provides an itemized list of major equipment for Case 9 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case 9.
- Process and System Description, Performance Results, Equipment List and Cost Estimates are discussed for Case 10.

4.2.1 PROCESS DESCRIPTION

In this section the subcritical PC process without CO_2 capture is described. The system description follows the block flow diagram (BFD) in Exhibit 4-3 and stream numbers reference the same Exhibit. The tables in Exhibit 4-4 provide process data for the numbered streams in the BFD.

Coal (stream 6) and primary air (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the overfire air, is provided by the forced draft fans (stream 2). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 5.

Flue gas exits the boiler through the SCR reactor (stream 8) and is cooled to 177°C (350°F) in the combustion air preheater (not shown) before passing through a fabric filter for particulate removal (stream 10). An ID fan increases the flue gas temperature to 188°C (370°F) and provides the motive force for the flue gas (stream 11) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 13), oxidation air (stream 14), limestone slurry (stream 12) and product gypsum (stream 15). The clean, saturated flue gas exiting the FGD unit (stream 16) passes to the plant stack and is discharged to atmosphere.

Exhibit 4-3 Case 9 Process Flow Diagram, Subcritical Unit without CO_2 Capture

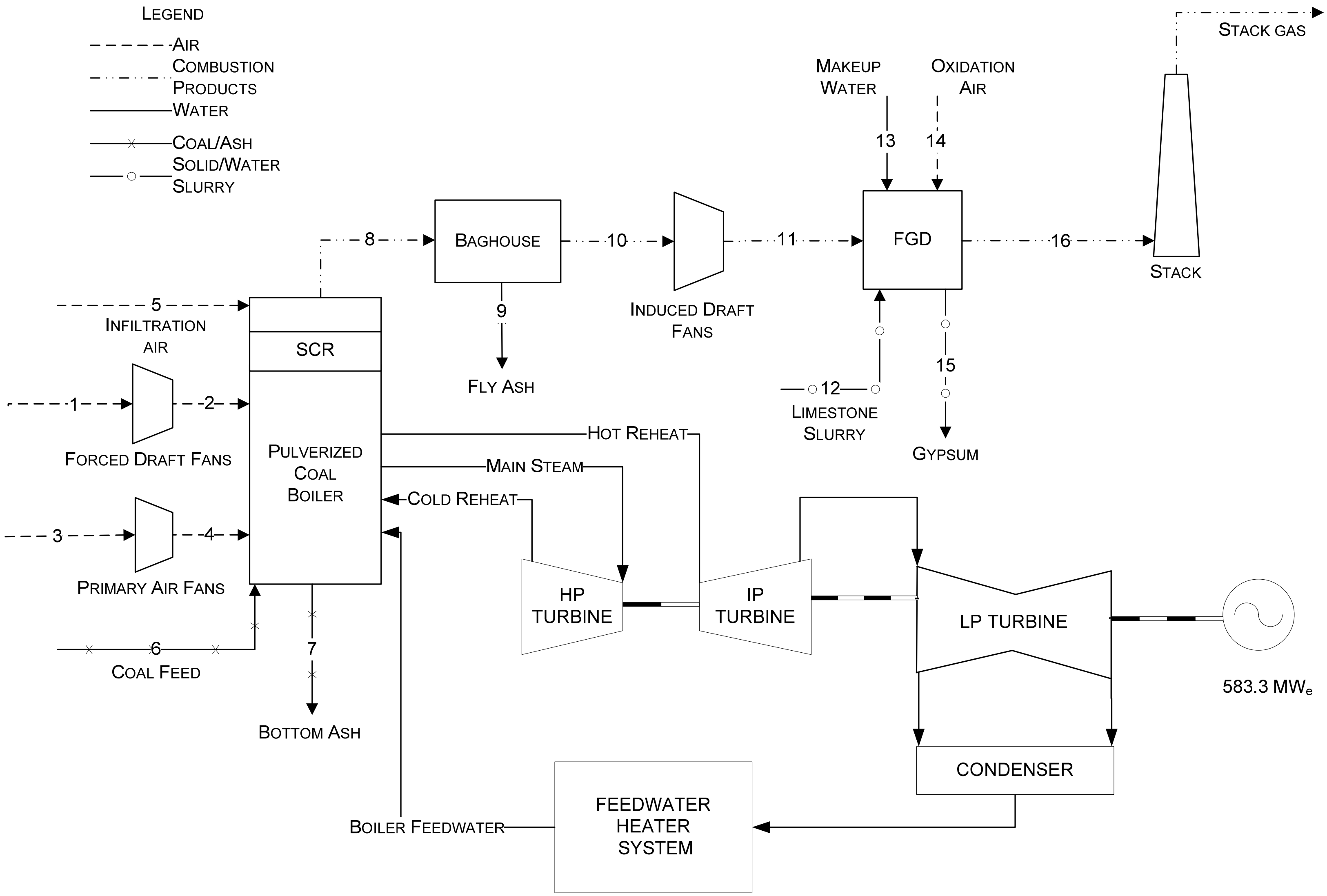


Exhibit 4-4 Case 9 Stream Table, Subcritical Unit without CO_2 Capture

	1	2	3	4	5	6	7	8
V-L Mole Fraction								
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flow (lb_{mol}/hr)	114,117	114,117	35,055	35,055	2,636	0	0	160,576
V-L Flow (lb/hr)	3,293,060	3,293,060	1,011,590	1,011,590	76,071	0	0	4,775,980
Solids Flowrate	0	0	0	0	0	437,699	8,489	33,954
Temperature (°F)	59	66	59	78	59	78	350	350
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.7
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	--	--	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	--	--	29.74

	9	10	11	12	13	14	15	16
V-L Mole Fraction								
Ar	0.0000	0.0087	0.0087	0.0000	0.0000	0.0092	0.0000	0.0079
CO_2	0.0000	0.1450	0.1450	0.0000	0.0000	0.0003	0.0014	0.1317
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0870	0.0870	1.0000	1.0000	0.0099	0.9978	0.1725
N_2	0.0000	0.7324	0.7324	0.0000	0.0000	0.7732	0.0007	0.6644
O_2	0.0000	0.0247	0.0247	0.0000	0.0000	0.2074	0.0000	0.0234
SO_2	0.0000	0.0021	0.0021	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	1.0000
V-L Flow (lb_{mol}/hr)	0	160,576	160,576	5,701	26,948	1,901	15,077	179,211
V-L Flow (lb/hr)	0	4,775,980	4,775,980	102,702	485,483	54,846	272,302	5,122,540
Solids Flowrate	33,954	0	0	43,585	0	0	67,754	0
Temperature (°F)	350	350	370	59	59	59	135	135
Pressure (psia)	14.20	14.20	15.26	14.70	14.70	14.70	14.70	14.70
Enthalpy (BTU/lb)[A]	51.4	136.3	141.5	--	32.4	13.1	88.0	139.1
Density (lb/ft^3)	--	0.05	0.05	62.62	62.62	0.08	39.65	0.07
Avg. Molecular Weight	--	29.74	29.74	18.02	18.02	28.86	18.06	28.58

A - Reference conditions are 32.02 F & 0.089 PSIA

4.2.2 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 9 and 10, subcritical PC with and without CO_2 capture, are compiled in Exhibit 4-5.

Exhibit 4-5 Subcritical PC Plant Study Configuration Matrix

	Case 9 w/o CO_2 Capture	**Case 10 w/CO_2 Capture**
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)	16.5/566/566 (2400/1050/1050)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, %	89	89
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	57 (135)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	86	86
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.8	99.8
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90
CO_2 Control	N/A	Econamine FG Plus
CO_2 Capture, % (A)	N/A	90
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the flue gas content
B. An SO_2 polishing step is included to meet more stringent SOx content limits in the flue gas (< 10 ppmv) to reduce formation of amine heat stable salts during the CO_2 absorption process
C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Cases 9 and 10

The balance of plant assumptions are common to all cases and are presented in Exhibit 4-6.

Exhibit 4-6 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local Publicly Owned Treatment Works (POTW) and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown will be treated for chloride and metals, and discharged.

4.2.3 SPARING PHILOSOPHY

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC subcritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case 10 only, two parallel Econamine FG Plus CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50%)

4.2.4 CASE 9 PERFORMANCE RESULTS

The plant produces a net output of 550 MWe at a net plant efficiency of 36.8 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 4-7 which includes auxiliary power requirements.

Exhibit 4-7 Case 9 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**583,315**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	420
Limestone Handling & Reagent Preparation	950
Pulverizers	2,980
Ash Handling	570
Primary Air Fans	1,390
Forced Draft Fans	1,770
Induced Draft Fans	7,590
SCR	60
Baghouse	100
FGD Pumps and Agitators	3,170
Amine System Auxiliaries	N/A
CO_2 Compression	N/A
Condensate Pumps	1,390
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	5,440
Cooling Tower Fans	2,810
Transformer Loss	1,830
TOTAL AUXILIARIES, kWe	**32,870**
NET POWER, kWe	**550,445**
Net Plant Efficiency (HHV)	36.8%
Net Plant Heat Rate (Btu/kWh)	9,276
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	2,656 (2,520)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	198,537 (437,699)
Limestone Sorbent Feed, kg/h (lb/h)	19,770 (43,585)
Thermal Input, kWt	1,496,479
Makeup water, m^3/min (gpm)	23.5 (6,212)

Notes:
1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 9 is presented in Exhibit 4-8.

Exhibit 4-8 Case 9 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	0.037 (0.085)	1,463 (1,613)	0.337 (0.743)
NO_X	0.030 (0.070)	1,331 (1,207)	0.278 (0.613)
Particulates	0.006 (0.013)	224 (247)	0.052 (0.114)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.020 (0.022)	4.5×10^{-6} (10.0×10^{-6})
CO_2	87.5 (203)	3,506,000 (3,865,000)	807 (1,780)
CO_2[1]			855 (1,886)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. CO_2 emissions represent the uncontrolled discharge from the process.

Exhibit 4-9 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream is re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-9 Case 9 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	2.4 (625)	0	2.4 (625)
BFW Makeup	0.3 (74)	0	0.3 (74)
Cooling Tower Makeup	21.2 (5,587)	0.3 (74)	20.9 (5,513)
Total	**23.9 (6,286)**	**0.3 (74)**	**23.6 (6,212)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 9 PC boiler, the FGD unit and steam cycle in Exhibit 4-10.

An overall plant energy balance is provided in tabular form in Exhibit 4-11. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-7) is calculated by multiplying the power out by a generator efficiency of 98.6 percent.

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Exhibit 4-10 Case 9 Heat and Mass Balance, Subcritical PC Boiler without CO_2 Capture

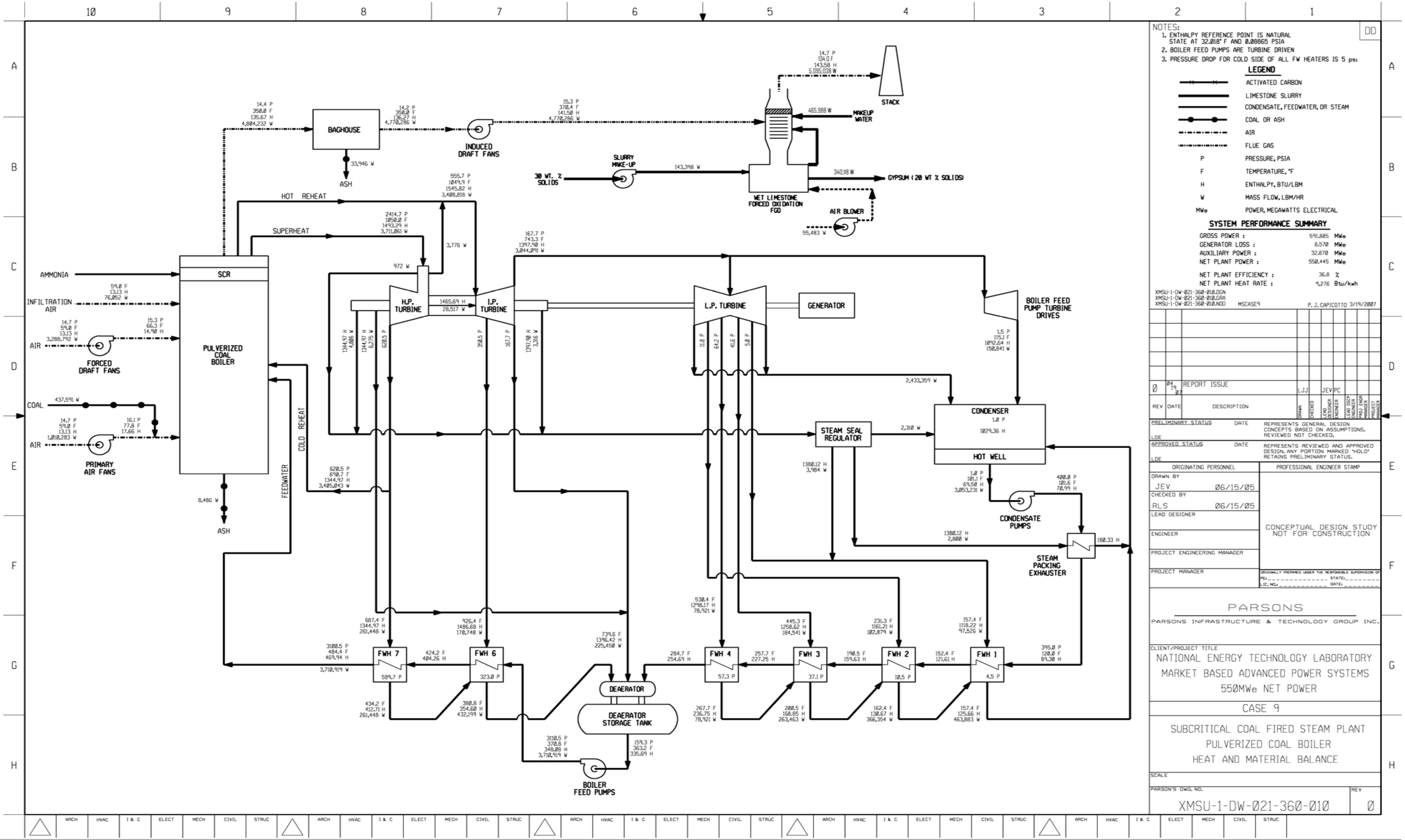

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Exhibit 4-11 Case 9 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	5,106.2	4.3		5,110.5
Ambient Air		56.5		56.5
Infiltration Air		1.0		1.0
Limestone		64.8		64.8
FGD Oxidant		0.7		0.7
Water		19.0		19.0
Auxiliary Power			112.2	112.2
Totals	**5,106.2**	**146.4**	**112.2**	**5,364.7**
Heat Out (MMBtu/hr)				
Bottom Ash		0.4		0.4
Fly Ash		1.7		1.7
Flue Gas Exhaust		712.5		712.5
Gypsum Slurry		29.9		29.9
Condenser		2,520.0		2,520.0
Process Losses (1)		80.5		80.5
Power			2,019.6	2,019.6
Totals	**0.0**	**3,345.1**	**2,019.6**	**5,364.7**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.2.5 CASE 9 – MAJOR EQUIPMENT LIST

Major equipment items for the subcritical PC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	163 tonne/h (180 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	327 tonne/h (360 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	163 tonne (180 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	327 tonne/h (360 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	327 tonne/h (360 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	82 tonne/h (90 tph)	1	0
21	Limestone Conveyor No. L1	Belt	82 tonne/h (90 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	64 tonne/h (70 tph)	1	0
24	Limestone Conveyor No. L2	Belt	64 tonne/h (70 tph)	1	0
25	Limestone Day Bin	w/ actuator	263 tonne (290 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	36 tonne/h (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	36 tonne/h (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	22 tonne/h (24 tph)	1	1
4	Limestone Ball Mill	Rotary	22 tonne/h (24 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	83,280 liters (22,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	336 lpm @ 12 m H2O (370 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	82 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	469,395 liters (124,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	236 lpm @ 9 m H2O (260 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,112,920 liters (294,000 gal)	2	0
2	Condensate Pumps	Vertical canned	25,741 lpm @ 335 m H2O (6,800 gpm @ 1,100 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,852,020 kg/h (4,083,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	31,041 lpm @ 2,499 m H2O (8,200 gpm @ 8,200 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 2,499 m H2O (2,400 gpm @ 8,200 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	762,036 kg/h (1,680,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,850,659 kg/h (4,080,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,850,659 kg/h (4,080,000 lb/h)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	13,098 lpm @ 43 m H2O (3,460 gpm @ 140 ft H2O)	2	1
21	Filtered Water Pumps	Stainless steel, single suction	1,590 lpm @ 49 m H2O (420 gpm @ 160 ft H2O)	2	1
22	Filtered Water Tank	Vertical, cylindrical	1,540,675 liter (407,000 gal)	1	0
23	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (160 gpm)	1	1
24	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	1,850,659 kg/h steam @ 16.5 MPa/566°C/566°C (4,080,000 lb/h steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	252,198 kg/h, 3,455 m3/min @ 123 cm WG (556,000 lb/h, 122,000 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	821,457 kg/h, 11,248 m3/min @ 47 cm WG (1,811,000 lb/h, 397,200 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,191,589 kg/h, 25,301 m3/min @ 90 cm WG (2,627,000 lb/h, 893,500 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,381,363 kg/h (5,250,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	142 m3/min @ 108 cm WG (5,000 scfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	155,203 liter (41,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	30 lpm @ 91 m H2O (8 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,191,589 kg/h (2,627,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	40,295 m3/min (1,423,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	140,061 lpm @ 64 m H2O (37,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,278 lpm (1,130 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	187 m3/min @ 0.3 MPa (6,620 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,060 lpm (280 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	34 tonne/h (37 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	644 lpm @ 12 m H2O (170 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	416,399 lpm (110,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,612 lpm @ 21 m H2O (690 gpm @ 70 ft H2O)	1	1

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.8 m (19 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	610 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,920 MMkJ/h (2,770 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	545,104 lpm @ 30.5 m (144,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 3,036 MMkJ/h (2,880 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	4.5 tonne/h (5 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H2O (40 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	151 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	16 m3/min @ 0.2 MPa (550 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	499 tonne (1,100 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	91 tonne/h (100 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 35 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.6 CASE 9 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-12 shows the total plant capital cost summary organized by cost account and Exhibit 4-13 shows a more detailed breakdown of the capital costs. Exhibit 4-14 shows the initial and annual O&M costs.

The estimated TPC of the subcritical PC boiler with no CO_2 capture is $1,548/kW. No process contingency is included in this case because all elements of the technology are commercially proven. The project contingency is 11.2 percent of the TPC. The 20-year LCOE is 64.0 mills/kWh

Exhibit 4-12 Case 9 Total Plant Cost Summary

Client:	USDOE/NETL	**Report Date:**	09-May-07
Project:	Bituminous Baseline Study		
	TOTAL PLANT COST SUMMARY		
Case:	Case 9 - Subcritical PC w/o CO2		
Plant Size:	550.4 MW,net **Estimate Type:** Conceptual	**Cost Base (Dec)**	2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	**Item/Description**	**Cost**	**Cost**	**Direct**	**Indirect**	**Tax**	**Cost $**	**H.O.& Fee**	**Process**	**Project**	**$**	**$/kW**
1	COAL & SORBENT HANDLING	$16,102	$4,348	$9,748	$0	$0	**$30,198**	$2,706	$0	$4,936	**$37,840**	$69
2	COAL & SORBENT PREP & FEED	$10,847	$629	$2,750	$0	$0	**$14,227**	$1,247	$0	$2,321	**$17,795**	$32
3	FEEDWATER & MISC. BOP SYSTEMS	$37,503	$0	$18,011	$0	$0	**$55,514**	$5,071	$0	$9,963	**$70,548**	$128
4	PC BOILER											
4.1	PC Boiler & Accessories	$127,763	$0	$82,570	$0	$0	**$210,334**	$20,391	$0	$23,072	**$253,797**	$461
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$127,763**	**$0**	**$82,570**	**$0**	**$0**	**$210,334**	**$20,391**	**$0**	**$23,072**	**$253,797**	**$461**
5	FLUE GAS CLEANUP	$83,756	$0	$28,598	$0	$0	**$112,354**	$10,675	$0	$12,303	**$135,332**	$246
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$17,476	$1,006	$11,965	$0	$0	**$30,447**	$2,787	$0	$4,336	**$37,570**	$68
	SUBTOTAL 7	**$17,476**	**$1,006**	**$11,965**	**$0**	**$0**	**$30,447**	**$2,787**	**$0**	**$4,336**	**$37,570**	**$68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$47,000	$0	$6,220	$0	$0	**$53,220**	$5,095	$0	$5,832	**$64,147**	$117
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$22,612	$1,045	$12,107	$0	$0	**$35,764**	$3,134	$0	$5,418	**$44,316**	$81
	SUBTOTAL 8	**$69,612**	**$1,045**	**$18,328**	**$0**	**$0**	**$88,984**	**$8,230**	**$0**	**$11,249**	**$108,463**	**$197**
9	COOLING WATER SYSTEM	$11,659	$6,571	$11,683	$0	$0	**$29,913**	$2,792	$0	$4,499	**$37,204**	$68
10	ASH/SPENT SORBENT HANDLING SYS	$4,383	$138	$5,829	$0	$0	**$10,350**	$985	$0	$1,166	**$12,502**	$23
11	ACCESSORY ELECTRIC PLANT	$15,802	$6,032	$17,773	$0	$0	**$39,607**	$3,506	$0	$5,366	**$48,479**	$88
12	INSTRUMENTATION & CONTROL	$8,006	$0	$8,413	$0	$0	**$16,419**	$1,503	$0	$2,204	**$20,126**	$37
13	IMPROVEMENTS TO SITE	$2,833	$1,629	$5,752	$0	$0	**$10,214**	$1,003	$0	$2,243	**$13,460**	$24
14	BUILDINGS & STRUCTURES	$0	$22,304	$21,358	$0	$0	**$43,662**	$3,934	$0	$11,899	**$59,495**	$108
	TOTAL COST	**$405,742**	**$43,703**	**$242,779**	**$0**	**$0**	**$692,224**	**$64,830**	**$0**	**$95,558**	**$852,612**	**$1,549**

Exhibit 4-13 Case 9 Total Plant Cost Details

	Client:	USDOE/NETL								Report Date:	09-May-07	
	Project:	Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case 9 - Subcritical PC w/o CO2										
	Plant Size:	550.4 MW,net		Estimate Type:		Conceptual				Cost Base (Dec)	2006	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,308	$0	$1,527	$0	$0	$4,834	$432	$0	$790	$6,056	$11
1.2	Coal Stackout & Reclaim	$4,275	$0	$979	$0	$0	$5,254	$460	$0	$857	$6,571	$12
1.3	Coal Conveyors	$3,975	$0	$968	$0	$0	$4,943	$433	$0	$806	$6,183	$11
1.4	Other Coal Handling	$1,040	$0	$224	$0	$0	$1,264	$110	$0	$206	$1,581	$3
1.5	Sorbent Receive & Unload	$133	$0	$40	$0	$0	$173	$15	$0	$28	$217	$0
1.6	Sorbent Stackout & Reclaim	$2,145	$0	$397	$0	$0	$2,542	$221	$0	$414	$3,177	$6
1.7	Sorbent Conveyors	$765	$165	$190	$0	$0	$1,119	$97	$0	$182	$1,399	$3
1.8	Other Sorbent Handling	$462	$108	$245	$0	$0	$815	$72	$0	$133	$1,020	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$4,076	$5,178	$0	$0	$9,254	$865	$0	$1,518	$11,637	$21
	SUBTOTAL 1.	**$16,102**	**$4,348**	**$9,748**	**$0**	**$0**	**$30,198**	**$2,706**	**$0**	**$4,936**	**$37,840**	**$69**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$1,900	$0	$374	$0	$0	$2,274	$198	$0	$371	$2,843	$5
2.2	Coal Conveyor to Storage	$4,864	$0	$1,073	$0	$0	$5,936	$519	$0	$968	$7,424	$13
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$3,645	$156	$765	$0	$0	$4,566	$398	$0	$745	$5,708	$10
2.6	Sorbent Storage & Feed	$439	$0	$170	$0	$0	$609	$54	$0	$99	$763	$1
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$473	$369	$0	$0	$842	$78	$0	$138	$1,057	$2
	SUBTOTAL 2.	**$10,847**	**$629**	**$2,750**	**$0**	**$0**	**$14,227**	**$1,247**	**$0**	**$2,321**	**$17,795**	**$32**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$15,086	$0	$5,277	$0	$0	$20,363	$1,787	$0	$3,322	$25,472	$46
3.2	Water Makeup & Pretreating	$4,700	$0	$1,511	$0	$0	$6,211	$582	$0	$1,359	$8,152	$15
3.3	Other Feedwater Subsystems	$4,982	$0	$2,114	$0	$0	$7,095	$632	$0	$1,159	$8,887	$16
3.4	Service Water Systems	$928	$0	$501	$0	$0	$1,429	$133	$0	$312	$1,873	$3
3.5	Other Boiler Plant Systems	$5,826	$0	$5,699	$0	$0	$11,525	$1,081	$0	$1,891	$14,498	$26
3.6	FO Supply Sys & Nat Gas	$248	$0	$305	$0	$0	$552	$51	$0	$91	$694	$1
3.7	Waste Treatment Equipment	$3,168	$0	$1,815	$0	$0	$4,982	$483	$0	$1,093	$6,558	$12
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,566	$0	$790	$0	$0	$3,356	$322	$0	$736	$4,414	$8
	SUBTOTAL 3.	**$37,503**	**$0**	**$18,011**	**$0**	**$0**	**$55,514**	**$5,071**	**$0**	**$9,963**	**$70,548**	**$128**
4	PC BOILER											
4.1	PC Boiler & Accessories	$127,763	$0	$82,570	$0	$0	$210,334	$20,391	$0	$23,072	$253,797	$461
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$127,763**	**$0**	**$82,570**	**$0**	**$0**	**$210,334**	**$20,391**	**$0**	**$23,072**	**$253,797**	**$461**

Exhibit 4-13 Case 9 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 9 - Subcritical PC w/o CO2
Plant Size: 550.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$58,310	$0	$12,562	$0	$0	$70,872	$6,708	$0	$7,758	$85,337	$155
5.2	Other FGD	$3,043	$0	$3,451	$0	$0	$6,494	$626	$0	$712	$7,831	$14
5.3	Bag House & Accessories	$16,683	$0	$10,596	$0	$0	$27,279	$2,609	$0	$2,989	$32,877	$60
5.4	Other Particulate Removal Materials	$1,129	$0	$1,209	$0	$0	$2,338	$225	$0	$256	$2,819	$5
5.5	Gypsum Dewatering System	$4,591	$0	$780	$0	$0	$5,372	$508	$0	$588	$6,467	$12
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$83,756**	**$0**	**$28,598**	**$0**	**$0**	**$112,354**	**$10,675**	**$0**	**$12,303**	**$135,332**	**$246**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$8,649	$0	$5,645	$0	$0	$14,295	$1,249	$0	$2,332	$17,875	$32
7.4	Stack	$8,826	$0	$5,169	$0	$0	$13,995	$1,337	$0	$1,533	$16,866	$31
7.9	Duct & Stack Foundations	$0	$1,006	$1,151	$0	$0	$2,157	$201	$0	$472	$2,830	$5
	SUBTOTAL 7.	**$17,476**	**$1,006**	**$11,965**	**$0**	**$0**	**$30,447**	**$2,787**	**$0**	**$4,336**	**$37,570**	**$68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$47,000	$0	$6,220	$0	$0	$53,220	$5,095	$0	$5,832	$64,147	$117
8.2	Turbine Plant Auxiliaries	$335	$0	$718	$0	$0	$1,054	$102	$0	$116	$1,271	$2
8.3	Condenser & Auxiliaries	$7,062	$0	$2,211	$0	$0	$9,272	$880	$0	$1,015	$11,168	$20
8.4	Steam Piping	$15,215	$0	$7,516	$0	$0	$22,731	$1,897	$0	$3,694	$28,322	$51
8.9	TG Foundations	$0	$1,045	$1,663	$0	$0	$2,708	$255	$0	$592	$3,555	$6
	SUBTOTAL 8.	**$69,612**	**$1,045**	**$18,328**	**$0**	**$0**	**$88,984**	**$8,230**	**$0**	**$11,249**	**$108,463**	**$197**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$8,335	$0	$2,730	$0	$0	$11,065	$1,051	$0	$1,212	$13,328	$24
9.2	Circulating Water Pumps	$1,938	$0	$127	$0	$0	$2,065	$177	$0	$224	$2,466	$4
9.3	Circ.Water System Auxiliaries	$516	$0	$69	$0	$0	$585	$55	$0	$64	$704	$1
9.4	Circ.Water Piping	$0	$4,162	$3,969	$0	$0	$8,131	$749	$0	$1,332	$10,212	$19
9.5	Make-up Water System	$458	$0	$607	$0	$0	$1,065	$101	$0	$175	$1,341	$2
9.6	Component Cooling Water Sys	$412	$0	$326	$0	$0	$738	$69	$0	$121	$928	$2
9.9	Circ.Water System Foundations& Structures	$0	$2,409	$3,855	$0	$0	$6,265	$590	$0	$1,371	$8,225	$15
	SUBTOTAL 9.	**$11,659**	**$6,571**	**$11,683**	**$0**	**$0**	**$29,913**	**$2,792**	**$0**	**$4,499**	**$37,204**	**$68**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$583	$0	$1,798	$0	$0	$2,381	$232	$0	$261	$2,874	$5
10.7	Ash Transport & Feed Equipment	$3,800	$0	$3,869	$0	$0	$7,669	$725	$0	$839	$9,234	$17
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$138	$163	$0	$0	$301	$28	$0	$66	$395	$1
	SUBTOTAL 10.	**$4,383**	**$138**	**$5,829**	**$0**	**$0**	**$10,350**	**$985**	**$0**	**$1,166**	**$12,502**	**$23**

Exhibit 4-13 Case 9 Total Plant Cost Details (Continued)

Client:	USDOE/NETL	Report Date:	09-May-07
Project:	Bituminous Baseline Study		

TOTAL PLANT COST SUMMARY

Case:	Case 9 - Subcritical PC w/o CO2				
Plant Size:	550.4 MW,net	Estimate Type:	Conceptual	Cost Base (Dec)	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,527	$0	$250	$0	$0	$1,777	$165	$0	$146	$2,088	$4
11.2	Station Service Equipment	$2,671	$0	$914	$0	$0	$3,585	$343	$0	$295	$4,222	$8
11.3	Switchgear & Motor Control	$3,174	$0	$544	$0	$0	$3,717	$344	$0	$406	$4,468	$8
11.4	Conduit & Cable Tray	$0	$2,038	$6,935	$0	$0	$8,973	$859	$0	$1,475	$11,306	$21
11.5	Wire & Cable	$0	$3,696	$7,305	$0	$0	$11,002	$927	$0	$1,789	$13,718	$25
11.6	Protective Equipment	$252	$0	$894	$0	$0	$1,146	$112	$0	$126	$1,384	$3
11.7	Standby Equipment	$1,178	$0	$28	$0	$0	$1,206	$114	$0	$132	$1,452	$3
11.8	Main Power Transformers	$7,000	$0	$166	$0	$0	$7,166	$544	$0	$771	$8,481	$15
11.9	Electrical Foundations	$0	$298	$737	$0	$0	$1,035	$98	$0	$227	$1,360	$2
	SUBTOTAL 11.	**$15,802**	**$6,032**	**$17,773**	**$0**	**$0**	**$39,607**	**$3,506**	**$0**	**$5,366**	**$48,479**	**$88**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$410	$0	$256	$0	$0	$666	$64	$0	$109	$839	$2
12.7	Distributed Control System Equipment	$4,139	$0	$754	$0	$0	$4,893	$466	$0	$536	$5,895	$11
12.8	Instrument Wiring & Tubing	$2,287	$0	$4,638	$0	$0	$6,924	$590	$0	$1,127	$8,641	$16
12.9	Other I & C Equipment	$1,170	$0	$2,766	$0	$0	$3,935	$383	$0	$432	$4,750	$9
	SUBTOTAL 12.	**$8,006**	**$0**	**$8,413**	**$0**	**$0**	**$16,419**	**$1,503**	**$0**	**$2,204**	**$20,126**	**$37**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$48	$959	$0	$0	$1,007	$99	$0	$221	$1,328	$2
13.2	Site Improvements	$0	$1,581	$1,978	$0	$0	$3,559	$349	$0	$782	$4,690	$9
13.3	Site Facilities	$2,833	$0	$2,815	$0	$0	$5,648	$554	$0	$1,240	$7,442	$14
	SUBTOTAL 13.	**$2,833**	**$1,629**	**$5,752**	**$0**	**$0**	**$10,214**	**$1,003**	**$0**	**$2,243**	**$13,460**	**$24**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,070	$7,192	$0	$0	$15,261	$1,371	$0	$4,158	$20,790	$38
14.2	Turbine Building	$0	$11,680	$11,031	$0	$0	$22,711	$2,045	$0	$6,189	$30,945	$56
14.3	Administration Building	$0	$555	$594	$0	$0	$1,149	$104	$0	$313	$1,566	$3
14.4	Circulation Water Pumphouse	$0	$159	$128	$0	$0	$287	$26	$0	$78	$391	$1
14.5	Water Treatment Buildings	$0	$620	$518	$0	$0	$1,138	$102	$0	$310	$1,550	$3
14.6	Machine Shop	$0	$371	$253	$0	$0	$624	$55	$0	$170	$849	$2
14.7	Warehouse	$0	$251	$256	$0	$0	$507	$46	$0	$138	$691	$1
14.8	Other Buildings & Structures	$0	$205	$177	$0	$0	$383	$34	$0	$104	$521	$1
14.9	Waste Treating Building & Str.	$0	$393	$1,209	$0	$0	$1,603	$151	$0	$439	$2,193	$4
	SUBTOTAL 14.	**$0**	**$22,304**	**$21,358**	**$0**	**$0**	**$43,662**	**$3,934**	**$0**	**$11,899**	**$59,495**	**$108**
	TOTAL COST	**$405,742**	**$43,703**	**$242,779**	**$0**	**$0**	**$692,224**	**$64,830**	**$0**	**$95,558**	**$852,612**	**$1,549**

Exhibit 4-14 Case 9 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 9 - Subcritical PC w/o CO2					Heat Rate-net(Btu/kWh):	9,276
					MWe-net:	550
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00 $/hour					
Operating Labor Burden:	30.00 % of base					
Labor O-H Charge Rate:	25.00 % of labor					
			Total			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	14.0		14.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$5,261,256	$9.558
Maintenance Labor Cost					$5,602,943	$10.179
Administrative & Support Labor					$2,716,050	$4.934
TOTAL FIXED OPERATING COSTS					**$13,580,249**	**$24.672**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$8,404,415**	**$0.00205**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	4,472.64	1.03	**$0**	**$1,429,266**	**$0.00035**
Chemicals						
MU & WT Chem.(lb)	151,553	21,650	0.16	$24,976	$1,106,970	$0.00027
Limestone (ton)	3,661	523	20.60	$75,419	$3,342,699	$0.00082
Carbon (Mercury Removal) (lb)	0	0	0.00	$0	$0	$0.00000
MEA Solvent (ton)	0	0	2,142.40	$0	$0	$0.00000
NaOH (tons)	0	0	412.96	$0	$0	$0.00000
H2SO4 (tons)	0	0	132.15	$0	$0	$0.00000
Corrosion Inhibitor	0	0	0.00	$0	$0	$0.00000
Activated Carbon(lb)	0	0	1.00	$0	$0	$0.00000
Ammonia (28% NH3) ton	550	79	123.60	$67,984	$3,013,146	$0.00074
Subtotal Chemicals				**$168,379**	**$7,462,815**	**$0.00182**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.47	5,500.00	$0	$794,147	$0.00019
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$794,147**	**$0.00019**
Waste Disposal						
Flyash (ton)	0	102	15.45	$0	$488,290	$0.00012
Bottom Ash(ton)	0	407	15.45	$0	$1,953,046	$0.00048
Subtotal-Waste Disposal				**$0**	**$2,441,336**	**$0.00060**
By-products & Emissions						
Gypsum (tons)	0	823	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$168,379**	**$20,531,979**	**$0.00501**
Fuel(ton)	157,562	5,252	42.11	**$6,634,942**	**$68,616,356**	**$0.01674**

4.2.7 CASE 10 – PC SUBCRITICAL UNIT WITH CO_2 CAPTURE

The plant configuration for Case 10, subcritical PC, is the same as Case 9 with the exception that the Econamine FG Plus technology was added for CO_2 capture. The nominal net output was maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility. Unlike the IGCC cases where gross output was fixed by the available size of the combustion turbines, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

The process description for Case 10 is essentially the same as Case 9 with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case 10 are shown in Exhibit 4-15 and Exhibit 4-16, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

4.2.8 CASE 10 PERFORMANCE RESULTS

The Case 10 modeling assumptions were presented previously in Section 4.2.2.

The plant produces a net output of 550 MW at a net plant efficiency of 24.9 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-17 which includes auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over half of the auxiliary plant load. The circulating water system (circulating water pumps and cooling tower fan) accounts for over 15 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 4-15 Case 10 Process Flow Diagram, Subcritical Unit with CO_2 Capture

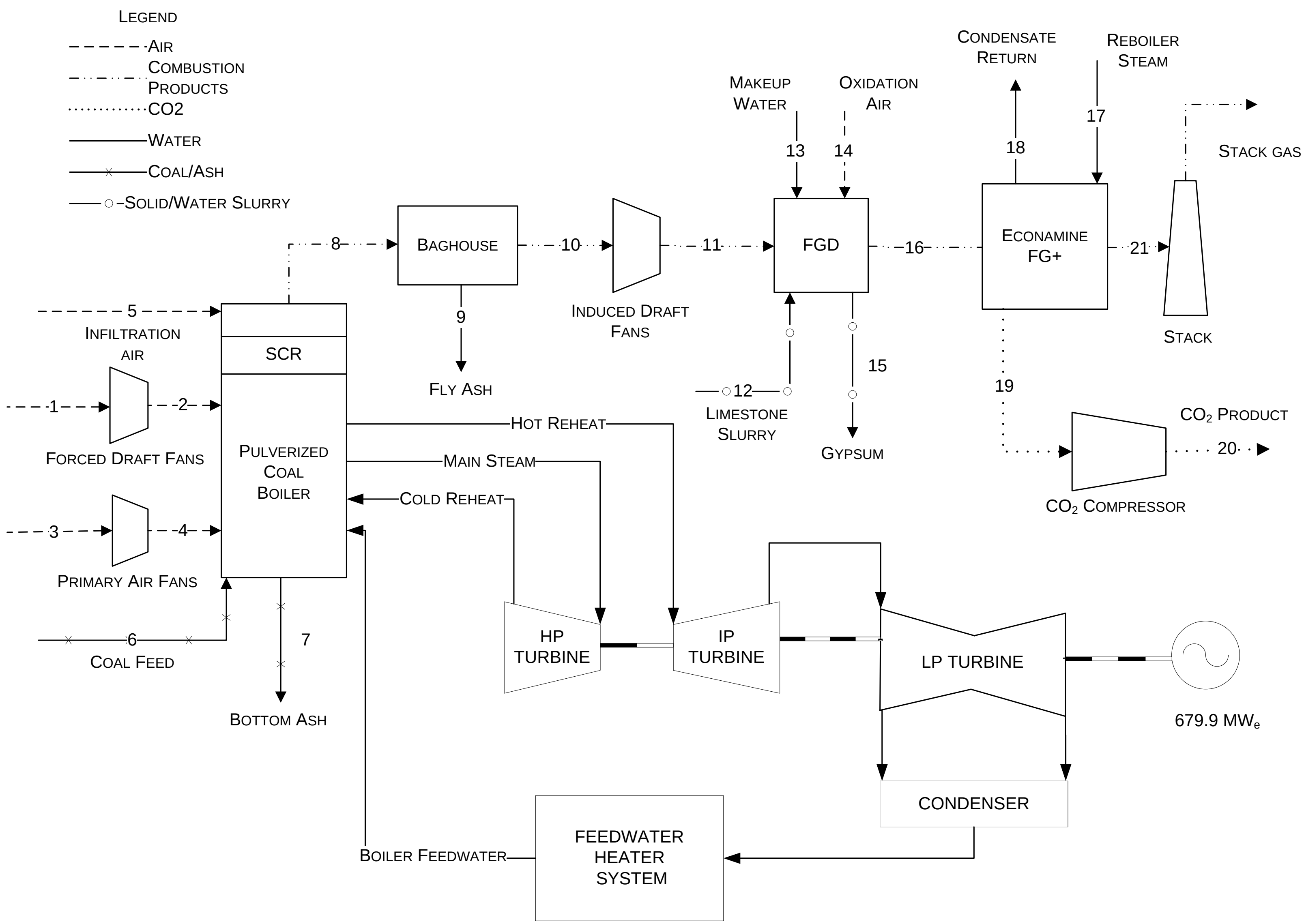

Exhibit 4-16 Case 10 Stream Table, Subcritical Unit with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1448	0.0000	0.1448	0.1448
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0869	0.0000	0.0869	0.0869
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7325	0.0000	0.7325	0.7325
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0250	0.0000	0.0250	0.0250
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	168,844	168,844	51,867	51,867	3,894	0	0	237,558	0	237,558	237,558
V-L Flowrate (lb/hr)	4,872,330	4,872,330	1,496,730	1,496,730	112,375	0	0	7,065,320	0	7,065,320	7,065,320
Solids Flowrate (lb/hr)	0	0	0	0	0	646,589	12,540	50,159	50,159	0	0
Temperature (°F)	59	66	59	78	59	78	350	350	350	350	370
Pressure (psia)	14.7	15.3	14.7	16.1	14.7	14.7	14.4	14.4	14.2	14.2	15.3
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.7	51.4	136.3	141.5
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	--	--	0.05	--	0.05	0.05
Molecular Weight	28.86	28.86	28.86	28.86	28.86	--	--	29.74	--	29.74	29.74

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0092	0.0000	0.0079	0.0000	0.0000	0.0000	0.0000	0.0107
CO_2	0.0000	0.0000	0.0003	0.0014	0.1314	0.0000	0.0000	0.9856	1.0000	0.0176
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0099	0.9978	0.1725	1.0000	1.0000	0.0144	0.0000	0.0458
N_2	0.0000	0.0000	0.7732	0.0007	0.6644	0.0000	0.0000	0.0000	0.0000	0.8940
O_2	0.0000	0.0000	0.2074	0.0000	0.0237	0.0000	0.0000	0.0000	0.0000	0.0319
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	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	8,120	40,086	2,816	22,176	265,166	110,756	110,756	31,826	31,369	197,020
V-L Flowrate (lb/hr)	146,287	722,155	81,276	400,501	7,578,830	1,995,300	1,995,300	1,388,770	1,380,530	5,535,170
Solids Flowrate (lb/hr)	63,956	0	0	99,659	0	0	0	0	0	0
Temperature (°F)	59	59	59	135	135	743	367	69	124	89
Pressure (psia)	14.7	14.7	14.7	14.7	14.7	167.7	167.7	23.5	2,215.0	14.7
Enthalpy (BTU/lb)[A]	---	32.4	13.1	88.0	143.6	1397.7	340.1	13.7	-70.8	45.7
Density (lb/ft^3)	62.62	62.62	0.08	40.44	0.07	0.24	54.94	0.18	40.76	0.07
Molecular Weight	18.02	18.02	28.86	18.06	28.58	18.02	18.02	43.64	44.01	28.09

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-17 Case 10 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**679,923**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	520
Limestone Handling & Reagent Preparation	1,400
Pulverizers	4,400
Ash Handling	840
Primary Air Fans	2,060
Forced Draft Fans	2,620
Induced Draft Fans	11,180
SCR	80
Baghouse	100
FGD Pumps and Agitators	4,680
Amine System Auxiliaries	23,500
CO_2 Compression	51,610
Condensate Pumps	1,210
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Circulating Water Pumps	14,060
Cooling Tower Fans	7,270
Transformer Loss	2,380
TOTAL AUXILIARIES, kWe	**130,310**
NET POWER, kWe	**549,613**
Net Plant Efficiency (HHV)	24.9%
Net Plant Heat Rate (Btu/kWh)	13,724
CONDENSER COOLING DUTY 10^6 kJ/h (10^6 Btu/h)	2,318 (2,199)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	293,288 (646,589)
Limestone Sorbent Feed, kg/h (lb/h)	29,010 (63,956)
Thermal Input, kWt	2,210,668
Makeup water, m^3/min (gpm)	53.4 (14,098)

Notes: 1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 10 is presented in Exhibit 4-18.

Exhibit 4-18 Case 10 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.030 (0.070)	1,783 (1,966)	0.352 (0.777)
Particulates	0.006 (0.013)	331 (365)	0.065 (0.144)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.029 (0.032)	5.8×10^{-6} (12.7×10^{-6})
CO_2	8.7 (20)	517,000 (570,000)	102 (225)
CO_2[1]			126 (278)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 10 ppmv using an NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in negligible SO_2 emissions.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

Exhibit 4-19 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the actual consumption is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream and condensate from cooling the flue gas prior to the CDR facility are re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-19 Case 10 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	3.5 (926)	0	3.5 (926)
BFW Makeup	0.4 (109)	0	0.4 (109)
Cooling Tower Makeup	47.5 (12,543)	5.3 (1,390)	42.2 (11,152)
Total	**51.4 (13,578)**	**5.3 (1,390)**	**46.1 (12,187)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 10 PC boiler, the FGD unit, CDR system and steam cycle in Exhibit 4-20.

An overall plant energy balance is provided in tabular form in Exhibit 4-21. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-17) is calculated by multiplying the power out by a generator efficiency of 98.4 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

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Exhibit 4-20 Case 10 Heat and Mass Balance, Subcritical PC Boiler with CO_2 Capture

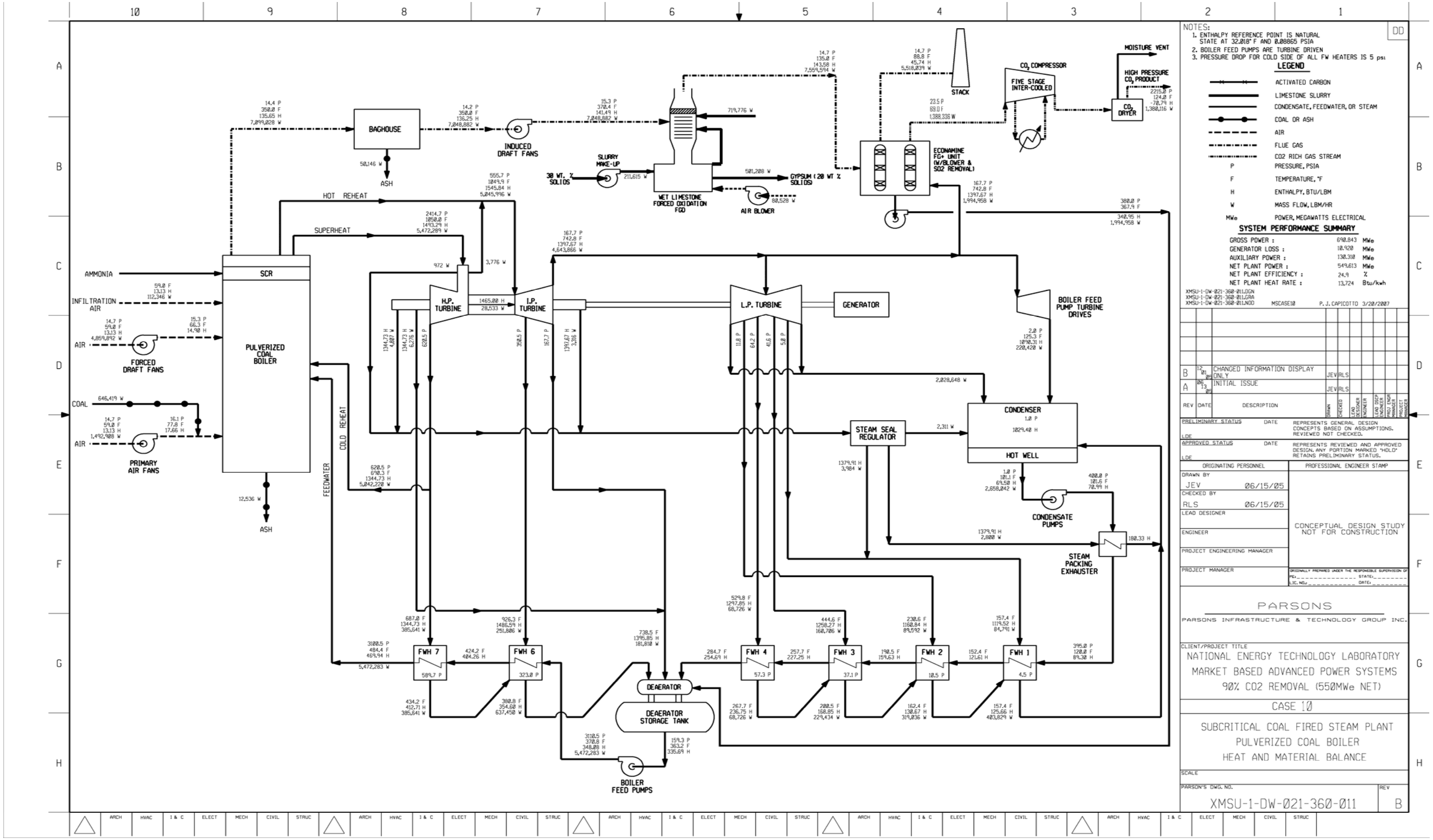

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Exhibit 4-21 Case 10 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	7,543.1	6.3		7,549.4
Ambient Air		83.6		83.6
Infiltration Air		1.5		1.5
Limestone		96.0		96.0
FGD Oxidant		1.1		1.1
Raw Water Makeup		161.8		161.8
Auxiliary Power			472.3	472.3
Totals	**7,543.1**	**350.2**	**472.3**	**8,365.6**
Heat Out (MMBtu/hr)				
Bottom Ash		0.6		0.6
Fly Ash		2.6		2.6
Flue Gas Exhaust		253.0		253.0
CO_2 Product		(96.8)		(96.8)
Condenser		2,200.0		2,200.0
Econamine Process		3514.7		3514.7
Cooling Tower Blowdown		73.1		73.1
Gypsum Slurry		3.1		3.1
Process Losses (1)		56.0		56.0
Power			2,359.2	2,359.2
Totals	**0.0**	**6,006.4**	**2,359.2**	**8,365.6**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.2.9 CASE 10 – MAJOR EQUIPMENT LIST

Major equipment items for the subcritical PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	64 tonne (70 ton)	2	1
9	Feeder	Vibratory	245 tonne/h (270 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	481 tonne/h (530 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	245 tonne (270 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	481 tonne/h (530 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	481 tonne/h (530 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,089 tonne (1,200 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	118 tonne/h (130 tph)	1	0
21	Limestone Conveyor No. L1	Belt	118 tonne/h (130 tph)	1	0
22	Limestone Reclaim Hopper	N/A	27 tonne (30 ton)	1	0
23	Limestone Reclaim Feeder	Belt	100 tonne/h (110 tph)	1	0
24	Limestone Conveyor No. L2	Belt	100 tonne/h (110 tph)	1	0
25	Limestone Day Bin	w/ actuator	381 tonne (420 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	54 tonne/h (60 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	54 tonne/h (60 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	32 tonne/h (35 tph)	1	1
4	Limestone Ball Mill	Rotary	32 tonne/h (35 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	121,134 liters (32,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	490 lpm @ 12m H2O (540 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	127 lpm (140 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	688,950 liters (182,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	345 lpm @ 9m H2O (380 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,639,096 liters (433,000 gal)	2	0
2	Condensate Pumps	Vertical canned	22,334 lpm @ 335 m H2O (5,900 gpm @ 1,100 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,730,629 kg/h (6,020,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	45,804 lpm @ 2,499 m H2O (12,100 gpm @ 8,200 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	13,628 lpm @ 2,499 m H2O (3,600 gpm @ 8,200 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	662,246 kg/h (1,460,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,730,629 kg/h (6,020,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,730,629 kg/h (6,020,000 lb/h)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	29,602 lpm @ 43 m H2O (7,820 gpm @ 140 ft H2O)	2	1
21	Filtered Water Pumps	Stainless steel, single suction	2,461 lpm @ 49 m H2O (650 gpm @ 160 ft H2O)	2	1
22	Filtered Water Tank	Vertical, cylindrical	2,377,257 liter (628,000 gal)	1	0
23	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,098 lpm (290 gpm)	1	1
24	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	2,730,629 kg/h steam @ 16.5 MPa/566°C/566°C (6,020,000 lb/h steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	373,307 kg/h, 5,111 m3/min @ 123 cm WG (823,000 lb/h, 180,500 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,215,629 kg/h, 16,642 m3/min @ 47 cm WG (2,680,000 lb/h, 587,700 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,762,662 kg/h, 37,427 m3/min @ 90 cm WG (3,886,000 lb/h, 1,321,700 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,524,417 kg/h (7,770,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	210 m3/min @ 108 cm WG (7,400 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	230,912 liter (61,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	44 lpm @ 91 m H2O (12 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,762,662 kg/h (3,886,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	59,607 m3/min (2,105,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	208,199 lpm @ 64 m H2O (55,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	6,284 lpm (1,660 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	278 m3/min @ 0.3 MPa (9,800 acfm @ 42 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,590 lpm (420 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	50 tonne/h (55 tph) 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	946 lpm @ 12 m H2O (250 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	643,525 lpm (170,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,861 lpm @ 21 m H2O (1,020 gpm @ 70 ft H2O)	1	1

ACCOUNT 5B CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,890,575 kg/h (4,168,000 lb/h) 20.2 wt % CO2 inlet concentration	2	0
2	CO2 Compressor	Integrally geared, multi-stage centrifugal	344,408 kg/h @ 15.3 MPa (759,289 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.1 m (20 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	720 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	800 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,551 MMkJ/h (2,420 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	704,092 lpm @ 30.5 m (186,000 gpm @ 100 ft)	4	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 6,821 MMkJ/h (6,470 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	6.4 tonne/h (7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	265 lpm @ 17 m H2O (70 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	265 lpm (70 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	23 m3/min @ 0.2 MPa (810 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	771 tonne (1,700 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	136 tonne/h (150 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 140 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 21 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.10 CASE 10 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-22 shows the total plant capital cost summary organized by cost account and Exhibit 4-23 shows a more detailed breakdown of the capital costs. Exhibit 4-24 shows the initial and annual O&M costs.

The estimated TPC of the subcritical PC boiler with CO_2 capture is $2,888/kW. Process contingency represents 3.6 percent of the TPC and project contingency represents 12.6 percent. The 20-year LCOE, including CO_2 TS&M costs of 4.3 mills/kWh, is 118.8 mills/kWh.

Exhibit 4-22 Case 10 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 10 - Subcritical PC w/ CO2
Plant Size: 549.6 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$20,525	$5,540	$12,420	$0	$0	**$38,485**	$3,449	$0	$6,290	**$48,223**	$88
2	COAL & SORBENT PREP & FEED	$13,990	$807	$3,544	$0	$0	**$18,342**	$1,608	$0	$2,992	**$22,942**	$42
3	FEEDWATER & MISC. BOP SYSTEMS	$53,307	$0	$25,510	$0	$0	**$78,817**	$7,217	$0	$14,343	**$100,377**	$183
4	PC BOILER											
4.1	PC Boiler & Accessories	$167,758	$0	$108,417	$0	$0	**$276,176**	$26,774	$0	$30,295	**$333,245**	$606
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$167,758**	**$0**	**$108,417**	**$0**	**$0**	**$276,176**	**$26,774**	**$0**	**$30,295**	**$333,245**	**$606**
5	FLUE GAS CLEANUP	$109,618	$0	$37,721	$0	$0	**$147,340**	$14,000	$0	$16,134	**$177,474**	$323
5B	CO_2 REMOVAL & COMPRESSION	$243,432	$0	$74,100	$0	$0	**$317,532**	$30,138	$56,039	$80,742	**$484,450**	$881
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$19,363	$1,062	$13,228	$0	$0	**$33,653**	$3,074	$0	$4,824	**$41,551**	$76
	SUBTOTAL 7	**$19,363**	**$1,062**	**$13,228**	**$0**	**$0**	**$33,653**	**$3,074**	**$0**	**$4,824**	**$41,551**	**$76**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$52,758	$0	$6,989	$0	$0	**$59,747**	$5,720	$0	$6,547	**$72,014**	$131
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$26,773	$1,170	$15,006	$0	$0	**$42,949**	$3,737	$0	$6,617	**$53,303**	$97
	SUBTOTAL 8	**$79,532**	**$1,170**	**$21,995**	**$0**	**$0**	**$102,697**	**$9,457**	**$0**	**$13,163**	**$125,317**	**$228**
9	COOLING WATER SYSTEM	$21,405	$11,272	$20,092	$0	$0	**$52,768**	$4,916	$0	$7,834	**$65,518**	$119
10	ASH/SPENT SORBENT HANDLING SYS	$5,440	$171	$7,234	$0	$0	**$12,844**	$1,223	$0	$1,448	**$15,515**	$28
11	ACCESSORY ELECTRIC PLANT	$20,789	$10,729	$30,669	$0	$0	**$62,187**	$5,554	$0	$8,642	**$76,384**	$139
12	INSTRUMENTATION & CONTROL	$9,150	$0	$9,615	$0	$0	**$18,765**	$1,718	$938	$2,635	**$24,056**	$44
13	IMPROVEMENTS TO SITE	$3,201	$1,840	$6,500	$0	$0	**$11,541**	$1,133	$0	$2,535	**$15,210**	$28
14	BUILDINGS & STRUCTURES	$0	$24,892	$23,781	$0	$0	**$48,672**	$4,385	$0	$7,959	**$61,016**	$111
	TOTAL COST	**$767,510**	**$57,483**	**$394,827**	**$0**	**$0**	**$1,219,819**	**$114,645**	**$56,977**	**$199,835**	**$1,591,277**	**$2,895**

Exhibit 4-23 Case 10 Total Plant Cost Details

Client:	USDOE/NETL	**Report Date:**	09-May-07
Project:	Bituminous Baseline Study		
	TOTAL PLANT COST SUMMARY		
Case:	Case 10 - Subcritical PC w/ CO2		
Plant Size:	549.6 MW,net **Estimate Type:** Conceptual	**Cost Base (Dec)**	2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$4,213	$0	$1,944	$0	$0	$6,158	$550	$0	$1,006	$7,714	$14
1.2	Coal Stackout & Reclaim	$5,445	$0	$1,246	$0	$0	$6,692	$586	$0	$1,092	$8,369	$15
1.3	Coal Conveyors	$5,062	$0	$1,233	$0	$0	$6,296	$552	$0	$1,027	$7,875	$14
1.4	Other Coal Handling	$1,324	$0	$285	$0	$0	$1,610	$141	$0	$263	$2,013	$4
1.5	Sorbent Receive & Unload	$170	$0	$52	$0	$0	$221	$20	$0	$36	$277	$1
1.6	Sorbent Stackout & Reclaim	$2,741	$0	$508	$0	$0	$3,249	$283	$0	$530	$4,061	$7
1.7	Sorbent Conveyors	$978	$210	$242	$0	$0	$1,431	$124	$0	$233	$1,788	$3
1.8	Other Sorbent Handling	$591	$138	$313	$0	$0	$1,042	$92	$0	$170	$1,304	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$5,192	$6,596	$0	$0	$11,787	$1,102	$0	$1,933	$14,823	$27
	SUBTOTAL 1.	**$20,525**	**$5,540**	**$12,420**	**$0**	**$0**	**$38,485**	**$3,449**	**$0**	**$6,290**	**$48,223**	**$88**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,458	$0	$484	$0	$0	$2,942	$257	$0	$480	$3,678	$7
2.2	Coal Conveyor to Storage	$6,292	$0	$1,388	$0	$0	$7,680	$672	$0	$1,253	$9,605	$17
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$4,677	$201	$981	$0	$0	$5,859	$510	$0	$955	$7,324	$13
2.6	Sorbent Storage & Feed	$563	$0	$218	$0	$0	$782	$69	$0	$128	$979	$2
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$607	$473	$0	$0	$1,080	$99	$0	$177	$1,357	$2
	SUBTOTAL 2.	**$13,990**	**$807**	**$3,544**	**$0**	**$0**	**$18,342**	**$1,608**	**$0**	**$2,992**	**$22,942**	**$42**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$20,059	$0	$7,016	$0	$0	$27,075	$2,376	$0	$4,418	$33,869	$62
3.2	Water Makeup & Pretreating	$8,410	$0	$2,704	$0	$0	$11,114	$1,042	$0	$2,431	$14,588	$27
3.3	Other Feedwater Subsystems	$6,624	$0	$2,810	$0	$0	$9,434	$841	$0	$1,541	$11,816	$21
3.4	Service Water Systems	$1,660	$0	$896	$0	$0	$2,556	$237	$0	$559	$3,352	$6
3.5	Other Boiler Plant Systems	$7,807	$0	$7,637	$0	$0	$15,444	$1,449	$0	$2,534	$19,426	$35
3.6	FO Supply Sys & Nat Gas	$271	$0	$333	$0	$0	$605	$56	$0	$99	$760	$1
3.7	Waste Treatment Equipment	$5,668	$0	$3,247	$0	$0	$8,915	$864	$0	$1,956	$11,734	$21
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,808	$0	$865	$0	$0	$3,674	$353	$0	$805	$4,832	$9
	SUBTOTAL 3.	**$53,307**	**$0**	**$25,510**	**$0**	**$0**	**$78,817**	**$7,217**	**$0**	**$14,343**	**$100,377**	**$183**
4	PC BOILER											
4.1	PC Boiler & Accessories	$167,758	$0	$108,417	$0	$0	$276,176	$26,774	$0	$30,295	$333,245	$606
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$167,758**	**$0**	**$108,417**	**$0**	**$0**	**$276,176**	**$26,774**	**$0**	**$30,295**	**$333,245**	**$606**

Exhibit 4-23 Case 10 Total Plant Cost Details (Continued)

Client: USDOE/NETL — **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 10 - Subcritical PC w/ CO2
Plant Size: 549.6 MW,net — **Estimate Type:** Conceptual — **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$75,926	$0	$16,357	$0	$0	$92,284	$8,734	$0	$10,102	$111,120	$202
5.2	Other FGD	$3,962	$0	$4,493	$0	$0	$8,456	$815	$0	$927	$10,197	$19
5.3	Bag House & Accessories	$22,462	$0	$14,266	$0	$0	$36,728	$3,513	$0	$4,024	$44,265	$81
5.4	Other Particulate Removal Materials	$1,520	$0	$1,628	$0	$0	$3,148	$303	$0	$345	$3,796	$7
5.5	Gypsum Dewatering System	$5,747	$0	$977	$0	$0	$6,724	$635	$0	$736	$8,096	$15
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$109,618**	**$0**	**$37,721**	**$0**	**$0**	**$147,340**	**$14,000**	**$0**	**$16,134**	**$177,474**	**$323**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$214,986	$0	$65,208	$0	$0	$280,194	$26,593	$56,039	$72,565	$435,391	$792
5B.2	CO_2 Compression & Drying	$28,446	$0	$8,892	$0	$0	$37,338	$3,545	$0	$8,177	$49,059	$89
	SUBTOTAL 5B.	**$243,432**	**$0**	**$74,100**	**$0**	**$0**	**$317,532**	**$30,138**	**$56,039**	**$80,742**	**$484,450**	**$881**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$10,045	$0	$6,556	$0	$0	$16,601	$1,450	$0	$2,708	$20,758	$38
7.4	Stack	$9,318	$0	$5,457	$0	$0	$14,775	$1,412	$0	$1,619	$17,805	$32
7.9	Duct & Stack Foundations	$0	$1,062	$1,215	$0	$0	$2,278	$212	$0	$498	$2,988	$5
	SUBTOTAL 7.	**$19,363**	**$1,062**	**$13,228**	**$0**	**$0**	**$33,653**	**$3,074**	**$0**	**$4,824**	**$41,551**	**$76**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$52,758	$0	$6,989	$0	$0	$59,747	$5,720	$0	$6,547	$72,014	$131
8.2	Turbine Plant Auxiliaries	$375	$0	$804	$0	$0	$1,179	$114	$0	$129	$1,423	$3
8.3	Condenser & Auxiliaries	$6,425	$0	$2,475	$0	$0	$8,900	$847	$0	$975	$10,721	$20
8.4	Steam Piping	$19,973	$0	$9,866	$0	$0	$29,839	$2,490	$0	$4,849	$37,179	$68
8.9	TG Foundations	$0	$1,170	$1,861	$0	$0	$3,031	$285	$0	$663	$3,979	$7
	SUBTOTAL 8.	**$79,532**	**$1,170**	**$21,995**	**$0**	**$0**	**$102,697**	**$9,457**	**$0**	**$13,163**	**$125,317**	**$228**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$14,689	$0	$4,810	$0	$0	$19,499	$1,852	$0	$2,135	$23,485	$43
9.2	Circulating Water Pumps	$4,326	$0	$310	$0	$0	$4,636	$397	$0	$503	$5,536	$10
9.3	Circ.Water System Auxiliaries	$912	$0	$122	$0	$0	$1,034	$98	$0	$113	$1,245	$2
9.4	Circ.Water Piping	$0	$7,355	$7,015	$0	$0	$14,370	$1,324	$0	$2,354	$18,048	$33
9.5	Make-up Water System	$749	$0	$993	$0	$0	$1,742	$165	$0	$286	$2,193	$4
9.6	Component Cooling Water Sys	$728	$0	$575	$0	$0	$1,304	$122	$0	$214	$1,640	$3
9.9	Circ.Water System Foundations& Structures	$0	$3,917	$6,267	$0	$0	$10,185	$959	$0	$2,229	$13,372	$24
	SUBTOTAL 9.	**$21,405**	**$11,272**	**$20,092**	**$0**	**$0**	**$52,768**	**$4,916**	**$0**	**$7,834**	**$65,518**	**$119**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$723	$0	$2,231	$0	$0	$2,954	$288	$0	$324	$3,566	$6
10.7	Ash Transport & Feed Equipment	$4,716	$0	$4,801	$0	$0	$9,517	$900	$0	$1,042	$11,458	$21
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$171	$203	$0	$0	$373	$35	$0	$82	$490	$1
	SUBTOTAL 10.	**$5,440**	**$171**	**$7,234**	**$0**	**$0**	**$12,844**	**$1,223**	**$0**	**$1,448**	**$15,515**	**$28**

Exhibit 4-23 Case 10 Total Plant Cost Details (Continued)

Client:	USDOE/NETL
Project:	Bituminous Baseline Study
Report Date:	09-May-07
Case:	Case 10 - Subcritical PC w/ CO2
Plant Size:	549.6 MW,net
Estimate Type:	Conceptual
Cost Base (Dec)	2006 ($x1000)

TOTAL PLANT COST SUMMARY

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,672	$0	$274	$0	$0	$1,946	$180	$0	$159	$2,285	$4
11.2	Station Service Equipment	$4,842	$0	$1,658	$0	$0	$6,499	$622	$0	$534	$7,655	$14
11.3	Switchgear & Motor Control	$5,754	$0	$986	$0	$0	$6,740	$624	$0	$736	$8,100	$15
11.4	Conduit & Cable Tray	$0	$3,695	$12,573	$0	$0	$16,268	$1,557	$0	$2,674	$20,498	$37
11.5	Wire & Cable	$0	$6,702	$13,245	$0	$0	$19,947	$1,681	$0	$3,244	$24,872	$45
11.6	Protective Equipment	$253	$0	$898	$0	$0	$1,152	$113	$0	$126	$1,391	$3
11.7	Standby Equipment	$1,268	$0	$30	$0	$0	$1,298	$123	$0	$142	$1,563	$3
11.8	Main Power Transformers	$7,000	$0	$185	$0	$0	$7,185	$546	$0	$773	$8,504	$15
11.9	Electrical Foundations	$0	$332	$821	$0	$0	$1,153	$110	$0	$253	$1,515	$3
	SUBTOTAL 11.	**$20,789**	**$10,729**	**$30,669**	**$0**	**$0**	**$62,187**	**$5,554**	**$0**	**$8,642**	**$76,384**	**$139**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$469	$0	$292	$0	$0	$761	$73	$38	$131	$1,003	$2
12.7	Distributed Control System Equipment	$4,731	$0	$861	$0	$0	$5,592	$533	$280	$640	$7,045	$13
12.8	Instrument Wiring & Tubing	$2,613	$0	$5,301	$0	$0	$7,914	$674	$396	$1,348	$10,331	$19
12.9	Other I & C Equipment	$1,337	$0	$3,161	$0	$0	$4,498	$438	$225	$516	$5,677	$10
	SUBTOTAL 12.	**$9,150**	**$0**	**$9,615**	**$0**	**$0**	**$18,765**	**$1,718**	**$938**	**$2,635**	**$24,056**	**$44**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$54	$1,084	$0	$0	$1,138	$112	$0	$250	$1,500	$3
13.2	Site Improvements	$0	$1,786	$2,235	$0	$0	$4,022	$395	$0	$883	$5,300	$10
13.3	Site Facilities	$3,201	$0	$3,181	$0	$0	$6,382	$626	$0	$1,402	$8,410	$15
	SUBTOTAL 13.	**$3,201**	**$1,840**	**$6,500**	**$0**	**$0**	**$11,541**	**$1,133**	**$0**	**$2,535**	**$15,210**	**$28**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,723	$7,774	$0	$0	$16,497	$1,481	$0	$2,697	$20,676	$38
14.2	Turbine Building	$0	$12,815	$12,103	$0	$0	$24,918	$2,244	$0	$4,074	$31,236	$57
14.3	Administration Building	$0	$613	$657	$0	$0	$1,270	$115	$0	$208	$1,592	$3
14.4	Circulation Water Pumphouse	$0	$281	$227	$0	$0	$508	$45	$0	$83	$636	$1
14.5	Water Treatment Buildings	$0	$1,110	$926	$0	$0	$2,036	$182	$0	$333	$2,551	$5
14.6	Machine Shop	$0	$410	$279	$0	$0	$689	$61	$0	$113	$863	$2
14.7	Warehouse	$0	$278	$282	$0	$0	$560	$51	$0	$92	$702	$1
14.8	Other Buildings & Structures	$0	$227	$196	$0	$0	$423	$38	$0	$69	$530	$1
14.9	Waste Treating Building & Str.	$0	$435	$1,336	$0	$0	$1,771	$167	$0	$291	$2,229	$4
	SUBTOTAL 14.	**$0**	**$24,892**	**$23,781**	**$0**	**$0**	**$48,672**	**$4,385**	**$0**	**$7,959**	**$61,016**	**$111**
	TOTAL COST	**$767,510**	**$57,483**	**$394,827**	**$0**	**$0**	**$1,219,819**	**$114,645**	**$56,977**	**$199,835**	**$1,591,277**	**$2,895**

Exhibit 4-24 Case 10 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 10 - Subcritical PC w/ CO2					Heat Rate-net(Btu/kWh):	13,724
					MWe-net:	550
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	11.3		11.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	2.0		2.0			
TOTAL-O.J.'s	16.3		16.3			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$6,138,007	$11.168
Maintenance Labor Cost					$10,295,213	$18.732
Administrative & Support Labor					$4,108,305	$7.475
TOTAL FIXED OPERATING COSTS					**$20,541,525**	**$37.375**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$15,442,820**	**$0.00377**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	10,151	1.03	**$0**	**$3,243,688**	**$0.00079**
Chemicals						
MU & WT Chem.(lb)	343,946	49,135	0.16	$56,682	$2,512,244	$0.00061
Limestone (ton)	5,372	767	20.60	$110,669	$4,905,029	$0.00120
Carbon (Mercury Removal) (lb)	0	0	0.00	$0	$0	$0.00000
MEA Solvent (ton)	1,174	1.67	2,142.40	$2,515,178	$1,108,686	$0.00027
NaOH (tons)	82	8.18	412.96	$33,863	$1,048,541	$0.00026
H2SO4 (tons)	79	7.91	132.15	$10,440	$324,224	$0.00008
Corrosion Inhibitor	0	0	0.00	$162,300	$7,730	$0.00000
Activated Carbon(lb)	0	1,992	1.00	$0	$618,018	$0.00015
Ammonia (28% NH3) ton	813	116	123.60	$100,439	$4,451,615	$0.00109
Subtotal Chemicals				**$2,989,571**	**$14,976,086**	**$0.00366**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.68	5,500.00	$0	$1,168,014	$0.00029
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$1,168,014**	**$0.00029**
Waste Disposal						
Flyash (ton)	0	144	15.45	$0	$690,819	$0.00017
Bottom Ash(ton)	0	577	15.45	$0	$2,763,393	$0.00068
Subtotal-Waste Disposal				**$0**	**$3,454,212**	**$0.00084**
By-products & Emissions						
Gypsum (tons)	0	1,196	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,989,571**	**$38,284,819**	**$0.00936**
Fuel(ton)	232,764	7,759	42.11	**$9,801,707**	**$101,365,989**	**$0.02477**

4.3 SUPERCRITICAL PC CASES

This section contains an evalution of plant designs for Cases 11 and 12 which are based on a supercritical PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F) cycle. The only difference between the two plants is that Case 12 includes CO_2 capture while Case 11 does not.

The balance of Section 4.3 is organized in an analogous manner to the subcrtical PC section:

- Process and System Description for Case 11
- Key Assumptions for Cases 11 and 12
- Sparing Philosophy for Cases 11 and 12
- Performance Results for Case 11
- Equipment List for Case 11
- Cost Estimates for Case 11
- Process and System Description, Performance Results, Equipment List and Cost Estimates for Case 12

4.3.1 PROCESS DESCRIPTION

In this section the supercritical PC process without CO_2 capture is described. The system description is nearly identical to the subcritical PC case without CO_2 capture but is repeated here for completeness. The description follows the block flow diagram (BFD) in Exhibit 4-25 and stream numbers reference the same Exhibit. The tables in Exhibit 4-26 provide process data for the numbered streams in the BFD.

Coal (stream 6) and primary air (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the overfire air, is provided by the forced draft fans (stream 2). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 5.

Flue gas exits the boiler through the SCR reactor (stream 8) and is cooled to 177°C (350°F) in the combustion air preheater (not shown) before passing through a fabric filter for particulate removal (stream 10). An ID fan increases the flue gas temperature to 188°C (370°F) and provides the motive force for the flue gas (stream 11) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 13), oxidation air (stream 14), limestone slurry (stream 12) and product gypsum (stream 15). The clean, saturated flue gas exiting the FGD unit (stream 16) passes to the plant stack and is discharged to atmosphere

Exhibit 4-25 Case 11 Process Flow Diagram, Supercritical Unit without CO_2 Capture

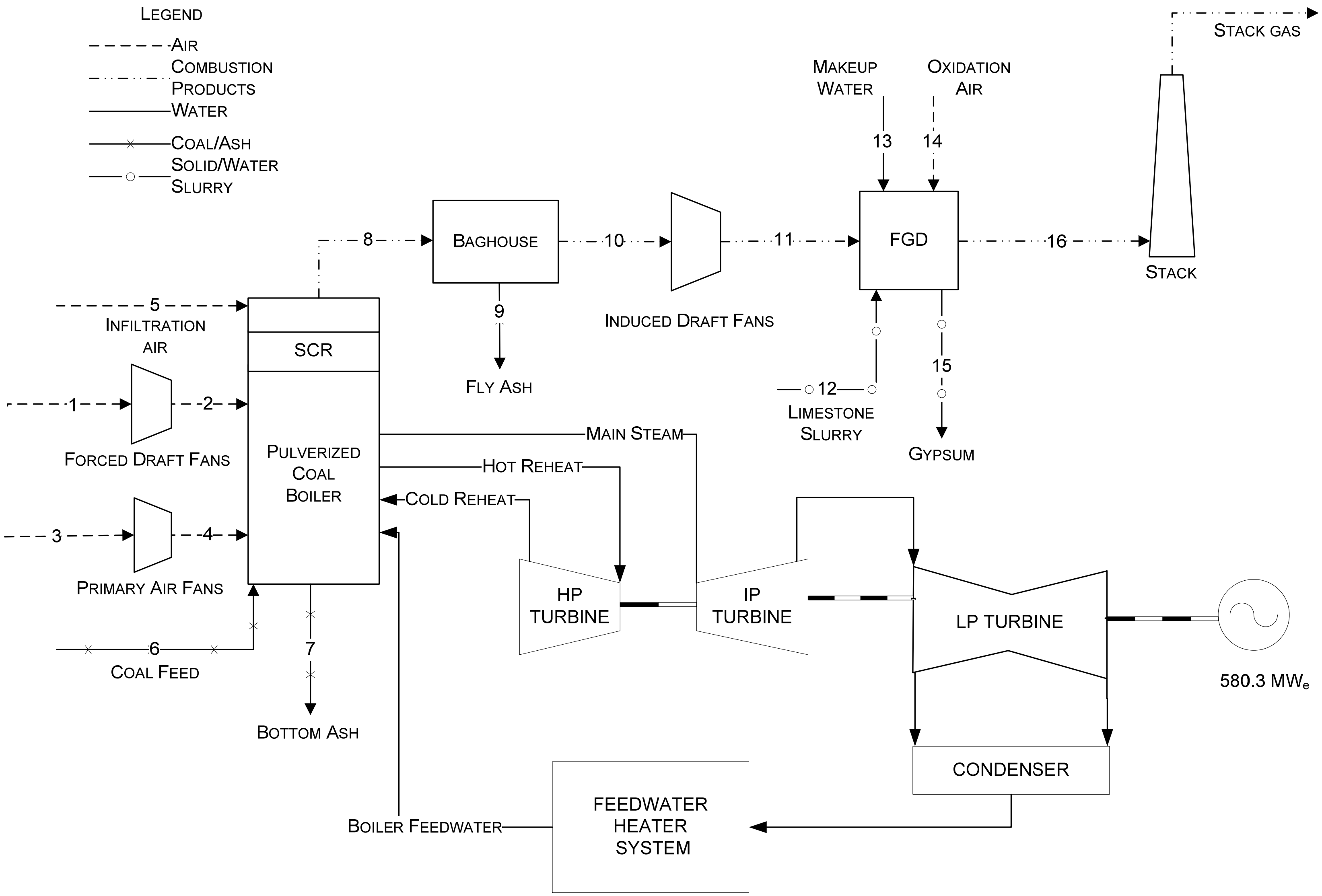

Exhibit 4-26 Case 11 Stream Table, Supercritical Unit without CO_2 Capture

	1	2	3	4	5	6	7	8
V-L Mole Fractions								
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flow (lb_{mol}/hr)	107,211	107,211	32,934	32,934	2,477	0	0	150,861
V-L Flow (lb/hr)	3,093,780	3,093,780	950,376	950,376	71,480	0	0	4,487,030
Solids Flowrate	0	0	0	0	0	411,282	7,976	31,905
Temperature (°F)	59	66	59	78	59	59	350	350
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.6
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	---	---	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	---	---	29.74

	9	10	11	12	13	14	15	16
V-L Mole Fractions								
Ar	0.0000	0.0087	0.0087	0.0000	0.0000	0.0092	0.0000	0.0080
CO_2	0.0000	0.1450	0.1450	0.0000	0.0000	0.0003	0.0016	0.1326
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0870	0.0870	1.0000	1.0000	0.0099	0.9976	0.1669
N_2	0.0000	0.7324	0.7324	0.0000	0.0000	0.7732	0.0008	0.6690
O_2	0.0000	0.0247	0.0247	0.0000	0.0000	0.2074	0.0000	0.0235
SO_2	0.0000	0.0021	0.0021	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	1.0000
V-L Flow (lb_{mol}/hr)	0	150,861	150,861	5,111	24,381	1,705	14,140	167,129
V-L Flow (lb/hr)	0	4,487,030	4,487,030	92,067	439,223	49,200	255,432	4,789,380
Solids Flowrate	31,905	0	0	40,819	0	0	63,529	0
Temperature (°F)	350	350	370	59	60	59	134	134
Pressure (psia)	14.20	14.20	15.26	14.70	14.70	14.70	14.70	14.70
Enthalpy (BTU/lb)[A]	51.4	136.2	141.5	---	33.3	13.1	87.0	139.1
Density (lb/ft^3)	---	0.05	0.05	62.62	62.59	0.08	36.10	0.07
Avg. Molecular Weight	---	29.74	29.74	18.02	18.02	28.86	18.06	28.66

A - Reference conditions are 32.02 F & 0.089 PSIA

4.3.2 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 11 and 12, supercritical PC with and without CO_2 capture, are compiled in Exhibit 4-27.

Exhibit 4-27 Supercritical PC Plant Study Configuration Matrix

	Case 11 w/o CO_2 Capture	**Case 12 w/CO_2 Capture**
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3500/1100/1100)	24.1/593/593 (3500/1100/1100)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, %	89	89
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	57 (135)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	86	86
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.8	99.8
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90
CO_2 Control	N/A	Econamine FG Plus
CO_2 Capture, % (A)	N/A	90
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the flue gas content
B. An SO_2 polishing step is included to meet more stringent SOx content limits in the flue gas (< 10 ppmv) to reduce formation of amine heat stable salts during the CO_2 absorption process
C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Cases 11 and 12

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 4-6.

4.3.3 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC supercritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case 12 only, two parallel Econamine FG Plus CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50%)

4.3.4 Case 11 Performance Results

The plant produces a net output of 550 MWe at a net plant efficiency of 39.1 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 4-28 which includes auxiliary power requirements.

Exhibit 4-28 Case 11 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**580,260**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	410
Limestone Handling & Reagent Preparation	890
Pulverizers	2,800
Ash Handling	530
Primary Air Fans	1,310
Forced Draft Fans	1,660
Induced Draft Fans	7,130
SCR	50
Baghouse	100
FGD Pumps and Agitators	2,980
Econamine FG Plus Auxiliaries	N/A
CO_2 Compression	N/A
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	790
Circulating Water Pumps	4,770
Cooling Tower Fans	2,460
Transformer Loss	1,830
TOTAL AUXILIARIES, kWe	**30,110**
NET POWER, kWe	**550,150**
Net Plant Efficiency (HHV)	39.1%
Net Plant Heat Rate (Btu/kWh)	8,721
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	2,314 (2,195)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	186,555 (411,282)
Limestone Sorbent Feed, kg/h (lb/h)	18,515 (40,819)
Thermal Input, kWt	1,406,161
Makeup Water, m^3/min (gpm)	20.6 (5,441)

Notes: 1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 11 is presented in Exhibit 4-29.

Exhibit 4-29 Case 11 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	0.036 (0.085)	1,373 (1,514)	0.318 (0.701)
NO_X	0.030 (0.070)	1,134 (1,250)	0.263 (0.579)
Particulates	0.006 (0.013)	211 (232)	0.049 (0.107)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.018 (0.020)	4.3×10^{-6} (9.4×10^{-6})
CO_2	87.5 (203)	3,295,000 (3,632,000)	763 (1,681)
CO_2[1]			804 (1,773)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. CO_2 emissions represent the uncontrolled discharge from the process.

Exhibit 4-30 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream is re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-30 Case 11 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	2.1 (546)	0	2.1 (546)
BFW Makeup	0.3 (73)	0	0.3 (73)
Cooling Tower Makeup	18.5 (4,895)	0.3 (73)	18.2 (4,822)
Total	**20.9 (5,514)**	**0.3 (73)**	**20.6 (5,441)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 11 PC boiler, the FGD unit and steam cycle in Exhibit 4-31.

An overall plant energy balance is provided in tabular form in Exhibit 4-32. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-28) is calculated by multiplying the power out by a generator efficiency of 98.4 percent.

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Exhibit 4-31 Case 11 Heat and Mass Balance, Supercritical PC Boiler without CO_2 Capture

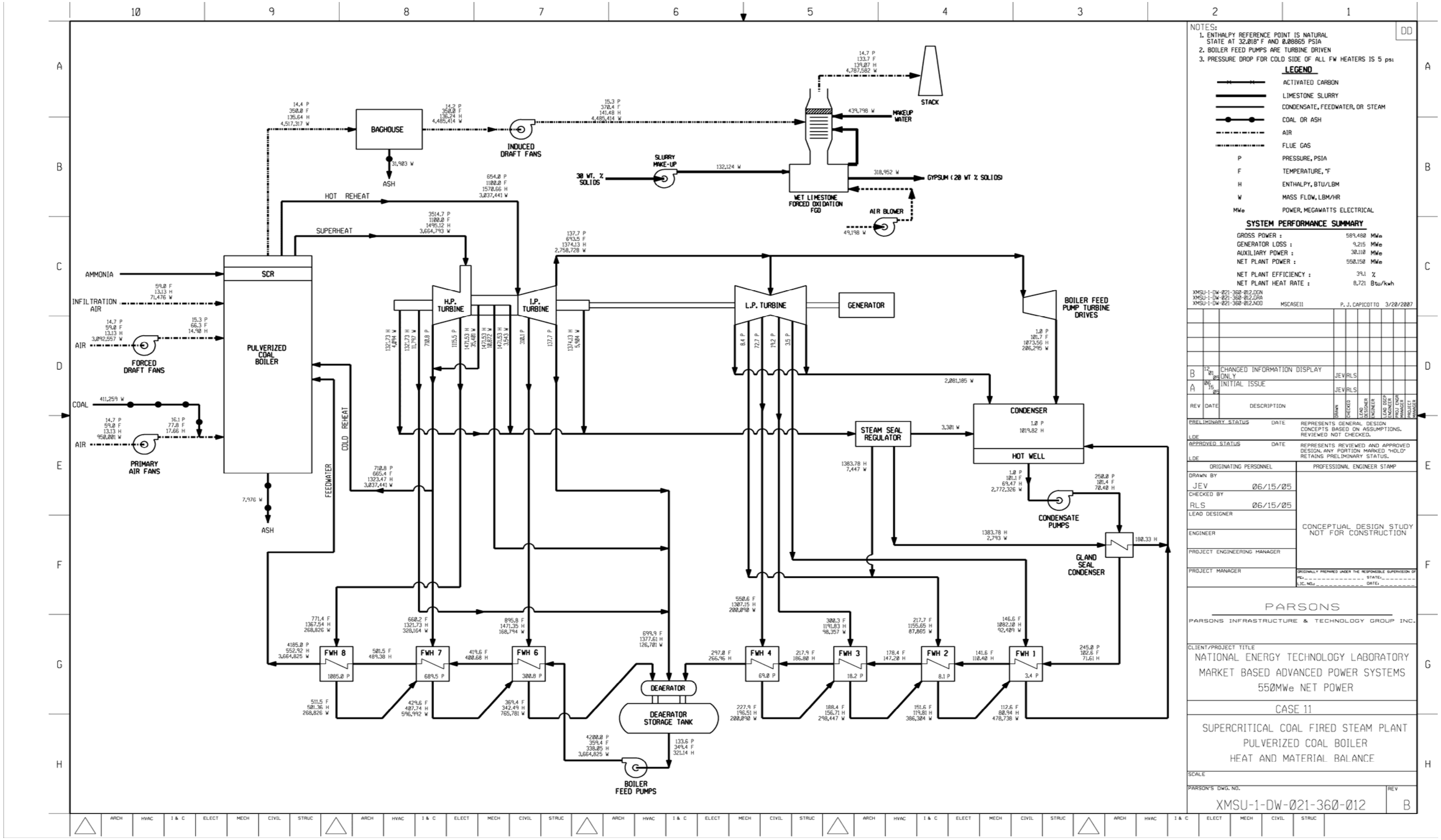

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Exhibit 4-32 Case 11 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	4,798.0	4.0		4,802.0
Ambient Air		53.1		53.1
Infiltration Air		0.9		0.9
Limestone		61.0		61.0
FGD Oxidant		0.6		0.6
Water		17.6		17.6
Auxiliary Power			102.0	102.0
Totals	**4,798.0**	**137.3**	**102.0**	**5,037.3**
Heat Out (MMBtu/hr)				
Bottom Ash		0.4		0.4
Fly Ash		1.6		1.6
Flue Gas Exhaust		666.1		666.1
Gypsum Slurry		27.7		27.7
Condenser		2,195.0		2,195.0
Process Losses (1)		135.1		135.1
Power			2,011.4	2,011.4
Totals	**0.0**	**3,025.9**	**2,011.4**	**5,037.3**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.3.5 CASE 11 – MAJOR EQUIPMENT LIST

Major equipment items for the supercritical PC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	36 tonne (40 ton)	2	1
9	Feeder	Vibratory	154 tonne/h (170 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	308 tonne/h (340 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	154 tonne (170 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	308 tonne/h (340 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	308 tonne/h (340 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	82 tonne/h (90 tph)	1	0
21	Limestone Conveyor No. L1	Belt	82 tonne/h (90 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	64 tonne/h (70 tph)	1	0
24	Limestone Conveyor No. L2	Belt	64 tonne/h (70 tph)	1	0
25	Limestone Day Bin	w/ actuator	245 tonne (270 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	36 tonne/h (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	36 tonne/h (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	20 tonne/h (22 tph)	1	1
4	Limestone Ball Mill	Rotary	20 tonne/h (22 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	75,709 liters (20,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	308 lpm @ 12m H2O (340 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	82 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	439,111 liters (116,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	218 lpm @ 9m H2O (240 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,097,778 liters (290,000 gal)	2	0
2	Condensate Pumps	Vertical canned	23,091 lpm @ 213 m H2O (6,100 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,828,433 kg/h (4,031,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	30,662 lpm @ 3,475 m H2O (8,100 gpm @ 11,400 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 3,475 m H2O (2,400 gpm @ 11,400 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	689,461 kg/h (1,520,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,827,979 kg/h (4,030,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,827,979 kg/h (4,030,000 lb/h)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	1,827,979 kg/h (4,030,000 lb/h)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	11,470 lpm @ 43 m H2O (3,030 gpm @ 140 ft H2O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	1,438 lpm @ 49 m H2O (380 gpm @ 160 ft H2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,377,901 liter (364,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (160 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	1,827,979 kg/h steam @ 24.1 MPa/593°C/593°C (4,030,000 lb/h steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	237,229 kg/h, 3,245 m3/min @ 123 cm WG (523,000 lb/h, 114,600 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	772,015 kg/h, 10,568 m3/min @ 47 cm WG (1,702,000 lb/h, 373,200 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,119,467 kg/h, 23,769 m3/min @ 90 cm WG (2,468,000 lb/h, 839,400 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,240,749 kg/h (4,940,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	133 m3/min @ 108 cm WG (4,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	147,632 liter (39,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 91 m H2O (7 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,119,467 kg/h (2,468,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	37,662 m3/min (1,330,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	132,490 lpm @ 64 m H2O (35,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,013 lpm (1,060 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	168 m3/min @ 0.3 MPa (5,930 acfm @ 42 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,022 lpm (270 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	32 tonne/h (35 tph) 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	606 lpm @ 12 m H2O (160 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	416,399 lpm (110,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,271 lpm @ 21 m H2O (600 gpm @ 70 ft H2O)	1	1

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.8 m (19 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	610 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,541 MMkJ/h (2,410 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	476,966 lpm @ 30.5 m (126,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,657 MMkJ/h (2,520 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	3.6 tonne/h (4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H2O (40 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	151 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	14 m3/min @ 0.2 MPa (510 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	499 tonne (1,100 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	91 tonne/h (100 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 640 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 10 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.3.6 CASE 11 – COSTS ESTIMATING RESULTS

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-33 shows the total plant capital cost summary organized by cost account and Exhibit 4-34 shows a more detailed breakdown of the capital costs. Exhibit 4-35 shows the initial and annual O&M costs.

The estimated TPC of the supercritical PC boiler with no CO_2 capture is \$1,574/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 10.7 percent of the TPC. The 20-year LCOE is 63.3 mills/kWh.

Exhibit 4-33 Case 11 Total Plant Cost Summary

Client: USDOE/NETL — **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 11 - Supercritical PC w/o CO2
Plant Size: 550.2 MW,net — **Estimate Type:** Conceptual — **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$15,481	$4,183	$9,376	$0	$0	**$29,040**	$2,602	$0	$4,746	**$36,389**	$66
2	COAL & SORBENT PREP & FEED	$10,405	$603	$2,638	$0	$0	**$13,646**	$1,196	$0	$2,226	**$17,068**	$31
3	FEEDWATER & MISC. BOP SYSTEMS	$40,107	$0	$18,856	$0	$0	**$58,963**	$5,369	$0	$10,462	**$74,795**	$136
4	PC BOILER											
4.1	PC Boiler & Accessories	$148,766	$0	$83,888	$0	$0	**$232,654**	$22,535	$0	$25,519	**$280,708**	$510
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$148,766**	**$0**	**$83,888**	**$0**	**$0**	**$232,654**	**$22,535**	**$0**	**$25,519**	**$280,708**	**$510**
5	FLUE GAS CLEANUP	$78,075	$0	$26,700	$0	$0	**$104,775**	$9,955	$0	$11,473	**$126,203**	$229
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$16,653	$959	$11,402	$0	$0	**$29,013**	$2,656	$0	$4,132	**$35,801**	$65
	SUBTOTAL 7	**$16,653**	**$959**	**$11,402**	**$0**	**$0**	**$29,013**	**$2,656**	**$0**	**$4,132**	**$35,801**	**$65**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$48,728	$0	$6,532	$0	$0	**$55,260**	$5,291	$0	$6,055	**$66,606**	$121
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$23,094	$1,042	$12,656	$0	$0	**$36,792**	$3,213	$0	$5,619	**$45,625**	$83
	SUBTOTAL 8	**$71,822**	**$1,042**	**$19,188**	**$0**	**$0**	**$92,052**	**$8,504**	**$0**	**$11,675**	**$112,231**	**$204**
9	COOLING WATER SYSTEM	$11,816	$6,553	$11,613	$0	$0	**$29,981**	$2,799	$0	$4,503	**$37,283**	$68
10	ASH/SPENT SORBENT HANDLING SYS	$4,232	$133	$5,628	$0	$0	**$9,992**	$951	$0	$1,126	**$12,069**	$22
11	ACCESSORY ELECTRIC PLANT	$15,533	$5,832	$17,190	$0	$0	**$38,556**	$3,411	$0	$5,217	**$47,183**	$86
12	INSTRUMENTATION & CONTROL	$8,069	$0	$8,480	$0	$0	**$16,549**	$1,515	$0	$2,222	**$20,285**	$37
13	IMPROVEMENTS TO SITE	$2,827	$1,625	$5,741	$0	$0	**$10,194**	$1,001	$0	$2,239	**$13,434**	$24
14	BUILDINGS & STRUCTURES	$0	$21,560	$20,672	$0	$0	**$42,232**	$3,805	$0	$6,906	**$52,943**	$96
	TOTAL COST	**$423,786**	**$42,490**	**$241,370**	**$0**	**$0**	**$707,646**	**$66,300**	**$0**	**$92,445**	**$866,391**	**$1,575**

Exhibit 4-34 Case 11 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 11 - Supercritical PC w/o CO2
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,183	$0	$1,469	$0	$0	$4,652	$415	$0	$760	$5,827	$11
1.2	Coal Stackout & Reclaim	$4,113	$0	$942	$0	$0	$5,055	$442	$0	$825	$6,322	$11
1.3	Coal Conveyors	$3,824	$0	$932	$0	$0	$4,756	$417	$0	$776	$5,949	$11
1.4	Other Coal Handling	$1,001	$0	$216	$0	$0	$1,216	$106	$0	$198	$1,521	$3
1.5	Sorbent Receive & Unload	$127	$0	$39	$0	$0	$166	$15	$0	$27	$208	$0
1.6	Sorbent Stackout & Reclaim	$2,056	$0	$381	$0	$0	$2,437	$212	$0	$397	$3,047	$6
1.7	Sorbent Conveyors	$734	$158	$182	$0	$0	$1,073	$93	$0	$175	$1,341	$2
1.8	Other Sorbent Handling	$443	$103	$235	$0	$0	$781	$69	$0	$128	$978	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$3,922	$4,982	$0	$0	$8,904	$832	$0	$1,460	$11,197	$20
	SUBTOTAL 1.	**$15,481**	**$4,183**	**$9,376**	**$0**	**$0**	**$29,040**	**$2,602**	**$0**	**$4,746**	**$36,389**	**$66**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$1,823	$0	$359	$0	$0	$2,182	$190	$0	$356	$2,728	$5
2.2	Coal Conveyor to Storage	$4,668	$0	$1,030	$0	$0	$5,698	$498	$0	$929	$7,125	$13
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$3,493	$150	$733	$0	$0	$4,376	$381	$0	$714	$5,470	$10
2.6	Sorbent Storage & Feed	$421	$0	$163	$0	$0	$584	$52	$0	$95	$731	$1
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$453	$353	$0	$0	$807	$74	$0	$132	$1,013	$2
	SUBTOTAL 2.	**$10,405**	**$603**	**$2,638**	**$0**	**$0**	**$13,646**	**$1,196**	**$0**	**$2,226**	**$17,068**	**$31**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$17,490	$0	$5,725	$0	$0	$23,214	$2,033	$0	$3,787	$29,034	$53
3.2	Water Makeup & Pretreating	$4,278	$0	$1,376	$0	$0	$5,654	$530	$0	$1,237	$7,420	$13
3.3	Other Feedwater Subsystems	$5,404	$0	$2,293	$0	$0	$7,697	$686	$0	$1,257	$9,641	$18
3.4	Service Water Systems	$844	$0	$456	$0	$0	$1,300	$121	$0	$284	$1,705	$3
3.5	Other Boiler Plant Systems	$6,403	$0	$6,264	$0	$0	$12,667	$1,188	$0	$2,078	$15,933	$29
3.6	FO Supply Sys & Nat Gas	$247	$0	$304	$0	$0	$551	$51	$0	$90	$692	$1
3.7	Waste Treatment Equipment	$2,883	$0	$1,652	$0	$0	$4,535	$439	$0	$995	$5,969	$11
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,558	$0	$788	$0	$0	$3,346	$321	$0	$733	$4,400	$8
	SUBTOTAL 3.	**$40,107**	**$0**	**$18,856**	**$0**	**$0**	**$58,963**	**$5,369**	**$0**	**$10,462**	**$74,795**	**$136**
4	PC BOILER											
4.1	PC Boiler & Accessories	$148,766	$0	$83,888	$0	$0	$232,654	$22,535	$0	$25,519	$280,708	$510
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$148,766**	**$0**	**$83,888**	**$0**	**$0**	**$232,654**	**$22,535**	**$0**	**$25,519**	**$280,708**	**$510**

Exhibit 4-34 Case 11 Total Plant Cost Details (Continued)

Client: USDOE/NETL — **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 11 - Supercritical PC w/o CO2
Plant Size: 550.2 MW,net — **Estimate Type:** Conceptual — **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$54,227	$0	$11,683	$0	$0	$65,910	$6,238	$0	$7,215	$79,363	$144
5.2	Other FGD	$2,830	$0	$3,209	$0	$0	$6,039	$582	$0	$662	$7,283	$13
5.3	Bag House & Accessories	$15,654	$0	$9,942	$0	$0	$25,596	$2,448	$0	$2,804	$30,849	$56
5.4	Other Particulate Removal Materials	$1,059	$0	$1,134	$0	$0	$2,194	$211	$0	$241	$2,646	$5
5.5	Gypsum Dewatering System	$4,304	$0	$732	$0	$0	$5,036	$476	$0	$551	$6,063	$11
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$78,075**	**$0**	**$26,700**	**$0**	**$0**	**$104,775**	**$9,955**	**$0**	**$11,473**	**$126,203**	**$229**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$8,242	$0	$5,379	$0	$0	$13,621	$1,190	$0	$2,222	$17,033	$31
7.4	Stack	$8,411	$0	$4,925	$0	$0	$13,336	$1,274	$0	$1,461	$16,071	$29
7.9	Duct & Stack Foundations	$0	$959	$1,097	$0	$0	$2,056	$192	$0	$449	$2,697	$5
	SUBTOTAL 7.	**$16,653**	**$959**	**$11,402**	**$0**	**$0**	**$29,013**	**$2,656**	**$0**	**$4,132**	**$35,801**	**$65**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$48,728	$0	$6,532	$0	$0	$55,260	$5,291	$0	$6,055	$66,606	$121
8.2	Turbine Plant Auxiliaries	$334	$0	$716	$0	$0	$1,050	$102	$0	$115	$1,268	$2
8.3	Condenser & Auxiliaries	$6,405	$0	$2,204	$0	$0	$8,610	$818	$0	$943	$10,370	$19
8.4	Steam Piping	$16,354	$0	$8,078	$0	$0	$24,433	$2,039	$0	$3,971	$30,443	$55
8.9	TG Foundations	$0	$1,042	$1,658	$0	$0	$2,699	$254	$0	$591	$3,544	$6
	SUBTOTAL 8.	**$71,822**	**$1,042**	**$19,188**	**$0**	**$0**	**$92,052**	**$8,504**	**$0**	**$11,675**	**$112,231**	**$204**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$8,669	$0	$2,702	$0	$0	$11,371	$1,079	$0	$1,245	$13,695	$25
9.2	Circulating Water Pumps	$1,765	$0	$111	$0	$0	$1,876	$160	$0	$204	$2,239	$4
9.3	Circ.Water System Auxiliaries	$515	$0	$69	$0	$0	$583	$55	$0	$64	$702	$1
9.4	Circ.Water Piping	$0	$4,150	$3,958	$0	$0	$8,108	$747	$0	$1,328	$10,183	$19
9.5	Make-up Water System	$457	$0	$605	$0	$0	$1,062	$101	$0	$174	$1,337	$2
9.6	Component Cooling Water Sys	$411	$0	$324	$0	$0	$735	$69	$0	$121	$924	$2
9.9	Circ.Water System Foundations& Structures	$0	$2,403	$3,844	$0	$0	$6,247	$588	$0	$1,367	$8,202	$15
	SUBTOTAL 9.	**$11,816**	**$6,553**	**$11,613**	**$0**	**$0**	**$29,981**	**$2,799**	**$0**	**$4,503**	**$37,283**	**$68**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$563	$0	$1,735	$0	$0	$2,298	$224	$0	$252	$2,774	$5
10.7	Ash Transport & Feed Equipment	$3,669	$0	$3,735	$0	$0	$7,403	$700	$0	$810	$8,914	$16
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$133	$158	$0	$0	$291	$27	$0	$64	$381	$1
	SUBTOTAL 10.	**$4,232**	**$133**	**$5,628**	**$0**	**$0**	**$9,992**	**$951**	**$0**	**$1,126**	**$12,069**	**$22**

Exhibit 4-34 Case 11 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 11 - Supercritical PC w/o CO2
Plant Size: 550.2 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,524	$0	$249	$0	$0	$1,773	$164	$0	$145	$2,083	$4
11.2	Station Service Equipment	$2,578	$0	$882	$0	$0	$3,460	$331	$0	$284	$4,075	$7
11.3	Switchgear & Motor Control	$3,063	$0	$525	$0	$0	$3,588	$332	$0	$392	$4,312	$8
11.4	Conduit & Cable Tray	$0	$1,967	$6,693	$0	$0	$8,660	$829	$0	$1,423	$10,913	$20
11.5	Wire & Cable	$0	$3,568	$7,051	$0	$0	$10,619	$895	$0	$1,727	$13,241	$24
11.6	Protective Equipment	$243	$0	$861	$0	$0	$1,104	$108	$0	$121	$1,333	$2
11.7	Standby Equipment	$1,176	$0	$28	$0	$0	$1,204	$114	$0	$132	$1,450	$3
11.8	Main Power Transformers	$6,950	$0	$165	$0	$0	$7,116	$541	$0	$766	$8,422	$15
11.9	Electrical Foundations	$0	$297	$735	$0	$0	$1,032	$98	$0	$226	$1,356	$2
	SUBTOTAL 11.	**$15,533**	**$5,832**	**$17,190**	**$0**	**$0**	**$38,556**	**$3,411**	**$0**	**$5,217**	**$47,183**	**$86**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$413	$0	$258	$0	$0	$671	$65	$0	$110	$846	$2
12.7	Distributed Control System Equipment	$4,172	$0	$760	$0	$0	$4,932	$470	$0	$540	$5,942	$11
12.8	Instrument Wiring & Tubing	$2,305	$0	$4,674	$0	$0	$6,979	$594	$0	$1,136	$8,710	$16
12.9	Other I & C Equipment	$1,179	$0	$2,787	$0	$0	$3,966	$386	$0	$435	$4,788	$9
	SUBTOTAL 12.	**$8,069**	**$0**	**$8,480**	**$0**	**$0**	**$16,549**	**$1,515**	**$0**	**$2,222**	**$20,285**	**$37**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$48	$958	$0	$0	$1,005	$99	$0	$221	$1,325	$2
13.2	Site Improvements	$0	$1,578	$1,974	$0	$0	$3,552	$349	$0	$780	$4,681	$9
13.3	Site Facilities	$2,827	$0	$2,809	$0	$0	$5,637	$553	$0	$1,238	$7,428	$14
	SUBTOTAL 13.	**$2,827**	**$1,625**	**$5,741**	**$0**	**$0**	**$10,194**	**$1,001**	**$0**	**$2,239**	**$13,434**	**$24**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$7,843	$6,990	$0	$0	$14,833	$1,332	$0	$2,425	$18,590	$34
14.2	Turbine Building	$0	$11,220	$10,597	$0	$0	$21,817	$1,964	$0	$3,567	$27,348	$50
14.3	Administration Building	$0	$554	$594	$0	$0	$1,147	$104	$0	$188	$1,439	$3
14.4	Circulation Water Pumphouse	$0	$159	$128	$0	$0	$286	$26	$0	$47	$359	$1
14.5	Water Treatment Buildings	$0	$565	$471	$0	$0	$1,036	$93	$0	$169	$1,299	$2
14.6	Machine Shop	$0	$370	$252	$0	$0	$623	$55	$0	$102	$780	$1
14.7	Warehouse	$0	$251	$255	$0	$0	$506	$46	$0	$83	$635	$1
14.8	Other Buildings & Structures	$0	$205	$177	$0	$0	$382	$34	$0	$62	$479	$1
14.9	Waste Treating Building & Str.	$0	$393	$1,208	$0	$0	$1,601	$151	$0	$263	$2,015	$4
	SUBTOTAL 14.	**$0**	**$21,560**	**$20,672**	**$0**	**$0**	**$42,232**	**$3,805**	**$0**	**$6,906**	**$52,943**	**$96**
	TOTAL COST	**$423,786**	**$42,490**	**$241,370**	**$0**	**$0**	**$707,646**	**$66,300**	**$0**	**$92,445**	**$866,391**	**$1,575**

Exhibit 4-35 Case 11 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES							
Case 11 - Supercritical PC w/o CO2					Cost Base (Dec)		2006
					Heat Rate-net(Btu/kWh):		8,721
					MWe-net:		550
					Capacity Factor: (%):		85
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	2.0		2.0				
Operator	9.0		9.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	2.0		2.0				
TOTAL-O.J.'s	14.0		14.0				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$5,261,256	$9.563
Maintenance Labor Cost						$5,818,574	$10.576
Administrative & Support Labor						$2,769,958	$5.035
TOTAL FIXED OPERATING COSTS						**$13,849,788**	**$25.175**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$8,727,862**	**$0.00213**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	3,918	1.03	**$0**		**$1,251,873**	**$0.00031**
Chemicals							
MU & WT Chem.(lb)	132,743	18,963	0.16	$21,876		$969,578	$0.00024
Limestone (ton)	3,429	490	20.60	$70,633		$3,130,564	$0.00076
Carbon (Mercury Removal) (lb)	0	0	1.00	$0		$0	$0.00000
MEA Solvent (ton)	0	0	2,142.40	$0		$0	$0.00000
NaOH (tons)	0	0	412.96	$0		$0	$0.00000
H2SO4 (tons)	0	0	132.15	$0		$0	$0.00000
Corrosion Inhibitor	0	0	0.00	$0		$0	$0.00000
Activated Carbon(lb)	0	0	1.00	$0		$0	$0.00000
Ammonia (28% NH3) ton	517	74	123.60	$63,883		$2,831,382	$0.00069
Subtotal Chemicals				**$156,392**		**$6,931,524**	**$0.00169**
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0		$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.44	5,500.00	$0		$747,563	$0.00018
Emission Penalties	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$747,563**	**$0.00018**
Waste Disposal							
Flyash (ton)	0	96	15.45	$0		$458,782	$0.00011
Bottom Ash(ton)	0	383	15.45	$0		$1,835,187	$0.00045
Subtotal-Waste Disposal				**$0**		**$2,293,969**	**$0.00056**
By-products & Emissions							
Gypsum (tons)	0	739	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$156,392**		**$19,952,791**	**$0.00487**
Fuel(ton)	148,057	4,935	42.11	**$6,234,675**		**$64,476,927**	**$0.01574**

4.3.7 CASE 12 – SUPERCRITICAL PC WITH CO_2 CAPTURE

The plant configuration for Case 12, supercritical PC, is the same as Case 11 with the exception that the Econamine FG Plus CDR technology was added for CO_2 capture. The nominal net output is maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility. Unlike the IGCC cases where gross output was fixed by the available size of the combustion turbines, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

The process description for Case 12 is essentially the same as Case 11 with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case 12 are shown in Exhibit 4-36 and Exhibit 4-37, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

4.3.8 CASE 12 PERFORMANCE RESULTS

The Case 12 modeling assumptions were presented previously in Section 4.3.2.

The plant produces a net output of 546 MW at a net plant efficiency of 27.2 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-38 which includes auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over 58 percent of the auxiliary plant load. The circulating water system (circulating water pumps and cooling tower fan) accounts for over 15 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 4-36 Case 12 Process Flow Diagram, Supercritical Unit with CO_2 Capture

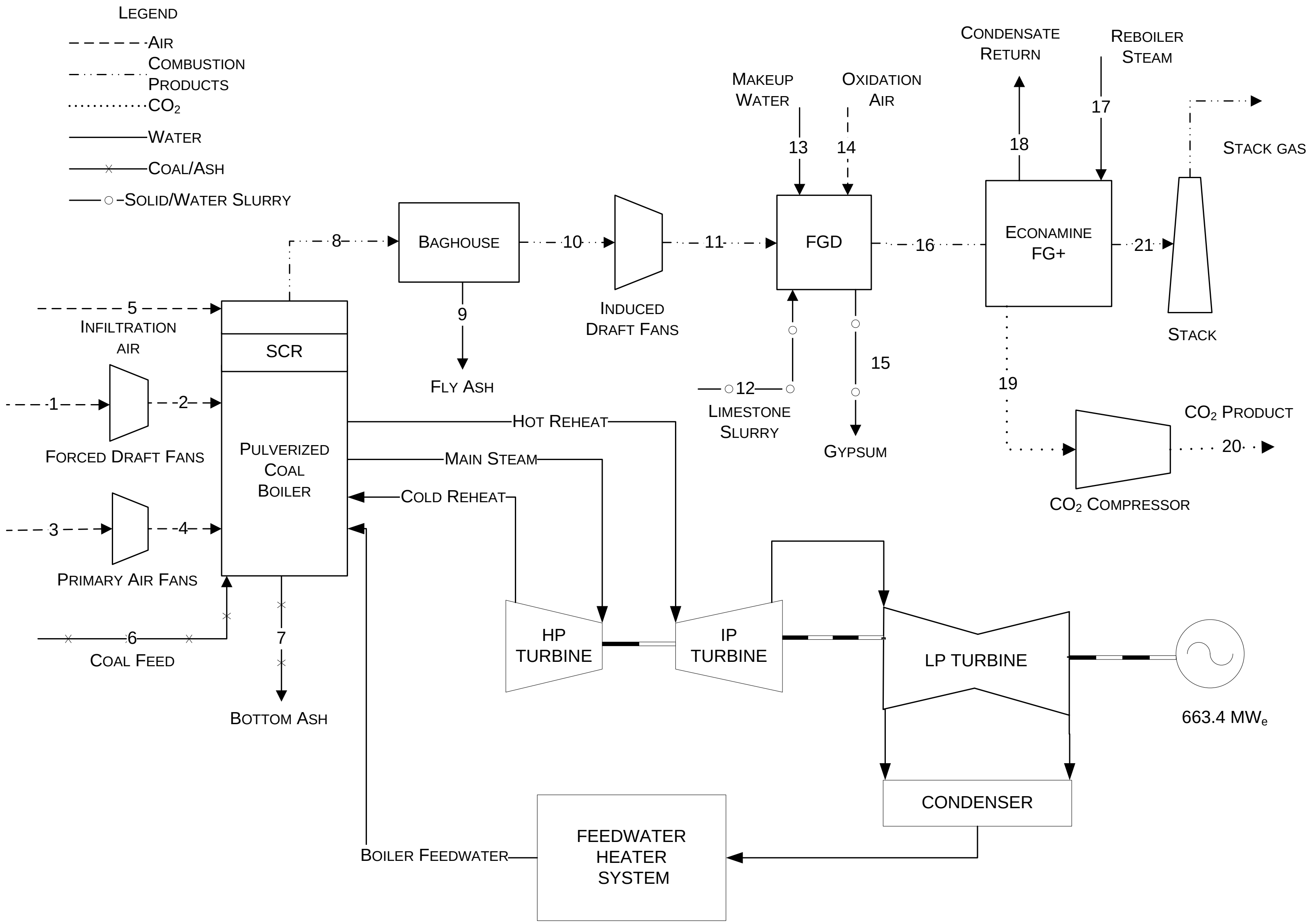

Exhibit 4-37 Case 12 Stream Table, Supercritical Unit with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fractions											
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flow (lb_{mol}/hr)	153,570	153,570	47,175	47,175	2,650	0	0	215,146	0	215,146	215,146
V-L Flow (lb/hr)	4,431,560	4,431,560	1,361,330	1,361,330	76,466	0	0	6,399,090	0	6,399,090	6,399,090
Solids Flowrate	0	0	0	0	0	586,627	11,377	45,507	45,507	0	0
Temperature (°F)	59	66	59	78	59	59	350	350	350	350	370
Pressure (psia)	14.70	15.25	14.70	16.14	14.70	14.70	14.40	14.40	14.20	14.20	15.26
Enthalpy (BTU/lb)[A]	13.1	14.9	13.1	17.7	13.1	11,676	51.4	135.6	51.4	136.2	141.5
Density (lb/ft^3)	0.08	0.08	0.08	0.08	0.08	---	---	0.05	---	0.05	0.05
Avg. Molecular Weight	28.86	28.86	28.86	28.86	28.86	---	---	29.74	---	29.74	29.74

	12	13	14	15	16	17	18	19	20	21
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0092	0.0000	0.0080	0.0000	0.0000	0.0000	0.0000	0.0109
CO_2	0.0000	0.0000	0.0003	0.0015	0.1326	0.0000	0.0000	0.9862	1.0000	0.0180
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0099	0.9977	0.1668	1.0000	1.0000	0.0138	0.0000	0.0281
N_2	0.0000	0.0000	0.7732	0.0008	0.6690	0.0000	0.0000	0.0000	0.0000	0.9109
O_2	0.0000	0.0000	0.2074	0.0000	0.0235	0.0000	0.0000	0.0000	0.0000	0.0320
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	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	7,537	34,486	2,535	20,128	238,453	100,792	100,792	28,856	28,458	175,090
V-L Flowrate (lb/hr)	135,788	621,279	73,155	363,564	6,833,360	1,815,800	1,815,800	1,259,600	1,252,440	4,951,450
Solids Flowrate (lb/hr)	58,054	0	0	90,446	0	0	0	0	0	0
Temperature (°F)	59	60	59	135	135	692	348	69	124	74
Pressure (psia)	14.70	14.70	14.70	15.20	15.20	130.86	130.86	23.52	2215.00	14.70
Enthalpy (BTU/lb)[A]	---	33.3	13.1	88.0	139.4	1373.8	319.5	11.4	-70.8	29.6
Density (lb/ft^3)	62.62	62.59	0.08	39.94	0.07	0.19	55.67	0.18	40.76	0.07
Molecular Weight	18.02	18.02	28.86	18.06	28.66	18.02	18.02	43.65	44.01	28.28

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-38 Case 12 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
TOTAL (STEAM TURBINE) POWER, kWe	**663,445**
AUXILIARY LOAD SUMMARY, kWe (Note 1)	
Coal Handling and Conveying	490
Limestone Handling & Reagent Preparation	1,270
Pulverizers	3,990
Ash Handling	760
Primary Air Fans	1,870
Forced Draft Fans	2,380
Induced Draft Fans	10,120
SCR	70
Baghouse	100
FGD Pumps and Agitators	4,250
Econamine FG Plus Auxiliaries	21,320
CO_2 Compression	46,900
Miscellaneous Balance of Plant (Note 2)	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	630
Circulating Water Pumps	12,260
Cooling Tower Fans	6,340
Transformer Loss	2,300
TOTAL AUXILIARIES, kWe	**117,450**
NET POWER, kWe	**545,995**
Net Plant Efficiency (HHV)	27.2%
Net Plant Heat Rate (Btu/kWh)	12,534
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	1,884 (1,787)
CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	266,090 (586,627)
Limestone Sorbent Feed, kg/h (lb/h)	26,333 (58,054)
Thermal Input, kWt	2,005,660
Makeup Water, m^3/min (gpm)	46.0 (12,159)

Notes: 1. Boiler feed pumps are steam turbine driven
2. Includes plant control systems, lighting, HVAC and miscellanous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 12 is presented in Exhibit 4-39.

Exhibit 4-39 Case 12 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.030 (0.070)	1,618 (1,784)	0.328 (0.722)
Particulates	0.006 (0.013)	300 (331)	0.061 (0.134)
Hg	0.49×10^{-6} (1.14×10^{-6})	0.026 (0.029)	5.3×10^{-6} (11.8×10^{-6})
CO_2	8.7 (20)	468,000 (516,000)	95 (209)
CO_2[1]			115 (254)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 10 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in negligible SO_2 emissions.

NOx emissions are controlled to about 0.5 $lb/10^6$ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 $lb/10^6$ Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions. Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

Exhibit 4-40 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream and condensate recovered from cooling the flue gas prior to the CO_2 absorber are re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 4-40 Case 12 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
FGD Makeup	2.9 (779)	0	2.9 (779)
BFW Makeup	0.4 (105)	0	0.4 (105)
Cooling Tower Makeup	41.2 (10,885)	5.0 (1,324)	36.2 (9,561)
Total	**44.5 (11,769)**	**5.0 (1,324)**	**39.5 (10,444)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 12 PC boiler, the FGD unit, CDR system and steam cycle in Exhibit 4-41.

An overall plant energy balance is provided in tabular form in Exhibit 4-42. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-38) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

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Exhibit 4-41 Case 12 Heat and Mass Balance, Supercritical PC Boiler with CO_2 Capture

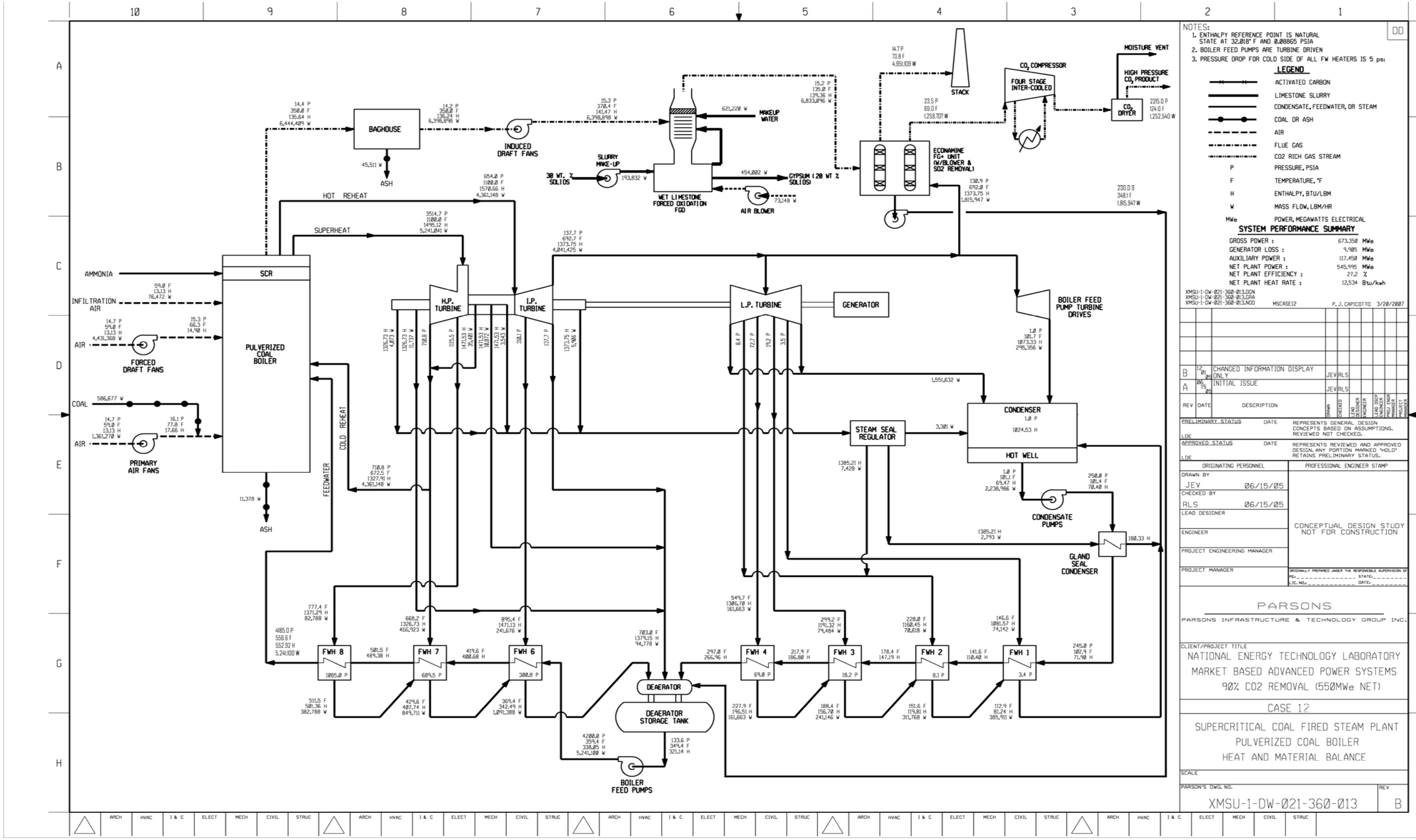

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Exhibit 4-42 Case 12 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	6,843.6	5.7		6,849.3
Ambient Air		76.1		76.1
Infiltration Air		1.0		1.0
Limestone		87.1		87.1
FGD Oxidant		1.0		1.0
Raw Water Makeup		136.4		136.4
Auxiliary Power			424.2	424.2
Totals	**6,843.6**	**307.3**	**424.2**	**7,575.0**
Heat Out (MMBtu/hr)				
Bottom Ash		0.6		0.6
Fly Ash		2.3		2.3
Flue Gas Exhaust		229.1		229.1
CO_2 Product		(88.7)		(88.7)
Condenser		1,787.0		1,787.0
Econamime Process		3154.6		3154.6
Cooling Tower Blowdown		63.3		63.3
Gypsum Slurry		2.8		2.8
Process Losses (1)		124.5		124.5
Power			2,299.5	2,299.5
Totals	**0.0**	**5,275.6**	**2,299.5**	**7,575.0**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

4.3.9 CASE 12 – MAJOR EQUIPMENT LIST

Major equipment items for the supercritical PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/h (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/h (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/h (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/h (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	2	1
9	Feeder	Vibratory	218 tonne/h (240 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	435 tonne/h (480 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	218 tonne (240 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	435 tonne/h (480 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	435 tonne/h (480 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	998 tonne (1,100 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	109 tonne/h (120 tph)	1	0
21	Limestone Conveyor No. L1	Belt	109 tonne/h (120 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	91 tonne/h (100 tph)	1	0
24	Limestone Conveyor No. L2	Belt	91 tonne/h (100 tph)	1	0
25	Limestone Day Bin	w/ actuator	345 tonne (380 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	45 tonne/h (50 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	45 tonne/h (50 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	29 tonne/h (32 tph)	1	1
4	Limestone Ball Mill	Rotary	29 tonne/h (32 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	109,778 liters (29,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	445 lpm @ 12m H2O (490 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	109 lpm (120 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	624,598 liters (165,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	308 lpm @ 9m H2O (340 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,570,958 liters (415,000 gal)	2	0
2	Condensate Pumps	Vertical canned	18,927 lpm @ 213 m H2O (5,000 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,614,963 kg/h (5,765,000 lb/h) 5 min. tank	1	0
4	Boiler Feed Pump and Steam Turbine Drive	Barrel type, multi-stage, centrifugal	43,911 lpm @ 3,475 m H2O (11,600 gpm @ 11,400 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	13,249 lpm @ 3,475 m H2O (3,500 gpm @ 11,400 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	557,919 kg/h (1,230,000 lb/h)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,612,695 kg/h (5,760,000 lb/h)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,612,695 kg/h (5,760,000 lb/h)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,612,695 kg/h (5,760,000 lb/h)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,632 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 MMkJ/h (50 MMBtu/h) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	25,514 lpm @ 43 m H2O (6,740 gpm @ 140 ft H2O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	2,120 lpm @ 49 m H2O (560 gpm @ 160 ft H2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	2,040,353 liter (539,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,022 lpm (270 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,612,695 kg/h steam @ 24.1 MPa/593°C/593°C (5,760,000 lb/h steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	339,741 kg/h, 4,650 m3/min @ 123 cm WG (749,000 lb/h, 164,200 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,105,406 kg/h, 15,135 m3/min @ 47 cm WG (2,437,000 lb/h, 534,500 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,596,647 kg/h, 33,898 m3/min @ 90 cm WG (3,520,000 lb/h, 1,197,100 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,193,294 kg/h (7,040,000 lb/h)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	190 m3/min @ 108 cm WG (6,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	208,199 liter (55,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	40 lpm @ 91 m H2O (11 gpm @ 300 ft H2O)	2	1

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,596,647 kg/h (3,520,000 lb/h) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	52,160 m3/min (1,842,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	181,701 lpm @ 64 m H2O (48,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,716 lpm (1,510 gpm) 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	250 m3/min @ 0.3 MPa (8,820 acfm @ 42 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,438 lpm (380 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	45 tonne/h (50 tph) 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	871 lpm @ 12 m H2O (230 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	567,816 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,255 lpm @ 21 m H2O (860 gpm @ 70 ft H2O)	1	1

ACCOUNT 5C CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,704,602 kg/h (3,758,000 lb/h) 20.4 wt % CO2 inlet concentration	2	0
2	CO2 Compressor	Integrally geared, multi-stage centrifugal	312,453 kg/h @ 15.3 MPa (688,840 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.5 m (18 ft) diameter	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	700 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	780 MVA @ 0.9 p.f., 24 kV, 60 Hz	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,077 MMkJ/h (1,970 MMBtu/h), Inlet water temperature 16ºC (60ºF), Water temperature rise 11ºC (20ºF)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	613,241 lpm @ 30.5 m (162,000 gpm @ 100 ft)	4	2
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 5,914 MMkJ/h (5,610 MMBtu/h) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	5.4 tonne/h (6 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	227 lpm @ 17 m H2O (60 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	227 lpm (60 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	21 m3/min @ 0.2 MPa (730 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	680 tonne (1,500 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	127 tonne/h (140 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 640 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 128 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.3.10 CASE 12 – COST ESTIMATING BASIS

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-43 shows the total plant capital cost summary organized by cost account and Exhibit 4-44 shows a more detailed breakdown of the capital costs. Exhibit 4-45 shows the initial and annual O&M costs.

The estimated TPC of the subcritical PC boiler with CO_2 capture is $2,868/kW. Process contingency represents 3.5 percent of the TPC and project contingency represents 12.4 percent. The 20-year LCOE, including CO_2 TS&M costs of 3.9 mills/kWh, is 114.8 mills/kWh.

Exhibit 4-43 Case 12 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 12 - Supercritical PC w/ CO2
Plant Size: 546.0 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$19,316	$5,215	$11,691	$0	$0	**$36,222**	$3,246	$0	$5,920	**$45,389**	$83
2	COAL & SORBENT PREP & FEED	$13,126	$758	$3,326	$0	$0	**$17,210**	$1,508	$0	$2,808	**$21,527**	$39
3	FEEDWATER & MISC. BOP SYSTEMS	$54,477	$0	$25,648	$0	$0	**$80,126**	$7,317	$0	$14,428	**$101,870**	$187
4	PC BOILER											
4.1	PC Boiler & Accessories	$190,969	$0	$107,678	$0	$0	**$298,647**	$28,927	$0	$32,757	**$360,332**	$660
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	Open	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$190,969**	**$0**	**$107,678**	**$0**	**$0**	**$298,647**	**$28,927**	**$0**	**$32,757**	**$360,332**	**$660**
5	FLUE GAS CLEANUP	$101,747	$0	$34,963	$0	$0	**$136,710**	$12,990	$0	$14,970	**$164,670**	$302
5B	CO_2 REMOVAL & COMPRESSION	$229,832	$0	$69,851	$0	$0	**$299,683**	$28,443	$52,879	$76,201	**$457,207**	$837
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 6	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	HRSG Accessories, Ductwork and Stack	$17,889	$981	$12,221	$0	$0	**$31,091**	$2,840	$0	$4,457	**$38,388**	$70
	SUBTOTAL 7	**$17,889**	**$981**	**$12,221**	**$0**	**$0**	**$31,091**	**$2,840**	**$0**	**$4,457**	**$38,388**	**$70**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$53,763	$0	$7,192	$0	$0	**$60,956**	$5,836	$0	$6,679	**$73,471**	$135
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$26,923	$1,148	$14,942	$0	$0	**$43,013**	$3,724	$0	$6,698	**$53,436**	$98
	SUBTOTAL 8	**$80,687**	**$1,148**	**$22,134**	**$0**	**$0**	**$103,969**	**$9,561**	**$0**	**$13,377**	**$126,907**	**$232**
9	COOLING WATER SYSTEM	$21,479	$11,200	$19,881	$0	$0	**$52,559**	$4,900	$0	$7,796	**$65,255**	$120
10	ASH/SPENT SORBENT HANDLING SYS	$5,154	$162	$6,854	$0	$0	**$12,169**	$1,158	$0	$1,371	**$14,699**	$27
11	ACCESSORY ELECTRIC PLANT	$20,196	$10,240	$29,287	$0	$0	**$59,723**	$5,331	$0	$8,288	**$73,343**	$134
12	INSTRUMENTATION & CONTROL	$9,195	$0	$9,662	$0	$0	**$18,857**	$1,726	$943	$2,648	**$24,174**	$44
13	IMPROVEMENTS TO SITE	$3,162	$1,818	$6,421	$0	$0	**$11,402**	$1,120	$0	$2,504	**$15,026**	$28
14	BUILDINGS & STRUCTURES	$0	$23,760	$22,735	$0	$0	**$46,495**	$4,189	$0	$7,603	**$58,287**	$107
	TOTAL COST	**$767,230**	**$55,282**	**$382,352**	**$0**	**$0**	**$1,204,865**	**$113,256**	**$53,822**	**$195,130**	**$1,567,073**	**$2,870**

Exhibit 4-44 Case 12 Total Plant Cost Details

Client: USDOE/NETL
Project: Bituminous Baseline Study
Report Date: 09-May-07

TOTAL PLANT COST SUMMARY

Case: Case 12 - Supercritical PC w/ CO2
Plant Size: 546.0 MW,net
Estimate Type: Conceptual
Cost Base (Dec) 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,967	$0	$1,831	$0	$0	$5,797	$518	$0	$947	$7,262	$13
1.2	Coal Stackout & Reclaim	$5,126	$0	$1,174	$0	$0	$6,300	$551	$0	$1,028	$7,879	$14
1.3	Coal Conveyors	$4,766	$0	$1,161	$0	$0	$5,927	$520	$0	$967	$7,414	$14
1.4	Other Coal Handling	$1,247	$0	$269	$0	$0	$1,516	$132	$0	$247	$1,895	$3
1.5	Sorbent Receive & Unload	$160	$0	$49	$0	$0	$208	$18	$0	$34	$260	$0
1.6	Sorbent Stackout & Reclaim	$2,576	$0	$477	$0	$0	$3,053	$266	$0	$498	$3,817	$7
1.7	Sorbent Conveyors	$919	$198	$228	$0	$0	$1,345	$116	$0	$219	$1,680	$3
1.8	Other Sorbent Handling	$555	$129	$294	$0	$0	$979	$87	$0	$160	$1,225	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$4,888	$6,210	$0	$0	$11,097	$1,037	$0	$1,820	$13,955	$26
	SUBTOTAL 1.	**$19,316**	**$5,215**	**$11,691**	**$0**	**$0**	**$36,222**	**$3,246**	**$0**	**$5,920**	**$45,389**	**$83**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,305	$0	$454	$0	$0	$2,759	$241	$0	$450	$3,449	$6
2.2	Coal Conveyor to Storage	$5,901	$0	$1,301	$0	$0	$7,203	$630	$0	$1,175	$9,007	$16
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$4,391	$188	$922	$0	$0	$5,501	$479	$0	$897	$6,878	$13
2.6	Sorbent Storage & Feed	$529	$0	$205	$0	$0	$734	$65	$0	$120	$919	$2
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$570	$444	$0	$0	$1,014	$93	$0	$166	$1,274	$2
	SUBTOTAL 2.	**$13,126**	**$758**	**$3,326**	**$0**	**$0**	**$17,210**	**$1,508**	**$0**	**$2,808**	**$21,527**	**$39**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$22,090	$0	$7,230	$0	$0	$29,320	$2,567	$0	$4,783	$36,670	$67
3.2	Water Makeup & Pretreating	$7,572	$0	$2,435	$0	$0	$10,007	$938	$0	$2,189	$13,134	$24
3.3	Other Feedwater Subsystems	$6,826	$0	$2,896	$0	$0	$9,722	$866	$0	$1,588	$12,176	$22
3.4	Service Water Systems	$1,495	$0	$807	$0	$0	$2,301	$214	$0	$503	$3,018	$6
3.5	Other Boiler Plant Systems	$8,357	$0	$8,175	$0	$0	$16,533	$1,551	$0	$2,713	$20,796	$38
3.6	FO Supply Sys & Nat Gas	$267	$0	$329	$0	$0	$596	$55	$0	$98	$749	$1
3.7	Waste Treatment Equipment	$5,103	$0	$2,923	$0	$0	$8,027	$778	$0	$1,761	$10,565	$19
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,768	$0	$853	$0	$0	$3,621	$348	$0	$794	$4,762	$9
	SUBTOTAL 3.	**$54,477**	**$0**	**$25,648**	**$0**	**$0**	**$80,126**	**$7,317**	**$0**	**$14,428**	**$101,870**	**$187**
4	PC BOILER											
4.1	PC Boiler & Accessories	$190,969	$0	$107,678	$0	$0	$298,647	$28,927	$0	$32,757	$360,332	$660
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$190,969**	**$0**	**$107,678**	**$0**	**$0**	**$298,647**	**$28,927**	**$0**	**$32,757**	**$360,332**	**$660**

Exhibit 4-44 Case 12 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 09-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 12 - Supercritical PC w/ CO2
Plant Size: 546.0 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies		TOTAL PLANT COST	
				Direct	Indirect				Process	Project	$	$/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$70,491	$0	$15,186	$0	$0	$85,677	$8,109	$0	$9,379	$103,165	$189
5.2	Other FGD	$3,679	$0	$4,172	$0	$0	$7,850	$756	$0	$861	$9,467	$17
5.3	Bag House & Accessories	$20,751	$0	$13,179	$0	$0	$33,931	$3,245	$0	$3,718	$40,894	$75
5.4	Other Particulate Removal Materials	$1,404	$0	$1,504	$0	$0	$2,908	$280	$0	$319	$3,507	$6
5.5	Gypsum Dewatering System	$5,422	$0	$922	$0	$0	$6,344	$599	$0	$694	$7,638	$14
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$101,747**	**$0**	**$34,963**	**$0**	**$0**	**$136,710**	**$12,990**	**$0**	**$14,970**	**$164,670**	**$302**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$202,944	$0	$61,453	$0	$0	$264,397	$25,093	$52,879	$68,474	$410,843	$752
5B.2	CO_2 Compression & Drying	$26,888	$0	$8,398	$0	$0	$35,286	$3,350	$0	$7,727	$46,363	$85
	SUBTOTAL 5.	**$229,832**	**$0**	**$69,851**	**$0**	**$0**	**$299,683**	**$28,443**	**$52,879**	**$76,201**	**$457,207**	**$837**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$9,280	$0	$6,057	$0	$0	$15,337	$1,340	$0	$2,501	$19,178	$35
7.4	Stack	$8,609	$0	$5,041	$0	$0	$13,650	$1,304	$0	$1,495	$16,450	$30
7.9	Duct & Stack Foundations	$0	$981	$1,123	$0	$0	$2,104	$196	$0	$460	$2,760	$5
	SUBTOTAL 7.	**$17,889**	**$981**	**$12,221**	**$0**	**$0**	**$31,091**	**$2,840**	**$0**	**$4,457**	**$38,388**	**$70**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$53,763	$0	$7,192	$0	$0	$60,956	$5,836	$0	$6,679	$73,471	$135
8.2	Turbine Plant Auxiliaries	$368	$0	$789	$0	$0	$1,158	$112	$0	$127	$1,397	$3
8.3	Condenser & Auxiliaries	$5,563	$0	$1,956	$0	$0	$7,519	$715	$0	$823	$9,057	$17
8.4	Steam Piping	$20,992	$0	$10,369	$0	$0	$31,362	$2,617	$0	$5,097	$39,076	$72
8.9	TG Foundations	$0	$1,148	$1,827	$0	$0	$2,975	$280	$0	$651	$3,906	$7
	SUBTOTAL 8.	**$80,687**	**$1,148**	**$22,134**	**$0**	**$0**	**$103,969**	**$9,561**	**$0**	**$13,377**	**$126,907**	**$232**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$15,181	$0	$4,731	$0	$0	$19,911	$1,890	$0	$2,180	$23,982	$44
9.2	Circulating Water Pumps	$3,928	$0	$285	$0	$0	$4,213	$361	$0	$457	$5,031	$9
9.3	Circ.Water System Auxiliaries	$907	$0	$121	$0	$0	$1,028	$97	$0	$112	$1,237	$2
9.4	Circ.Water Piping	$0	$7,315	$6,977	$0	$0	$14,292	$1,317	$0	$2,341	$17,950	$33
9.5	Make-up Water System	$740	$0	$981	$0	$0	$1,721	$163	$0	$283	$2,167	$4
9.6	Component Cooling Water Sys	$723	$0	$571	$0	$0	$1,294	$121	$0	$212	$1,628	$3
9.9	Circ.Water System Foundations& Structures	$0	$3,884	$6,215	$0	$0	$10,099	$951	$0	$2,210	$13,260	$24
	SUBTOTAL 9.	**$21,479**	**$11,200**	**$19,881**	**$0**	**$0**	**$52,559**	**$4,900**	**$0**	**$7,796**	**$65,255**	**$120**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$685	$0	$2,113	$0	$0	$2,799	$273	$0	$307	$3,379	$6
10.7	Ash Transport & Feed Equipment	$4,468	$0	$4,548	$0	$0	$9,016	$853	$0	$987	$10,856	$20
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$162	$192	$0	$0	$354	$33	$0	$77	$464	$1
	SUBTOTAL 10.	**$5,154**	**$162**	**$6,854**	**$0**	**$0**	**$12,169**	**$1,158**	**$0**	**$1,371**	**$14,699**	**$27**

Exhibit 4-44 Case 12 Total Plant Cost Details (Continued)

Client:	USDOE/NETL					**Report Date:**	09-May-07
Project:	Bituminous Baseline Study						
	TOTAL PLANT COST SUMMARY						
Case:	Case 12 - Supercritical PC w/ CO2						
Plant Size:	546.0 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Dec)**	2006	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,647	$0	$270	$0	$0	$1,917	$178	$0	$157	$2,251	$4
11.2	Station Service Equipment	$4,617	$0	$1,581	$0	$0	$6,197	$593	$0	$509	$7,299	$13
11.3	Switchgear & Motor Control	$5,487	$0	$940	$0	$0	$6,427	$595	$0	$702	$7,724	$14
11.4	Conduit & Cable Tray	$0	$3,523	$11,989	$0	$0	$15,512	$1,485	$0	$2,549	$19,546	$36
11.5	Wire & Cable	$0	$6,390	$12,630	$0	$0	$19,020	$1,603	$0	$3,093	$23,716	$43
11.6	Protective Equipment	$243	$0	$861	$0	$0	$1,104	$108	$0	$121	$1,333	$2
11.7	Standby Equipment	$1,253	$0	$30	$0	$0	$1,282	$121	$0	$140	$1,544	$3
11.8	Main Power Transformers	$6,950	$0	$182	$0	$0	$7,132	$542	$0	$767	$8,441	$15
11.9	Electrical Foundations	$0	$326	$806	$0	$0	$1,133	$108	$0	$248	$1,488	$3
	SUBTOTAL 11.	**$20,196**	**$10,240**	**$29,287**	**$0**	**$0**	**$59,723**	**$5,331**	**$0**	**$8,288**	**$73,343**	**$134**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$471	$0	$294	$0	$0	$765	$74	$38	$131	$1,008	$2
12.7	Distributed Control System Equipment	$4,754	$0	$866	$0	$0	$5,620	$535	$281	$644	$7,080	$13
12.8	Instrument Wiring & Tubing	$2,626	$0	$5,327	$0	$0	$7,953	$677	$398	$1,354	$10,382	$19
12.9	Other I & C Equipment	$1,343	$0	$3,176	$0	$0	$4,520	$440	$226	$519	$5,704	$10
	SUBTOTAL 12.	**$9,195**	**$0**	**$9,662**	**$0**	**$0**	**$18,857**	**$1,726**	**$943**	**$2,648**	**$24,174**	**$44**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$53	$1,071	$0	$0	$1,124	$111	$0	$247	$1,482	$3
13.2	Site Improvements	$0	$1,765	$2,208	$0	$0	$3,973	$390	$0	$873	$5,236	$10
13.3	Site Facilities	$3,162	$0	$3,142	$0	$0	$6,305	$619	$0	$1,385	$8,308	$15
	SUBTOTAL 13.	**$3,162**	**$1,818**	**$6,421**	**$0**	**$0**	**$11,402**	**$1,120**	**$0**	**$2,504**	**$15,026**	**$28**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,384	$7,472	$0	$0	$15,857	$1,424	$0	$2,592	$19,873	$36
14.2	Turbine Building	$0	$12,152	$11,477	$0	$0	$23,629	$2,128	$0	$3,864	$29,621	$54
14.3	Administration Building	$0	$608	$651	$0	$0	$1,259	$114	$0	$206	$1,579	$3
14.4	Circulation Water Pumphouse	$0	$279	$225	$0	$0	$503	$45	$0	$82	$631	$1
14.5	Water Treatment Buildings	$0	$999	$834	$0	$0	$1,833	$164	$0	$300	$2,297	$4
14.6	Machine Shop	$0	$406	$277	$0	$0	$683	$61	$0	$112	$855	$2
14.7	Warehouse	$0	$275	$280	$0	$0	$555	$50	$0	$91	$696	$1
14.8	Other Buildings & Structures	$0	$225	$194	$0	$0	$419	$38	$0	$69	$525	$1
14.9	Waste Treating Building & Str.	$0	$431	$1,325	$0	$0	$1,756	$166	$0	$288	$2,210	$4
	SUBTOTAL 14.	**$0**	**$23,760**	**$22,735**	**$0**	**$0**	**$46,495**	**$4,189**	**$0**	**$7,603**	**$58,287**	**$107**
	TOTAL COST	**$767,230**	**$55,282**	**$382,352**	**$0**	**$0**	**$1,204,865**	**$113,256**	**$53,822**	**$195,130**	**$1,567,073**	**$2,870**

Exhibit 4-45 Case 12 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Dec)	2006
Case 12 - Supercritical PC w/ CO2						Heat Rate-net(Btu/kWh):	12,534
						MWe-net:	546
						Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	33.00	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	2.0		2.0				
Operator	11.3		11.3				
Foreman	1.0		1.0				
Lab Tech's, etc.	2.0		2.0				
TOTAL-O.J.'s	16.3		16.3				
						Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost						$6,138,007	$11.242
Maintenance Labor Cost						$10,271,860	$18.813
Administrative & Support Labor						$4,102,467	$7.514
TOTAL FIXED OPERATING COSTS						**$20,512,333**	**$37.569**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$15,407,790**	**$0.00379**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water(/1000 gallons)	0	8,755	1.03	**$0**		**$2,797,790**	**$0.00069**
Chemicals							
MU & WT Chem.(lb)	296,665	42,381	0.16	$48,890		$2,166,895	$0.00053
Limestone (ton)	4,877	697	20.60	$100,457		$4,452,382	$0.00110
Carbon (Mercury Removal) (lb)	0	0	1.00	$0		$0	$0.00000
MEA Solvent (ton)	1,065	1.51	2,142.40	$2,281,656		$1,004,996	$0.00025
NaOH (tons)	74	7.36	412.96	$30,559		$942,457	$0.00023
H2SO4 (tons)	72	7.18	132.15	$9,515		$294,213	$0.00007
Corrosion Inhibitor	0	0	0.00	$147,250		$7,000	$0.00000
Activated Carbon(lb)	657,450	1,800	1.00	$657,450		$558,450	$0.00014
Ammonia (28% NH3) ton	813	116	123.60	$100,439		$4,451,615	$0.00109
Subtotal Chemicals				**$3,376,216**		**$13,878,007**	**$0.00341**
Other							
Supplemental Fuel(MBtu)	0	0	0.00	$0		$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.62	5,500.00	$0		$1,058,976	$0.00026
Emission Penalties	0	0	0.00	$0		$0	$0.00000
Subtotal Other				**$0**		**$1,058,976**	**$0.00026**
Waste Disposal							
Flyash (ton)	0	137	15.45	$0		$654,409	$0.00016
Bottom Ash(ton)	0	546	15.45	$0		$2,617,579	$0.00064
Subtotal-Waste Disposal				**$0**		**$3,271,988**	**$0.00080**
By-products & Emissions							
Gypsum (tons)	0	1,085	0.00	$0		$0	$0.00000
Subtotal By-Products				**$0**		**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$3,376,216**		**$36,414,550**	**$0.00896**
Fuel(ton)	211,183	7,039	42.11	$8,892,927		**$91,967,691**	**$0.02262**

4.4 PC CASE SUMMARY

The performance results of the four PC plant configurations modeled in this study are summarized in Exhibit 4-46.

Exhibit 4-46 Estimated Performance and Cost Results for Pulverized Coal Cases

	Pulverized Coal Boiler			
	PC Subcritical		PC Supercritical	
	Case 9	Case 10	Case 11	Case 12
CO_2 Capture	No	Yes	No	Yes
Gross Power Output (kW_e)	583,315	679,923	580,260	663,445
Auxiliary Power Requirement (kW_e)	32,870	130,310	30,110	117,450
Net Power Output (kW_e)	550,445	549,613	550,150	545,995
Coal Flowrate (lb/hr)	437,699	646,589	411,282	586,627
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A
HHV Thermal Input (kW_{th})	1,496,479	2,210,668	1,406,161	2,005,660
Net Plant HHV Efficiency (%)	36.8%	24.9%	39.1%	27.2%
Net Plant HHV Heat Rate (Btu/kW-hr)	9,276	13,724	8,721	12,534
Raw Water Usage, gpm	6,212	12,187	5,441	10,444
Total Plant Cost ($ x 1,000)	852,612	1,591,277	866,391	1,567,073
Total Plant Cost ($/kW)	1,549	2,895	1,575	2,870
LCOE (mills/kWh)[1]	64.0	118.8	63.3	114.8
CO_2 Emissions (lb/MWh)[2]	1,780	225	1,681	209
CO_2 Emissions (lb/MWh)[3]	1,886	278	1,773	254
SO_2 Emissions (lb/MWh)[2]	0.7426	Negligible	0.7007	Negligible
NOx Emissions (lb/MWh)[2]	0.613	0.777	0.579	0.722
PM Emissions (lb/MWh)[2]	0.114	0.144	0.107	0.134
Hg Emissions (lb/MWh)[2]	1.00E-05	1.27E-05	9.45E-06	1.18E-05

[1] Based on an 85% capacity factor
[2] Value is based on gross output
[3] Value is based on net output

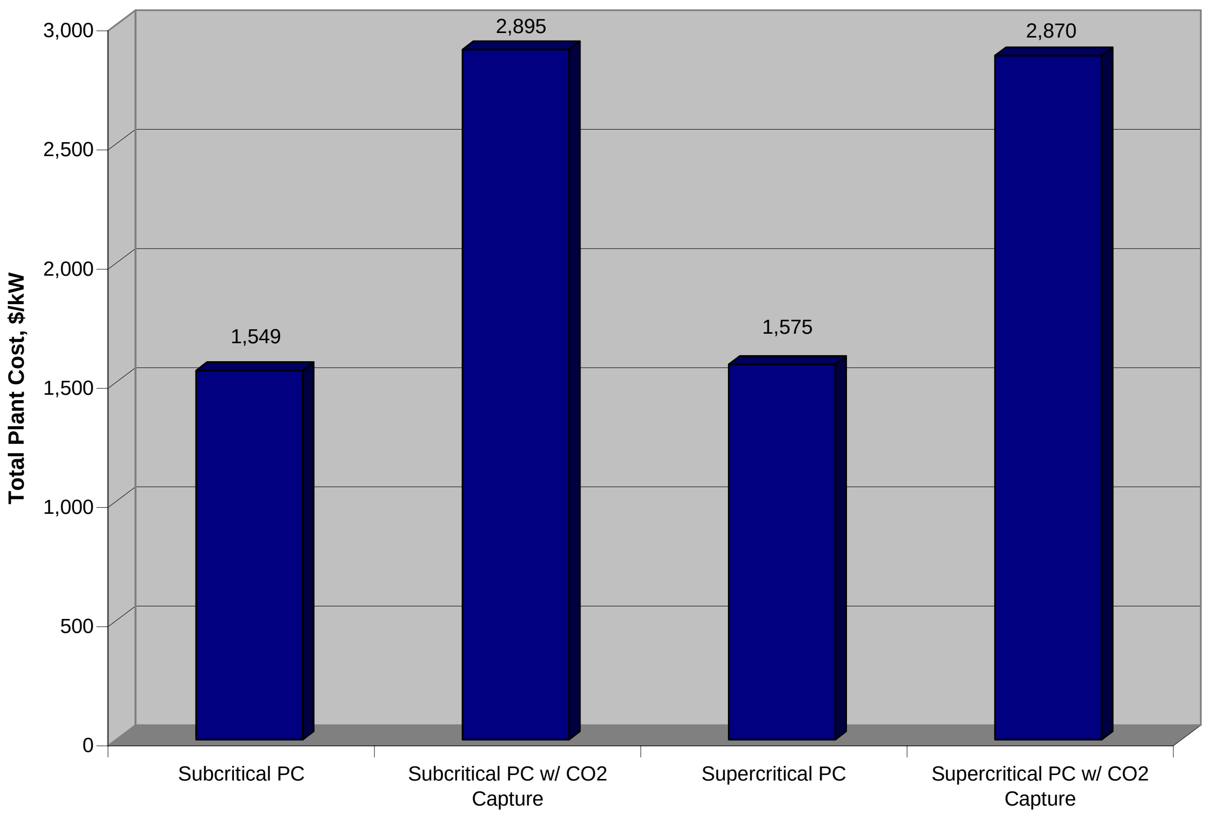
The TPC for each of the PC cases is shown in Exhibit 4-47.

The following observations can be made:

- The TPC of the non-capture supercritical PC case is only incrementally greater than subcritical PC (less than 2 percent). The TPC of supercritical PC with CO_2 capture is 0.9 percent less than subcritical PC.
- The capital cost penalty for adding CO_2 capture in the subcritical case is 87 percent and in the supercritical case is 82 percent. The Econamine FG Plus cost includes a process contingency of approximately $100/kW in both the subcritical and supercritical cases. Eliminating the process contingency results in a CO_2 capture cost penalty of 76 and 80 percent for the supercritical and subcritical PC cases, respectively. In addition to the high cost of the Econamine process, there is a significant increase in the cost of the cooling towers and circulating water pumps in the CO_2 capture cases because of the larger cooling water demand discussed previously. In addition, the gross output of the two PC plants increases by 97 MW (subcritical) and 83 MW (supercritical) to maintain the net

output at 550 MW. The increased gross output results in higher coal flow rate and consequent higher costs for all cost accounts in the estimate.

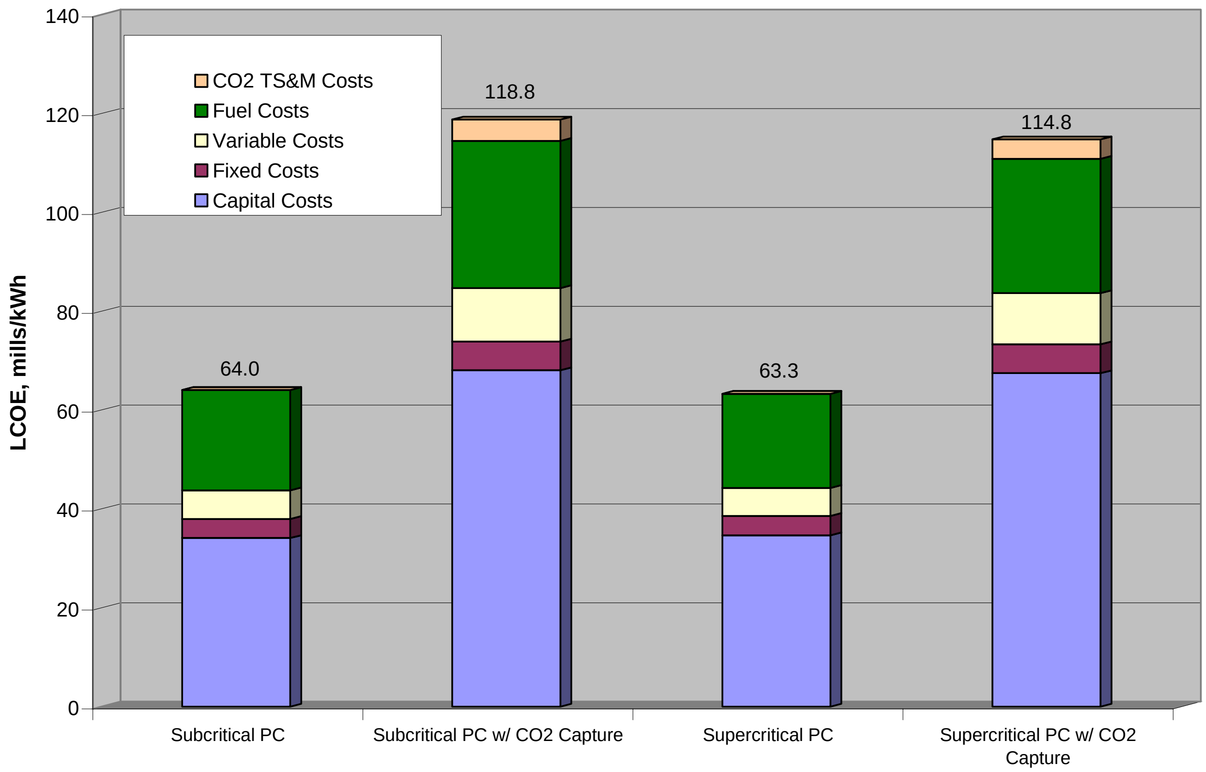
Exhibit 4-47 Total Plant Cost for PC Cases



The LCOE is shown for the four PC cases in Exhibit 4-48. The following observations can be made:

- Capital costs represent the largest fraction of LCOE in all cases, but particularly so in the CO_2 capture cases. Fuel cost is the second largest component of LCOE, and capital charges and fuel costs combined represent about 83 percent of the total in all cases.
- In the non-capture case the slight increase in capital cost in the supercritical case is more than offset by the efficiency gain so that the LCOE for supercritical PC is 1 percent less than subcritical despite having a nearly 2 percent higher TPC.
- In the CO_2 capture case, the cost differential between subcritical and supercritical PC is negligible (less than 1 percent), but the supercritical PC has a 3 percent lower LCOE because of the higher efficiency.

Exhibit 4-48 LCOE for PC Cases



The sensitivity of LCOE to capacity factor is shown in Exhibit 4-49. Implicit in the curves is the assumption that an efficiency of greater than 85 percent can be achieved without the expenditure of additional capital. The subcritical and supercritical cases with no CO_2 capture are nearly identical making it difficult to distinguish between the two lines. The LCOE increases more steeply at low capacity factor because the relatively high capital component is spread over fewer kilowatt-hours of generation.

The sensitivity of LCOE to coal price is shown in Exhibit 4-50. As in the IGCC cases, the LCOE in the PC cases is relatively insensitive to coal price.

As presented in Section 2.4 the cost of CO_2 capture was calculated in two ways, CO_2 removed and CO_2 avoided. The results for the PC carbon capture cases are shown in Exhibit 4-51.

The cost of CO_2 captured and avoided is nearly identical for the subcritical and supercritical PC cases. The avoided cost is significantly higher than the captured cost because the gross output of the capture case is 83-96 MW higher than the non-capture case which reduces the amount of CO_2 avoided between cases.

Exhibit 4-49 Sensitivity of LCOE to Capacity Factor for PC Cases

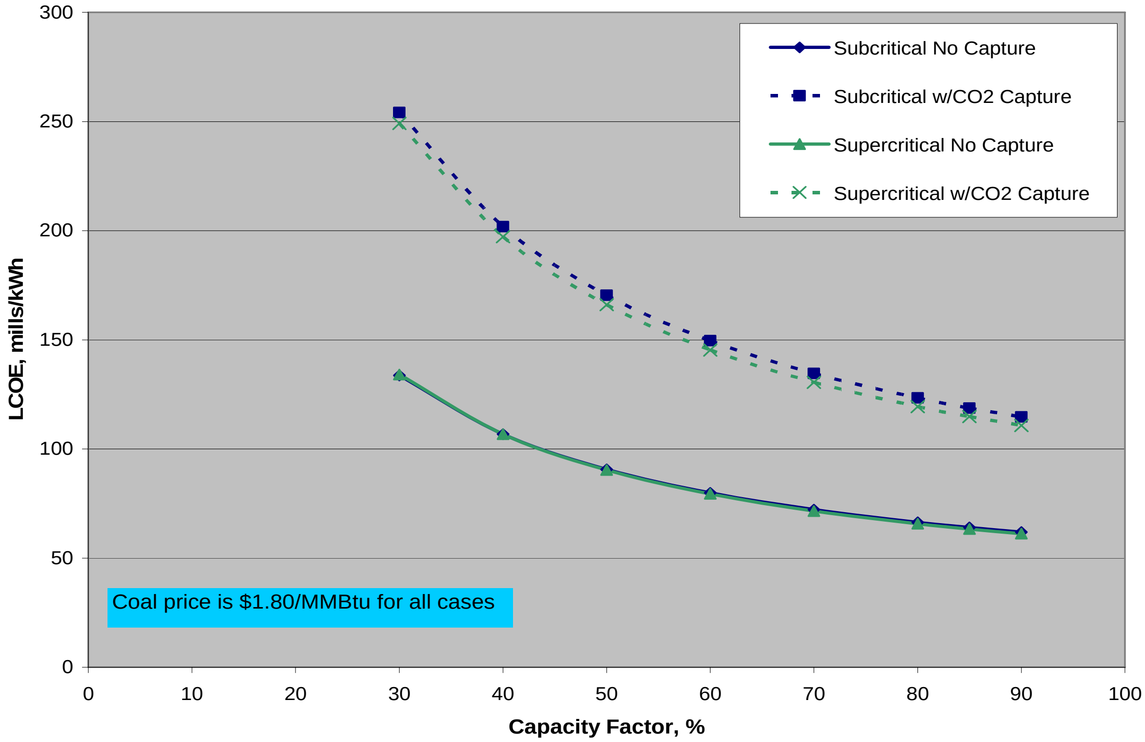


Exhibit 4-50 Sensitivity of LCOE to Coal Price for PC Cases

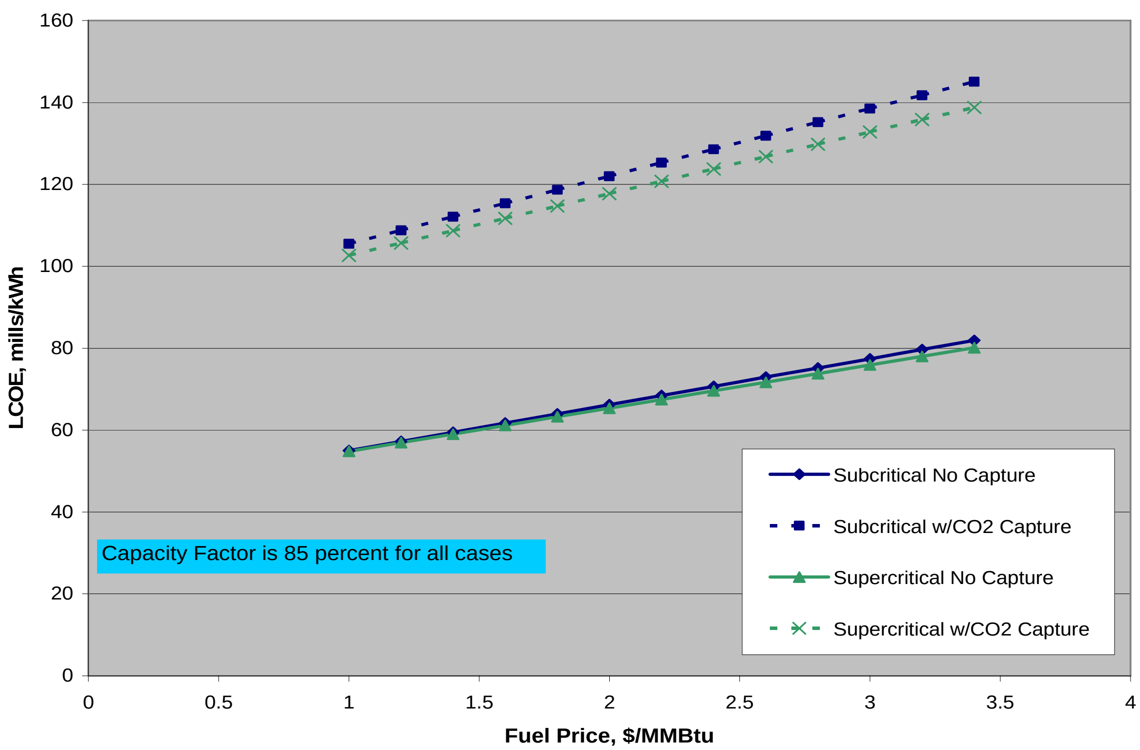
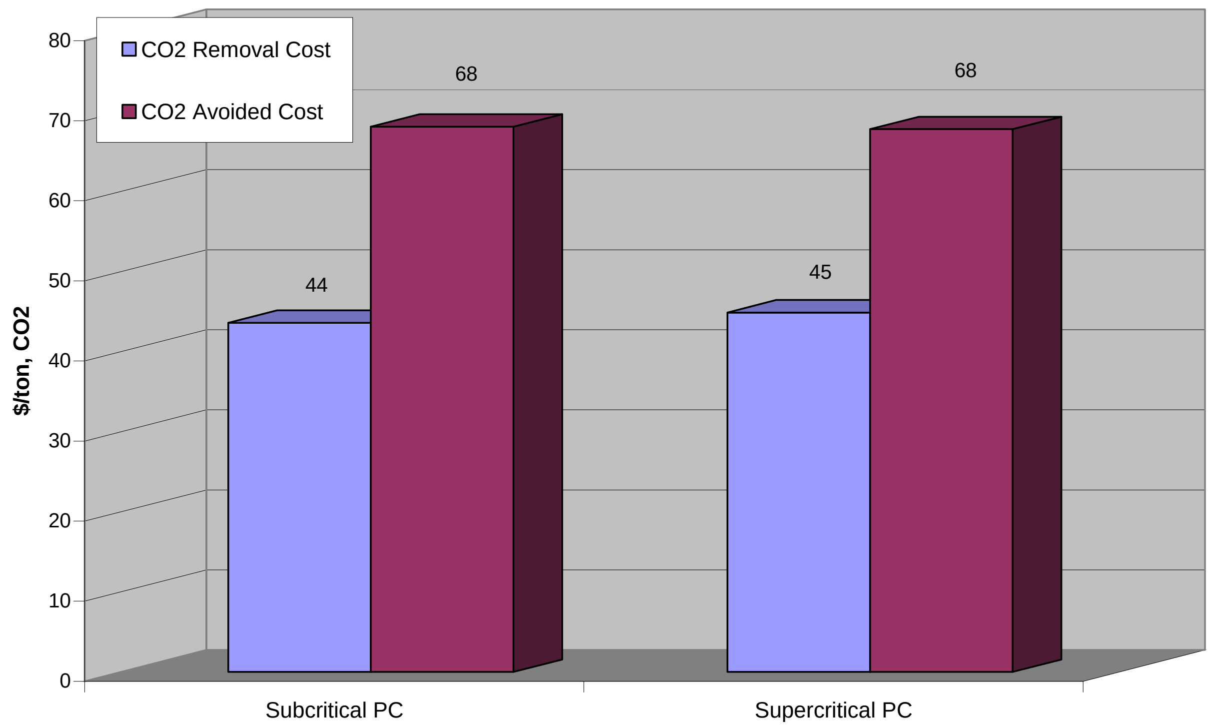


Exhibit 4-51 Cost of CO_2 Captured and Avoided in PC Cases



The following observations can be made regarding plant performance with reference to Exhibit 4-46:

- The efficiency of the supercritical PC plant is 2.3 percentage points higher than than the equivalent subcritical PC plant (39.1 percent compared to 36.8 percent). The efficiencies are comparable to those reported in other studies once steam cycle conditions are considered. For example, in an EPA study [62] comparing PC and IGCC plant configurations the subcritical PC plant using bituminous coal had an efficiency of 35.9 percent with a steam cycle of 16.5 MPa/538°C/538°C (2400 psig/1000°F/1000°F). The higher steam cycle temperature in this study 566°C/566°C (1050°F/1050°F) results in a higher net efficiency. The same study reported a supercritical plant efficiency of 38.3 percent with a steam cycle of 24.1 MPa/566°C/566°C (3500 psig/1050°F/1050°F). Again, the more aggressive steam conditions in this study, 593°C/593°C (1100°F/1100°F) resulted in a higher net efficiency.

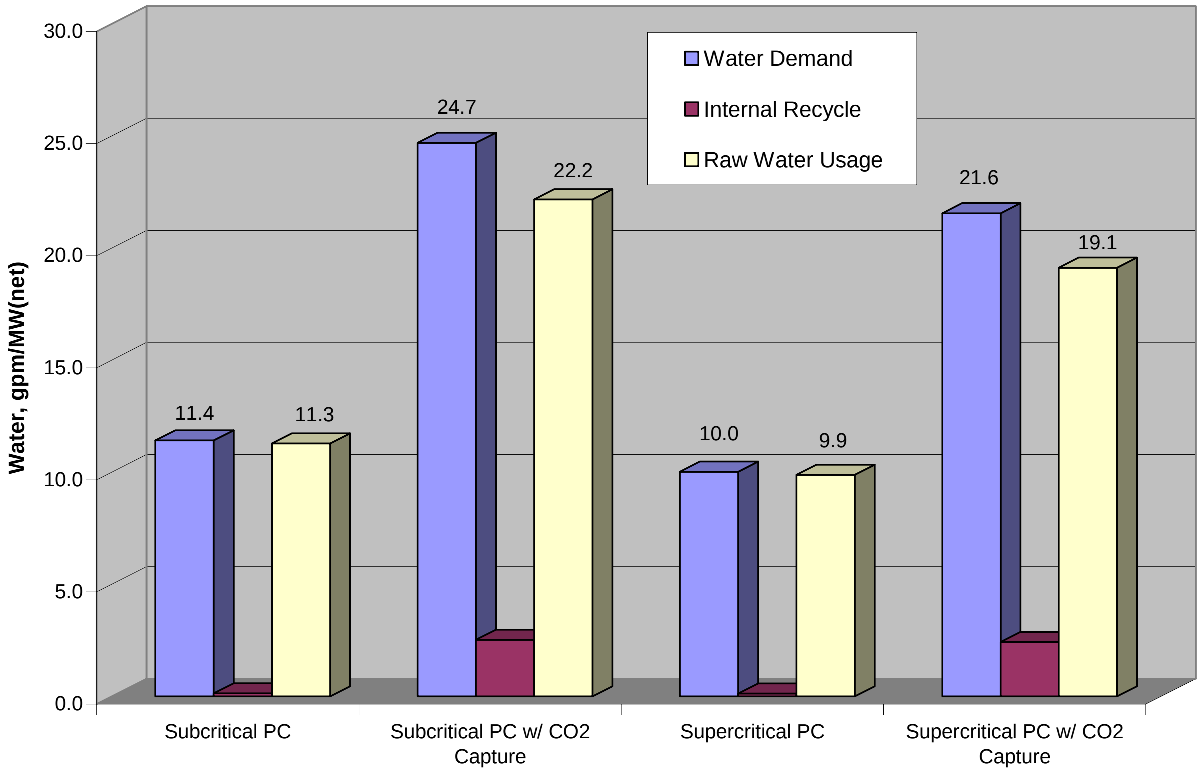
  Similar results from an EPRI study using Illinois No. 6 coal were reported as follows [63]:

  - Subcritical PC efficiency of 35.7 percent with a steam cycle of 16.5 MPa/538°C/538°C (2400 psig/1000°F/1000°F).
  - Supercritical PC efficiency of 38.3 percent with a steam cycle of 24.8 MPa/593°C/593°C (3600 psig/1100°F/1100°F).

- The addition of CO_2 capture to the two PC cases results in the same absolute efficiency impact, namely an 11.9 percentage point decrease. The efficiency is negatively impacted by the large auxiliary loads of the Econamine process and CO_2 compression, as well as the large increase in cooling water requirement, which increases the circulating water pump and cooling tower fan auxiliary loads. The auxiliary load increases by 97 MW in the subcritical PC case and by 87 MW in the supercritical PC case.
- NOx, PM and Hg emissions are the same for all four PC cases on a heat input basis because of the environmental target assumptions of fixed removal efficiencies for each case (86 percent SCR efficiency, 99.8 percent baghouse efficiency and 90 percent co-benefit capture). The emissions on a mass basis or normalized by gross output are higher for subcritical cases than supercritical cases and are higher for CO_2 capture cases than non-capture cases because of the higher efficiencies of supercritical PC and non-capture PC cases.
- SO_2 emissions are likewise constant on a heat input basis for the non-capture cases, but the Econamine process polishing scrubber and absorber vessel result in negligible SO_2 emissions in CO_2 capture cases. The SO_2 emissions for subcritical PC are higher than supercritical on a mass basis and when normalized by gross output because of the lower efficiency.
- Uncontrolled CO_2 emissions on a mass basis are greater for subcritical PC compared to supercritical because of the lower efficiency. The capture cases result in a 90% reduction of CO_2 for both subcritical and supercritical PC.
- Raw water usage for all cases is dominated by cooling tower makeup requirements, which accounts for about 89 percent of raw water in non-capture cases and 92 percent of raw water in CO_2 capture cases. The amount of raw water usage in the CO_2 capture cases is greatly increased by the cooling water requirements of the Econamine process. Cooling water is required to:
    - Reduce the flue gas temperature from 57°C (135°F) (FGD exit temperature) to 32°C (89°F) (Econamine absorber operating temperature), which also requires condensing water from the flue gas that comes saturated from the FGD unit.
    - Remove the heat input by the stripping steam to cool the solvent
    - Remove the heat input from the auxiliary electric loads
    - Remove heat in the CO_2 compressor intercoolers

The normalized water demand, internal recycle and raw water usage are shown in Exhibit 4-52 for each of the PC cases. The only internal recycle stream that affects the overall balance in the non-capture cases is the boiler feedwater blowdown stream which is recycled to the cooling tower as makeup water. In the CO_2 capture cases, additional water is recovered from the flue gas as it is cooled to the absorber temperature of 32°C (89°F). The condensate is treated and also used as cooling tower makeup.

Exhibit 4-52 Water Usage in PC Cases



5 NATURAL GAS COMBINED CYCLE PLANTS

Two natural gas combined cycle (NGCC) power plant configurations were evaluated and are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available in time to support a 2010 start up date. Each design consists of two advanced F class combustion turbine generators (CTG), two HRSG's and one steam turbine generator (STG) in a multi-shaft 2x2x1 configuration.

The NGCC cases are evaluated with and without carbon capture on a common thermal input basis. The NGCC designs that include CDR have a smaller plant net output resulting from the additional CDR facility auxiliary loads. Like in the IGCC cases, the sizes of the NGCC designs were determined by the output of the commercially available combustion turbine. Hence, evaluation of the NGCC designs on a common net output basis was not possible.

The Rankine cycle portion of both designs uses a single reheat 16.5 MPa/566°C/510°C (2400 psig/1050°F/950°F) steam cycle. A more aggressive steam cycle was considered but not chosen because there are very few HRSGs in operation that would support such conditions. [54]

5.1 NGCC COMMON PROCESS AREAS

The two NGCC cases are nearly identical in configuration with the exception that Case 14 includes CO_2 capture while Case 13 does not. The process areas that are common to the two plant configurations are presented in this section.

5.1.1 NATURAL GAS SUPPLY SYSTEM

It was assumed that a natural gas main with adequate capacity is in close proximity (within 16 km [10 miles]) to the site fence line and that a suitable right of way is available to install a branch line to the site. For the purposes of this study it was also assumed that the gas will be delivered to the plant custody transfer point at 3.0 MPa (435 psig) and 38°C (100ºF), which matches the advanced F Class fuel system requirements. Hence, neither a pressure reducing station with gas preheating (to prevent moisture and hydrocarbon condensation), nor a fuel booster compressor are required.

A new gas metering station is assumed to be added on the site, adjacent to the new combustion turbine. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete time-line record of gas consumption rates and cumulative consumption is provided.

5.1.2 COMBUSTION TURBINE

The combined cycle plant is based on two CTG's. The combustion turbine generator is representative of the advanced F Class turbines with an ISO base rating of 184,400 kW when firing natural gas. [64] This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes and dry LNB combustion system.

Each combustion turbine generator is provided with inlet air filtration systems; inlet silencers; lube and control oil systems including cooling; electric motor starting systems; acoustical enclosures including heating and ventilation; control systems including supervisory, fire protection, and fuel systems. No back up fuel was envisioned for this project.

The CTG is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical, and control systems required for CTG operation. Site CTG installation involves module interconnection and linking CTG modules to the plant systems. The CTG package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. A typical scope of supply is presented in Exhibit 5-1.

Exhibit 5-1 Combustion Turbine Typical Scope of Supply

System	System Scope
ENGINE ASSEMBLY	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
Engine Assembly with Bedplate	Variable Inlet Guide Vane System, Compressor, Bleed System, Purge Air System, Bearing Seal Air System, Combustors, Dual Fuel Nozzles, Turbine Rotor Cooler
Walk-in acoustical enclosure	HVAC, Lighting, and Low Pressure CO_2 Fire Protection System
MECHANICAL PACKAGE	HVAC and Lighting, Air Compressor for Pneumatic System, Low Pressure CO_2 Fire Protection System
Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps, DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister, Oil Heaters, Oil Interconnect Piping (SS and CS), Oil System Instrumentation, Oil for Flushing and First Filling
ELECTRICAL PACKAGE	HVAC and Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant DCS Supervisory System, Bentley Nevada Vibration Monitoring System, Low Pressure CO_2 Fire Protection System, Cable Tray and Conduit Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards
INLET AND EXHAUST SYSTEMS	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self Cleaning Filters, Hoist System For Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Exhaust Silencers Inlet and Exhaust Flow, Pressure and Temperature Ports and Instrumentation
FUEL SYSTEMS	
N. Gas System	Gas Valves Including Vent, Throttle and Trip Valves, Gas Filter/Separator, Gas Supply Instruments and Instrument Panel
STARTING SYSTEM	Enclosure, Starting Motor or Static Start System, Turning Gear and Clutch Assembly, Starting Clutch, Torque Converter
GENERATOR	Static or Rotating Exciter (Excitation transformer to be included for a static system), Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer, and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Generator Breaker, Iso-Phase bus connecting generator and breaker, Grounding System Connectors
Generator Cooling	TEWAC System (including circulation system, interconnecting piping and controls), or Hydrogen Cooling System (including H_2 to Glycol and Glycol to Air heat exchangers, liquid level detector circulation system, interconnecting piping and controls)
MISCELLANEOUS	Interconnecting Pipe, Wire, Tubing and Cable Instrument Air System Including Air Dryer On Line and Off Line Water Wash System LP CO_2 Storage Tank Drain System Drain Tanks Coupling, Coupling Cover and Associated Hardware

The generators would typically be provided with the combustion turbine package. The generators are assumed to be 24 kV, 3-phase, 60 hertz, constructed to meet American National Standards Institute (ANSI) and National Electrical Manufacturers Association (NEMA) standards for turbine-driven synchronous generators. The generator is totally enclosed, water-air cooled (TEWAC), complete with excitation system, cooling, and protective relaying.

5.1.3 HEAT RECOVERY STEAM GENERATOR

The HRSG is configured with HP, IP, and LP steam drums, and superheater, reheater, and economizer sections. The HP drum is supplied with feedwater by the HP boiler feed pump to generate HP steam, which passes to the superheater section for heating to 566°C (1050°F). The IP drum is supplied with feedwater from an interstage bleed on the HP boiler feed pump. The IP steam from the drum is superheated to 482°C (900°F) and mixed with hot reheat steam from the reheat section at 510°C (950ºF) and a portion of HP steam also at 510°C (950ºF). The combined flows are admitted into the IP section of the steam turbine. The LP drum provides steam to the integral deaerator, and also to the LP turbine.

The economizer sections heat condensate and feedwater (in separate tube bundles). The HRSG tubes are typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 ferritic alloy material; the low-temperature portions (< 399°C [750°F]) are carbon steel. Each HRSG exhausts directly to the stack, which is fabricated from carbon steel plate materials and lined with Type 409 stainless steel. The stack for the NGCC cases is assumed to be 46 m (150 ft) high, and the cost is included in the HRSG account.

5.1.4 NOX CONTROL SYSTEM

This reference plant is designed to achieve 2.5 ppmvd NOx emissions (expressed as NO_2 and referenced to 15 percent O_2). Two measures are taken to reduce the NOx. The first is a dry low NOx burner in the CTG. The dry LNB burners are a low NOx design and reduce the emissions to about 25 ppmvd (referenced to 15 percent O_2). [65]

The second measure taken to reduce the NOx emissions was the installation of a SCR system. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of reactor, and ammonia supply and storage system. The SCR system is designed for 90 percent reduction while firing natural gas. This along with the dry LNB achieves the emission limit of 2.5 ppmvd (referenced to 15 percent O_2).

Operation Description - The SCR reactor is located in the flue gas path inside the HRSG between the high pressure and intermediate pressure sections. The SCR reactor is equipped with one catalyst layer consisting of catalyst modules stacked in line on a supporting structural frame. The SCR reactor has space for installation of an additional layer. Ammonia is injected into the gas immediately prior to entering the SCR reactor. The ammonia injection grid is arranged into several sections, and consists of multiple pipes with nozzles. Ammonia flow rate into each injection grid section is controlled taking into account imbalances in the flue gas flow distribution across the HRSG. The catalyst contained in the reactor enhances the reaction between the ammonia and the NOx in the gas. The catalyst consists of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The optimum inlet flue gas temperature range for the catalyst is 260°C (500°F) to 343°C (650°F).

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, and dilution air skid.

5.1.5 CARBON DIOXIDE RECOVERY FACILITY

A CDR facility is used in Case 14 to remove 90 percent of the CO_2 in the flue gas exiting the HRSG, purify it, and compress it to a supercritical condition. It is assumed that all of the carbon in the natural gas is converted to CO_2. The CDR is comprised of flue gas supply, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for Case 14 is based on the Fluor Econamine FG Plus technology as previously described in Section 4.1.7 with the exception that no SO_2 polishing step is required in the NGCC case. If the pipeline natural gas used in this study contained the maximum amount of sulfur allowed per EPA specifications (0.6 gr S/100 scf), the flue gas would contain 0.4 ppmv of SO_2, which is well below the limit where a polishing scrubber would be required (10 ppmv). A description of the basic process steps is repeated here for completeness with minor modifications to reflect application in an NGCC system as opposed to PC.

Flue Gas Cooling and Supply

The function of the flue gas cooling and supply system is to transport flue gases from the HRSG to the CO_2 absorption tower, and condition flue gas pressure, temperature and moisture content so it meets the requirements of the Econamine process. Temperature and hence moisture content of the flue gas exiting the HRSG is reduced in the Direct Contact Flue Gas Cooler, where flue gas is cooled using cooling water.

The water condensed from the flue gas is collected in the bottom of the Direct Contact Flue Gas Cooler section and re-circulated to the top of the Direct Contact Flue Gas Cooler section via the Flue Gas Circulation Water Cooler, which rejects heat to the plant circulating water system. Level in the Direct Contact Flue Gas Cooler is controlled by directing the excess water to the cooling water return line. In the Direct Contact Flue Gas Cooler, flue gas is cooled beyond the CO_2 absorption process requirements to 33°C (91°F) to account for the subsequent flue gas temperature increase of 14°C (25°F) in the flue gas blower. Downstream from the Direct Contact Flue Gas Cooler flue gas pressure is boosted in the flue gas blowers by approximately 0.01 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the NGCC plant circulating water system and returned to the NGCC plant cooling tower. The CDR facility requires a significant amount of cooling water for flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, the lean solvent cooler, and CO_2 compression interstage cooling. The cooling water requirements for the CDR facility in the NGCC capture case is about 681,380 lpm (180,000 gpm), which greatly exceeds the NGCC plant cooling water requirement of about 227,125 lpm (60,000 gpm).

CO_2 Absorption

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent called Econamine FG Plus. Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, and the rest leaves the top of the absorber section and flows into the water wash section of the tower. The lean solvent enters the top of the absorber, absorbs the CO_2 from the flue gases and leaves the bottom of the absorber with the absorbed CO_2.

Water Wash Section

The purpose of the Water Wash section is to minimize solvent losses due to mechanical entrainment and evaporation. The flue gas from the top of the CO_2 Absorption section is contacted with a re-circulating stream of water for the removal of most of the lean solvent. The scrubbed gases, along with unrecovered solvent, exit the top of the wash section for discharge to the atmosphere via the vent stack. The water stream from the bottom of the wash section is collected on a chimney tray. A portion of the water collected on the chimney tray spills over to the absorber section as water makeup for the amine with the remainder pumped via the Wash Water Pump and cooled by the Wash Water Cooler, and recirculated to the top of the CO_2 Absorber. The wash water level is maintained by water makeup from the Wash Water Makeup Pump.

Rich/Lean Amine Heat Exchange System

The rich solvent from the bottom of the CO_2 Absorber is preheated by the lean solvent from the Solvent Stripper in the Rich Lean Solvent Exchanger. The heated rich solvent is routed to the Solvent Stripper for removal of the absorbed CO_2. The stripped solvent from the bottom of the Solvent Stripper is pumped via the Hot Lean Solvent Pumps through the Rich Lean Exchanger to the Solvent Surge Tank. Prior to entering the Solvent Surge Tank, a slipstream of the lean solvent is pumped via the Solvent Filter Feed Pump through the Solvent Filter Package to prevent buildup of contaminants in the solution. From the Solvent Surge Tank the lean solvent is pumped via the Warm Lean Solvent Pumps to the Lean Solvent Cooler for further cooling, after which the cooled lean solvent is returned to the CO_2 Absorber, completing the circulating solvent circuit.

Solvent Stripper

The purpose of the Solvent Stripper is to separate the CO_2 from the rich solvent feed exiting the bottom of the CO_2 Absorber. The rich solvent is collected on a chimney tray below the bottom packed section of the Solvent Stripper and routed to the Solvent Stripper Reboilers where the rich solvent is heated by steam, stripping the CO_2 from the solution. Steam is provided from the LP section of the steam turbine at about 0.47 MPa (68 psia) and 291°C (555°F). The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Solvent Stripper Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Solvent Stripper Reflux Drum where the vapor and liquid are separated. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Solvent Stripper Reflux Drum is pumped via the Solvent Stripper Reflux Pumps where a portion of condensed overhead liquid is used as make-up water for the Water Wash section of the CO_2 Absorber. The rest of the pumped liquid is routed back to the Solvent Stripper as reflux, which aids in limiting the amount of solvent vapors entering the stripper overhead system.

Solvent Stripper Reclaimer

A small slipstream of the lean solvent from the Solvent Stripper bottoms is fed to the Solvent Stripper Reclaimer for the removal of high-boiling nonvolatile impurities (heat stable salts – HSS), volatile acids and iron products from the circulating solvent solution. The solvent bound in the HSS is recovered by reaction with caustic and heating with steam. The solvent reclaimer system reduces corrosion, foaming and fouling in the solvent system. The reclaimed solvent is returned to the Solvent Stripper and the spent solvent is pumped via the Solvent Reclaimer Drain Pump to the Solvent Reclaimer Drain Tank.

Steam Condensate

Steam condensate from the Solvent Stripper Reclaimer accumulates in the Solvent Reclaimer Condensate Drum and level controlled to the Solvent Reboiler Condensate Drum. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler Condensate Drum and returned to the steam cycle just downstream of the deaerator via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System

A proprietary corrosion inhibitor is continuously injected into the CO_2 Absorber rich solvent bottoms outlet line, the Solvent Stripper bottoms outlet line and the Solvent Stripper top tray. This constant injection is to help control the rate of corrosion throughout the CO_2 recovery plant system.

Gas Compression and Drying System

In the compression section, the CO_2 is compressed to 15.3 MPa (2,215 psia) by a six-stage centrifugal compressor. The discharge pressures of the stages were balanced to give reasonable power distribution and discharge temperatures across the various stages as shown in Exhibit 5-2.

Power consumption for this large compressor was estimated assuming an isentropic efficiency of 84 percent. During compression to 15.3 MPa (2,215 psia) in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE using the methodology described in Section 2.7.

5.1.6 STEAM TURBINE

The steam turbine consists of an HP section, an IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing.

Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2400 psig/1050°F). The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 2.3 MPa/510°C (328 psia/950°F). After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the cross-over line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Exhibit 5-2 CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.36 (52)
2	0.78 (113)
3	1.71 (248)
4	3.76 (545)
5	8.27 (1,200)
6	15.3 (2,215)

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. The generator is a hydrogen-cooled synchronous type, generating power at 24 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The steam turbine generator is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color monitor/operator interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

5.1.7 WATER AND STEAM SYSTEMS

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser; and the low-temperature economizer section in the HRSG.

The system consists of one main condenser; two 50 percent capacity, motor-driven vertical multistage condensate pumps (total of two pumps for the plant); one gland steam condenser; condenser air removal vacuum pumps, condensate polisher, and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater

The function of the feedwater (FW) system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. One 100 percent capacity motor-driven feed pump is provided per each HRSG (total of two pumps for the plant). The FW pumps are equipped with an interstage takeoff to provide IP and LP feedwater. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Steam System

The steam system is comprised of main, reheat, intermediate, and low-pressure steam systems. The function of the main steam system is to convey main steam from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater and from the HRSG reheater outlet to the turbine reheat stop valves.

Main steam exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine.

Cold reheat steam exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam, for the auxiliary cooling system and for the CDR facility in Case 14. The system consists of two 50 percent capacity vertical circulating water pumps (total of two pumps for the plant), a mechanical draft evaporative cooling tower, and interconnecting piping. The condenser is a single pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

The auxiliary cooling system is a closed loop system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. The system provides cooling water to the following systems:

1. Combustion turbine generator lube oil coolers
2. Combustion turbine generator air coolers
3. Steam turbine generator lube oil coolers
4. Steam turbine generator hydrogen coolers
5. Boiler feed water pumps
6. Air compressors

7. Generator seal oil coolers (as applicable)
8. Sample room chillers
9. Blowdown coolers
10. Condensate extraction pump-motor coolers

The CDR system in Case 14 requires a substantial amount of cooling water that is provided by the NGCC plant circulating water system. The additional cooling load imposed by the CDR is reflected in the significantly larger circulating water pumps and cooling tower in that case.

Buildings and Structures

Structures assumed for NGCC cases can be summarized as follows:

1. Generation Building housing the STG
2. Circulating Water Pump House
3. Administration / Office / Control Room / Maintenance Building
4. Water Treatment Building
5. Fire Water Pump House

5.1.8 ACCESSORY ELECTRIC PLANT

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, wire, and cable. It also includes the main transformer, required foundations and standby equipment.

5.1.9 INSTRUMENTATION AND CONTROL

An integrated plant-wide DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of video monitors and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability.

The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual procedures with operator selection of modular automation routines available.

5.2 NGCC CASES

This section contains an evalution of plant designs for Cases 13 and 14. These two cases are similar in design and are based on an NGCC plant with a constant thermal input. Both plants use a single reheat 16.5 MPa/566°C/510°C (2400 psig/1050°F/950°F) cycle. The only difference between the two plants is that Case 14 includes CO_2 capture while Case 13 does not.

The balance of Section 5.2 is organized as follows:

- Process and System Description provides an overview of the technology operation as applied to Case 13. The systems that are common to all NGCC cases were covered in Section 5.1 and only features that are unique to Case 13 are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relavant to Cases 13 and 14.
- Sparing Philosophy is provided for both Cases 13 and 14.
- Performance Results provides the main modeling results from Case 13, including the performance summary, environmental performance, water balance, mass and energy balance diagrams and energy balance table.
- Equipment List provides an itemized list of major equipment for Case 13 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case 13.
- Process and System Description, Performance Results, Equipment List and Cost Estimates are reported for Case 14.

5.2.1 PROCESS DESCRIPTION

In this section the NGCC process without CO_2 capture is described. The system description follows the block flow diagram (BFD) in Exhibit 5-3 and stream numbers reference the same Exhibit. The tables in Exhibit 5-4 provide process data for the numbered streams in the BFD. The BFD shows only one of the two combustion turbine/HRSG combinations, but the flow rates in the stream table are the total for two systems.

Ambient air (stream 1) and natural gas (stream 2) are combined in the dry LNB, which is operated to control the rotor inlet temperature at 1399°C (2550°F). The flue gas exits the turbine at 631°C (1167°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG at 104°C (220°F) and passes to the plant stack

Exhibit 5-3 Case 13 Process Flow Diagram, NGCC without CO_2 Capture

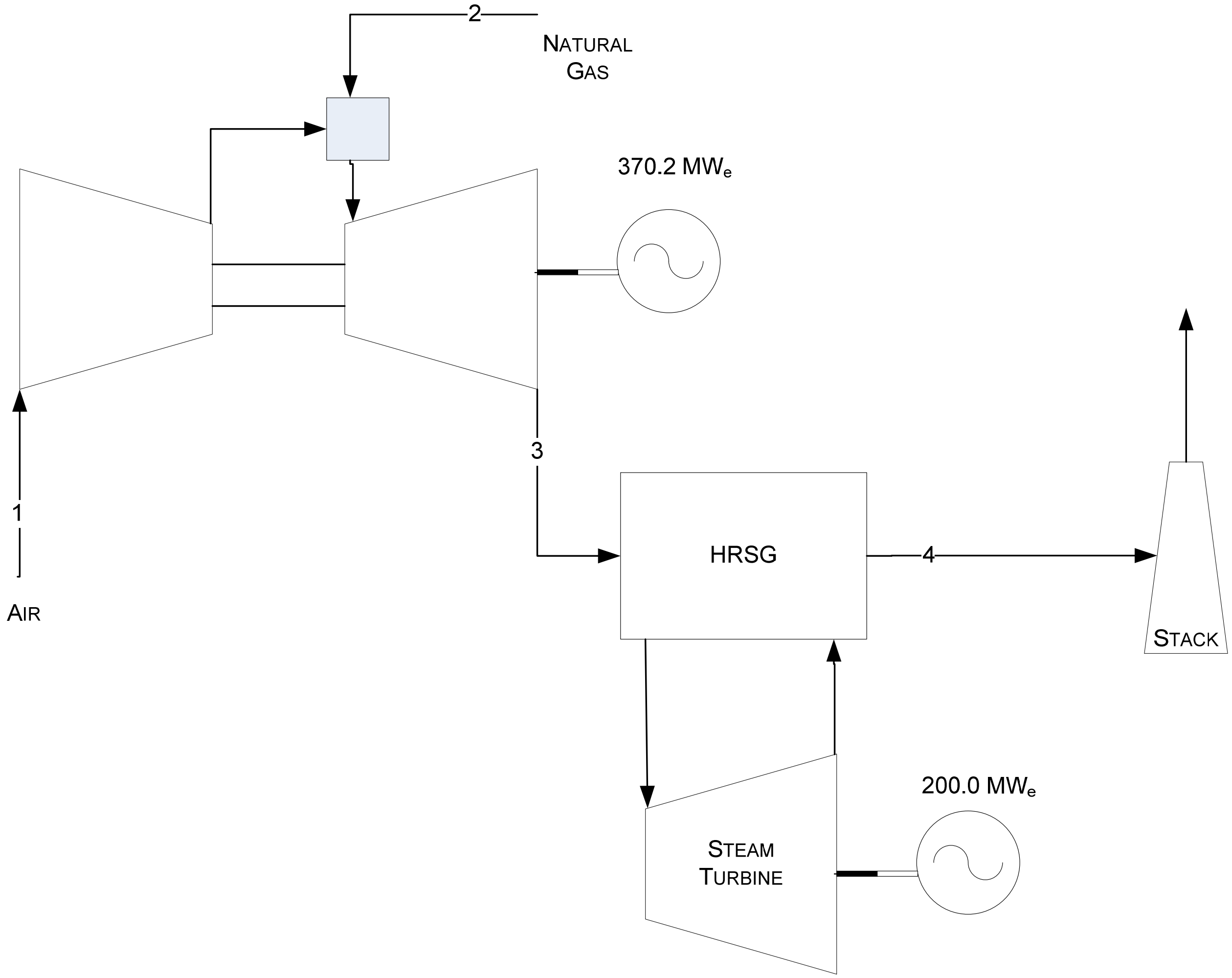


Exhibit 5-4 Case 13 Stream Table, NGCC without CO_2 Capture

	1	2	3	4
V-L Mole Fraction				
Ar	0.0092	0.0000	0.0089	0.0089
CH_4	0.0000	0.9390	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000
CO_2	0.0003	0.0100	0.0405	0.0405
H_2O	0.0099	0.0000	0.0869	0.0869
N_2	0.7732	0.0080	0.7430	0.7430
O_2	0.2074	0.0000	0.1207	0.1207
SO_2	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lb_{mol}/hr)	120,220	4,793	250,304	250,304
V-L Flowrate (lb/hr)	3,469,190	82,591	7,103,560	7,103,560
Temperature (°F)	59	100	1,167	220
Pressure (psia)	14.7	450.0	15.2	15.2
Enthalpy (BTU/lb)[A]	13.1	34.4	360.5	106.6
Density (lb/ft^3)	0.076	1.291	0.025	0.059
Molecular Weight	28.857	17.232	28.380	28.380

A - Reference conditions are 32.02 F & 0.089 PSIA

5.2.2 KEY SYSTEM ASSUMPTIONS

System assumptions for Cases 13 and 14, NGCC with and without CO_2 capture, are compiled in Exhibit 5-5.

Exhibit 5-5 NGCC Plant Study Configuration Matrix

	Case 13 w/o CO_2 Capture	**Case 14 w/CO_2 Capture**
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/510 (2400/1050/950)	16.5/566/510 (2400/1050/950)
Fuel	Natural Gas	Natural Gas
Fuel Pressure at Plant Battery Limit MPa (psig)	3.1 (450)	3.1 (450)
Condenser Pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Cooling Water to Condenser, °C (ºF)	16 (60)	16 (60)
Cooling Water from Condenser, °C (ºF)	27 (80)	27 (80)
Stack Temperature, °C (°F)	104 (220)	29 (85)
SO_2 Control	Low Sulfur Fuel	Low Sulfur Fuel
NOx Control	LNB and SCR	LNB and SCR
SCR Efficiency, % (A)	90	90
Ammonia Slip (End of Catalyst Life), ppmv	10	10
Particulate Control	N/A	N/A
Mercury Control	N/A	N/A
CO_2 Control	N/A	Econamine FG Plus
CO_2 Capture, % (A)	N/A	90
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the flue gas content

Balance of Plant – Cases 13 and 14

The balance of plant assumptions are common to both NGCC cases and are presented in Exhibit 5-6.

Exhibit 5-6 NGCC Balance of Plant Assumptions

Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage Natural Gas	Pipeline supply at 3.1 MPa (450 psia) and 38°C (100°F)
Ash	N/A
Gypsum	N/A
Limestone	N/A
Plant Distribution Voltage Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water Makeup Water	The water supply is 50 percent from a local Publicly Owned Treatment Works (POTW) and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

5.2.3 SPARING PHILOSOPHY

Dual trains are used to accommodate the size of commercial gas turbines. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two advanced F class combustion turbine generators (2 x 50%)
- Two 3-pressure reheat HRSGs with self supporting stacks and SCR systems (2 x 50%)
- One 3-pressure reheat, triple-admission steam turbine generator (1 x 100%)

- Two trains of Econamine FG Plus CO_2 capture (2 x 50%) (Case 14 only)

5.2.4 CASE 13 PERFORMANCE RESULTS

The plant produces a net output of 560 MW at a net plant efficiency of 50.8 percent (HHV basis).

Overall plant performance is summarized in Exhibit 5-7 which includes auxiliary power requirements.

Exhibit 5-7 Case 13 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	370,170
Steam Turbine Power	200,030
TOTAL POWER, kWe	**570,200**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	130
Boiler Feedwater Pumps	2,970
Miscellaneous Balance of Plant (Note 1)	500
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Amine System Auxiliaries	N/A
CO_2 Compression	N/A
Circulating Water Pumps	2,450
Cooling Tower Fans	1,260
Transformer Loss	1,730
TOTAL AUXILIARIES, kWe	**9,840**
NET POWER, kWe	**560,360**
Net Plant Efficiency (HHV)	50.8%
Net Plant Heat Rate (Btu/kWh)	6,719
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**1,162 (1,102)**
CONSUMABLES	
Natural Gas, kg/h (lb/h)	74,926 (165,182)
Thermal Input, kWt (HHV)	1,103,363
Raw Water Usage, m^3/min (gpm)	9.5 (2,512)

Notes:
1. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 13 is presented in Exhibit 5-8.

Exhibit 5-8 Case 13 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.004 (0.009)	115 (127)	0.027 (0.060)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	51 (119)	1,507,000 (1,662,000)	355 (783)
CO_2[1]			361 (797)

[1] CO_2 emissions based on net power instead of gross power

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, results in very low levels of NOx emissions and negligible levels of SO_2, particulate and Hg emissions. As noted in Section 2.4, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO_2 emissions would be 21 tonnes/yr (23 tons/yr) at 85 percent capacity factor, or 0.00195 lb/MMBtu.

The low level of NOx production (2.5 ppmvd at 15 percent O_2) is achieved by utilizing a dry LNB coupled with an SCR system.

CO_2 emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

Exhibit 5-9 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream is re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 5-9 Case 13 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
BFW Makeup	0.1 (23)	0	0.1 (23)
Cooling Tower Makeup	9.5 (2,511)	0.1 (23)	9.4 (2,488)
Total	**9.6 (2,534)**	**0.1 (23)**	**9.5 (2,511)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 5-10.

An overall plant energy balance is provided in tabular form in Exhibit 5-11. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-7) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 5-10 Case 13 Heat and Mass Balance, NGCC without CO_2 Capture

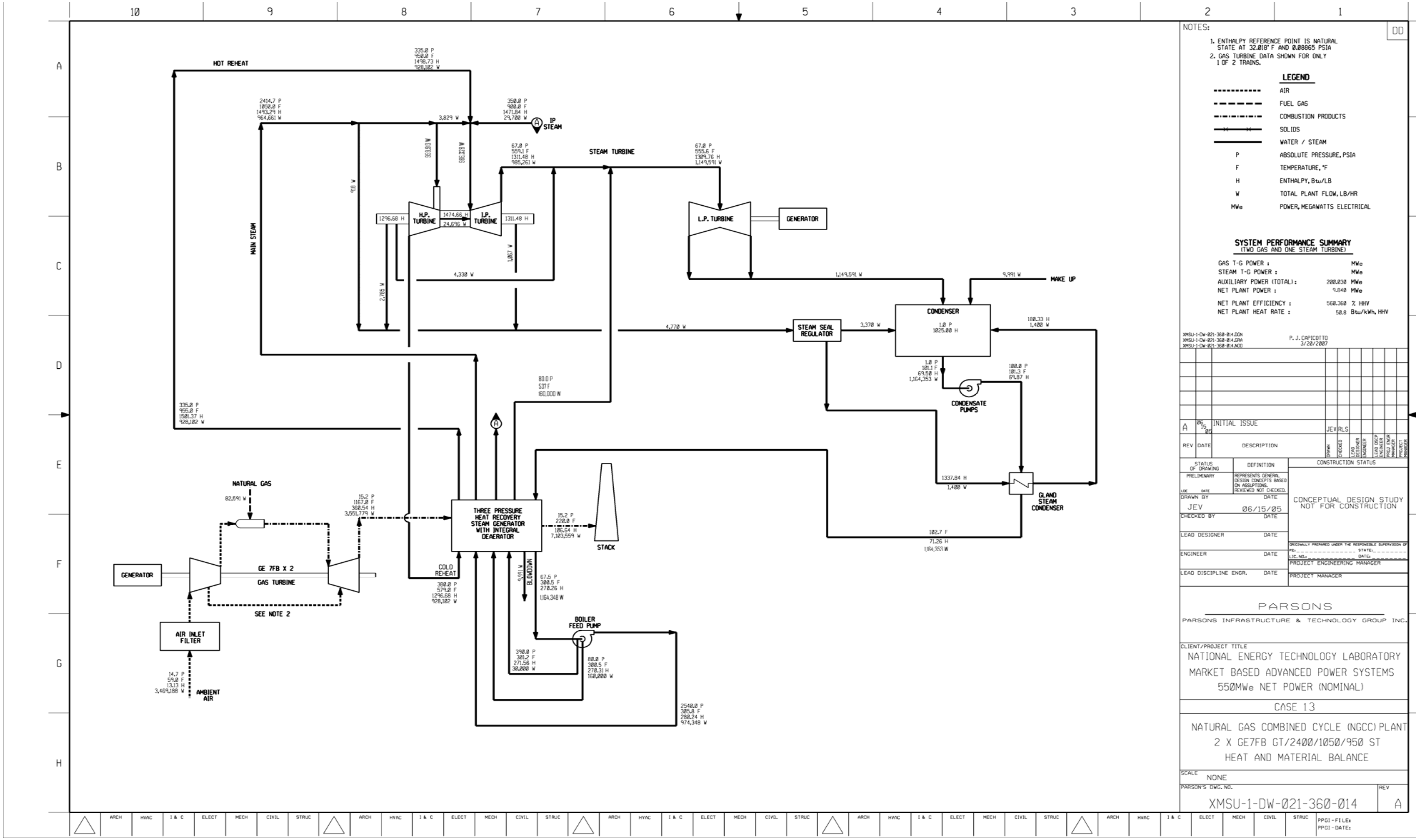

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Exhibit 5-11 Case 13 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Natural Gas	3,764.8	5.7		3,770.5
Ambient Air		91.1		91.1
Water		0.3		0.3
Auxiliary Power			33.6	33.6
Totals	**3,764.8**	**97.1**	**33.6**	**3,895.5**
Heat Out (MMBtu/hr)				
Flue Gas Exhaust		757.5		757.5
Condenser		1,102.0		1,102.0
Process Losses (1)		58.7		58.7
Power			1,977.3	1,977.3
Totals	**0.0**	**1,918.2**	**1,977.3**	**3,895.5**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

5.2.5 CASE 13 – MAJOR EQUIPMENT LIST

Major equipment items for the NGCC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL AND SORBENT HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	56 m3/min @ 3.1 MPa (1,991 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (10 mile)	0
2	Gas Metering Station	--	56 m3/min (1,991 acfm)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	696,521 liters (184,000 gal)	2	0
2	Condensate Pumps	Vertical canned	4,883 lpm @ 85 m H2O (1,290 gpm @ 280 ft H2O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,088 lpm @ 2,103 m H2O (1,080 gpm @ 6,900 ft H2O) IP water: 114 lpm @ 274 m H2O (30 gpm @ 900 ft H2O) LP water: 681 lpm @ 9.1 m H2O (180 gpm @ 30 ft H2O)	2	1
4	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	40 MMkJ/hr (38 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	15,520 lpm @ 21 m H2O (4,100 gpm @ 70 ft H2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	5,300 lpm @ 18 m H2O (1,400 gpm @ 60 ft H2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H2O (40 gpm @ 160 ft H2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	143,847 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	341 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, BOILER AND ACCESSORIES

N/A

ACCOUNT 5 FLUE GAS CLEANUP

N/A

ACCOUNT 6 COMBUSTION TURBINE GENERATORS AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class w/ dry low-NOx burner	185 MW	2	0
2	Gas Turbine Generator	TEWAC	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 5.2 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 240,660 kg/h, 16.5 MPa/566°C (530,564 lb/h, 2,400 psig/1,050°F) Reheat steam - 231,539 kg/h, 2.3 MPa/510°C (510,456 lb/h, 335 psig/950°F)	2	0
3	SCR Reactor	Space for spare layer	1,773,548 kg/h (3,910,000 lb/h)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	21 m3/min @ 91 cm WG (750 scfm @ 36 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 82 m H2O (1 gpm @ 270 ft H2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	87,065 liter (23,000 gal)	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Tandem compound, HP, IP, and two-flow LP turbines	211 MW 16.5 MPa/566°C/510°C (2400 psig/ 1050°F/950°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,276 MMkJ/hr, (1,210 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	246,054 lpm @ 30.5 m (65,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 1,365 MMkJ/hr (1,295 MMBtu/hr) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

N/A

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 220 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 09 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 1 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.2.6 CASE 13 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 5-12 shows the total plant capital cost summary organized by cost account and Exhibit 5-13 shows a more detailed breakdown of the capital costs. Exhibit 5-14 shows the initial and annual O&M costs.

The estimated TPC of the NGCC with no CO_2 capture is \$554/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 10.7 percent of TPC. The 20-year LCOE is 68.4 mills/kWh.

Exhibit 5-12 Case 13 Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 13 - NGCC w/o CO2
Plant Size: 560.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$21,803	$4,553	$6,567	$0	$0	$32,923	$2,758	$0	$5,693	$41,374	$74
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	$0	$0	$0	$0	$0	$0
4.4-4.9	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5	Gas Cleanup & Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B	CO_2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	$76,589	$6,456	$0	$8,304	$91,349	$163
6.2-6.9	Combustion Turbine Other	$0	$681	$709	$0	$0	$1,390	$116	$0	$301	$1,807	$3
	SUBTOTAL 6	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$166**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	$36,200	$3,060	$0	$3,926	$43,186	$77
7.2-7.9	SCR System, Ductwork and Stack	$1,177	$881	$1,044	$0	$0	$3,101	$263	$0	$544	$3,908	$7
	SUBTOTAL 7	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$84**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,464	$0	$3,675	$0	$0	$26,139	$2,244	$0	$2,838	$31,222	$56
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$8,415	$755	$5,340	$0	$0	$14,511	$1,171	$0	$2,151	$17,834	$32
	SUBTOTAL 8	**$30,880**	**$755**	**$9,016**	**$0**	**$0**	**$40,651**	**$3,415**	**$0**	**$4,989**	**$49,055**	**$88**
9	COOLING WATER SYSTEM	$5,474	$4,330	$3,883	$0	$0	$13,686	$1,128	$0	$2,107	$16,921	$30
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	ACCESSORY ELECTRIC PLANT	$15,227	$3,466	$7,567	$0	$0	$26,261	$1,986	$0	$3,074	$31,321	$56
12	INSTRUMENTATION & CONTROL	$5,308	$555	$4,596	$0	$0	$10,459	$884	$0	$1,301	$12,643	$23
13	IMPROVEMENTS TO SITE	$1,635	$888	$4,384	$0	$0	$6,907	$608	$0	$1,503	$9,017	$16
14	BUILDINGS & STRUCTURES	$0	$3,920	$4,225	$0	$0	$8,145	$661	$0	$1,321	$10,127	$18
	TOTAL COST	**$185,504**	**$20,029**	**$50,779**	**$0**	**$0**	**$256,312**	**$21,334**	**$0**	**$33,064**	**$310,710**	**$554**

Exhibit 5-13 Case 13 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 13 - NGCC w/o CO2
Plant Size: 560.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.2	Coal Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.3	Coal Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.4	Other Coal Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Slurry Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,501	$2,609	$2,147	$0	$0	$7,256	$597	$0	$1,178	$9,030	$16
3.2	Water Makeup & Pretreating	$1,459	$152	$761	$0	$0	$2,373	$201	$0	$515	$3,088	$6
3.3	Other Feedwater Subsystems	$1,151	$390	$328	$0	$0	$1,869	$150	$0	$303	$2,321	$4
3.4	Service Water Systems	$174	$355	$1,151	$0	$0	$1,679	$145	$0	$365	$2,190	$4
3.5	Other Boiler Plant Systems	$1,167	$448	$1,037	$0	$0	$2,652	$222	$0	$431	$3,305	$6
3.6	FO Supply Sys & Nat Gas	$13,960	$483	$421	$0	$0	$14,864	$1,251	$0	$2,417	$18,533	$33
3.7	Waste Treatment Equipment	$524	$0	$300	$0	$0	$824	$71	$0	$179	$1,074	$2
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$869	$117	$421	$0	$0	$1,406	$121	$0	$306	$1,833	$3
	SUBTOTAL 3.	**$21,803**	**$4,553**	**$6,567**	**$0**	**$0**	**$32,923**	**$2,758**	**$0**	**$5,693**	**$41,374**	**$74**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling (w/ 4.1	w/4.1	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	$0	$0	$0	$0	$0	$0
4.4	LT Heat Recovery & FG Saturation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging		$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-13 Case 13 Total Plant Cost Details (Continued)

Client:	USDOE/NETL	**Report Date:**	10-May-07
Project:	Bituminous Baseline Study		
	TOTAL PLANT COST SUMMARY		
Case:	Case 13 - NGCC w/o CO2		
Plant Size:	560.4 MW,net	**Estimate Type:** Conceptual	**Cost Base (Dec)** 2006 ($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.2	Elemental Sulfur Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.3	Mercury Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.4	Shift Reactors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.9	HGCU Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	$76,589	$6,456	$0	$8,304	$91,349	$163
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$681	$709	$0	$0	$1,390	$116	$0	$301	$1,807	$3
	SUBTOTAL 6.	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$166**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	$36,200	$3,060	$0	$3,926	$43,186	$77
7.2	SCR System	$1,177	$494	$694	$0	$0	$2,365	$202	$0	$385	$2,952	$5
7.3	Ductwork	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.4	Stack	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.9	HRSG,Duct & Stack Foundations	$0	$386	$349	$0	$0	$736	$61	$0	$159	$956	$2
	SUBTOTAL 7.	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$84**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,464	$0	$3,675	$0	$0	$26,139	$2,244	$0	$2,838	$31,222	$56
8.2	Turbine Plant Auxiliaries	$153	$0	$352	$0	$0	$505	$44	$0	$55	$604	$1
8.3	Condenser & Auxiliaries	$4,112	$0	$1,053	$0	$0	$5,165	$439	$0	$560	$6,164	$11
8.4	Steam Piping	$4,150	$0	$2,733	$0	$0	$6,884	$524	$0	$1,111	$8,519	$15
8.9	TG Foundations	$0	$755	$1,202	$0	$0	$1,957	$165	$0	$424	$2,547	$5
	SUBTOTAL 8.	**$30,880**	**$755**	**$9,016**	**$0**	**$0**	**$40,651**	**$3,415**	**$0**	**$4,989**	**$49,055**	**$88**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,850	$0	$525	$0	$0	$4,375	$370	$0	$474	$5,219	$9
9.2	Circulating Water Pumps	$1,122	$0	$67	$0	$0	$1,189	$91	$0	$128	$1,409	$3
9.3	Circ.Water System Auxiliaries	$93	$0	$12	$0	$0	$105	$9	$0	$11	$125	$0
9.4	Circ.Water Piping	$0	$2,752	$656	$0	$0	$3,409	$270	$0	$552	$4,230	$8
9.5	Make-up Water System	$228	$0	$302	$0	$0	$529	$45	$0	$86	$661	$1
9.6	Component Cooling Water Sys	$181	$217	$143	$0	$0	$541	$45	$0	$88	$674	$1
9.9	Circ.Water System Foundations& Structures	$0	$1,361	$2,177	$0	$0	$3,538	$298	$0	$767	$4,603	$8
	SUBTOTAL 9.	**$5,474**	**$4,330**	**$3,883**	**$0**	**$0**	**$13,686**	**$1,128**	**$0**	**$2,107**	**$16,921**	**$30**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-13 Case 13 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 13 - NGCC w/o CO2
Plant Size: 560.4 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$2,320	$0	$1,405	$0	$0	$3,724	$314	$0	$303	$4,342	$8
11.2	Station Service Equipment	$1,115	$0	$98	$0	$0	$1,213	$103	$0	$99	$1,415	$3
11.3	Switchgear & Motor Control	$1,421	$0	$243	$0	$0	$1,664	$138	$0	$180	$1,983	$4
11.4	Conduit & Cable Tray	$0	$695	$2,110	$0	$0	$2,805	$240	$0	$457	$3,502	$6
11.5	Wire & Cable	$0	$2,128	$1,338	$0	$0	$3,467	$225	$0	$554	$4,245	$8
11.6	Protective Equipment	$0	$519	$1,838	$0	$0	$2,356	$206	$0	$256	$2,819	$5
11.7	Standby Equipment	$95	$0	$90	$0	$0	$185	$16	$0	$20	$221	$0
11.8	Main Power Transformers	$10,277	$0	$140	$0	$0	$10,416	$707	$0	$1,112	$12,236	$22
11.9	Electrical Foundations	$0	$124	$306	$0	$0	$430	$37	$0	$93	$560	$1
	SUBTOTAL 11.	**$15,227**	**$3,466**	**$7,567**	**$0**	**$0**	**$26,261**	**$1,986**	**$0**	**$3,074**	**$31,321**	**$56**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$675	$0	$439	$0	$0	$1,114	$96	$0	$181	$1,391	$2
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$202	$0	$126	$0	$0	$328	$28	$0	$53	$409	$1
12.7	Computer & Accessories	$3,228	$0	$101	$0	$0	$3,329	$283	$0	$361	$3,973	$7
12.8	Instrument Wiring & Tubing	$0	$555	$1,085	$0	$0	$1,640	$124	$0	$265	$2,028	$4
12.9	Other I & C Equipment	$1,203	$0	$2,845	$0	$0	$4,049	$353	$0	$440	$4,842	$9
	SUBTOTAL 12.	**$5,308**	**$555**	**$4,596**	**$0**	**$0**	**$10,459**	**$884**	**$0**	**$1,301**	**$12,643**	**$23**
13	Improvements to Site											
13.1	Site Preparation	$0	$87	$1,757	$0	$0	$1,845	$163	$0	$401	$2,409	$4
13.2	Site Improvements	$0	$801	$1,002	$0	$0	$1,803	$159	$0	$392	$2,353	$4
13.3	Site Facilities	$1,635	$0	$1,624	$0	$0	$3,259	$287	$0	$709	$4,255	$8
	SUBTOTAL 13.	**$1,635**	**$888**	**$4,384**	**$0**	**$0**	**$6,907**	**$608**	**$0**	**$1,503**	**$9,017**	**$16**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$212	$113	$0	$0	$325	$26	$0	$53	$403	$1
14.2	Steam Turbine Building	$0	$1,855	$2,503	$0	$0	$4,357	$357	$0	$707	$5,422	$10
14.3	Administration Building	$0	$429	$294	$0	$0	$723	$57	$0	$117	$898	$2
14.4	Circulation Water Pumphouse	$0	$143	$72	$0	$0	$215	$17	$0	$35	$267	$0
14.5	Water Treatment Buildings	$0	$317	$293	$0	$0	$610	$49	$0	$99	$758	$1
14.6	Machine Shop	$0	$372	$241	$0	$0	$613	$49	$0	$99	$761	$1
14.7	Warehouse	$0	$240	$147	$0	$0	$387	$31	$0	$63	$480	$1
14.8	Other Buildings & Structures	$0	$72	$53	$0	$0	$125	$10	$0	$20	$155	$0
14.9	Waste Treating Building & Str.	$0	$281	$509	$0	$0	$791	$66	$0	$128	$985	$2
	SUBTOTAL 14.	**$0**	**$3,920**	**$4,225**	**$0**	**$0**	**$8,145**	**$661**	**$0**	**$1,321**	**$10,127**	**$18**
	TOTAL COST	**$185,504**	**$20,029**	**$50,779**	**$0**	**$0**	**$256,312**	**$21,334**	**$0**	**$33,064**	**$310,710**	**$554**

Exhibit 5-14 Case 13 Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 13 - NGCC w/o CO2					Heat Rate-net(Btu/kWh):	6,719
					MWe-net:	560
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	1.0		1.0			
Operator	2.0		2.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	1.0		1.0			
TOTAL-O.J.'s	5.0		5.0			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$1,879,020	$3.353
Maintenance Labor Cost					$2,521,575	$4.500
Administrative & Support Labor					$1,100,149	$1.963
TOTAL FIXED OPERATING COSTS					**$5,500,743**	**$9.816**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$3,782,362**	**$0.00091**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	1,808	1.03	**$0**	**$577,734**	**$0.00014**
Chemicals						
MU & WT Chem.(lb)	75,397	10,771	0.16	$12,425	$550,716	$0.00013
Carbon (Mercury Removal) (lb.)	0	0	1.00	$0	$0	$0.00000
COS Catalyst (lb)	0	0	0.60	$0	$0	$0.00000
MEA Solvent (ton)	0	0	2,142.40	$0	$0	$0.00000
Activated Carbon(lb)	0	0	1.00	$0	$0	$0.00000
Corrosion Inhibitor	0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.08	5,500.00	$0	$140,093	$0.00003
Ammonia (28% NH3) ton	55	8	190.00	$10,438	$462,620	$0.00011
Subtotal Chemicals				**$22,863**	**$1,153,429**	**$0.00028**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb.)	0	0	0.00	$0	$0	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0	0	0.00	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
Sulfur(tons)	0	0	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$22,863**	**$5,513,526**	**$0.00132**
Fuel(MMBtu)	2,710,842	90,361	6.75	**$18,298,186**	**$189,233,740**	**$0.04535**

5.2.7 CASE 14 – NGCC WITH CO_2 CAPTURE

The plant configuration for Case 14 is the same as Case 13 with the exception that the Econamine FG Plus CDR technology was added for CO_2 capture. The nominal net output decreases to 482 MW because, like the IGCC cases, the combustion turbine fixes the output and the CDR facility significantly increases the auxiliary power load.

The process description for Case 14 is essentially the same as Case 13 with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case 14 are shown in Exhibit 5-15 and Exhibit 5-16, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

5.2.8 CASE 14 PERFORMANCE RESULTS

The Case 14 modeling assumptions were presented previously in Section 5.2.2.

The plant produces a net output of 482 MW at a net plant efficiency of 43.7 percent (HHV basis). Overall plant performance is summarized in Exhibit 5-17 which includes auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over 64 percent of the auxiliary plant load. The circulating water system (circulating water pumps and cooling tower fan) accounts for nearly 20 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 5-15 Case 14 Process Flow Diagram, NGCC with CO_2 Capture

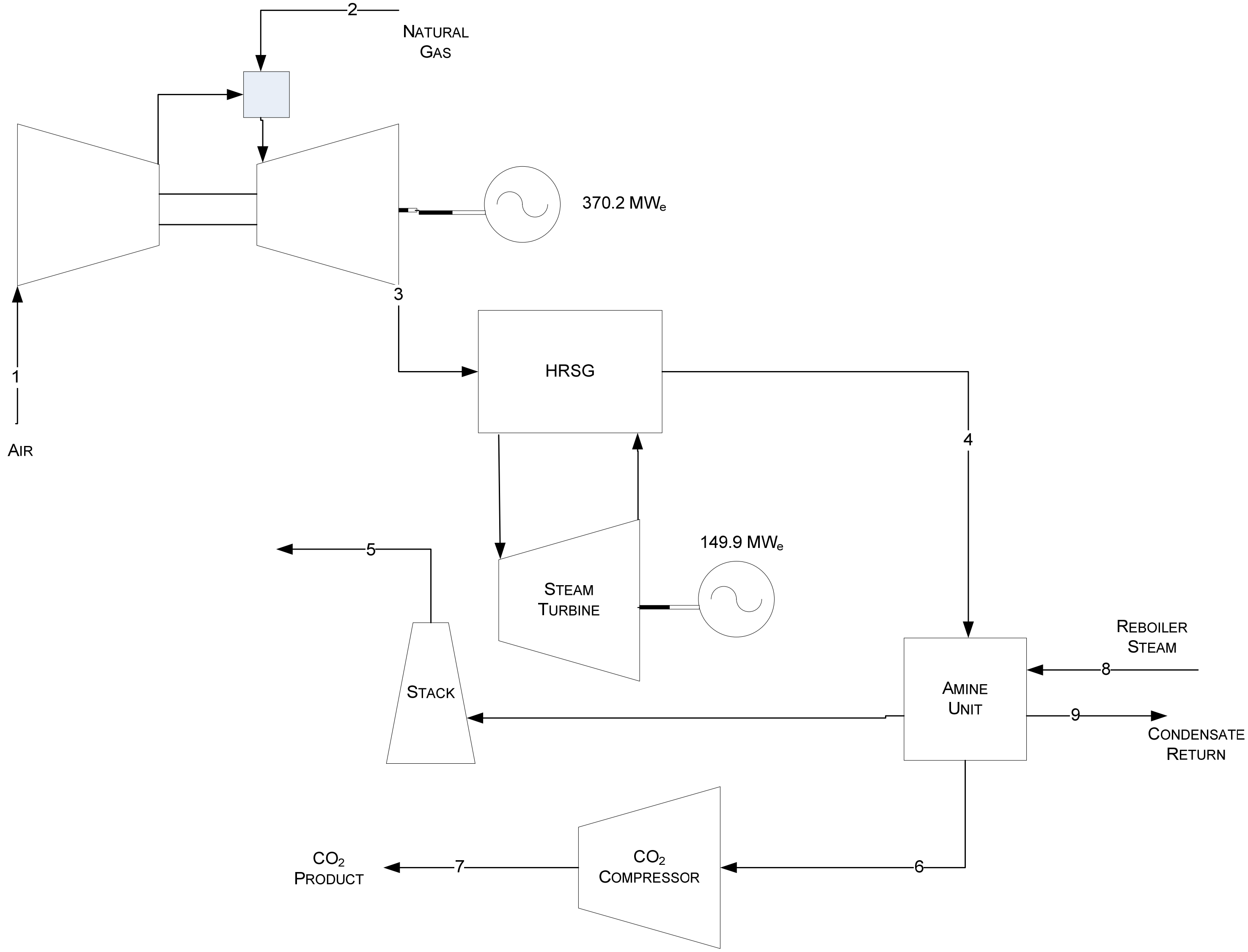

Exhibit 5-16 - Case 14 Stream Table, NGCC with CO_2 Capture

	1	2	3	4	5	6	7	8	9
V-L Mole Fraction									
Ar	0.0092	0.0000	0.0089	0.0089	0.0098	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.9390	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0405	0.0405	0.0045	0.9767	1.0000	0.0000	0.0000
H_2O	0.0099	0.0000	0.0869	0.0869	0.0339	0.0233	0.0000	1.0000	1.0000
N_2	0.7732	0.0080	0.7430	0.7430	0.8188	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1207	0.1207	0.1330	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)	120,220	4,793	125,152	250,304	227,129	9,347	9,130	34,122	34,122
V-L Flowrate (lb/hr)	3,469,190	82,591	3,551,780	7,103,560	6,448,730	405,714	401,794	614,710	614,710
Temperature (°F)	59	100	1,167	283	85	69	124	555	300
Pressure (psia)	14.7	450.0	15.2	15.2	14.7	23.5	2,214.7	67.5	67.5
Enthalpy (BTU/lb)[A]	13.1	34.4	360.5	122.6	36.1	11.2	-70.8	1309.6	270.3
Density (lb/ft^3)	0.08	1.29	0.02	0.05	0.07	0.18	40.75	0.11	57.28
Molecular Weight	28.86	17.23	28.38	28.38	28.39	43.40	44.01	18.02	18.02

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 5-17 Case 14 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	370,170
Steam Turbine Power	149,920
TOTAL POWER, kWe	**520,090**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	60
Boiler Feedwater Pumps	2,920
Miscellaneous Balance of Plant (Note 1)	500
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Amine System Auxiliaries	9,580
CO_2 Compression	15,040
Circulating Water Pumps	5,040
Cooling Tower Fans	2,600
Transformer Loss	1,660
TOTAL AUXILIARIES, kWe	**38,200**
NET POWER, kWe	**481,890**
Net Plant Efficiency (HHV)	43.7%
Net Plant Heat Rate (Btu/kWh)	7,813
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**550 (522)**
CONSUMABLES	
Natural Gas kg/h (lb/h)	74,926 (165,182)
Thermal Input, kWt (HHV)	1,103,363
Raw Water Usage, m^3/min (gpm)	17.7 (4,680)

Notes:

1. Includes plant control systems, lighting, HVAC and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Case 14 is presented in Exhibit 5-18.

Exhibit 5-18 Case 14 Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 85% capacity factor	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NO_X	0.004 (0.009)	115 (127)	0.030 (0.066)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	5.1 (12)	151,000 (166,000)	39 (86)
CO_2[1]			42 (93)

[1] CO_2 emissions based on net power instead of gross power

The operation of the modern, state-of-the-art gas turbine fueled by natural gas, coupled to a HRSG, results in very low levels of NOx emissions and negligible levels of SO_2, particulate and Hg emissions. As noted in Section 2.4, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO_2 emissions would be 21 tonnes/yr (23 tons/yr) at 85 percent capacity factor, or 0.00195 lb/MMBtu.

The low level of NOx production (2.5 ppmvd at 15 percent O_2) is achieved by utilizing a dry LNB coupled with an SCR system.

Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

Exhibit 5-19 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). The water usage represents only the contribution of raw water makeup. In some cases the water demand is greater than raw water makeup because of internal water recycle streams. For example, the boiler feedwater blowdown stream and condensate recovered from the flue gas prior to the CO_2 absorber are re-used as makeup to the cooling tower, thus reducing the raw water requirement by that amount.

Exhibit 5-19 Case 14 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Makeup, m^3/min (gpm)
BFW Makeup	0.1 (23)	0	0.1 (23)
Cooling Tower Makeup	16.6 (4,395)	2.0 (518)	14.7 (3,877)
Total	**16.7 (4,418)**	**2.0 (518)**	**14.8 (3,900)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 5-20.

An overall plant energy balance is provided in tabular form in Exhibit 5-21. The power out is the combined combustion turbine and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-17) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

Exhibit 5-20 Case 14 Heat and Mass Balance, NGCC with CO_2 Capture

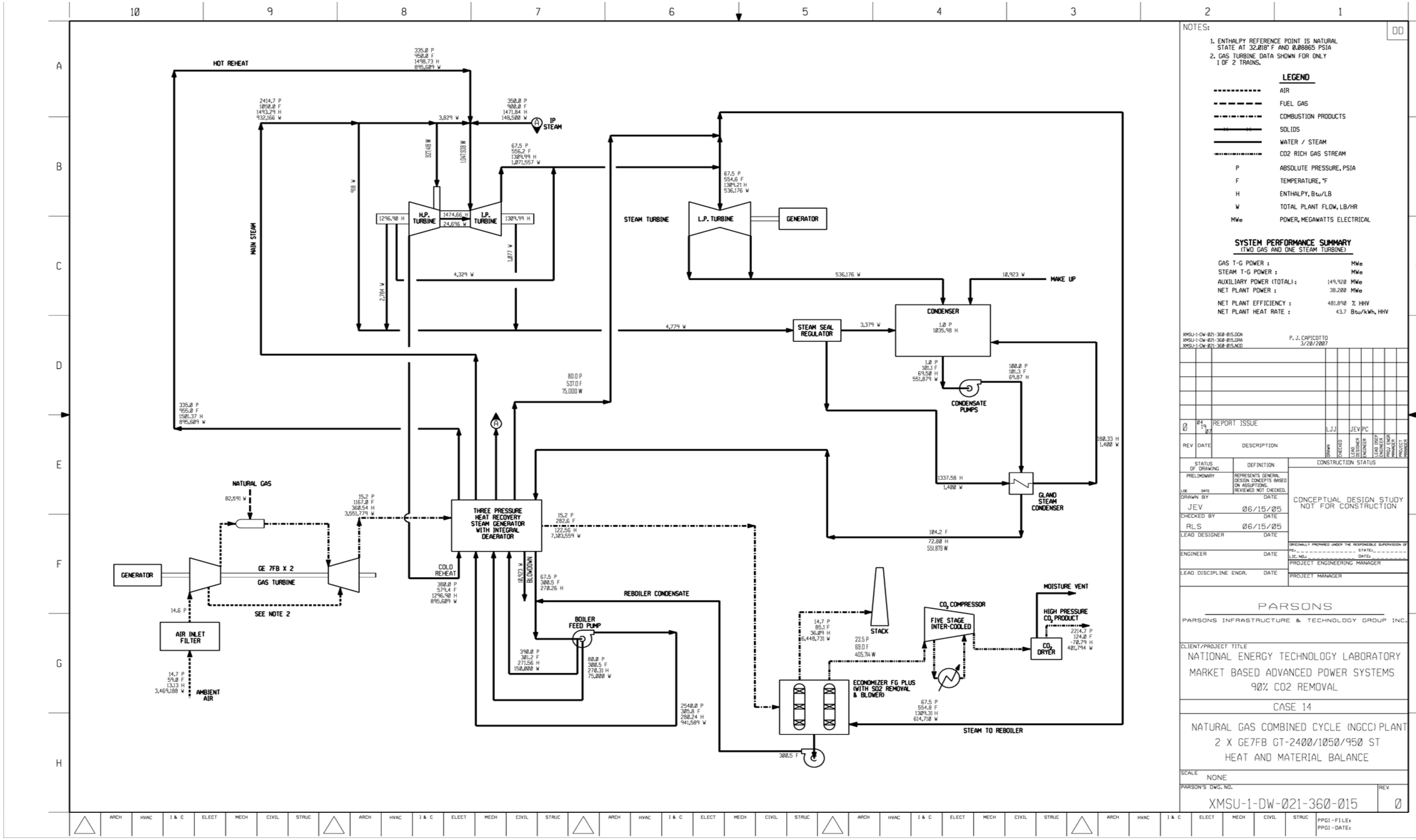

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Exhibit 5-21 Case 14 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Natural Gas	3,764.8	5.7		3,770.5
Ambient Air		91.1		91.1
Raw Water Makeup		49.7		49.7
Auxiliary Power			125.3	125.3
Totals	**3,764.8**	**146.5**	**125.3**	**4036.6**
Heat Out (MMBtu/hr)				
Flue Gas Exhaust		232.7		232.7
Condenser		522.0		522.0
Econamine Process		1463.8		1463.8
Cooling Tower Blowdown		25.1		25.1
CO_2 Product		(28.4)		(28.4)
Process Losses (1)		17.1		17.1
Power			1,804.4	1,804.4
Totals	**0.0**	**2,232.2**	**1,804.4**	**4,036.6**

(1) Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

5.2.9 CASE 14 MAJOR EQUIPMENT LIST

Major equipment items for the NGCC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 COAL AND SORBENT HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	56 m3/min @ 3.1 MPa (1,990 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (10 mile)	0
2	Gas Metering Station	--	56 m3/min (1,990 acfm)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	348,261 liters (92,000 gal)	2	0
2	Condensate Pumps	Vertical canned	2,309 lpm @ 85 m H2O (610 gpm @ 280 ft H2O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,937 lpm @ 2,103 m H2O (1,040 gpm @ 6,900 ft H2O) IP water: 757 lpm @ 274 m H2O (200 gpm @ 900 ft H2O) LP water: 303 lpm @ 09 m H2O (80 gpm @ 30 ft H2O)	2	1
4	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	40 MMkJ/hr (38 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	15,520 lpm @ 21 m H2O (4,100 gpm @ 70 ft H2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	10,978 lpm @ 18 m H2O (2,900 gpm @ 60 ft H2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	174 lpm @ 49 m H2O (46 gpm @ 160 ft H2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	166,559 liter (44,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	379 lpm (100 gpm)	1	0
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4 GASIFIER, BOILER AND ACCESSORIES

N/A

ACCOUNT 5B CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based carbon dioxide capture system	Flue gas flow rate: 1,772,187 kg/h (3,907,000 lb/h), Inlet CO2 concentration: 6.3 wt%	2	0
2	Carbon Dioxide Compression System	Integrally geared, multi-stage centrifugal	100,698 kg/h @ 15.3 MPa (222,000 lb/h @ 2,215 psia)	2	0

ACCOUNT 6 COMBUSTION TURBINE GENERATORS AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class w/ dry low-NOx burner	185 MW	2	0
2	Gas Turbine Generator	TEWAC	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 4.5 m (15 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 232,553 kg/h, 16.5 MPa/566°C (512,691 lb/h, 2,400 psig/1,050°F) Reheat steam - 223,433 kg/h, 2.3 MPa/510°C (492,585 lb/h, 335 psig/950°F)	2	0
3	SCR Reactor	Space for spare layer	1,610,255 kg/h (3,550,000 lb/h)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	21 m3/min @ 91 cm WG (750 scfm @ 36 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 82 m H2O (1 gpm @ 270 ft H2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	87,065 liter (23,000 gal)	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.
1	Steam Turbine	Tandem compound, HP, IP, and two-flow LP turbines	158 MW 16.5 MPa/566°C/510°C (2400 psig/ 1050°F/950°F)	1
2	Steam Turbine Generator	Hydrogen cooled, static excitation	180 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	601 MMkJ/hr, (570 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	503,464 lpm @ 30.5 m (133,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 2,393 MMkJ/hr (2,270 MMBtu/hr) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

N/A

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 130 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 41 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

5.2.10 CASE 14 – COST ESTIMATING

The cost estimating methodology was described previously in Section 2.6. Exhibit 5-22 shows the total plant capital cost summary organized by cost account and Exhibit 5-23 shows a more detailed breakdown of the capital costs. Exhibit 5-24 shows the initial and annual O&M costs.

The estimated TPC of the NGCC with CO_2 capture is $1,169/kW. Process contingency represents 5.0 percent of the TPC and project contingency represents 13.3 percent. The 20-year LCOE, including CO_2 TS&M costs of 2.9 mills/kWh, is 97.4 mills/kWh.

Exhibit 5-22 Case 14 Total Plant Cost Summary

Client: USDOE/NETL — **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 14 - NGCC w/ CO2
Plant Size: 481.9 MW,net — **Estimate Type:** Conceptual — **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$23,544	$4,970	$8,285	$0	$0	**$36,798**	$3,088	$0	$6,473	**$46,360**	$96
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Other Gasification Equipment	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5	Gas Cleanup & Piping	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO_2 REMOVAL & COMPRESSION	$121,446	$0	$35,469	$0	$0	**$156,915**	$13,337	$27,564	$39,563	**$237,380**	$493
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	**$76,588**	$6,456	$0	$8,304	**$91,348**	$190
6.2-6.9	Combustion Turbine Other	$0	$681	$709	$0	$0	**$1,390**	$116	$0	$301	**$1,807**	$4
	SUBTOTAL 6	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$193**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	**$36,200**	$3,060	$0	$3,926	**$43,186**	$90
7.2-7.9	SCR System, Ductwork and Stack	$1,177	$881	$1,044	$0	$0	**$3,101**	$263	$0	$544	**$3,908**	$8
	SUBTOTAL 7	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$98**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$19,753	$0	$3,134	$0	$0	**$22,887**	$1,964	$0	$2,485	**$27,336**	$57
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$7,020	$606	$4,906	$0	$0	**$12,532**	$1,003	$0	$1,902	**$15,437**	$32
	SUBTOTAL 8	**$26,772**	**$606**	**$8,041**	**$0**	**$0**	**$35,419**	**$2,967**	**$0**	**$4,387**	**$42,774**	**$89**
9	COOLING WATER SYSTEM	$8,060	$6,365	$5,482	$0	$0	**$19,908**	$1,638	$0	$3,040	**$24,585**	$51
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$15,809	$5,267	$9,893	$0	$0	**$30,969**	$2,356	$0	$3,779	**$37,104**	$77
12	INSTRUMENTATION & CONTROL	$6,914	$723	$5,986	$0	$0	**$13,622**	$1,151	$681	$1,772	**$17,227**	$36
13	IMPROVEMENTS TO SITE	$1,643	$893	$4,406	$0	$0	**$6,942**	$611	$0	$1,511	**$9,063**	$19
14	BUILDINGS & STRUCTURES	$0	$3,885	$4,066	$0	$0	**$7,952**	$644	$0	$1,289	**$9,886**	$21
	TOTAL COST	**$309,365**	**$24,270**	**$92,170**	**$0**	**$0**	**$425,805**	**$35,687**	**$28,245**	**$74,891**	**$564,628**	**$1,172**

Exhibit 5-23 Case 14 Total Plant Cost Details

Client: USDOE/NETL **Report Date:** 10-May-07

Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 14 - NGCC w/ CO2

Plant Size: 481.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.2	Coal Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.3	Coal Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.4	Other Coal Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying incl w/2.3	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Slurry Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,425	$2,530	$2,082	$0	$0	$7,037	$579	$0	$1,142	$8,758	$18
3.2	Water Makeup & Pretreating	$2,271	$237	$1,185	$0	$0	$3,692	$312	$0	$801	$4,805	$10
3.3	Other Feedwater Subsystems	$1,116	$378	$318	$0	$0	$1,813	$145	$0	$294	$2,252	$5
3.4	Service Water Systems	$270	$552	$1,791	$0	$0	$2,613	$226	$0	$568	$3,407	$7
3.5	Other Boiler Plant Systems	$1,815	$696	$1,614	$0	$0	$4,126	$346	$0	$671	$5,143	$11
3.6	FO Supply Sys & Nat Gas	$13,946	$458	$399	$0	$0	$14,803	$1,246	$0	$2,407	$18,456	$38
3.7	Waste Treatment Equipment	$815	$0	$467	$0	$0	$1,282	$111	$0	$279	$1,671	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$885	$119	$428	$0	$0	$1,432	$124	$0	$311	$1,866	$4
	SUBTOTAL 3.	**$23,544**	**$4,970**	**$8,285**	**$0**	**$0**	**$36,798**	**$3,088**	**$0**	**$6,473**	**$46,360**	**$96**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling (w/ 4.1	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	w/equip.	$0	$0	$0	$0	$0	$0	$0	$0
4.4	LT Heat Recovery & FG Saturation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging		$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-23 Case 14 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 14 - NGCC w/ CO2
Plant Size: 481.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.2	Elemental Sulfur Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.3	Mercury Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.4	Shift Reactors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.7	Fuel Gas Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.9	HGCU Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$106,600	$0	$31,220	$0	$0	$137,821	$11,715	$27,564	$35,420	$212,519	$441
5B.2	CO2 Compression & Drying	$14,846	$0	$4,248	$0	$0	$19,094	$1,623	$0	$4,143	$24,860	$52
	SUBTOTAL 5.	**$121,446**	**$0**	**$35,469**	**$0**	**$0**	**$156,915**	**$13,337**	**$27,564**	**$39,563**	**$237,380**	**$493**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$72,000	$0	$4,588	$0	$0	$76,588	$6,456	$0	$8,304	$91,348	$190
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$681	$709	$0	$0	$1,390	$116	$0	$301	$1,807	$4
	SUBTOTAL 6.	**$72,000**	**$681**	**$5,298**	**$0**	**$0**	**$77,979**	**$6,571**	**$0**	**$8,606**	**$93,156**	**$193**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,000	$0	$4,200	$0	$0	$36,200	$3,060	$0	$3,926	$43,186	$90
7.2	SCR System	$1,177	$494	$694	$0	$0	$2,365	$202	$0	$385	$2,952	$6
7.3	Ductwork	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.4	Stack	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.9	HRSG,Duct & Stack Foundations	$0	$386	$349	$0	$0	$736	$61	$0	$159	$956	$2
	SUBTOTAL 7.	**$33,177**	**$881**	**$5,244**	**$0**	**$0**	**$39,301**	**$3,323**	**$0**	**$4,470**	**$47,094**	**$98**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$19,753	$0	$3,134	$0	$0	$22,887	$1,964	$0	$2,485	$27,336	$57
8.2	Turbine Plant Auxiliaries	$135	$0	$303	$0	$0	$438	$38	$0	$48	$524	$1
8.3	Condenser & Auxiliaries	$2,643	$0	$845	$0	$0	$3,488	$297	$0	$378	$4,163	$9
8.4	Steam Piping	$4,242	$0	$2,794	$0	$0	$7,036	$535	$0	$1,136	$8,707	$18
8.9	TG Foundations	$0	$606	$964	$0	$0	$1,570	$132	$0	$341	$2,043	$4
	SUBTOTAL 8.	**$26,772**	**$606**	**$8,041**	**$0**	**$0**	**$35,419**	**$2,967**	**$0**	**$4,387**	**$42,774**	**$89**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,487	$0	$749	$0	$0	$6,236	$527	$0	$676	$7,439	$15
9.2	Circulating Water Pumps	$1,832	$0	$117	$0	$0	$1,949	$149	$0	$210	$2,308	$5
9.3	Circ.Water System Auxiliaries	$141	$0	$19	$0	$0	$160	$14	$0	$17	$191	$0
9.4	Circ.Water Piping	$0	$4,191	$999	$0	$0	$5,191	$411	$0	$840	$6,442	$13
9.5	Make-up Water System	$325	$0	$430	$0	$0	$755	$64	$0	$123	$942	$2
9.6	Component Cooling Water Sys	$276	$330	$218	$0	$0	$824	$68	$0	$134	$1,026	$2
9.9	Circ.Water System Foundations& Structures	$0	$1,844	$2,950	$0	$0	$4,794	$404	$0	$1,040	$6,238	$13
	SUBTOTAL 9.	**$8,060**	**$6,365**	**$5,482**	**$0**	**$0**	**$19,908**	**$1,638**	**$0**	**$3,040**	**$24,585**	**$51**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$0		$0	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

Exhibit 5-23 Case 14 Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 10-May-07
Project: Bituminous Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case 14 - NGCC w/ CO2
Plant Size: 481.9 MW,net **Estimate Type:** Conceptual **Cost Base (Dec)** 2006 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$2,198	$0	$1,331	$0	$0	$3,529	$298	$0	$287	$4,114	$9
11.2	Station Service Equipment	$1,829	$0	$160	$0	$0	$1,989	$169	$0	$162	$2,321	$5
11.3	Switchgear & Motor Control	$2,330	$0	$399	$0	$0	$2,729	$226	$0	$296	$3,251	$7
11.4	Conduit & Cable Tray	$0	$1,140	$3,460	$0	$0	$4,600	$393	$0	$749	$5,743	$12
11.5	Wire & Cable	$0	$3,490	$2,194	$0	$0	$5,685	$369	$0	$908	$6,962	$14
11.6	Protective Equipment	$0	$520	$1,844	$0	$0	$2,364	$207	$0	$257	$2,828	$6
11.7	Standby Equipment	$91	$0	$86	$0	$0	$177	$15	$0	$19	$211	$0
11.8	Main Power Transformers	$9,361	$0	$131	$0	$0	$9,492	$644	$0	$1,014	$11,150	$23
11.9	Electrical Foundations	$0	$116	$287	$0	$0	$403	$34	$0	$87	$525	$1
	SUBTOTAL 11.	**$15,809**	**$5,267**	**$9,893**	**$0**	**$0**	**$30,969**	**$2,356**	**$0**	**$3,779**	**$37,104**	**$77**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$879	$0	$572	$0	$0	$1,451	$125	$73	$247	$1,896	$4
12.5	Signal Processing Equipment	W/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$263	$0	$164	$0	$0	$427	$37	$21	$73	$557	$1
12.7	Computer & Accessories	$4,205	$0	$131	$0	$0	$4,336	$368	$217	$492	$5,413	$11
12.8	Instrument Wiring & Tubing	$0	$723	$1,413	$0	$0	$2,136	$161	$107	$361	$2,764	$6
12.9	Other I & C Equipment	$1,568	$0	$3,706	$0	$0	$5,273	$460	$264	$600	$6,597	$14
	SUBTOTAL 12.	**$6,914**	**$723**	**$5,986**	**$0**	**$0**	**$13,622**	**$1,151**	**$681**	**$1,772**	**$17,227**	**$36**
13	Improvements to Site											
13.1	Site Preparation	$0	$88	$1,766	$0	$0	$1,854	$164	$0	$404	$2,421	$5
13.2	Site Improvements	$0	$805	$1,007	$0	$0	$1,812	$159	$0	$394	$2,366	$5
13.3	Site Facilities	$1,643	$0	$1,633	$0	$0	$3,276	$288	$0	$713	$4,277	$9
	SUBTOTAL 13.	**$1,643**	**$893**	**$4,406**	**$0**	**$0**	**$6,942**	**$611**	**$0**	**$1,511**	**$9,063**	**$19**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$222	$119	$0	$0	$341	$27	$0	$55	$423	$1
14.2	Steam Turbine Building	$0	$1,593	$2,149	$0	$0	$3,742	$307	$0	$607	$4,656	$10
14.3	Administration Building	$0	$437	$300	$0	$0	$736	$59	$0	$119	$914	$2
14.4	Circulation Water Pumphouse	$0	$167	$84	$0	$0	$250	$20	$0	$40	$310	$1
14.5	Water Treatment Buildings	$0	$484	$447	$0	$0	$931	$75	$0	$151	$1,157	$2
14.6	Machine Shop	$0	$379	$245	$0	$0	$624	$49	$0	$101	$775	$2
14.7	Warehouse	$0	$245	$150	$0	$0	$394	$31	$0	$64	$489	$1
14.8	Other Buildings & Structures	$0	$73	$54	$0	$0	$127	$10	$0	$21	$158	$0
14.9	Waste Treating Building & Str.	$0	$287	$519	$0	$0	$805	$67	$0	$131	$1,003	$2
	SUBTOTAL 14.	**$0**	**$3,885**	**$4,066**	**$0**	**$0**	**$7,952**	**$644**	**$0**	**$1,289**	**$9,886**	**$21**
	TOTAL COST	**$309,365**	**$24,270**	**$92,170**	**$0**	**$0**	**$425,805**	**$35,687**	**$28,245**	**$74,891**	**$564,628**	**$1,172**

Exhibit 5-24 Case 14 Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Dec)	2006
Case 14 - NGCC w/ CO2					Heat Rate-net(Btu/kWh):	7,813
					MWe-net:	482
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	33.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	1.0		1.0			
Operator	3.3		3.3			
Foreman	1.0		1.0			
Lab Tech's, etc.	1.0		1.0			
TOTAL-O.J.'s	6.3		6.3			
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$2,378,839	$4.936
Maintenance Labor Cost					$4,034,866	$8.373
Administrative & Support Labor					$1,603,426	$3.327
TOTAL FIXED OPERATING COSTS					**$8,017,131**	**$16.637**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$6,052,299**	**$0.00169**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water(/1000 gallons)	0	3,370.32	1.00	**$0**	**$1,045,642**	**$0.00029**
Chemicals						
MU & WT Chem.(lb)	140,555.73	20,079.39	0.16	$21,888	$970,101	$0.00027
Carbon (Mercury Removal) (lb.)	0.00	0.00	1.00	$0	$0	$0.00000
COS Catalyst (lb)	0.00	0.00	0.60	$0	$0	$0.00000
MEA Solvent (ton)	342.00	0.48	2,142.40	$732,701	$319,046	$0.00009
Activated Carbon(lb)	210,384.00	576.00	1.00	$210,384	$178,704	$0.00005
Corrosion Inhibitor	1.00	0.00	0.00	$47,000	$2,250	$0.00000
SCR Catalyst (m3)	w/equip.	0.08	5,500.00	$0	$140,093	$0.00004
Ammonia (28% NH3) ton	54.94	7.85	190.00	$10,438	$462,620	$0.00013
Subtotal Chemicals				**$1,022,410**	**$2,072,814**	**$0.00058**
Other						
Supplemental Fuel(MBtu)	0.00	0.00	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0.00	0.00	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0.00	0.00	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb.)	0.00	0.00	0.00	$0	$0	$0.00000
Flyash (ton)	0.00	0.00	0.00	$0	$0	$0.00000
Bottom Ash(ton)	0.00	0.00	0.00	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
Sulfur(tons)	0.00	0.00	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,022,410**	**$9,170,755**	**$0.00256**
Fuel(MMbtu)	2,710,805	90,360	6.75	**$18,297,932**	**$189,231,113**	**$0.05274**

5.3 NGCC CASE SUMMARY

The performance results of the two NGCC plant configurations modeled in this study are summarized in Exhibit 5-25.

Exhibit 5-25 Estimated Performance and Cost Results for NGCC Cases

	NGCC	
	Advanced F Class	
	Case 13	Case 14
CO_2 Capture	No	Yes
Gross Power Output (kW_e)	570,200	520,090
Auxiliary Power Requirement (kW_e)	9,840	38,200
Net Power Output (kW_e)	560,360	481,890
Coal Flowrate (lb/hr)	N/A	N/A
Natural Gas Flowrate (lb/hr)	165,182	165,182
HHV Thermal Input (kW_{th})	1,103,363	1,103,363
Net Plant HHV Efficiency (%)	50.8%	43.7%
Net Plant HHV Heat Rate (Btu/kW-hr)	6,719	7,813
Raw Water Usage, gpm	2,511	3,901
Total Plant Cost ($ x 1,000)	310,710	564,628
Total Plant Cost ($/kW)	554	1,172
LCOE (mills/kWh)[1]	68.4	97.4
CO_2 Emissions (lb/MWh)[2]	783	85.8
CO_2 Emissions (lb/MWh)[3]	797	93
SO_2 Emissions (lb/MWh)[2]	Negligible	Negligible
NOx Emissions (lb/MWh)[2]	0.060	0.066
PM Emissions (lb/MWh)[2]	Negligible	Negligible
Hg Emissions (lb/MWh)[2]	Negligible	Negligible

[1] Based on an 85% capacity factor
[2] Value is based on gross output
[3] Value is based on net output

The TPC for the two NGCC cases is shown in Exhibit 5-26. The capital cost of the non-capture case, $554/kW, is the lowest of all technologies studied by at least 64 percent. Addition of CO_2 capture more than doubles the capital cost, but NGCC with capture is still the least capital intensive of all the capture technologies by at least 51 percent. The process contingency included for the Econamine process totals $57/kW, which represents 5 percent of TPC.

The LCOE for NGCC cases is heavily dependent on the price of natural gas as shown in Exhibit 5-27. The fuel component of LCOE represents 78 percent of the total in the non-capture case and 63 percent of the total in the CO_2 capture case. Because LCOE has a small capital component, it is less sensitive to capacity factor than the more capital intensive PC and IGCC cases. The decrease in net kilowatt-hours produced is nearly offset by a corresponding decrease in fuel cost. The CO_2 TS&M component of LCOE is only 3 percent of the total in the CO_2 capture case.

Exhibit 5-26 TPC of NGCC Cases

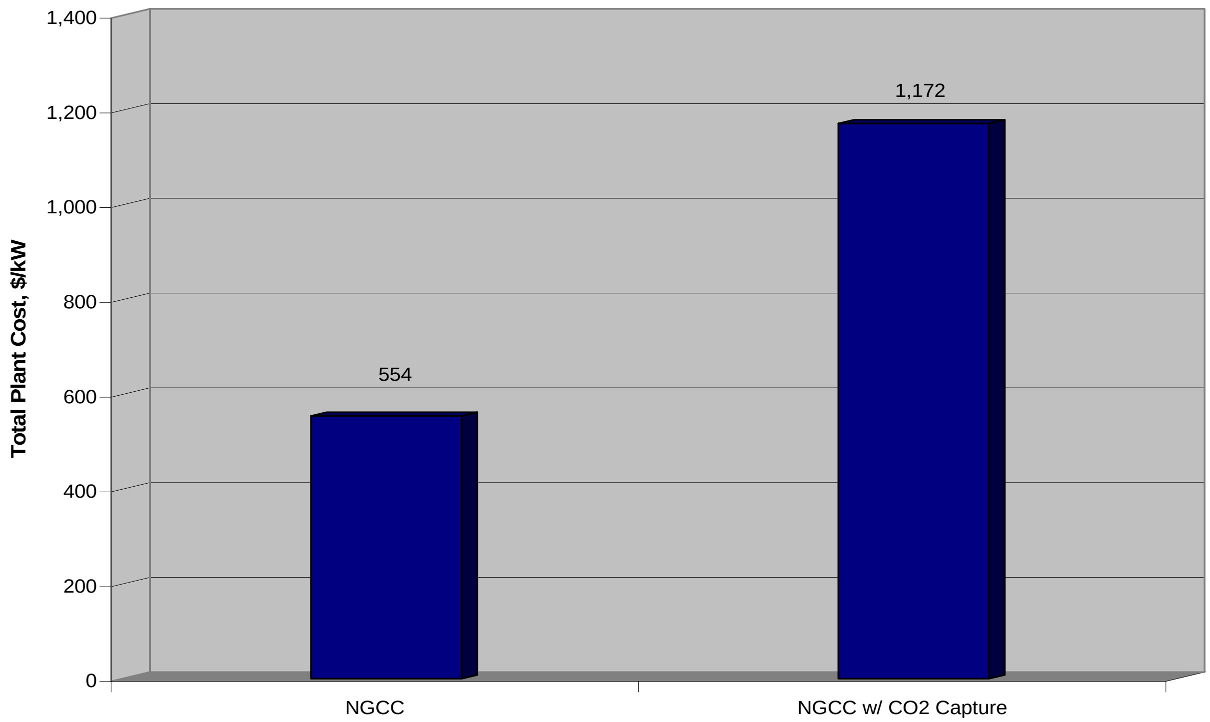
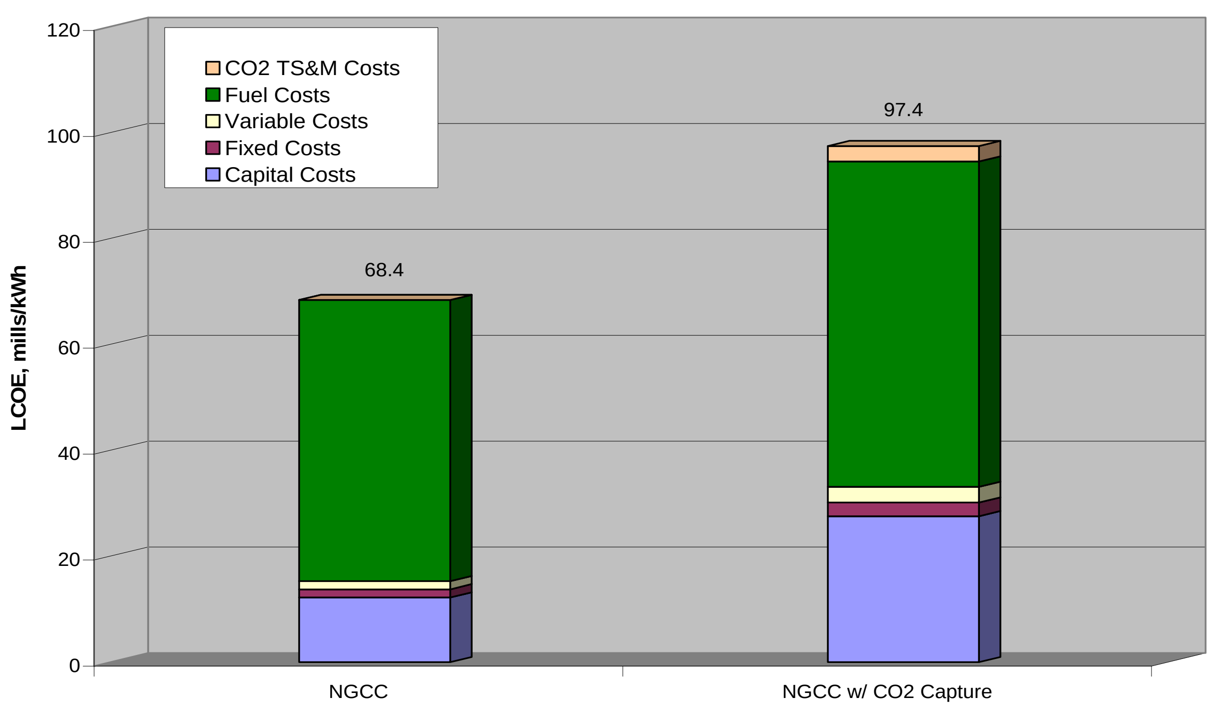


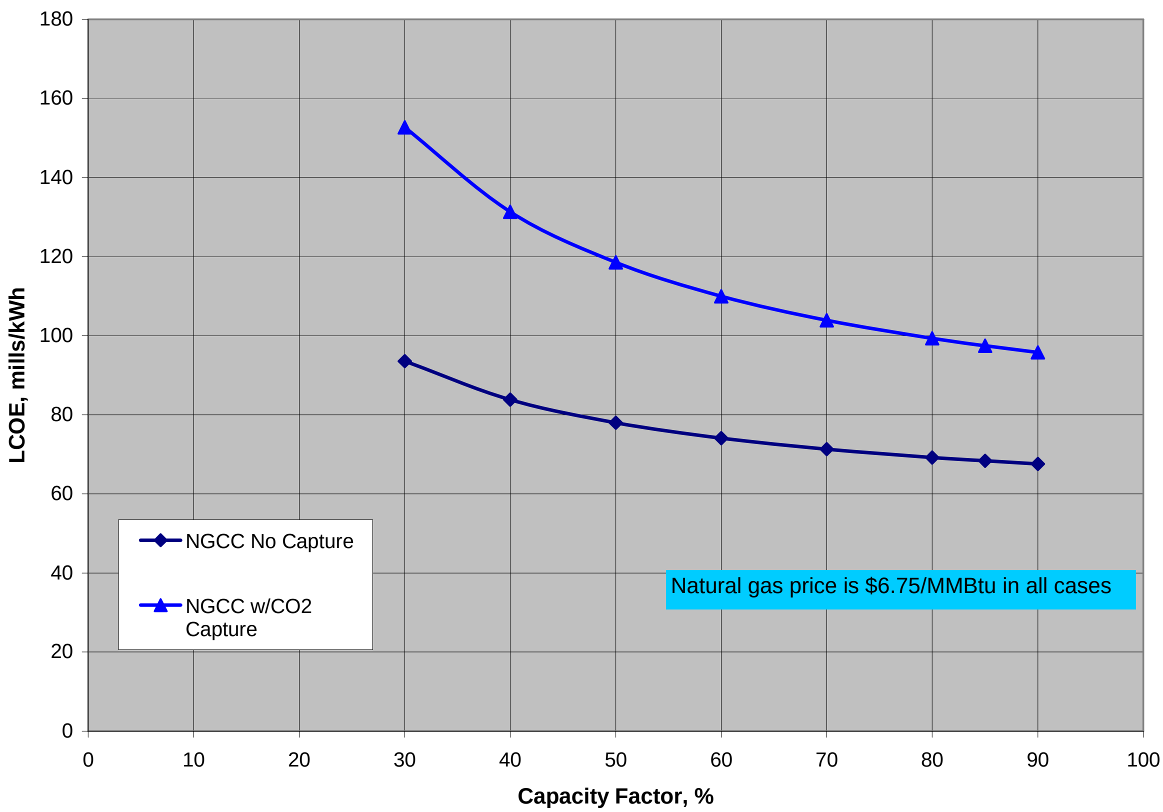
Exhibit 5-27 LCOE of NGCC Cases



The sensitivity of NGCC to capacity factor is shown in Exhibit 5-28. Unlike the PC and IGCC case, NGCC is relatively insensitive to capacity factor but highly sensitive to fuel cost as shown in Exhibit 5-29. A 33 percent increase in natural gas price (from $6 to $8/MMBtu) results in a LCOE increase of 25 percent in the non-capture case and 20 percent in the CO_2 capture case. Because of the higher capital cost in the CO_2 capture case, the impact of fuel price changes is slightly diminished.

As presented in Section 2.4 the cost of CO_2 capture was calculated in two ways, CO_2 removed and CO_2 avoided. In the NGCC case the cost of CO_2 removed is $70/ton and the cost of CO_2 avoided is $83/ton. The high cost relative to PC and IGCC technologies is mainly due to the much smaller amount of CO_2 generated by NGCC and therefore captured in the Econamine process.

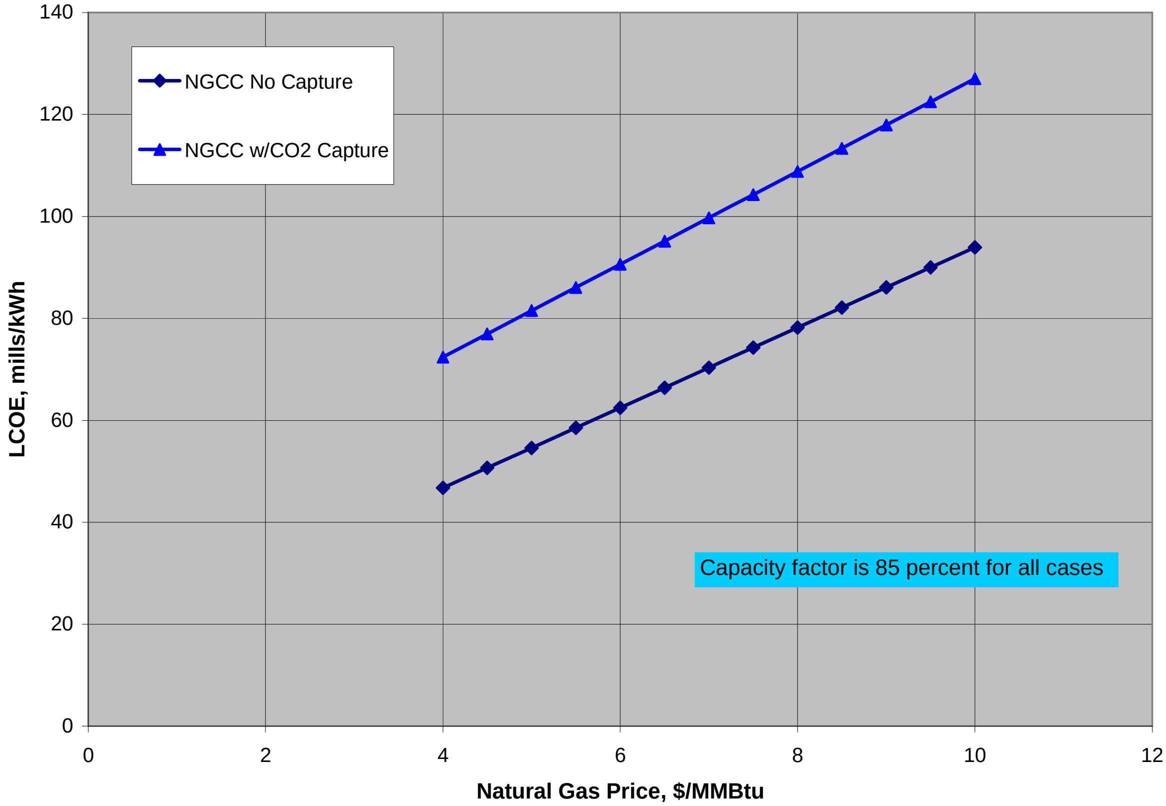
Exhibit 5-28 Sensitivity of LCOE to Capacity Factor in NGCC Cases



The following observations can be made regarding plant performance with reference to Exhibit 5-25:

- The efficiency of the NGCC case with no CO_2 capture is 50.8 percent (HHV basis). Gas Turbine World provides estimated performance for an advanced F class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 57.5 percent (LHV basis). [66] Adjusting the result from this study to an LHV basis results in an efficiency of 56.3 percent.

Exhibit 5-29 Sensitivity of LCOE to Fuel Price in NGCC Cases



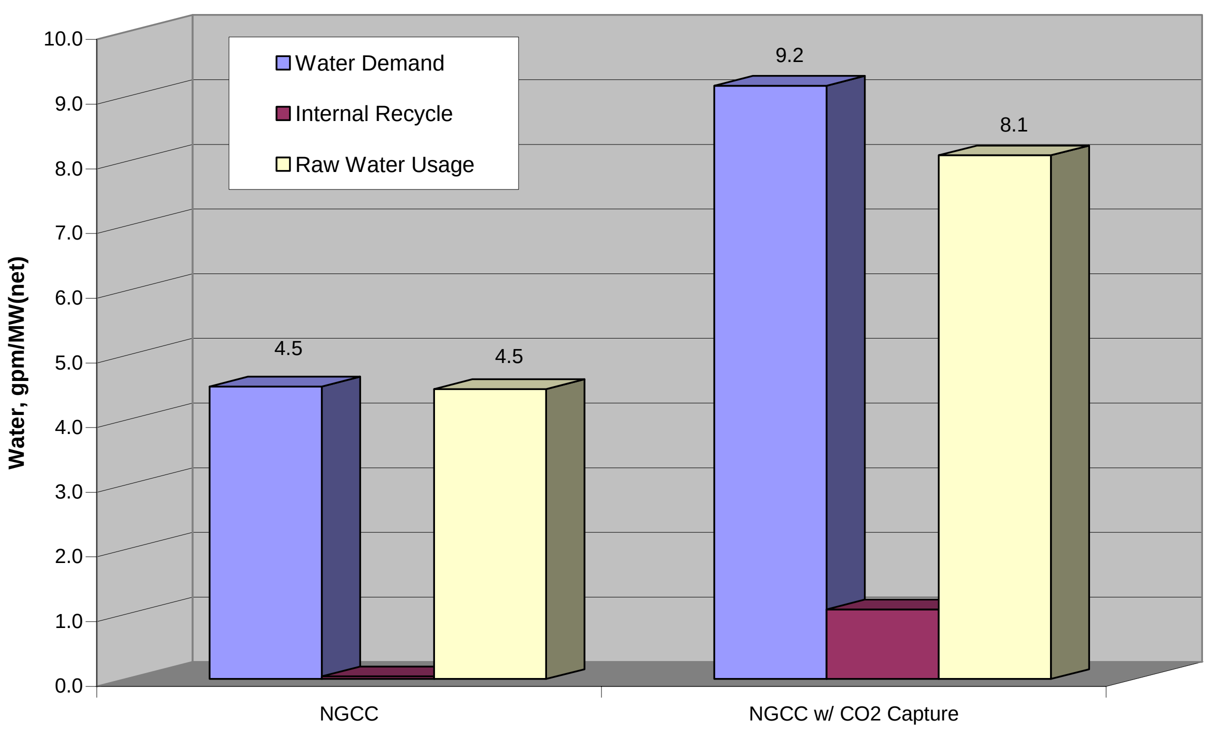
- The efficiency penalty to add CO_2 capture in the NGCC case is 7.1 percentage points. The efficiency reduction is caused primarily by the auxiliary loads of the Econamine system and CO_2 compression as well as the significantly increased cooling water requirement, which increases the auxiliary load of the circulating water pumps and the cooling tower fan. CO_2 capture results in a 28 MW increase in auxiliary load compared to the non-capture case.
- The energy penalty for NGCC is less than PC (7.1 percentage points for NGCC compared to 11.9 percentage points for PC) mainly because natural gas has a lower carbon intensity than coal. In the PC cases, about 589,670 kg/h (1.3 million lb/h) of CO_2 must be captured and compressed while in the NGCC case only about 181,437 kg/h (400,000 lb/h) is captured and compressed.
- A study assumption is that the natural gas contains no PM or Hg, resulting in negligible emissions of both.
- This study also assumes that the natural gas contains no sulfur compounds, resulting in negligible emissions of SO_2. As noted previously in the report, if the natural gas contained the maximum allowable amount of sulfur per EPA's pipeline natural gas specification, the resulting SO_2 emissions would be 21 tonnes/yr (23 tons/yr), or 0.00195 lb/MMBtu.

- NOx emissions are identical for the two NGCC cases on a heat input and mass basis. This is a result of the fixed output from the gas turbine (25 ppmv at 15 percent O_2) and the fixed efficiency of the SCR (90 percent).

The normalized water demand, internal recycle and raw water usage are shown in Exhibit 5-30 for the NGCC cases. The following observations can be made:

- Normalized water demand increases 103 percent and normalized raw water usage 81 percent in the CO_2 capture case. The high cooling water demand of the Econamine process results in a large increase in cooling tower makeup requirements.
- Cooling tower makeup comprises over 99 percent of the raw water usage in both NGCC cases. The only internal recycle stream in the non-capture case is the boiler feedwater blowdown, which is recycled to the cooling tower. In the CO_2 capture case condensate is recovered from the flue gas as it is cooled to the absorber temperature of 32°C (89°F) and is also recycled to the cooling tower.

Exhibit 5-30 Water Usage in NGCC Cases



6 REVISION CONTROL

The initial issue of this report was made public on May 15, 2007. Subsequent to the issue date, updates have been made to various report sections. These additions were made for clarification and aesthetic purposes and to correct an error made in determining the Econamine cooling water requirement in the PC and NGCC CO_2 capture cases. The water balances and water usage comparison exhibits were updated accordingly. In addition, the PC and NGCC energy balance tables contained errors which have been corrected in this version of the report. None of the changes affect the conclusions previously drawn. Exhibit 6-1 contains information added, changed or deleted in successive revisions.

Exhibit 6-1 Record of Revisions

Revision Number	Revision Date	Description of Change	Comments
1	8/23/07	Added disclaimer to Executive Summary and Introduction	Disclaimer involves clarification on extent of participation of technology vendors.
		Removed reference to Cases 7 and 8 in Exhibits ES-1 and 1-1.	SNG cases moved to Volume 2 of this report as explained in the Executive Summary and Section 1.
		Added Section 2.8	Explains differences in IGCC TPC estimates in this study versus costs reported by other sources.
		Added Exhibit ES-14	Mercury emissions are now shown in a separate exhibit from SO_2, NOx and PM because of the different y-axis scale.
		Corrected PC and NGCC CO_2 capture case water balances	The Econamine process cooling water requirement for the PC and NGCC CO_2 capture cases was overstated and has been revised.
		Replaced Exhibits ES-4, 3-121, 4-52 and 5-30	The old water usage figures were in gpm (absolute) and in the new figures the water numbers are normalized by net plant output.
		Update Selexol process description	Text was added to Section 3.1.5 to describe how H_2 slip was handled in the models.

Revision Number	Revision Date	Description of Change	Comments
		Revised PC and NGCC CO_2 capture case energy balances (Exhibits 4-21, 4-42 and 5-21)	The earlier version of the energy balances improperly accounted for the Econamine process heat losses. The heat removed from the Econamine process is rejected to the cooling tower.
		Corrected Exhibit 5-11 and Exhibit 5-21	Sensible heat for combustion air in the two NGCC cases was for only one of the two combustion turbines – corrected to account for both turbines

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