NATIONAL ENERGY TECHNOLOGY LABORATORY

NETL

Cost and Performance Baseline for Fossil Energy Plants

Volume 3a: Low Rank Coal to Electricity: IGCC Cases

May 2011

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COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 3a: LOW RANK COAL TO ELECTRICITY: IGCC CASES

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Final Report

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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 Integrated Gasification Combined Cycle (IGCC) plants with and without carbon dioxide (CO_2) capture and sequestration using both Powder River Basin (PRB) and North Dakota lignite (NDL) coals.

Approach

The power plant configurations analyzed in this study were modeled using the ASPEN Plus® (Aspen) 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. Operation and maintenance (O&M) costs and the cost for transporting, storing, and monitoring (TS&M) carbon dioxide (CO_2) in the cases with carbon capture were also estimated based on reference data and scaled estimates. The cost of electricity (COE) was determined for all plants assuming investor-owned utility (IOU) 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.

Fossil Energy RD&D aims at improving the performance and cost of clean coal power systems including the development of new approaches to capture and sequester greenhouse gases (GHGs). 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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LIST OF ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
ADIP	Aqueous di-isoproponal
AEO	Annual Energy Outlook
AFUDC	Allowance for funds used during construction
AGR	Acid gas removal
Aspen	Aspen Plus®
ASU	Air separation unit
BACT	Best available control technology
BEC	Bare erected cost
BFD	Block flow diagram
BFW	Boiler feedwater
BFP	Boiler feed pump
BLS	Bureau of Labor Statistics
Btu	British thermal unit
Btu/hr	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
CAMR	Clean Air Mercury Rule
CCF	Capital Charge Factor
CCPI	Clean Coal Power Initiative
CCS	Carbon capture and storage
CF	Capacity factor
CFB	Circulating fluidized bed
CGE	Cold gas efficiency
CL	Closed-loop
cm	Centimeter
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
CoP	Conoco Phillips
COS	Carbonyl sulfide
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CTG	Combustion Turbine-Generator
CWP	Circulating water pump
CWT	Cold water temperature
DCS	Distributed control system
DEA	Diethanolamine
DI	De-ionized
DIPA	Diisopropanolamine

DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPCM	Engineering/Procurement/Construction Management
EPRI	Electric Power Research Institute
FBG	Fluidized bed gasifier
FGD	Flue gas desulfurization
FEED	Front-End Engineering Design
FOAK	First-of-a-kind
FW	Feedwater
ft	Foot, feet
GDP	Gross domestic product
GEE	GE Energy
GHG	Greenhouse gas
GJ	gigajoules
GJ/hr	Gigajoules per hour
GPD	Gallons per day
gpm	Gallons per minute
GRE	Great River Energy
GT	Gas turbine
GTC	Gasification Technology Conference
hr	Hour
Hg	Mercury
H_2	Hydrogen
HDPE	High density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat-recovery steam generator
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
ICR	Information Collection Request
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated gasification combined cycle
IGVs	Inlet guide vanes
IOU	Investor-owned utility
IP	Intermediate pressure
ISO	International Standards Organization
KBR	Kellogg Brown and Root
kg/hr	Kilogram per hour

kJ/kg	Kilojoules per kilogram
kJ/kWh	Kilojoules per kilowatt hour
kJ/Nm^3	Kilojoules per normal cubic meter
km	kilometer
KO	Knockout
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatt-ton
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
LCOE	Levelized cost of electricity
LHV	Lower heating value
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
m	Meters
m^3/min	Cubic meter per minute
MDEA	Methyldiethanolamine
MJ/Nm^3	Megajoule per normal cubic meter
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/hr	Million British thermal units (also shown as 10^6 Btu) per hour
MMkJ/hr	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
MWth	Megawatts thermal
N/A	Not applicable
NDL	North Dakota lignite
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
Nm^3/hr	Normal cubic meter per hour
NMP	N-methyl-2-pyrrolidone
NOAK	Nth-of-a-kind
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review

N_2	Nitrogen
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
O_2	Oxygen
PC	Pulverized coal
ph	Phase
PM	Particulate matter
PO	Purchase order
POTW	Publicly Owned Treatment Works
ppbw	Parts Per billion by weight
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
ppmw	Parts per million by weight
PRB	Powder River Basin coal region
PSD	Prevention of Significant Deterioration
PSDF	Power Systems Development Facility
PSFM	Power Systems Financial Model
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
RDS	Research and Development Solutions, LLC
RH	Reheater
SC	Supercritical
scf	Standard cubic feet
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
SCGP	Shell Coal Gasification Process
SCOT	Shell Claus Off-gas Treating
SEP	Samenwerkende Electriciteits-Productiebedrijven NV
SFG	Siemens Fuel Gasifier
SGC	Synthesis gas cooler
SGS	Sour gas shift
SO_2	Sulfur dioxide
SRU	Sulfur recovery unit
SS	Stainless steel
STG	Steam turbine generator
Syngas	Synthesis gas
TASC	Total as-spent cost
TEWAC	Totally Enclosed Water-to-Air Cooled
TGTU	Tail gas treating unit
TOC	Total overnight cost
Tonne	Metric Ton (1000 kg)

TPC	Total plant cost
tpd	Tons per day
TPH	Tons per hour
TRIG™	Transport Reactor Integrated Gasification
TS&M	Transport, storage, and monitoring
vol%	Volume percent
WB	Wet bulb
WGS	Water gas shift
wt%	Weight percent
$/MMBtu	Dollars per million British thermal units
$/MWh	dollars per megawatt hour
°C	Degrees Celsius
°F	Degrees Fahrenheit
5-10s	50-hour work-week

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EXECUTIVE SUMMARY

The objective of this report is to present an independent assessment of the cost and performance of low rank coal-fired power systems, specifically integrated gasification combined cycle (IGCC) plants, using a consistent technical and economic approach that accurately reflects current or near term market conditions. This document is Volume 3a of the Low Rank Coal Baseline Reports, which are part of a four volume series consisting of the following:

- Volume 1: Bituminous Coal and Natural Gas to Electricity
- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)
- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels with Carbon Capture

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
- Environmental issues and performance
- 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 commercial-scale demonstrations under the Department of Energy's (DOE) Clean Coal Programs

As listed in Exhibit ES-1, 12 IGCC power plant configurations were analyzed based on the Shell Coal Gasification Process (SCGP), Transport Integrated Gasification (TRIG™) gasifier, Siemens Fuel Gasifier (SFG), and Conoco Phillips (CoP) E-Gas™ gasifier. The list includes eight cases firing Rosebud Powder River Basin (PRB) coal at the high elevation Montana site and four cases firing North Dakota lignite (NDL) at the mid elevation North Dakota site, with and without carbon dioxide (CO_2) capture.

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 judgment. Capital and operating costs were estimated based on simulation results and through a combination of vendor quotes, scaled estimates from previous design projects, or a combination of the two. Baseline fuel costs for this analysis were determined using data from the Energy Information Administration's (EIA) 2008 Annual Energy Outlook (AEO). The 2007 delivered costs used are \$0.84/gigajoule (GJ) (\$0.89/million British thermal unit [MMBtu]) for rail delivered Powder River Basin (PRB) coal and \$0.79/GJ (\$0.83/MMBtu) for minemouth North Dakota lignite (NDL), both on a higher heating value (HHV) basis and in June 2007 United States (U.S.) dollars.

Exhibit ES-1 Case Descriptions

Case	Coal Type	Coal Drying Process	Gasifier/Boiler Technology	ASU Integration	H_2S Separation/ Removal	CO_2 Separation	CO_2 Capture
S1A	S	WTA	Shell SCGP	Yes	Sulfinol-M		
S1B	S	WTA	Shell SCGP	No	Selexol	Selexol 2nd stage	90%
L1A	L	WTA	Shell SCGP	Yes	Sulfinol-M		
L1B	L	WTA	Shell SCGP	No	Selexol	Selexol 2nd stage	90%
S2A	S	Flash Pulverizer	TRIG™	Yes	Sulfinol-M		
S2B	S	Flash Pulverizer	TRIG™	No	Selexol	Selexol 2nd stage	83%
S3A	S	WTA	Siemens SFG	Yes	Sulfinol-M		
S3B	S	WTA	Siemens SFG	No	Selexol	Selexol 2nd stage	90%
L3A	L	WTA	Siemens SFG	Yes	Sulfinol-M		
L3B	L	WTA	Siemens SFG	No	Selexol	Selexol 2nd stage	90%
S4A	S	None	CoP E-Gas™	Yes	MDEA		
S4B	S	None	CoP E-Gas™	No	Selexol	Selexol 2nd stage	90%

Coal Type S= Subbituminous, L= Lignite

All plant configurations were evaluated based on installation at a greenfield site (Montana, 3400 ft elevation, for PRB cases and North Dakota, 1900 ft elevation, for lignite cases). To compare the plants on an equivalent basis, it was assumed that these plants would be dispatched any time they are available. The study capacity factor (CF) was chosen to reflect the maximum availability demonstrated for the specific plant type (e.g., 80 percent for IGCC configurations). Since variations in fuel costs and other factors can influence dispatch order and CF, sensitivity of cost of electricity (COE) to CF was evaluated and presented later in this Executive Summary (Exhibit ES-9).

The gross and net output varies among the IGCC cases because of the gas turbine (GT) size constraint. The advanced F-class turbine used to model these cases comes in a standard size of 232 megawatt (MW) when operated on synthesis gas (syngas) at International Standards Organization (ISO) conditions. Each case uses two combustion turbines (CTs) for a combined potential gross output of 464 MW. Because these cases were operated at elevations higher than sea level, the output was reduced from the turbine's ISO condition potential. In the combined cycle, a heat recovery steam generator (HRSG) extracts heat from the CT exhaust to power a steam turbine. However, the CO_2 capture cases consume more extraction steam than the non-capture cases, thus reducing the steam-turbine output. In addition, the CO_2 capture cases have a higher auxiliary load requirement than non-capture cases, which serves to further reduce net plant output.

Exhibit ES-2 shows the cost, performance, and environmental profile summary for all cases discussed below.

Energy Efficiency

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

- The Shell case with no CO_2 capture firing PRB coal at the Montana site has the highest plant efficiency of the technologies modeled in this study, with an efficiency of 42.0 percent.
- The Shell case with CO_2 capture firing PRB coal at the Montana site has the highest efficiency among all of the capture technologies modeled in this study, with an efficiency of 32.1 percent.
- The CO_2 capture results in an efficiency penalty of 6 to 10 absolute percent, relative to the analogous non-capture case, while noting that the TRIG™ case only captures 83 percent of the overall carbon.
- The PRB coal cases at 3,400 ft of elevation have higher efficiency than the corresponding lignite coal cases at 1,900 ft of elevation. The negative efficiency impact of coal quality is greater than the negative efficiency impacts caused by the elevation differences and associated combustion turbine derate.

Water Use

Three water values are presented for each technology in Exhibit ES-4: raw water withdrawal, process discharge, and raw water consumption. Each value is normalized by net output. Raw water withdrawal is the difference between demand and internal recycle. Demand is the amount of water required to satisfy a particular process (cooling tower makeup, quench makeup, slag handling, etc.) and internal recycle is water available within the process. Raw water withdrawal is the water removed from the ground or diverted from a surface-water source for use in the plant. Raw water consumption is the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source it was withdrawn from. Raw water consumption is the difference between withdrawal and process discharge, 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.

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

	Shell IGCC Cases				TRIG IGCC Cases		Siemens IGCC Cases				CoP IGCC Cases	
PERFORMANCE	**S1A**	**L1A**	**S1B**	**L1B**	**S2A**	**S2B**	**S3A**	**L3A**	**S3B**	**L3B**	**S4A**	**S4B**
CO_2 Capture	No	No	Yes	Yes	No	Yes	No	No	Yes	Yes	No	Yes
Gross Power Output (kW_e)	696,700	752,600	663,400	713,300	652,700	621,300	622,200	678,800	634,700	676,900	738,300	727,200
Auxiliary Power Requirement (kW_e)	124,020	135,900	191,790	213,240	107,280	160,450	117,480	135,680	189,410	210,390	133,460	212,130
Net Power Output (kW_e)	572,680	616,700	471,610	500,060	545,420	460,850	504,720	543,120	445,290	466,510	604,840	515,070
Coal Flowrate (lb/hr)	542,713	760,093	585,970	814,029	545,197	577,946	531,119	743,918	579,796	801,651	656,228	675,058
HHV Thermal Input (kW_{th})	1,362,134	1,474,011	1,470,704	1,578,608	1,368,368	1,450,564	1,333,034	1,442,644	1,455,207	1,554,603	1,647,041	1,694,303
Net Plant HHV Efficiency (%)	42.0%	41.8%	32.1%	31.7%	39.9%	31.8%	37.9%	37.6%	30.6%	30.0%	36.7%	30.4%
Net Plant HHV Heat Rate (Btu/kWh)	8,116	8,156	10,641	10,772	8,560	10,740	9,012	9,063	11,151	11,371	9,292	11,224
Raw Water Withdrawal (gpm/MW_{net})	3.1	3.0	7.2	7.8	3.7	6.5	4.5	4.0	9.0	8.9	5.4	8.4
Process Water Discharge (gpm/MW_{net})	0.8	0.8	1.4	1.6	0.8	1.0	1.1	1.1	1.6	1.7	1.1	1.5
Raw Water Consumption (gpm/MW_{net})	2.3	2.2	5.9	6.2	2.9	5.5	3.4	2.9	7.4	7.2	4.3	6.9
CO_2 Emissions (lb/MMBtu)	214	219	22	22	211	36	214	219	22	22	213	22
CO_2 Emissions (lb/MWh_{gross})	1,426	1,461	165	170	1,507	287	1,563	1,585	172	175	1,620	174
CO_2 Emissions (lb/MWh_{net})	1,735	1,783	233	242	1,803	386	1,927	1,981	246	255	1,977	245
SO_2 Emissions (lb/MMBtu)	0.0023	0.0023	0.0009	0.0010	0.0019	0.0009	0.0039	0.0021	0.0009	0.0010	0.0016	0.0009
SO_2 Emissions (lb/MWh_{gross})	0.015	0.015	0.007	0.007	0.013	0.007	0.029	0.016	0.007	0.008	0.012	0.007
NOx Emissions (lb/MMBtu)	0.062	0.063	0.050	0.049	0.059	0.049	0.061	0.061	0.051	0.050	0.052	0.044
NOx Emissions (lb/MWh_{gross})	0.412	0.418	0.381	0.371	0.422	0.390	0.444	0.445	0.397	0.391	0.398	0.348
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071
PM Emissions (lb/MWh_{gross})	0.047	0.047	0.054	0.054	0.051	0.057	0.052	0.051	0.056	0.056	0.054	0.056
Hg Emissions (lb/TBtu)	0.351	0.560	0.351	0.560	0.351	0.351	0.351	0.560	0.351	0.560	0.351	0.351
Hg Emissions (lb/MWh_{gross})	2.34E-06	3.74E-06	2.66E-06	4.23E-06	2.51E-06	2.80E-06	2.57E-06	4.06E-06	2.75E-06	4.39E-06	2.67E-06	2.79E-06
COST												
Total Plant Cost (2007$/kW)	2,506	2,539	3,480	3,584	2,236	3,019	2,610	2,656	3,533	3,626	2,265	3,144
Total Overnight Cost (2007$/kW)	3,056	3,094	4,253	4,378	2,728	3,691	3,185	3,239	4,318	4,430	2,771	3,851
Bare Erected Cost	1,914	1,941	2,610	2,692	1,692	2,228	2,006	2,044	2,654	2,730	1,737	2,357
Home Office Expenses	177	179	242	250	157	207	186	189	247	254	162	221
Project Contingency	343	349	486	502	305	421	359	367	493	508	306	431
Process Contingency	72	69	142	141	83	164	60	56	139	135	60	135
Owner's Costs	550	556	773	794	492	672	575	583	785	804	505	706
Total Overnight Cost (2007$x1,000)	1,750,189	1,908,200	2,005,883	2,189,363	1,488,063	1,701,132	1,607,607	1,759,016	1,922,741	2,066,464	1,675,790	1,983,369
Total As Spent Capital (2007$/kW)	3,484	3,527	4,849	4,991	3,110	4,208	3,631	3,692	4,922	5,050	3,159	4,390
COE (mills/kWh, 2007$)[1]	83.2	83.5	119.7	121.9	74.5	105.2	86.8	87.3	121.7	123.7	78.7	112.3
CO_2 TS&M Costs	0.0	0.0	6.0	5.7	0.0	5.9	0.0	0.0	6.3	6.2	0.0	5.8
Fuel Costs	7.2	6.7	9.5	8.9	7.6	9.5	8.0	7.5	9.9	9.4	8.3	10.0
Variable Costs	8.0	8.2	10.6	11.1	6.8	8.8	8.2	8.4	10.6	11.1	8.3	10.9
Fixed Costs	13.7	13.6	18.3	18.6	11.8	15.5	14.1	14.0	18.4	18.6	13.0	17.4
Capital Costs	54.2	54.9	75.4	77.6	48.4	65.4	56.5	57.4	76.6	78.5	49.1	68.3
LCOE (mills/kWh, 2007$)[1]	105.4	105.8	151.8	154.5	94.5	133.3	110.0	110.7	154.3	156.9	99.8	142.4

[1] COE and Levelized COE are defined in Section 2.6

Exhibit ES-3 Net Plant Efficiency

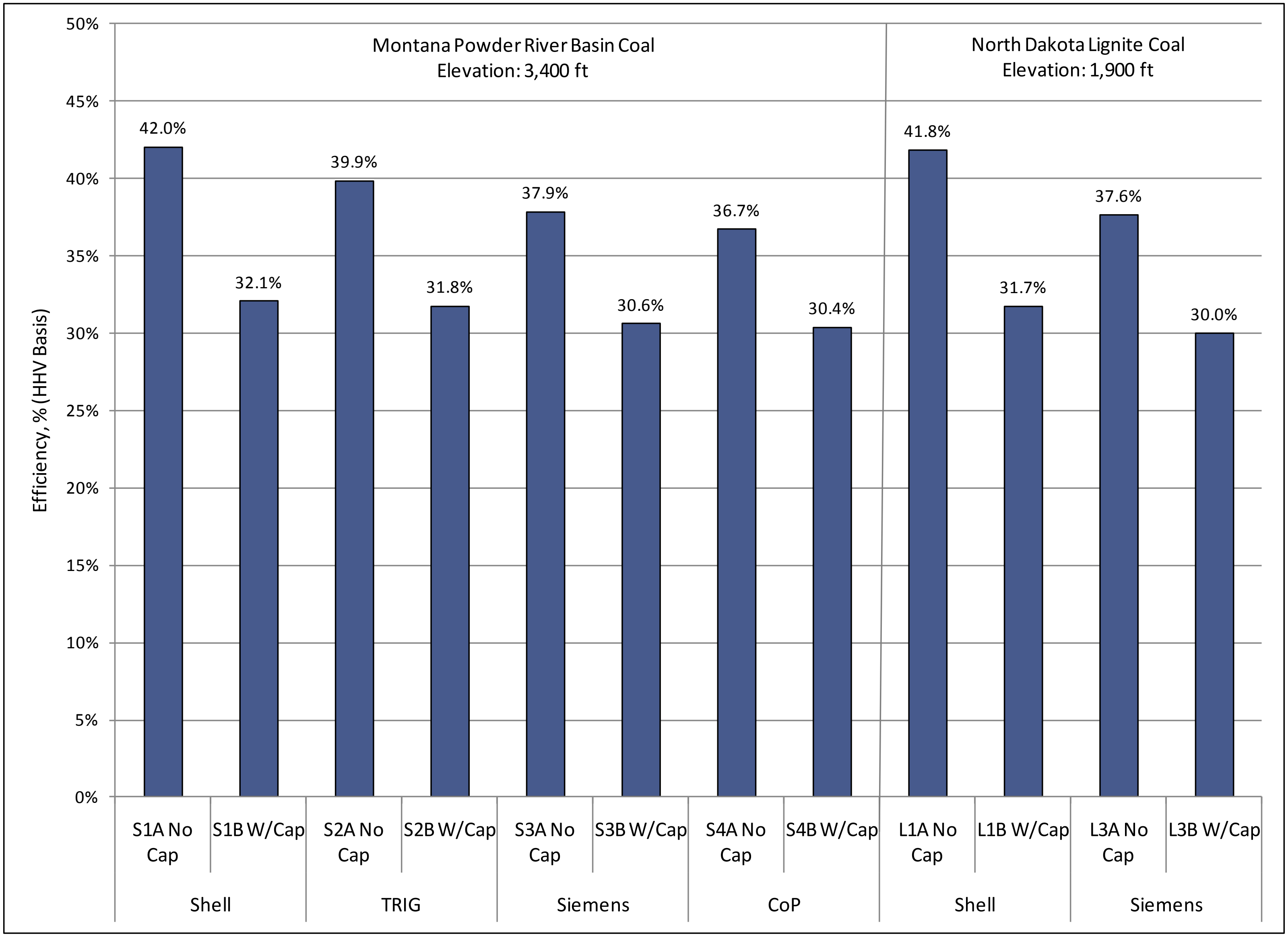
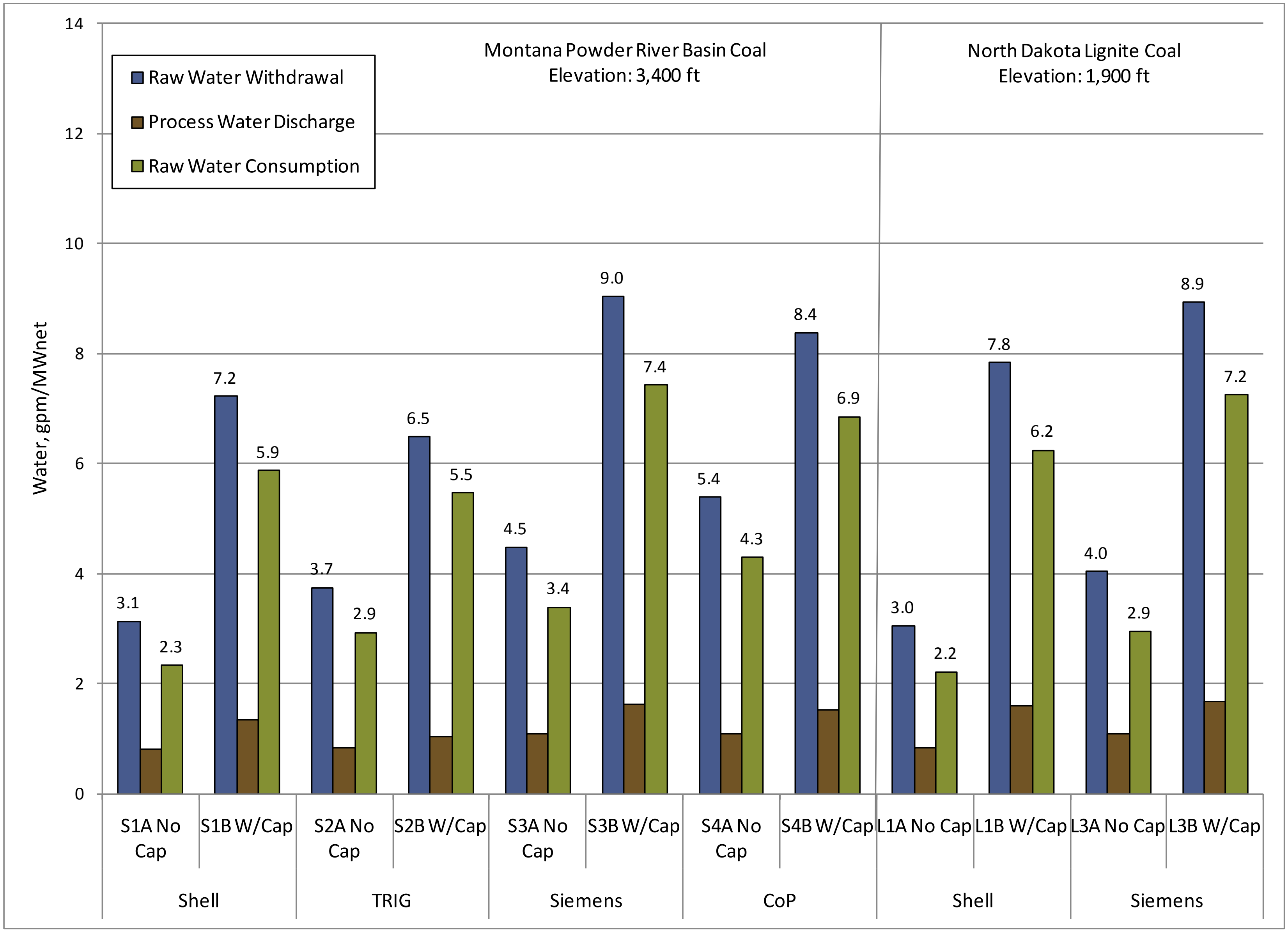


Exhibit ES-4 Raw Water Withdrawal and Consumption



The largest consumer of raw water in all cases is cooling tower makeup. Since plants located in the Western U.S. need to consider limited water supplies, a parallel wet/dry condenser was chosen for all plant configurations. In a parallel cooling system half of the turbine exhaust steam is condensed in an air-cooled condenser and half in a water-cooled condenser. The cooling water is provided by a mechanical draft, evaporative cooling tower. The primary conclusions that can be drawn are:

- The raw water usage is lower in the lignite coal cases because of its higher moisture content, and a significant amount of the coal moisture is recovered in the drying process for dry feed cases and used as internal recycle. Thus, while the water demand is nearly equal in the Montana PRB and North Dakota lignite cases, the water usage is significantly lower when using lignite coal.
- The use of the parallel wet/dry cooling system reduces water demand by 36-47 percent in the non-capture cases and by 24-30 percent in the CO_2 capture cases relative to using a purely wet cooling system. The water savings is less in the CO_2 capture cases because a significant amount of extraction steam is used in the shift reaction and therefore not condensed in the surface condenser.
- The water demand is significantly greater in the CO_2 capture cases because one-half of the condenser load represents a smaller percentage of the total water requirement, again due primarily to the high shift steam requirement.

Cost Results

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, including preproduction costs, inventory capital, initial cost for catalyst and chemicals, land, financing costs and other owner's costs were added to TPC to generate total overnight cost (TOC). Property taxes and insurance were included in the fixed operating costs as an additional owner's cost. Escalation and interest on debt during the capital expenditure period were estimated and added to the TOC to provide the Total As-Spent Cost (TASC).

The cost estimates carry an accuracy of -15/+30%, consistent with a "feasibility 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 relative 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 (FOAK) or posed significant risk due to lack of operating experience. The cost accounts that received a process contingency include:

- Gasifiers and Syngas Coolers: 15–20 percent on all IGCC cases, with next-generation commercial offering and integration with the power island.
- Two-Stage Selexol: 20 percent on all IGCC capture cases, with lack of operating experience at commercial scale in IGCC service.
- Mercury Removal: 5 percent on all IGCC cases, with minimal commercial scale experience in IGCC applications.
- Combustion Turbine Generator (CTG): 5 percent on all IGCC non-capture cases, with syngas firing and ASU integration; 10 percent on all IGCC capture cases, with high hydrogen firing.
- Instrumentation and Controls: 5 percent on all IGCC accounts, with integration issues.

The normalized components of TOC and overall TASC are shown for each plant configuration in Exhibit ES-5. The TOC, which is used for COE calculations, is the TPC plus owner's costs. The following conclusions can be drawn:

- The TOC is higher for the North Dakota elevation lignite coal cases as compared to the Montana elevation PRB coal cases by approximately 9 percent.
- The TOC increase to add CO_2 capture is approximately 38 percent.
- The TASC is approximately 15% greater than the TOC based on the study assumptions.

Cost of Electricity

The cost metric used in this study is the COE, which is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant*. To calculate the COE, the Power Systems Financial Model (PSFM) [2] was used to determine a "base-year" (2007) COE that, when escalated at an assumed nominal annual general inflation rate of 3 percent[1], provided the stipulated internal rate of return on equity over the entire economic analysis period (capital expenditure period plus thirty years of operation). The first year capital charge factor (CCF) shown in Exhibit ES-6, which was derived using the PSFM, can also be used to calculate COE using a simplified equation as detailed in Section 2.6.4.

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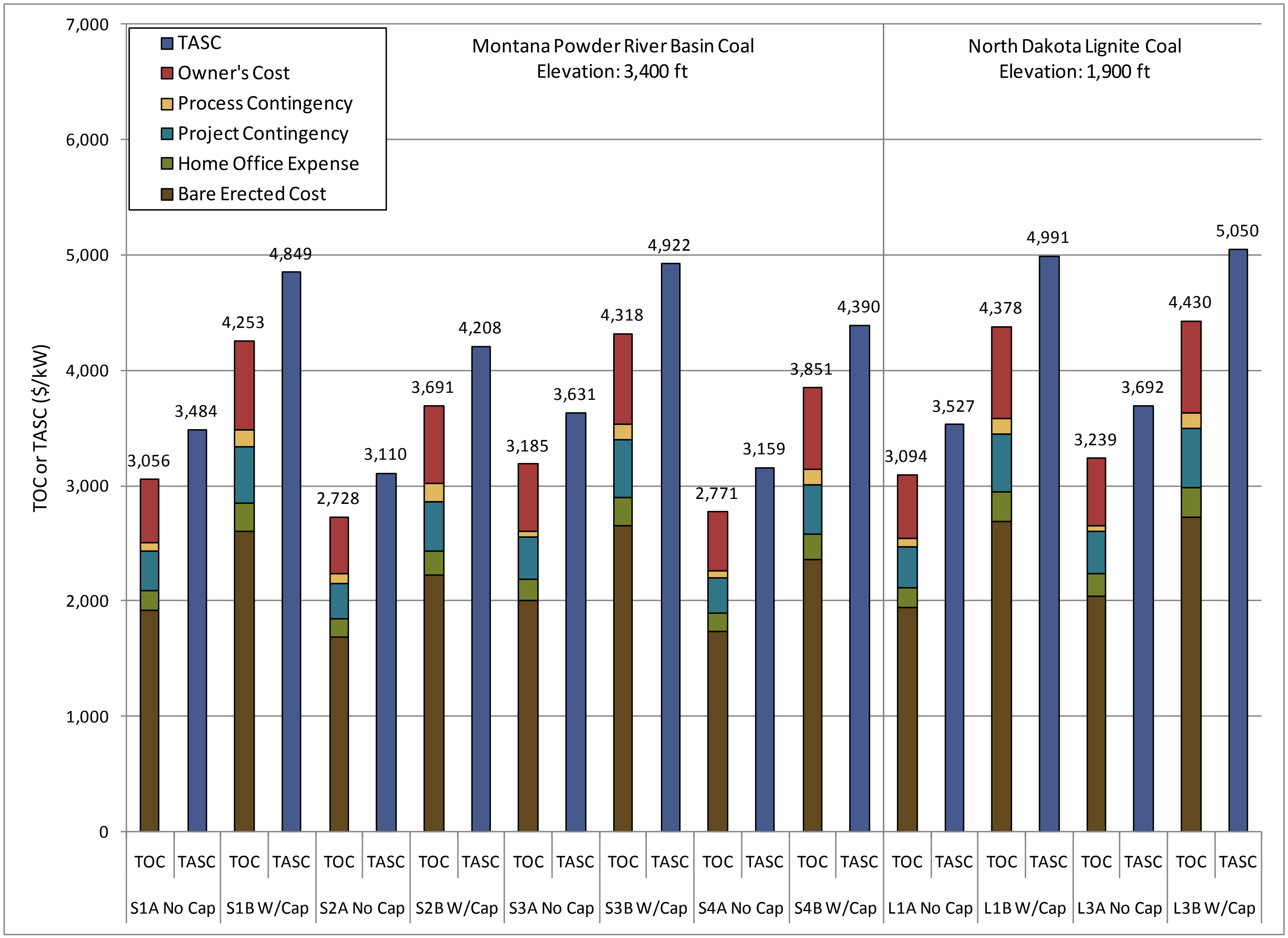
[1] This nominal escalation rate is equal to the average annual inflation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods. This index was used instead of the Producer Price Index for the Electric Power Generation Industry because the Electric Power Index only dates back to December 2003 and the Producer Price Index is considered the "headline" index for all of the various Producer Price Indices.

Exhibit ES-5 Plant Capital Costs



Note: TOC expressed in 2007 dollars. TASC expressed in mixed-year 2007 to 2011 year dollars.

The project financial structure varies depending on the type of project (high or low risk). All cases were assumed to be undertaken at investor owned utilities (IOUs). High risk projects are those in which commercial scale operating experience is limited. All IGCC cases (with and without CO_2 capture) were considered to be high risk. All cases were assumed to have a 5 year capital expenditure period. The current-dollar, 30-year levelized cost of electricity (LCOE) was also calculated and is shown in Exhibit ES-2, but the primary metric used in the balance of this study is COE. A more detailed discussion of the two metrics is provided in Section 2.6.

Exhibit ES-6 Economic Parameters Used to Calculate COE

	High Risk (5 year capital expenditure period)	Low Risk (5 year capital expenditure period)
First Year Capital Charge Factor	0.1243	0.1165

Commodity prices fluctuate over time based on overall economic activity and general supply and demand curves. While the cost basis for this study is June 2007, many price indices had similar values in January 2010 compared to June 2007. For example, the Chemical Engineering Plant Cost Index was 532.7 in June 2007 and 532.9 in January 2010, and the Gross Domestic Product Chain-type Price Index was 106.7 on July 1, 2007 and 110.0 on January 1, 2010. Hence the June 2007 dollar cost base used in this study is expected to be representative of January 2010 costs.

The COE 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:

- The COEs for the Shell and Siemens systems are higher than TRIG™ and CoP for both capture and non-capture cases. Note that TRIG™ and CoP were only studied for PRB coal and TRIG™ with capture only achieved 83 percent carbon capture.
- TRIG™ is the only technology evaluated that has not been demonstrated at commercial scale. For this reason, TRIG™ COEs are subject to a greater level of uncertainty than the other technologies in the group.
- The COE is dominated by capital charges in all cases. The capital cost component of COE ranges from 61 to 66 percent for IGCC cases.
- The fuel cost component is relatively minor in all cases, ranging from 7 to 10 percent of the COE for IGCC cases.
- The CO_2 TS&M component adds approximately 5 percent to the COE.
- The COE increases by 40 to 46% percent for IGCC plants when CO_2 capture is added.
- The COE is generally lower for Montana PRB cases compared to the North Dakota lignite cases.

Exhibit ES-7 COE by Cost Component

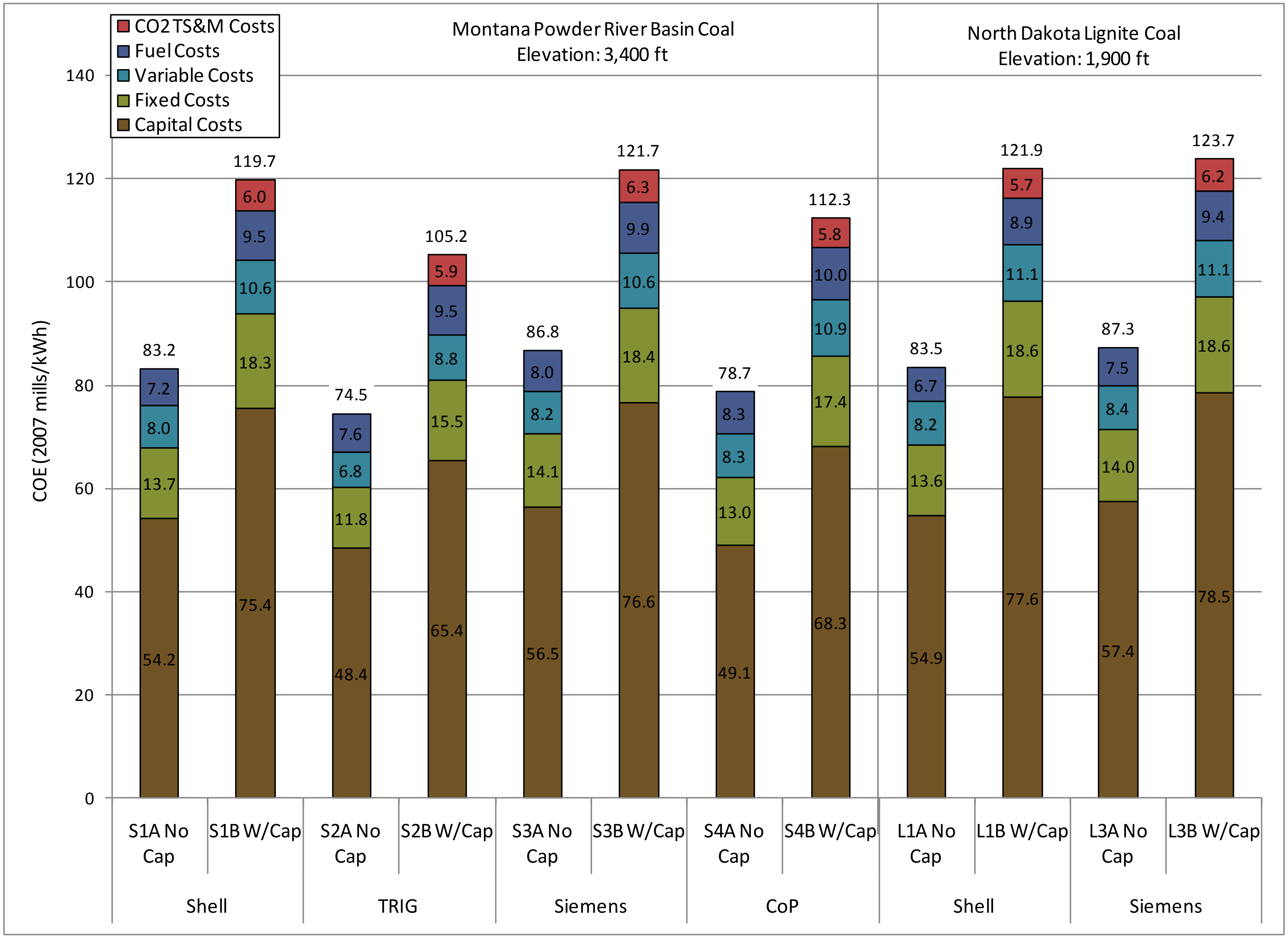


Exhibit ES-8 shows the COE sensitivity to fuel costs. The solid lines are the COE of non-capture cases. The dotted lines are the capture cases. As expected, all cases show a linear decrease in COE with the decrease in coal prices. As the price for PRB coal decreases from \$0.89 to \$0/MMBtu, the average COE decreases from 81 to 73 tenths of a cent per kilowatt hour (mills/kWh) for the non-capture PRB cases and from 115 to 105 mills/kWh for the PRB capture cases. As the price for ND lignite coal decreases from \$0.83 to \$0/MMBtu, the average COE decreases from 85 to 78 tenths of a cent per kilowatt hour (mills/kWh) for the non-capture lignite cases and from 123 to 113 mills/kWh for the lignite capture cases.

The sensitivity of COE to CF is shown in Exhibit ES-9. CF is equal to availability since it was assumed that the plants are able to operate at 100 percent capacity whenever power production is needed. The solid lines are the COE of non-capture cases. The dotted lines are the capture cases. All cases show a decrease in COE with the increase in CF. As the CF increases from 80 to 100 percent, the average COE decreases from 81 to 66 mills/kWh for the non-capture PRB cases and from 115 to 94 mills/kWh for the CO_2 capture PRB cases. The average COE decreases from 85 to 70 mills/kWh for the non-capture lignite cases and from 123 to 100 mills/kWh for the lignite capture cases.

<u>Cost of CO_2 Avoided</u>

The CO_2 emissions per megawatt-hour (MWh) are dependent on the chosen technology and configuration, and they are higher for the North Dakota lignite cases compared to the Montana PRB cases. The first year cost of CO_2 avoided is calculated using the equation:

$$Avoided\ Cost = \frac{\{COE_{with\ removal} - COE_{reference}\}\ \$/MWh}{\{CO_2\ Emissions_{reference} - CO_2\ Emissions_{with\ removal}\}\ tons/MWh}$$

The COE with CO_2 removal includes the costs of capture and compression, as well as TS&M costs. The resulting avoided costs are shown in Exhibit ES-10 for each of the CO_2 capture technologies modeled. The cost of CO_2 avoided compared to the analogous non-capture design averages \$45/ton, with a range of \$40/ton–\$53/ton. The cost of CO_2 avoided, compared to the baseline Supercritical (SC) PC non-capture design, was determined using results shown in Exhibit 2-22 and averages \$70/ton, with a range of \$63/ton-\$77/ton. The analogous CO_2 avoided costs are lower for the Montana PRB coal than the North Dakota lignite cases, mainly because of the capital cost increase due to the low energy density lignite fuel. The cost of CO_2 avoided, compared to the baseline SC PC plant, follows the same general trend as the COE for each of the cases after accounting for the overall carbon removal efficiency. The comparison of the analogous Shell designs is affected by the change from a water quench in the CO_2 capture case to high temperature syngas heat recovery in the non-capture case. This increases efficiency when high water concentrations are not required for the WGS reaction, as is the case for non-capture cases, at the expense of including high temperature heat exchangers, thus increasing the cost of avoiding CO_2 emissions for the semi-analogous Shell cases.

Exhibit ES-8 COE Sensitivity to Fuel Costs

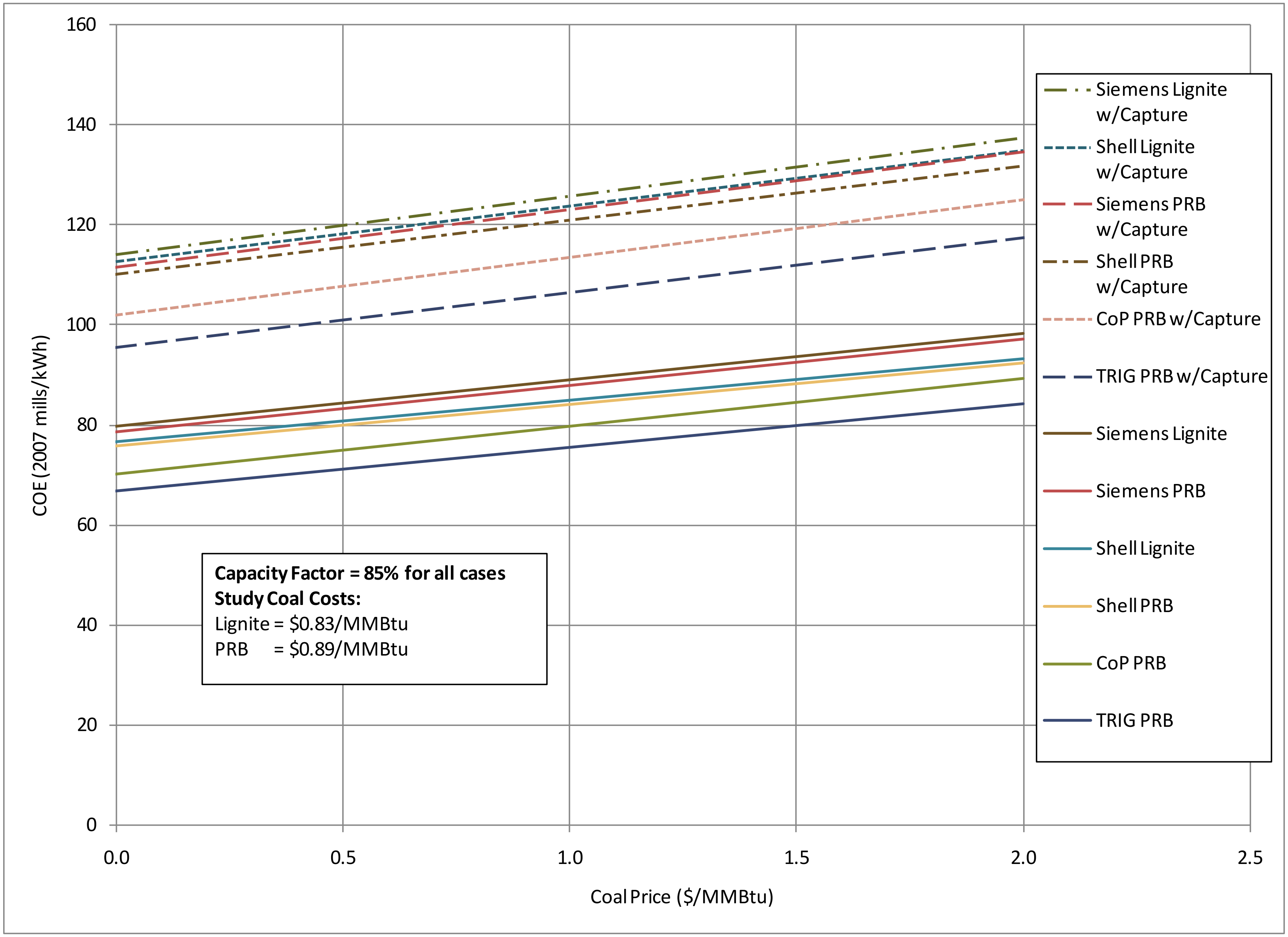


Exhibit ES-9 COE Sensitivity to Capacity Factor

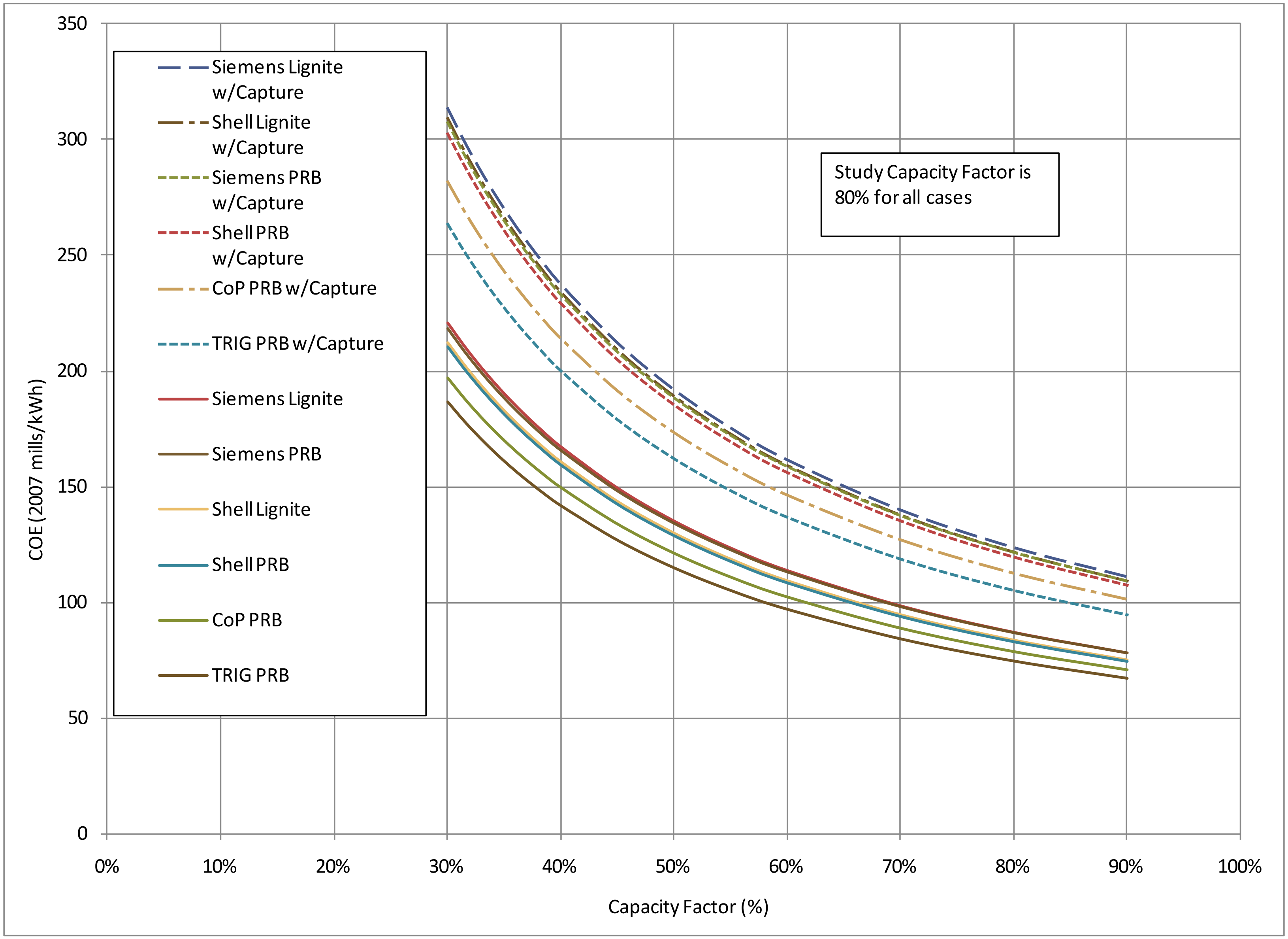
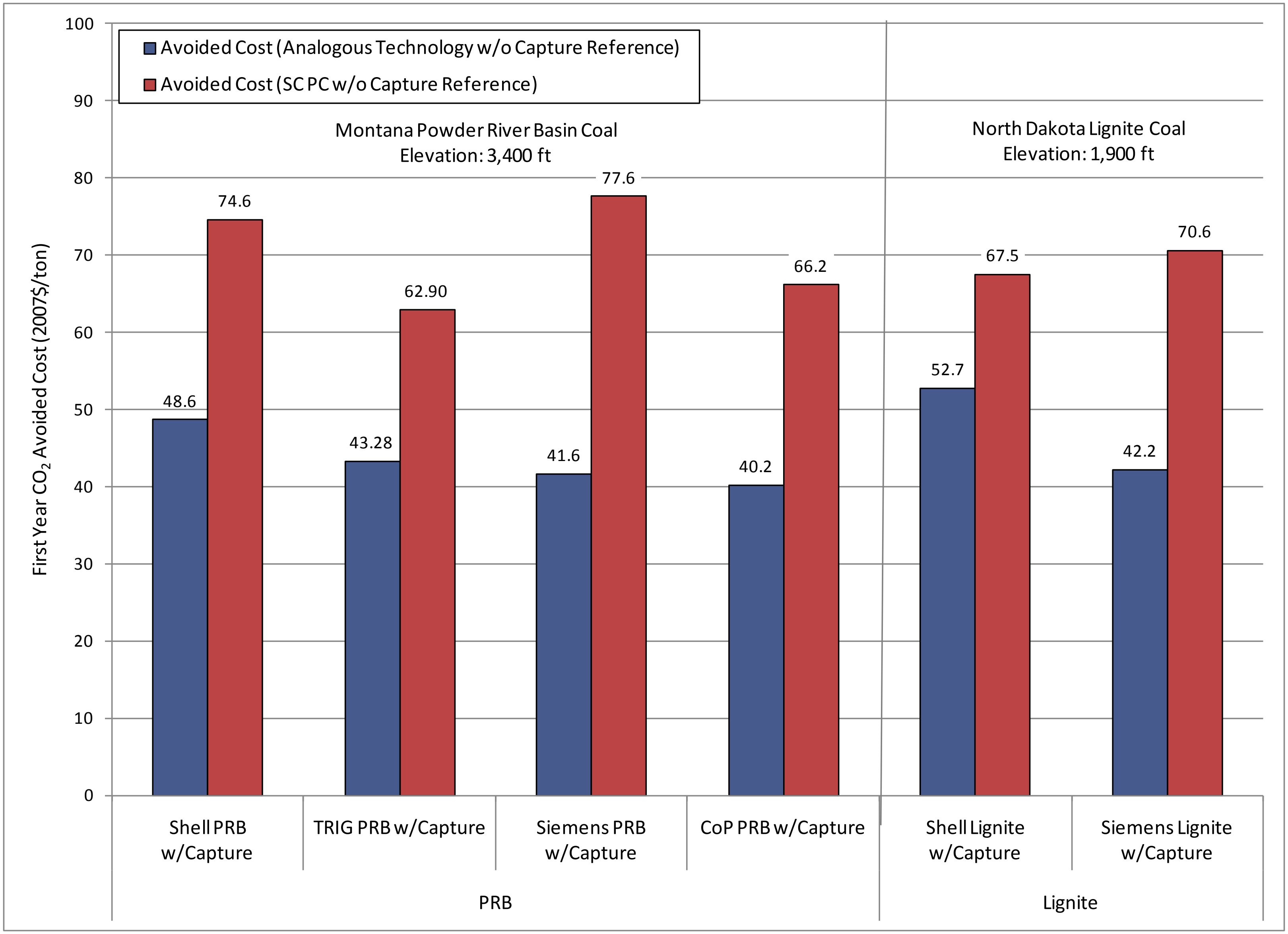


Exhibit ES-10 CO_2 Avoided Costs



Environmental Performance

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 ES-11. Emission rates of sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM) are shown graphically in Exhibit ES-12, and emission rates of mercury (Hg) are shown separately in Exhibit ES-13 because of the orders of magnitude difference in emission rate values.

Exhibit ES-11 Study Environmental Targets

Pollutant	Environmental Target	Control Technology
NOx	15 ppmv (dry) @ 15% O_2	Low NOx burners and syngas nitrogen dilution
SO_2	0.0128 lb/MMBtu	Selexol, MDEA or Sulfinol (depending on gasifier technology)
Particulate Matter (Filterable)	0.0071 lb/MMBtu	Quench, water scrubber, and/or cyclones and candle filters (depending on gasifier technology)
Mercury	> 90% capture	Carbon bed

The following observations can be made:

- Emissions of SO_2 are uniformly extremely low. The same environmental target was used as in the bituminous coal cases of Volume 1 of this study, and because the coal sulfur content is significantly lower in the design coals of this study, the resulting SO_2 emissions are also significantly lower.
- Particulate emissions are the same for each case because it was a study assumption that the combination of cyclones and candle filters would exactly meet the environmental target of 0.0071 lb/MMBtu.
- NOx emissions were assumed to be 15 ppmv at 15 percent oxygen in all cases. The resulting emissions on a lb/MMBtu basis vary slightly because of the variable coal feed rates and flue gas volumes generated among cases.
- Mercury emissions are constant for each coal type and significantly below the NSPS limit of 20×10^{-6} lb/MWh for IGCC systems. The emissions shown in Exhibit ES-13 are equivalent to $3.7 – 4.4 \times 10^{-6}$ lb/MWh for the four lignite cases (which have the higher Hg concentration of the two coal types), or a minimum of 78 percent less than NSPS.

Exhibit ES-12 SO_2, NOx and Particulate Emission Rates

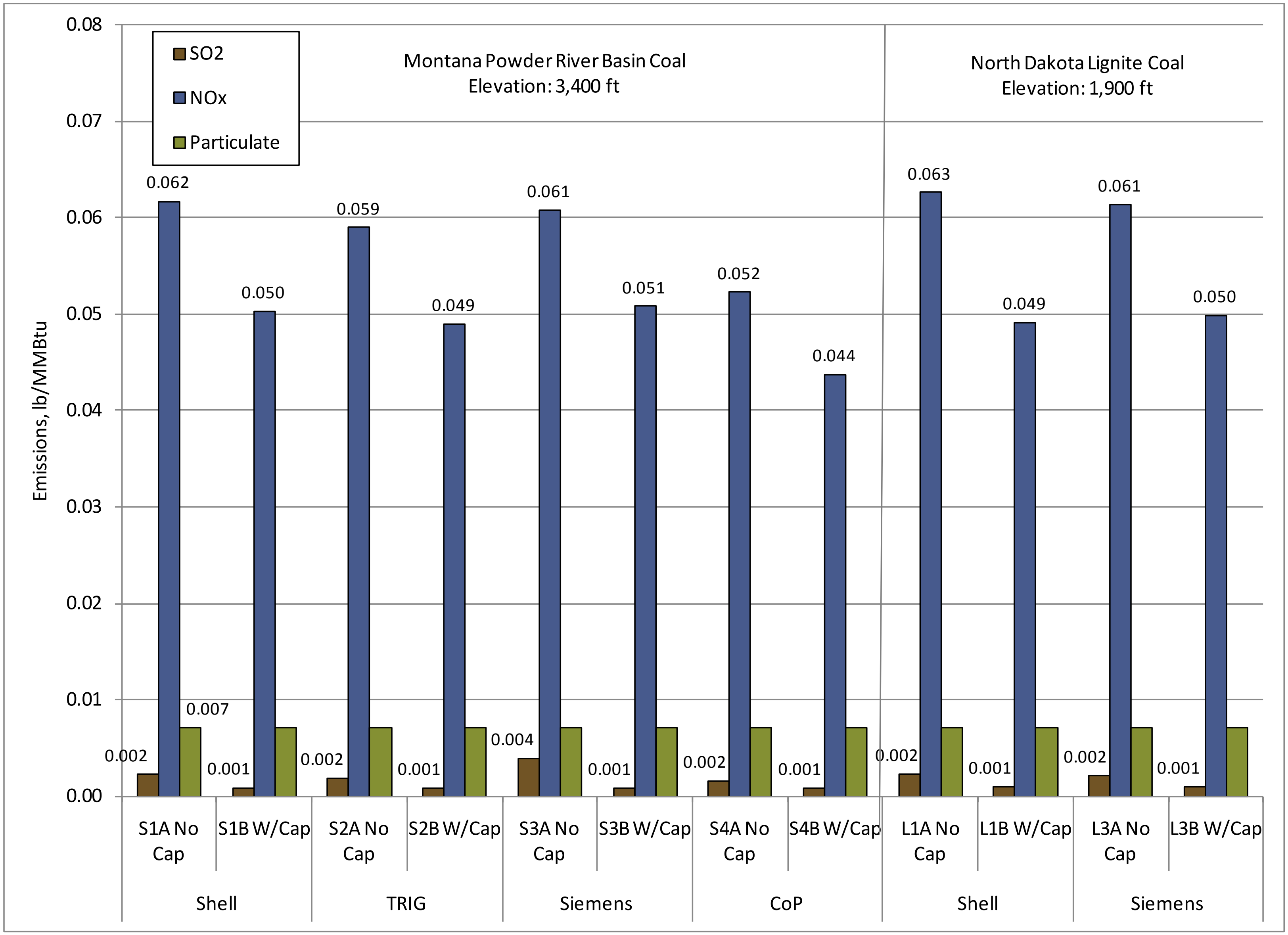
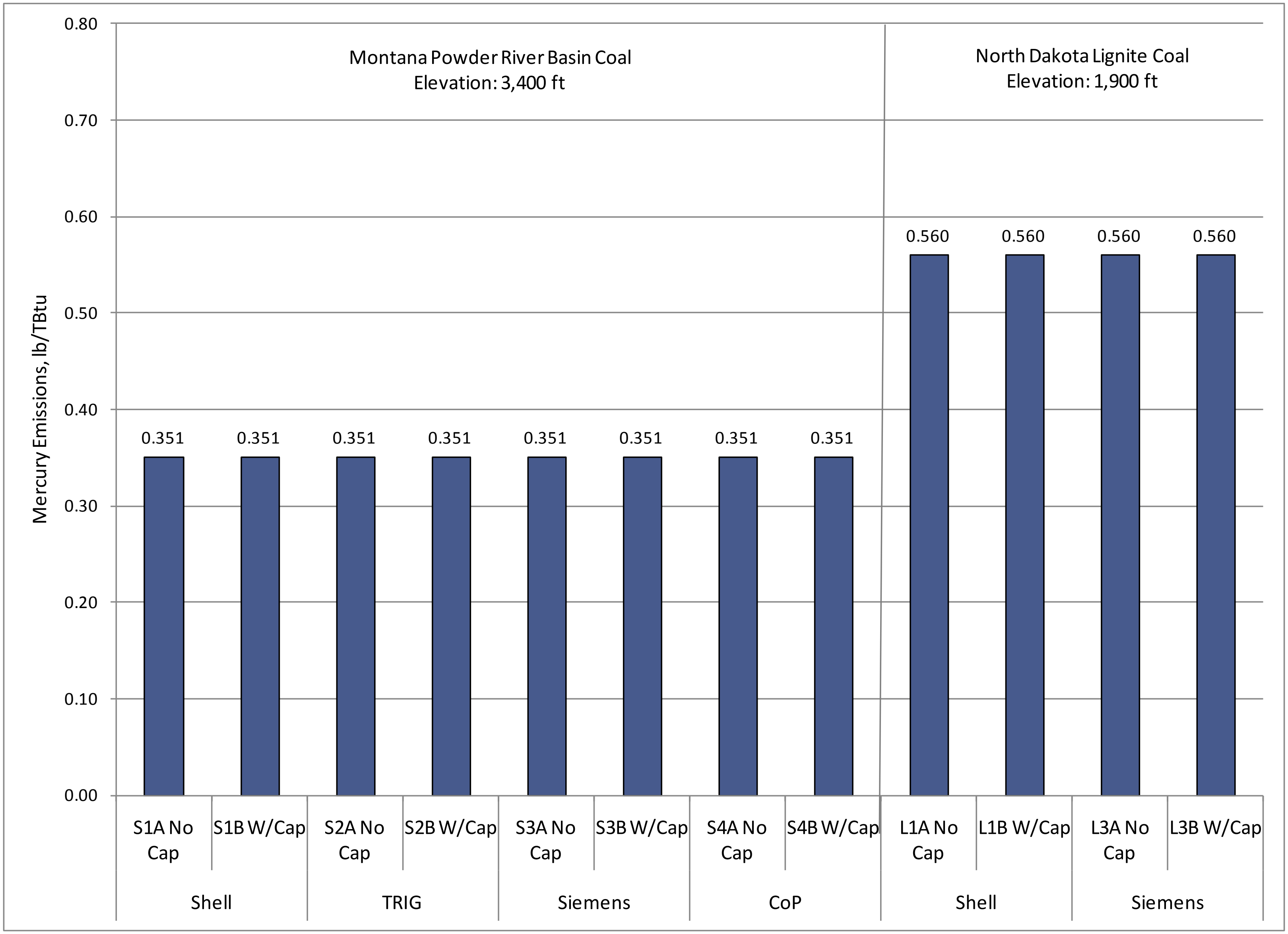


Exhibit ES-13 Mercury Emission Rates



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, the Shell Coal Gasification Process (SCGP), TRIG™, Siemens Fuel Gasifier (SFG), and CoP E-Gas™ gasifiers using low rank Rosebud PRB and ND Lignite coals—in a consistent technical and economic manner that accurately reflects current market conditions for plants starting operation in the near term. This document is Volume 3a of the Low Rank Coal Baseline Reports, which are part of a four volume series consisting of the following:

- Volume 1: Bituminous Coal and Natural Gas to Electricity
- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)
- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels with Carbon Capture

Twelve IGCC cases are modeled and analyzed. Eight cases use PRB subbituminous coal at the high elevation Montana site, and four cases use North Dakota Lignite coal at the mid elevation North Dakota site, with and without CO_2 capture. The different IGCC configurations considered in this study are displayed in Exhibit 1-1.

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. More detailed engineering for specific project applications must be considered with the appropriate technology vendors to determine the preferred designs, based on project details and current state of the art. This study's main use should be to identify important parameters that could be optimized for different project goals or specific operating conditions and to help quantify the tradeoffs of different power generation configurations.

Generating Unit Configurations

The gross and net output varies among the IGCC cases because of the GT size constraint. The advanced F-class turbine used to model these cases comes in a standard size of 232 MW when operated on syngas at ISO conditions. Each case uses two CTs for a combined potential gross output of 464 MW. Because these cases are operated at elevations greater than sea level, the output is reduced from the turbine's ISO condition potential. In the combined cycle, a HRSG extracts heat from the CT exhaust to power a steam turbine. However, the CO_2 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. Thus, the overall combined cycle gross output ranges from 621 to 753 MW, which results in a range of net output from 445 to 617 MW. The coal feed rate required to achieve the gross power output is also different between the cases, ranging from 240,912 to 369,244 kilogram per hour (kg/hr) (531,119 to 814,029 pounds per hour [lb/hr]). The large range of coal feed rates is due to the different gasifier performance, coal types, and the addition of CO_2 capture.

Exhibit 1-1 IGCC Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Coal Type	Coal Drying Process	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	ASU Integration	H_2S Separation/ Removal	Sulfur Removal/ Recovery	CO_2 Separation	CO_2 Capture
S1A	IGCC	1800/1050/1050	S	WTA	2 x Advanced F-class	Shell SCGP	95 mol% O_2	Yes	Sulfinol-M	Claus Plant		
S1B	IGCC	1800/1000/1000	S	WTA	2 x Advanced F-class	Shell SCGP	95 mol% O_2	No	Selexol	Claus Plant	Selexol 2nd stage	90%
L1A	IGCC	1800/1050/1050	L	WTA	2 x Advanced F-class	Shell SCGP	95 mol% O_2	Yes	Sulfinol-M	Claus Plant		
L1B	IGCC	1800/1000/1000	L	WTA	2 x Advanced F-class	Shell SCGP	95 mol% O_2	No	Selexol	Claus Plant	Selexol 2nd stage	90%
S2A	IGCC	1800/1050/1050	S	Flash Pulverizer	2 x Advanced F-class	TRIG™	95 mol% O_2	Yes	Sulfinol-M	Claus Plant		
S2B	IGCC	1800/1000/1000	S	Flash Pulverizer	2 x Advanced F-class	TRIG™	95 mol% O_2	No	Selexol	Claus Plant	Selexol 2nd stage	83%[1]
S3A	IGCC	1800/1050/1050	S	WTA	2 x Advanced F-class	Siemens SFG	95 mol% O_2	Yes	Sulfinol-M	Claus Plant		
S3B	IGCC	1800/1000/1000	S	WTA	2 x Advanced F-class	Siemens SFG	95 mol% O_2	No	Selexol	Claus Plant	Selexol 2nd stage	90%
L3A	IGCC	1800/1050/1050	L	WTA	2 x Advanced F-class	Siemens SFG	95 mol% O_2	Yes	Sulfinol-M	Claus Plant		
L3B	IGCC	1800/1000/1000	L	WTA	2 x Advanced F-class	Siemens SFG	95 mol% O_2	No	Selexol	Claus Plant	Selexol 2nd stage	90%
S4A	IGCC	1800/1050/1050	S	None	2 x Advanced F-class	CoP E-Gas™	95 mol% O_2	Yes	MDEA	Claus Plant		
S4B	IGCC	1800/1000/1000	S	None	2 x Advanced F-class	CoP E-Gas™	95 mol% O_2	No	Selexol	Claus Plant	Selexol 2nd stage	90%

[1] Limited due to syngas methane content

Report Structure

The balance of this report is organized as follows:

- Chapter 2 provides the basis for technical, environmental, and cost evaluations.
- Chapter 3 provides the results of the different IGCC configurations.
- Chapter 4 contains the reference list.

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2. GENERAL EVALUATION BASIS

For each of the plant configurations in this study, an Aspen 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 projects, and/or best engineering judgment. 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. Ultimately, a FY COE 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, environmental targets and cost assumptions used in the study.

2.1 SITE CHARACTERISTICS

The plants are located at two different generic plant sites. Plants using PRB coal are assumed to be located in Montana. Plants using lignite coal are assumed to be located at a minemouth site in North Dakota. The ambient conditions for the two sites are shown in Exhibit 2-1 and Exhibit 2-2.

Exhibit 2-1 Montana Site Ambient Conditions for PRB Coal Cases

Elevation, m (ft)	1,036 (3,400)
Barometric Pressure, MPa (psia)	0.09 (13.0)
Design Ambient Temperature, Dry Bulb, °C (°F)	5.6 (42)
Design Ambient Temperature, Wet Bulb, °C (°F)	2.8 (37)
Design Ambient Relative Humidity, %	62

Exhibit 2-2 North Dakota Site Ambient Conditions for Lignite Coal Cases

Elevation, m (ft)	579 (1,900)
Barometric Pressure, MPa (psia)	0.10 (13.8)
Design Ambient Temperature, Dry Bulb, °C (°F)	4.4 (40)
Design Ambient Temperature, Wet Bulb, °C (°F)	2.2 (36)
Design Ambient Relative Humidity, %	68

The site characteristics are assumed to be the same for both plant locations as shown in Exhibit 2-3.

Exhibit 2-3 Site Characteristics

Location	Greenfield
Topography	Level
Size, acres	300
Transportation	Rail
Ash/Slag Disposal	Off Site
Water	Municipal (50%) / Groundwater (50%)
Access	Landlocked, having access by rail 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 all 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 all cases it was assumed that the steam turbine is enclosed in a turbine building, but the gasifier is 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

There are two design coals: a subbituminous PRB coal from Montana and lignite coal from North Dakota. The coal properties are from National Energy Technology Laboratory's (NETL) Coal Quality Guidelines and are shown in Exhibit 2-4 and Exhibit 2-5 [1].

The Power Systems Financial Model (PSFM) was used to derive the first year capital charge factor for this study [2]. The PSFM requires that all cost inputs have a consistent cost year basis. Because the capital and operating cost estimates are in June 2007 dollars, the fuel costs must also be in June 2007 dollars.

The cost of coal used in this study is $0.84/GJ ($0.89/MMBtu) for PRB coal and $0.78/GJ ($0.83/MMBtu) for NDL coal (2007 cost of coal in June 2007 dollars). All coal costs are based on HHV. These costs were determined using the following information from the EIA 2008 AEO:

- The 2007 minemouth cost of PRB coal in 2006 dollars, $13.02/metric ton (tonne) ($11.81/ton), was obtained from Supplemental Table 112 of the EIA's 2008 AEO for western Montana medium-sulfur subbituminous coal. The 2007 minemouth cost of NDL coal in 2006 dollars, $11.67/tonne ($10.59/ton), was obtained from the same source.
- The 2007 cost of PRB coal was escalated to June 2007 dollars using the gross domestic product (GDP) chain-type price index from AEO 2008, resulting in a price of $13.42/tonne ($12.17/ton) [3]. Similarly, the 2007 cost of NDL coal in June 2007 dollars is $12.04/tonne ($10.92/ton) or $0.79/GJ ($0.83/MMBtu).
- Transportation costs for PRB coal were estimated to be 25 percent of the minemouth cost based on the average transportation rate for medium subbituminous coal from the western Montana region delivered to the mountain region [4]. The final delivered cost of PRB coal used in the calculations is $16.78/tonne ($15.22/ton) or $0.85/GJ ($0.89/MMBtu).
- Note: The PRB coal cost conversion of $15.22/ton to dollars per million Btu results in $0.8884/MMBtu, which was used in calculations, but only two decimal places are shown in the report. Similarly, the NDL fuel cost converts to $0.8251/MMBtu, which was used in calculations, but only two decimal places are shown.

Exhibit 2-4 Montana Rosebud PRB, Area D, Western Energy Co. Mine, Subbituminous Design Coal Analysis

Proximate Analysis	Dry Basis, %	As Received, %
Moisture	0.0	25.77
Ash	11.04	8.19
Volatile Matter	40.87	30.34
Fixed Carbon	48.09	35.70
Total	100.0	100.0
Ultimate Analysis	**Dry Basis, %**	**As Received, %**
Carbon	67.45	50.07
Hydrogen	4.56	3.38
Nitrogen	0.96	0.71
Sulfur	0.98	0.73
Chlorine	0.01	0.01
Ash	11.03	8.19
Moisture	0.00	25.77
Oxygen[1]	15.01	11.14
Total	100.0	100.0
Heating Value	**Dry Basis**	**As Received**
HHV, kJ/kg	26,787	19,920
HHV, Btu/lb	11,516	8,564
LHV, kJ/kg	25,810	19,195
LHV, Btu/lb	11,096	8,252
Hardgrove Grindability Index	57	
Ash Mineral Analysis		**%**
Silica	SiO_2	38.09
Aluminum Oxide	Al_2O_3	16.73
Iron Oxide	Fe_2O_3	6.46
Titanium Dioxide	TiO_2	0.72
Calcium Oxide	CaO	16.56
Magnesium Oxide	MgO	4.25
Sodium Oxide	Na_2O	0.54
Potassium Oxide	K_2O	0.38
Sulfur Trioxide	SO_3	15.08
Phosphorous Pentoxide	P_2O_5	0.35
Barium Oxide	Ba_2O	0.00
Strontium Oxide	SrO	0.00
Unknown	---	0.84
	Total	100.0
Trace Components		**ppmd**
Mercury[2]	Hg	0.081

[1] By difference

[2] Mercury value is the mean plus one standard deviation using EPA's ICR data

Exhibit 2-5 North Dakota Beulah-Zap Lignite, Freedom, ND Mine, Lignite Design Coal Analysis

Proximate Analysis	**Dry Basis, %**	**As Received, %**
Moisture	0.0	36.08
Ash	15.43	9.86
Volatile Matter	41.49	26.52
Fixed Carbon	43.09	27.54
Total	100.0	100.0
Ultimate Analysis	**Dry Basis, %**	**As Received, %**
Carbon	61.88	39.55
Hydrogen	4.29	2.74
Nitrogen	0.98	0.63
Sulfur	0.98	0.63
Chlorine	0.00	0.00
Ash	15.43	9.86
Moisture	0.00	36.08
Oxygen[1]	16.44	10.51
Total	100.0	100.0
Heating Value	**Dry Basis**	**As Received**
HHV, kJ/kg	24,254	15,391
HHV, Btu/lb	10,427	6,617
LHV, kJ/kg	23,335	14,804
LHV, Btu/lb	10,032	6,364
Hardgrove Grindability Index	Not applicable	
Ash Mineral Analysis		**%**
Silica	SiO_2	35.06
Aluminum Oxide	Al_2O_3	12.29
Iron Oxide	Fe_2O_3	5.12
Titanium Dioxide	TiO_2	0.58
Calcium Oxide	CaO	14.39
Magnesium Oxide	MgO	6.61
Sodium Oxide	Na_2O	5.18
Potassium Oxide	K_2O	0.64
Sulfur Trioxide	SO_3	16.27
Barium Oxide	Ba_2O	0.56
Strontium Oxide	SrO	0.27
Manganese Dioxide	MnO_2	0.02
Unknown	---	3.00
	Total	100.0
Trace Components		**ppmd**
Mercury[2]	Hg	0.116

[1] By Difference
[2] Mercury value is the mean plus one standard deviation using EPA's ICR data

2.3 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 June 2007 [5] and shown in Exhibit 2-6, which represents the minimum level of control that would be required for a new fossil energy plant.

The 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 CTs 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 pounds per megawatt hour (lb/MWh) are based on gross power output.

Exhibit 2-6 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

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 Western 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.

Mercury

The Clean Air Mercury Rule (CAMR), issued on March 15, 2005, established NSPS limits for mercury (Hg) emissions from new power plants. These rules were vacated by court action on February 8, 2008 and the final resolution of these rules is unknown at this time. Even though the rules are vacated, the CAMR emission limits are included for reference only. The NSPS limits for IGCC plants, based on gross output, are shown in Exhibit 2-7. The applicable limit in this study is 20×10^{-6} lb/MWh.

Exhibit 2-7 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 coal Hg concentration used for this study did not come from NETL's Coal Quality Guidelines, but rather was determined from the EPA's ICR database. The ICR database has 137 records of Montana Rosebud subbituminous coal with an average Hg concentration of 0.056 parts per million (ppm) (dry) and a standard deviation of 0.025 ppm. There are 266 records for NDL from the Beulah seam with an average Hg concentration of 0.081 ppm (dry) and a standard deviation of 0.035 ppm. The mercury values in Exhibit 2-4 and Exhibit 2-5 are the mean plus one standard deviation, or 0.081 ppm (dry) for PRB coal and 0.116 ppm (dry) for NDL [7]. It was further assumed that all of the coal Hg enters the gas phase and none leaves with the bottom ash or slag.

Design Targets

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 [8]. Design targets were established specifically for bituminous coal, but are applied to the subbituminous and lignite cases as well. Because of the lower coal sulfur content in the low rank coals, actual sulfur dioxide (SO_2) emissions are substantially lower than the environmental target. EPRI notes that these are design targets and are not to be used for permitting values.

Exhibit 2-8 IGCC Environmental Targets

Pollutant	Environmental Target	NSPS Limit	Control Technology
NOx	15 ppmv (dry) @ 15% O_2	1.0 lb/MWh	Low NOx burners and syngas nitrogen dilution
SO_2	0.0128 lb/MMBtu	1.4 lb/MWh	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 x 10^{-6} lb/MWh	Carbon bed

Based on published vendor literature, it was assumed that LNBs and nitrogen dilution can achieve 15 ppmv (dry) at 15 percent O_2, and that value was used for all IGCC cases [9,10].

To achieve an environmental target of 0.0128 lb/MMBtu of SO_2 requires approximately 12 ppmv sulfur in the sweet syngas. The acid gas removal (AGR) process required a sulfur capture efficiency of about 99.7 percent to reach the environmental target using PRB with a sulfur content of 0.73 percent. Vendor data on the AGR processes used in this study indicate that this level of sulfur removal is possible. When similar AGR technologies to the Volume 1 IGCC cases of this study are used, SO_2 emissions are substantially lower because of the lower coal sulfur content. In the CO_2 capture cases, the two-stage Selexol process results in a sulfur capture of greater than 99.7 percent, hence lower sulfur emissions in the CO_2 capture cases.

The ash portion of the coal is largely removed from the gasifier as slag for higher temperature slagging gasifiers. 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. The amount of entrained ash is dependent on the ash content in the coal and the specific gasifier technology. The environmental target of 0.0071 lb/MMBtu filterable particulates can be achieved with the combination of particulate control devices employed by each gasifier technology so that 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 GE Energy (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 pounds per square inch gage [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 [11]. 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.

Carbon Dioxide

CO_2 is not currently regulated nationally. 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. CO_2 emissions are reported on both a pound (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 maximum removal is limited by the amount of carbon that is fully oxidized to CO_2, either through the gasification or WGS reaction. Lower temperature gasifiers tend to produce more methane, which, unless reformed into CO_2, cannot be removed effectively and lowers the maximum removal. The H_2O:CO molar ratio is adjusted as necessary (with a minimum of 0.25 outlet steam:dry gas ratio) to achieve 90 percent overall CO_2 removal, when possible.

2.4 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, CF and availability are equal. Input from EPRI and their work on the CoalFleet for Tomorrow Initiative were used to set the IGCC case CF.

There are five operating IGCC plants worldwide that use a solid feedstock and are primarily power producers (Polk, Wabash, Buggenum, Puertollano, and Nakoso). Higman et al. examined the reliability of these IGCC power generation units and concluded that typical annual on-stream times are around 80 percent [12]. The CF 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 Higman et al. and others [13], a CF of 80 percent was chosen for IGCC with no spare gasifier required.

The addition of carbon capture and storage (CCS) to each technology was assumed not to impact the CF. This assumption was made to enable a comparison based on the impact of capital and variable operating costs only. Any reduction in assumed CF would further increase the COE for the CO_2 capture cases.

2.5 RAW WATER WITHDRAWAL AND CONSUMPTION

A water balance was performed for each case on the major water consumers in the process. The total water demand for each major subsystem was determined and internal recycle water available from various sources like boiler feedwater (BFW) blowdown and condensate from syngas was applied to offset the water demand. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is the water removed from the ground or diverted from a surface-water source for use in the plant. Raw water consumption is also accounted for as the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source it was withdrawn from.

Raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from groundwater. Raw water withdrawal 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, BFW makeup, slurry preparation makeup, ash handling makeup, syngas humidification, and quench system makeup. The difference between withdrawal and process water returned to the source is consumption. Consumption represents the net impact of the process on the water source.

BFW blowdown and a portion of the sour water stripper blowdown were assumed to be treated and recycled to the cooling tower. The cooling tower blowdown and the balance of the sour water system (SWS) blowdown streams were assumed to be treated and 90 percent returned to the water source with the balance sent to the ash ponds for evaporation.

The largest consumer of raw water in all cases is cooling tower makeup. Since plants located in the Western United States (U.S.) need to consider limited water supplies, a parallel wet/dry steam condenser was chosen for all plant configurations similar to the system recently installed at the Comanche 3 plant. In a parallel cooling system half of the turbine exhaust steam is condensed in an air-cooled condenser and half in a water-cooled condenser. The cooling water is provided by 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 3°C (37°F) at the Montana site and 2°C (36°F) at the NDL site (Exhibit 2-1 and Exhibit 2-2) was used to achieve a cooling water temperature of 9°C (48°F) and 8°C (47°F), respectively at the two sites using an approach of 6°C (11°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following [14]:

- Evaporative losses = 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses = 0.001 percent of the circulating water flow rate
- Blowdown losses = Evaporative Losses / (Cycles of Concentration - 1)
  Where cycles of concentration are a measure of water quality, and a mid-range value of 4 was chosen for this study.

Typical design conditions for air-cooled condensers include an initial temperature difference (ITD) of 40-55°F [15]. The ITD is the temperature difference between saturated steam at the steam turbine generator (STG) exhaust and the inlet dry bulb cooling air temperature. The ITDs at the two locations in this study are 48 and 50°F. The fan power requirement is estimated at 3.5 times the power required for a wet cooling tower with equivalent heat duty [16].

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, the amount of raw water withdrawal by difference, the amount of process water returned to the source and the raw water consumption, again by difference.

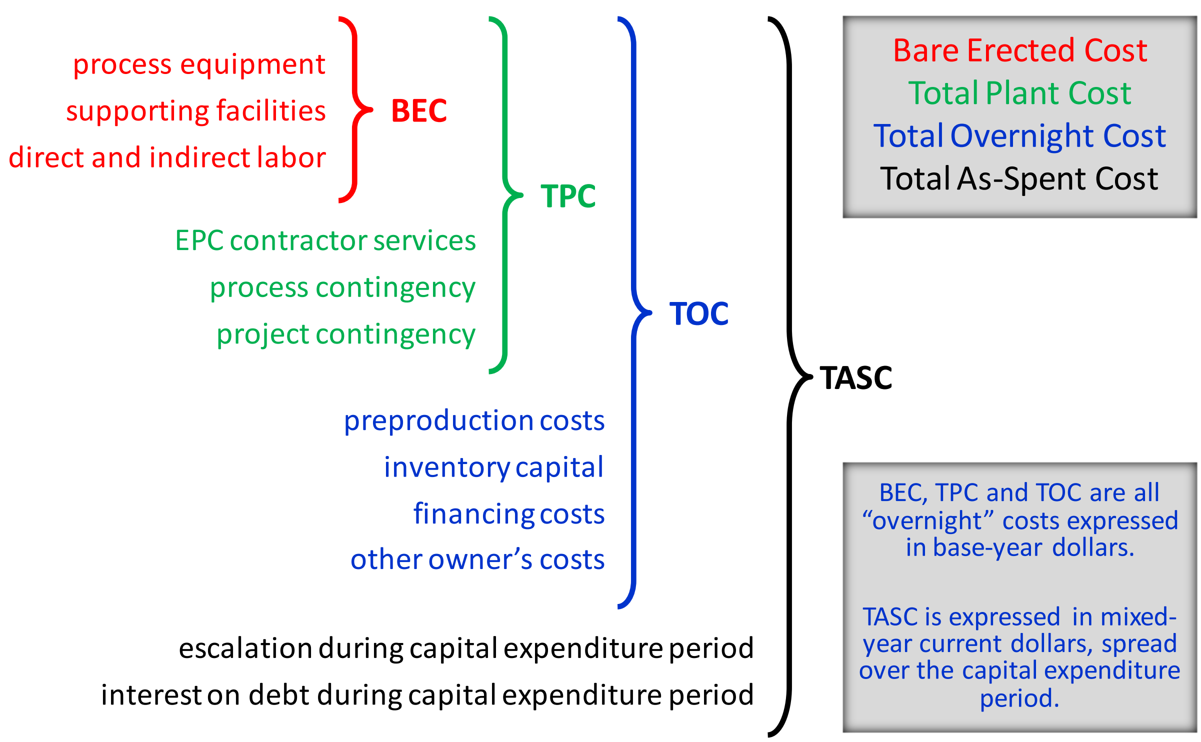
2.6 COST ESTIMATING METHODOLOGY

The estimating methodology for capital costs, operations and maintenance costs, and CO_2 TS&M costs are described below. The finance structure, basis for the discounted cash flow analysis, and first-year COE cost calculations are also described.

2.6.1 Capital Costs

As illustrated in Exhibit 2-9, this study reports capital cost at four levels: Bare Erected Cost (BEC), Total Plant Cost (TPC), Total Overnight Cost (TOC) and Total As-spent Capital (TASC). BEC, TPC and TOC are "overnight" costs and are expressed in "base-year" dollars. The base year is the first year of capital expenditure, which for this study is assumed to be 2007. TASC is expressed in mixed-year, current-year dollars over the entire capital expenditure period, which is assumed to last five years for coal plants (2007 to 2012).

Exhibit 2-9 Capital Cost Levels and their Elements



The BEC comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, road), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies is not included in BEC. BEC is an overnight cost expressed in base-year (2007) dollars.

The TPC comprises the BEC plus the cost of services provided by the engineering, procurement and construction (EPC) contractor and project and process contingencies. EPC services include:

detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs. TPC is an overnight cost expressed in base-year (2007) dollars.

The TOC comprises the TPC plus owner's costs. TOC is an "overnight" cost, expressed in base-year (2007) dollars and as such does not include escalation during construction or interest during construction.

The TASC is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction. Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period.

Cost Estimate Basis and Classification

The TPC and Operation and Maintenance (O&M) costs for each of the cases in the study were estimated by WorleyParsons using an in-house database and conceptual estimating models. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design projects.

Recommended Practice 18R-97 of the Association for the Advancement of Cost Engineering International (AACE) describes a Cost Estimate Classification System as applied in Engineering, Procurement and Construction for the process industries [17].

Most techno-economic studies completed by NETL feature cost estimates intended for the purpose of a "Feasibility Study" (AACE Class 4). Exhibit 2-10 describes the characteristics of an AACE Class 4 Cost Estimate. Cost estimates in this study have an expected accuracy range of -15%/+30%.

Exhibit 2-10 Features of an AACE Class 4 Cost Estimate

Project Definition	Typical Engineering Completed	Expected Accuracy
1 to 15%	plant capacity, block schematics, indicated layout, process flow diagrams for main process systems, and preliminary engineered process and utility equipment lists	-15% to -30% on the low side, and +20% to +50% on the high side

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 non-capture IGCC cases are 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 than PC or NGCC plants, and the costs listed reflect the "next commercial offering" level of cost rather than mature n^{th}-of-a-kind (NOAK) 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 pre-combustion CO_2 removal technology for the IGCC capture cases has a stronger commercial experience base than for PC or NGCC plants. 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 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. As a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. 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 and absorbs higher project management costs, 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. The plant 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. TS&M cost is not included in the reported capital cost or O&M costs, but is treated separately and added to the COE.

Capital Cost Assumptions

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.

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop using factors from PAS, Inc [18]. PAS presents information for eight separate regions. Volume 1 of this study used a generic Midwestern site, typical of Region 5 (IL, IN, MI, MN, OH, and WI). The weighted average rate for Region 8 (CO, MT, ND, SD, UT, and WY) is within less than one-half of one percent of that for Region 5. The difference is inconsequential so the same rates used in Volume 1 were maintained in this study. Costs would need to be re-evaluated 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.
- 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, which are treated as an addition to COE.
- Engineering and Construction Management are estimated as a percentage of BEC. 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.

Price Fluctuations

During the course of this study, the prices of equipment and bulk materials fluctuated quite substantially. Some reference quotes pre-dated the 2007 year cost basis while others were received post-2007. All vendor quotes used to develop these estimates were adjusted to June 2007 dollars accounting for the price fluctuations. Adjustments of costs pre-dating 2007 benefitted from a vendor survey of actual and projected pricing increases from 2004 through mid-2007 that WorleyParsons conducted for another project. The results of that survey were used to validate/recalibrate the corresponding escalation factors used in the conceptual estimating models. The more recent economic down turn has resulted in a reduction of commodity prices such that many price indices have similar values in January 2010 compared to June 2007. For example, the Chemical Engineering Plant Cost Index was 532.7 in June 2007 and 532.9 in January 2010, and the Gross Domestic Product Chain-type Price Index was 106.7 on July 1, 2007 and 110.0 on January 1, 2010. While these overall indices are nearly constant, it should be noted that the cost of individual equipment types may still deviate from the June 2007 reference point.

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.

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 CTs for the IGCC capture cases include an additional cost for firing a high hydrogen content fuel.
- Lower overall carbon removal for TRIG™ CO_2 capture case due to high methane content.

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 excluded from the capital costs:

- All taxes, with the exception of payroll and property taxes (property taxes are included with the fixed O&M costs)
- 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 5-10s
- Additional premiums associated with an EPC contracting approach

Contingency

Process and project contingencies are included in estimates to account for unknown costs that are omitted or unforeseen due to a lack of complete project definition and engineering. Contingencies are added because experience has shown that such costs are likely, and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared.

Capital cost contingencies do not cover uncertainties or risks associated with

- scope changes
- changes in labor availability or productivity
- delays in equipment deliveries
- changes in regulatory requirements

- unexpected cost escalation
- performance of the plant after startup (e.g., availability, efficiency)

Project Contingency

AACE 16R-90 states that project contingency for a "budget-type" estimate (AACE Class 4 or 5) should be 15 to 30 percent of the sum of BEC, EPC fees and process contingency. This was used as a general guideline, but some project contingency values outside of this range occur based on WorleyParsons' in-house experience.

Process Contingency

Process contingency is intended to compensate for uncertainty in cost estimates caused by performance uncertainties associated with the development status of a technology. Process contingencies are applied to each plant section based on its current technology status.

As shown in Exhibit 2-11, AACE International Recommended Practice 16R-90 provides guidelines for estimating process contingency based on EPRI philosophy [19].

Process contingencies have been applied to the estimates in this study as follows:

- 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
- CTG – 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 – integration issues

Exhibit 2-11 AACE Guidelines for Process Contingency

Technology Status	Process Contingency (% of Associated Process Capital)
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

Process contingency is typically not applied to costs that are set equal to a research goal or programmatic target since these values presume to reflect the total cost.

Owner's Costs

Exhibit 2-13 explains the estimation method for owner's costs. With some exceptions, the estimation method follows guidelines in Sections 12.4.7 to 12.4.12 of AACE International Recommended Practice No. 16R-90 [19]. The Electric Power Research Institute's "Technical Assessment Guide (TAG®) – Power Generation and Storage Technology Options" also has guidelines for estimating owner's costs. The EPRI and AACE guidelines are very similar. In instances where they differ, this study has sometimes adopted the EPRI approach.

Interest during construction and escalation during construction are not included as owner's costs but are factored into the COE and are included in TASC. These costs vary based on the capital expenditure period and the financing scenario. Ratios of TASC/TOC determined from the PSFM are used to account for escalation and interest during construction. Given TOC, TASC can be determined from the ratios given in Exhibit 2-12.

Exhibit 2-12 TASC/TOC Factors

Finance Structure	IOU High Risk	IOU Low Risk
TASC/TOC	1.140	1.134

Exhibit 2-13 Owner's Costs Included in TOC

Owner's Cost	Estimate Basis
Prepaid Royalties	Any technology royalties are assumed to be included in the associated equipment cost, and thus are not included as an owner's cost.
Preproduction (Start-Up) Costs	• 6 months operating labor • 1 month maintenance materials at full capacity • 1 month non-fuel consumables at full capacity • 1 month waste disposal • 25% of one month's fuel cost at full capacity • 2% of TPC Compared to AACE 16R-90, this includes additional costs for operating labor (6 months versus 1 month) to cover the cost of training the plant operators, including their participation in startup, and involving them occasionally during the design and construction. AACE 16R-90 and EPRI TAG® differ on the amount of fuel cost to include; this estimate follows EPRI.
Working Capital	Although inventory capital (see below) is accounted for, no additional costs are included for working capital.
Inventory Capital	• 0.5% of TPC for spare parts • 60 day supply (at full capacity) of fuel. Not applicable for natural gas. • 60 day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site. Does not include catalysts and adsorbents that are batch replacements such as WGS, COS, and SCR catalysts and activated carbon. AACE 16R-90 does not include an inventory cost for fuel, but EPRI TAG® does.
Land	• \$3,000/acre (300 acres for IGCC)
Financing Cost	• 2.7% of TPC This financing cost (not included by AACE 16R-90) covers the cost of securing financing, including fees and closing costs but not including interest during construction (or AFUDC). The "rule of thumb" estimate (2.7% of TPC) is based on a 2008 private communication with a capital services firm.

<table>
<tr><th>Owner’s Cost</th><th>Estimate Basis</th></tr>
<tr><td>Other Owner’s Costs</td><td>
15% of TPC
This additional lumped cost is not included by AACE 16R-90 or EPRI TAG®. The “rule of thumb” estimate (15% of TPC) is based on a 2009 private communication with WorleyParsons. Significant deviation from this value is possible as it is very site and owner specific. The lumped cost includes:
− Preliminary feasibility studies, including a Front-End Engineering Design (FEED) study
− Economic development (costs for incentivizing local collaboration and support)
− Construction and/or improvement of roads and/or railroad spurs outside of site boundary
− Legal fees
− Permitting costs
− Owner’s engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors)
− Owner’s contingency (Sometimes called “management reserve”, these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of a five-day/ten-hour-per-day work week. Owner’s contingency is NOT a part of project contingency.)
This lumped cost does NOT include:
− EPC Risk Premiums (Costs estimates are based on an Engineering Procurement Construction Management approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule and cost)
− Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar.
− Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes.
− Unusual site improvements: normal costs associated with improvements to the plant site are included in the bare erected cost, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: 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.
</td></tr>
<tr><td>Initial Cost for Catalysts and Chemicals</td><td>All initial fills not included in BEC</td></tr>
<tr><td>Taxes & Insurance</td><td>2% of TPC (Fixed O&M Cost)</td></tr>
</table>

2.6.2 Operations and Maintenance Costs

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 $34.65/hour. The associated labor burden is estimated at 30 percent of the base labor rate. Taxes and insurance are included as fixed O&M costs totaling 2 percent of the TPC.

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.

Administrative and Support Labor

Labor administration and overhead charges are assessed at rate of 25 percent of the burdened O&M 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 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 CF.

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

Waste Disposal

Waste quantities and disposal costs were determined similarly to the consumables. In this study slag from the IGCC cases is considered a non-hazardous waste with a disposal cost of \$17.89/tonne (\$16.23/ton). The carbon used for mercury control is considered a hazardous waste with disposal cost of \$926/tonne (\$840/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 sulfur, no credit was taken for potential salable value.

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. Slag is a potential by-product in certain markets. However, as stated above, the slag is considered a non-hazardous waste in this study with a concomitant disposal cost.

2.6.3 CO_2 Transport, Storage and Monitoring

For those cases that feature carbon sequestration, the capital and operating costs for CO_2 TS&M were independently estimated by NETL. Those costs were converted to a TS&M COE increment that was added to the plant COE.

CO_2 TS&M was modeled 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 2-14 [20]. A glycol dryer located near the mid-point of the compression train is used to meet the moisture specification.
- The CO_2 is transported 80 km (50 miles) via pipeline to a geologic sequestration field for injection into a saline formation.
- The CO_2 is transported and injected as a SC fluid in order to avoid two-phase flow and achieve maximum efficiency [21]. The pipeline is assumed to have an outlet pressure (above the SC pressure) of 8.3 MPa (1,200 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 6.9 MPa (1,000 psi) over an 80 km (50 mile) pipeline length [22]. (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, with hydrostatic head making up the difference between the injection and reservoir pressure.

Exhibit 2-14 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)	35 (95)
N_2 Concentration	ppmv	< 300
O_2 Concentration	ppmv	< 40
Ar Concentration	ppmv	< 10
H_2O Concentration	ppmv	< 150

- The saline formation is at a depth of 1,236 m (4,055 ft) and has a permeability of 22 millidarcy (md) (22 μm^2) 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 2-15.

Exhibit 2-15 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 (μm^2)	22 (22)
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (ton) CO_2/day	9,360 (10,320)

The cost metrics utilized in this study provide a best estimate of TS&M costs for a “favorable” sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by industrial sources where possible. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following sections describe the sources and methodology used for each metric.

TS&M Capital Costs

TS&M capital costs include both a 20 percent process contingency and 30 percent project contingency.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized similar to the other costs.

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [21, 23, 24]. The University of California performed a regression analysis to generate cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs, and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [24]. These cost curves were escalated to the June 2007 year dollars used in this study.

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment [23]. This study utilized a similar basis for pipeline costs (O&GJ Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled Economic Evaluation of CO_2 Storage and Sink Enhancement Options [21]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a) do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were divided into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from Economic Evaluation of CO_2 Storage and Sink Enhancement Options [21]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface volume where the CO_2 will be stored, i.e., the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University, which examined existing sub-surface rights acquisition as it pertains to natural gas storage [25]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners, require a number of "best engineering judgment" decisions to be made. In this study it was assumed that long-term lease rights were acquired from the property owners in the projected CO_2 plume growth region for a nominal fee, and that an annual "rent" was paid when the plume reached each individual acre of their property for a period of up to 100 years from the injection start date. The present value of the life cycle pore volume costs are assessed at a 10 percent discount rate and a capital fund is set up to pay for these costs over the 100 year rent scenario.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemes have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [26]. However, at present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation, which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [27,28,29]. In the case of Louisiana, a trust fund totaling five million dollars is established over the first ten years (120 months) of injection operations for each injector. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

Liability costs assume that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This bond level may be conservatively high, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. The bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the International Energy Agency (IEA) Greenhouse Gas (GHG) R&D Programme's Overview of Monitoring Projects for Geologic Storage Projects report [30]. In this scenario, operational monitoring of the CO_2 plume occurs over 30 years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey; EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

2.6.4 Finance Structure, Discounted Cash Flow Analysis, and COE

The global economic assumptions are listed in Exhibit 2-16.

Finance structures were chosen based on the assumed type of developer/owner (investor-owned utility (IOU) or independent power producer) and the assumed risk profile of the plant being assessed (low-risk or high-risk). For this study the owner/developer was assumed to be an IOU. All IGCC cases were considered high risk.

Exhibit 2-17 describes the low-risk IOU (for reference) and high-risk IOU finance structures that were assumed for this study. These finance structures were recommended in a 2008 NETL report based on interviews with project developers/owners, financial organizations and law firms [31].

Exhibit 2-16 Global Economic Assumptions

Parameter	Value
TAXES	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
CONTRACTING AND FINANCING TERMS	
Contracting Strategy	Engineering Procurement Construction Management (owner assumes project risks for performance, schedule and cost)
Type of Debt Financing	Non-Recourse (collateral that secures debt is limited to the real assets of the project)
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
ANALYSIS TIME PERIODS	
Capital Expenditure Period	Coal Plants: 5 Years
Operational Period	30 years
Economic Analysis Period (used for IRROE)	35 Years (capital expenditure period plus operational period)
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Capital Expenditure Period (nominal annual rate)	3.6%[2]
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	5-Year Period: 10%, 30%, 25%, 20%, 15%
Working Capital	zero for all parameters

[2] A nominal average annual rate of 3.6 percent is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the *Chemical Engineering* Plant Cost Index.

Parameter	Value
% of Total Overnight Capital that is Depreciated	100% *(this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)*
ESCALATION OF OPERATING REVENUES AND COSTS	
Escalation of COE (revenue), O&M Costs, and Fuel Costs (nominal annual rate)	3.0%[3]

Exhibit 2-17 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	4.5%	2.25%	
Equity	50	12%	6%	
Total			8.25%	7.39%
High Risk				
Debt	45	5.5%	2.475%	
Equity	55	12%	6.6%	
Total			9.075%	8.13%

DCF Analysis and Cost of Electricity

The NETL Power Systems Financial Model (PSFM) is a nominal-dollar[4] (current dollar) discounted cash flow (DCF) analysis tool. As explained below, the PSFM was used to calculate COE[5] in two ways: a COE and a levelized COE (LCOE). To illustrate how the two are related, COE solutions are shown in Exhibit 2-18 for a generic pulverized coal (PC) power plant and a generic natural gas combined cycle (NGCC) power plant, each with carbon capture and sequestration installed.

[3] An average annual inflation rate of 3.0 percent is assumed. This rate is equivalent to the average annual escalation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods, the so-called "headline" index of the various Producer Price Indices. (The Producer Price Index for the Electric Power Generation Industry may be more applicable, but that data does not provide a long-term historical perspective since it only dates back to December 2003.)

[4] Since the analysis takes into account taxes and depreciation, a nominal dollar basis is preferred to properly reflect the interplay between depreciation and inflation.

[5] For this calculation, "cost of electricity" is somewhat of a misnomer because from the power plant's perspective it is actually the "price" received for the electricity generated to achieve the stated IRROE. However, since the price paid for generation is ultimately charged to the end user, from the customer's perspective it is part of the cost of electricity.

- The **COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant*. To calculate the COE, the PSFM was used to determine a "base-year" (2007) COE that, when escalated at an assumed nominal annual general inflation rate of 3 percent[6], provided the stipulated internal rate of return on equity over the entire economic analysis period (capital expenditure period plus thirty years of operation). The COE solutions are shown as curved lines in the upper portion of Exhibit 2-18 for a PC power plant and a NGCC power plant. Since this analysis assumes that COE increases over the economic analysis period at the nominal annual general inflation rate, it remains constant in real terms and the first-year COE is equivalent to the base-year COE when expressed in base-year (2007) dollars.

- The **LEVELIZED COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate of 0 percent, i.e., that it remains constant in nominal terms over the operational period of the power plant.* This study reports LCOE on a current-dollar basis over thirty years. "Current dollar" refers to the fact that levelization is done on a nominal, rather than a real, basis[7]. "Thirty-years" refers to the length of the operational period assumed for the economic analysis. To calculate the LCOE, the PSFM was used to calculate a base-year COE that, when escalated at a nominal annual rate of 0 percent, provided the stipulated return on equity over the entire economic analysis period. For the example PC and NGCC power plant cases, the LCOE solutions are shown as horizontal lines in the upper portion of Exhibit 2-18.

Exhibit 2-18 also illustrates the relationship between COE and the assumed developmental and operational timelines for the power plants. As shown in the lower portion of Exhibit 2-18, the capital expenditure period is assumed to start in 2007 for all cases in this report. All capital costs included in this analysis, including project development and construction costs, are assumed to be incurred during the capital expenditure period. Coal-fueled plants are assumed to have a capital expenditure period of five years and natural gas-fueled plants are assumed to have a capital expenditure period of three years. Since both types of plants begin expending capital in the base year (2007), this means that the analysis assumes that they begin operating in different years: 2012 for coal plants (see Volume 3b for cost and performance of combustion based plants) and 2010 for natural gas plants in this study (see Volume 3c for cost and performance of NGCC plants). Note that, according to the *Chemical Engineering* Plant Cost Index, June-2007 dollars are nearly equivalent to January-2010 dollars.

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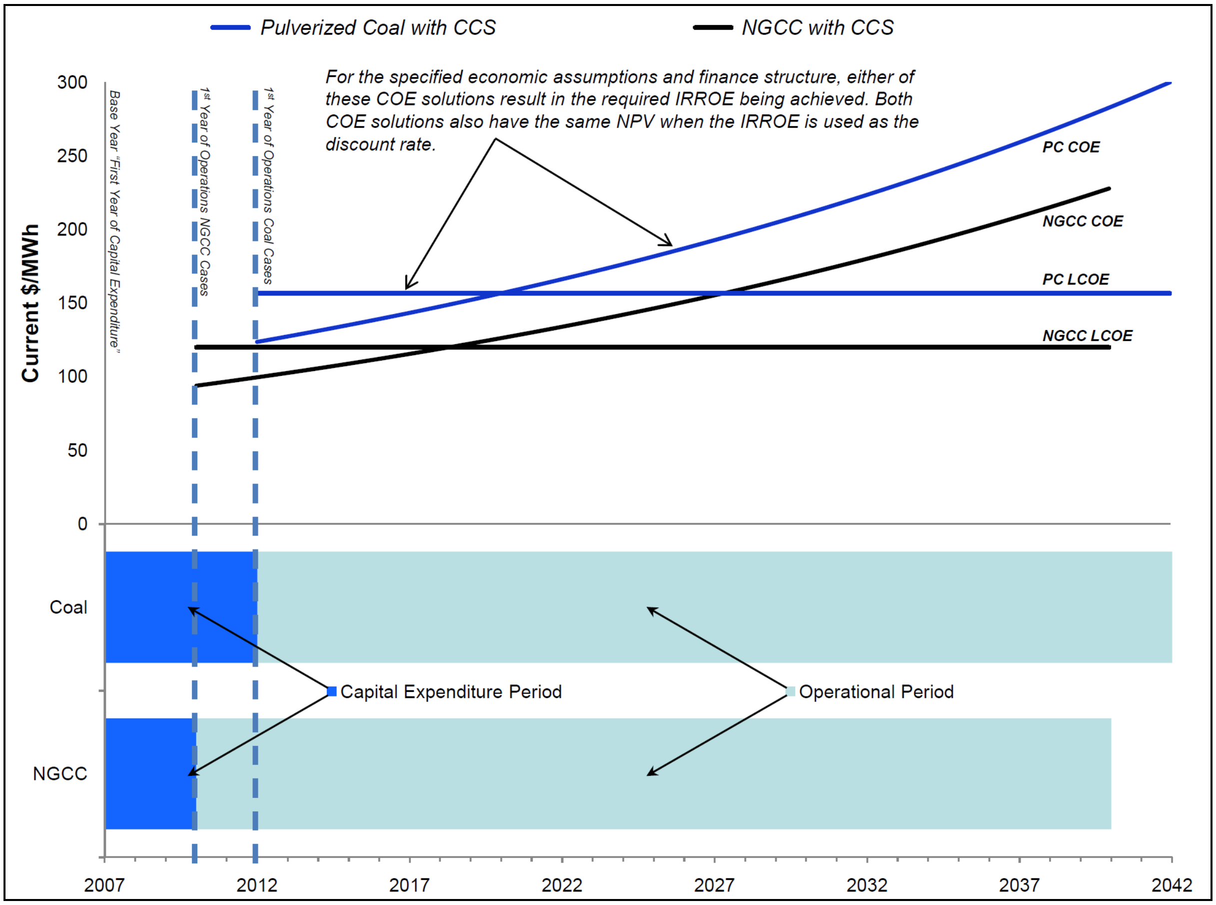
[6] This nominal escalation rate is equal to the average annual inflation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods. This index was used instead of the Producer Price Index for the Electric Power Generation Industry because the Electric Power Index only dates back to December 2003 and the Producer Price Index is considered the "headline" index for all of the various Producer Price Indices.

[7] For this current-dollar analysis, the LCOE is uniform in current dollars over the analysis period. In contrast, a constant-dollar analysis would yield an LCOE that is uniform in constant dollars over the analysis period.

Exhibit 2-18 Illustration of COE Solutions using DCF Analysis



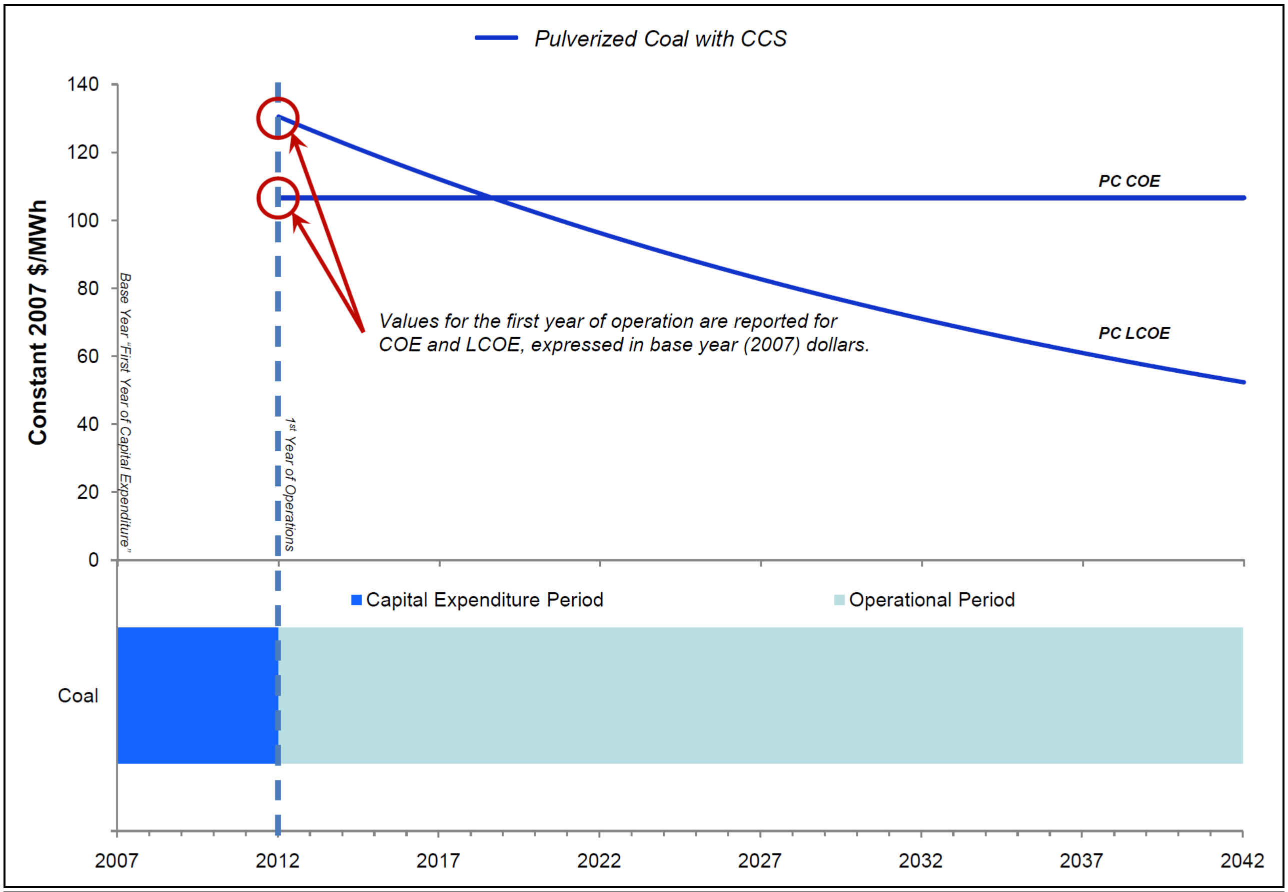
In addition to the capital expenditure period, the economic analysis considers thirty years of operation.

Since 2007 is the first year of the capital expenditure period, it is also the base year for the economic analysis. Accordingly, it is convenient to report the results of the economic analysis in base-year (June 2007) dollars, except for TASC, which is expressed in mixed-year, current dollars over the capital expenditure period.

Consistent with our nominal-dollar discounted cash flow methodology, the COEs shown on Exhibit 2-18 are expressed in current dollars. However, they can also be expressed in constant, base year dollars (June 2007) as shown in Exhibit 2-19 by adjusting them with the assumed nominal annual general inflation rate (3 percent).

Exhibit 2-19 illustrates the same information as in Exhibit 2-18 for a PC plant with CCS only on a constant 2007 dollar basis. With an assumed nominal COE escalation rate equal to the rate of inflation, the COE line now becomes horizontal and the LCOE decreases at a rate of 3 percent per year.

Exhibit 2-19 PC with CCS in Current 2007 Dollars



Estimating COE with Capital Charge Factors

For scenarios that adhere to the global economic assumptions listed in Exhibit 2-16 and utilize one of the finance structures listed in Exhibit 2-17, the following simplified equation can be used to estimate COE as a function of TOC[8], fixed O&M, variable O&M (including fuel), capacity factor and net output. The equation requires the application of one of the capital charge factors (CCF) listed in Exhibit 2-20. These CCFs are valid only for the global economic assumptions listed in Exhibit 2-16, the stated finance structure, and the stated capital expenditure period.

Exhibit 2-20 Capital Charge Factors for COE Equation

Finance Structure	High Risk IOU	Low Risk IOU
Capital Charge Factor (CCF)	0.1243	0.1165

[8] Although TOC is used in the simplified COE equation, the CCF that multiplies it accounts for escalation during construction and interest during construction (along with other factors related to the recovery of capital costs).

All factors in the COE equation are expressed in base-year dollars. The base year is the first year of capital expenditure, which for this study is assumed to be 2007. As shown in Exhibit 2-16, all factors (COE, O&M and fuel) are assumed to escalate at a nominal annual general inflation rate of 3.0 percent. Accordingly, all first-year costs (COE and O&M) are equivalent to base-year costs when expressed in base-year (2007) dollars.

$$COE = \frac{\begin{matrix} first\ year \\ capital\ charge \end{matrix} + \begin{matrix} first\ year \\ fixed\ operating \\ costs \end{matrix} + \begin{matrix} first\ year \\ variable\ operating \\ costs \end{matrix}}{\begin{matrix} annual\ net\ megawatt\ hours \\ of\ power\ generated \end{matrix}}$$

$$COE = \frac{(CCF)(TOC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

where:

COE =	revenue received by the generator (\$/MWh, equivalent to mills/kWh) during the power plant's first year of operation (*but expressed in base-year dollars*), assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant.
CCF =	capital charge factor taken from Exhibit 2-20 that matches the applicable finance structure and capital expenditure period
TOC =	total overnight capital, expressed in *base-year dollars*
OC_{FIX} =	the sum of all fixed annual operating costs, *expressed in base-year dollars*
OC_{VAR} =	the sum of all variable annual operating costs, including fuel at 100 percent capacity factor, *expressed in base-year dollars*
CF =	plant capacity factor, assumed to be constant over the operational period
MWH =	annual net megawatt-hours of power generated at 100 percent capacity factor

The primary cost metric in this study is the COE, which is the base-year cost presented in base-year dollars. Ex X presents this cost metric along with the COE escalated to the first year of operation (2012 for coal cases) using the average annual inflation rate of 3 percent. Similarly, the LCOE is presented in both base-year dollars and first year of operation dollars. Using a similar methodology, the reader may generate either metric in the desired cost year basis.

The cost of avoiding CO_2 was calculated in two ways: the cost of CO_2 avoided compared to the analogous non-capture design and the cost of CO_2 avoided compared to a baseline SC PC boiler plant firing the same coal at the same design conditions, using the equation below:

$$Avoided\ Cost = \frac{\{COE_{with\ removal} - COE_{reference}\}\ \$/MWh}{\{CO_2\ Emissions_{reference} - CO_2\ Emissions_{with\ removal}\}\ tons/MWh}$$

Exhibit 2-21 COE and LCOE Summary

Case	COE		LCOE	
	Base-Year	First Operational Year	Base-Year	First Operational Year
	2007$	2012$	2007$	2012$
S1A	83.2	96.4	105.4	122.2
S1B	119.7	138.8	151.8	175.9
L1A	83.5	96.8	105.8	122.7
L1B	121.9	141.3	154.5	179.1
S2A	74.5	86.4	94.5	109.5
S2B	105.2	122.0	133.4	154.6
S3A	86.8	100.6	110.0	127.5
S3B	121.7	141.1	154.3	178.9
L3A	87.3	101.2	110.7	128.3
L3B	123.7	143.5	156.9	181.9
S4A	78.7	91.3	99.8	115.7
S4B	112.3	130.2	142.4	165.1

The baseline SC PC boiler plant is a 550MW plant with the results presented in Exhibit 2-22, below, and in the combustion portion of this report volume. The COE in the CO_2 capture cases includes TS&M, as well as capture and compression.

Exhibit 2-22 Baseline SC PC Results for CO_2 Cost Calculation

	PRB (S12A)	Lignite (L12A)
Net Output (MW)	550	550
COE (mills/kWh)	57.80	62.19
Emissions (lb/net-MWh)	1,892	1,996

2.7 IGCC STUDY COST ESTIMATES COMPARED TO INDUSTRY ESTIMATES

The estimated TOC for IGCC cases in this study ranges from \$2,728 to \$3,239/kW for non- CO_2 capture cases and \$3,691/kW to \$4,430/kW for capture cases. Plant size ranges from 504 - 617 MW (net) for non-capture cases and 445 - 515 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. In November 2007, the Indiana Utility Regulatory Commission approved Duke Energy's proposal to build an IGCC plant in Edwardsport, Indiana. The estimated cost to build the 630 MW plant is \$4,472/kW in June 2007 dollars. Duke expects the plant to begin operation in 2012. Other published estimates for similar proposed non-CO_2 capture gasification plants range from \$2,483/kW to \$3,122/kW in June 2007 dollars. Corresponding plant sizes range form 770 - 600 MW, respectively. Published estimates from similar CO_2 capture facilities range from \$4,581/kW to \$5,408/kW, in June 2007 dollars, with sizes ranging from 400 to 580 MW [32,33,34,35].[9]

<u>Differences in Cost Estimates</u>

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 (GSUs).

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 greenfield site having "normal" characteristics. Accordingly, the estimates do not address items such as:

- Piles or caissons
- Rock removal
- Excessive dewatering

[9] Costs were adjusted to June 2007 using the Chemical Engineering Plant Cost Index

- 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
- SCR 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.

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.

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3. IGCC POWER PLANTS

Twelve 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 the near term.

The six cases are based on the Shell Coal Gasification Process, TRIG™ gasifier, Siemens Fuel Gasifier and CoP E-Gas™ gasifier, each with and without CO_2 capture. As discussed in Section 1, the net output for the twelve cases varies because of the constraint imposed by the fixed GT output and the high auxiliary loads imparted by the CO_2 capture process. The TRIG™ gasifier development has focused more on air-blown gasification for power generation, for characterizing the gasifier performance on a range of coals, so only PRB coal was considered as a starting point for comparison to other potential configurations. The CoP E-Gas™ gasifier feed has an upper limit for coal slurry concentration, which becomes a concern for lower rank coals, so to err on the side of more proven feedstocks, only PRB coal was considered for CoP cases.

The CT is based on an advanced F-class design. The HRSG/steam turbine cycle is nominally 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) for all of the non-CO_2 capture cases and nominally 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 the gasifier background sections.

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, coal drying, 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.

Operation Description – The coal is delivered to the site by 100-car unit trains comprised of 91 tonne (100 ton) rail cars for PRB cases. The lignite cases are located at a minemouth location. 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 centimeters (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 Coal Drying

Reduction in coal moisture content can improve the efficiency of dry-feed gasifiers, with a corresponding increase in auxiliaries and drying equipment costs. Coal moisture consists of two components, surface moisture and inherent moisture. Low rank coals have higher inherent moisture content and total moisture content than bituminous and other high rank coals. Depending on the size of the coal fed to the gasifier, it may be necessary to reduce most, if not all, of the surface moisture for coal transport properties to be acceptable. It should be noted that fluidization tests would need to be performed for the specific coals, in conjunction with the gasifier vendors, to ensure that the coal drying scheme results in the required coal transportation properties.

Dry feed gasifiers utilize coal drying schemes as described below. This reduces the amount of diluent fed to the gasifier, balanced out by the auxiliaries required to vaporize the coal moisture, generally providing a net increase to efficiency while introducing additional cost and complexity to the feed system. The slurry feed system is described in the individual technology section for the CoP E-Gas™ IGCC cases.

In a Gasification Technology Conference (GTC) paper [36], Shell indicated for its entrained flow gasifier feeding coal in the size range of 50 – 100 microns that it would dry lignite coal from 53 to 12 percent and subbituminous coal from 30 to 6 percent. The presentation indicated the coal would be dried using the fine grain WTA (fluidized bed drying technology with built-in waste heat recovery) process, which dries coal at a particle size of about 1 millimeter (mm) (1,000 microns). Consequently, the coal must be run through a pulverizer after drying before being fed to the gasifier.

In personal correspondence with Shell, they indicated the moisture content of the coal after drying should be 3-14 percent depending on coal type [37]. EPRI and IEA recently performed studies that included the Shell gasifier using lignite coal that used a design moisture content of 5 percent entering the gasifier [38,39].

Publications by Southern Company Services indicate for their transport gasifier that coal with a top size of 700 microns [40] would be dried to a moisture level of 18 weight percent (wt%) [41].

Consequently, for the dry-feed entrained flow gasifiers in this study it is assumed that the subbituminous coal is dried to 6 percent moisture and the lignite to 12 percent moisture. For the transport gasifiers in this study, the coal will be dried to 18 percent moisture. In more detailed designs, coal fluidization tests would be performed to fine tune the coal feeding process.

The coal drying process selected for a specific IGCC system is a function of the drying requirement. The options considered for coal drying include:

- Option 1: Use conventional IGCC coal drying methods, which consist of deriving heat from the combustion of natural gas and/or syngas and using the flue gas, either directly or indirectly (by heating a nitrogen stream), for use in drying the coal. Some examples include the following:

    - At the Buggenum facility bituminous coal is ground in a conventional roller mill and simultaneously dried using a heated inert recycle gas stream that carries the evaporated water from the system as it sweeps the PC through an internal, rotating classifier. The inert gas generator is fueled by the in-line combustion of treated syngas. Excess gas is vented on pressure control [42].

    - At the Puertollano facility, coal is ground in mills using nitrogen for drying from 10 percent to less than 2 percent moisture. The drying circuit is heated to about 250°C (482°F) by intermediate pressure (IP)-steam and additional burning of natural gas. The report notes that a dual drying circuit using only natural gas and the produced syngas could be studied [43].

- Option 2: Use a conventional drying method with the warm gas exiting the HRSG used as the heat source. The HRSG exit gas is typically around 270°F and contains 10-11 percent oxygen. The high oxygen concentration is a concern with low rank coals and self ignition levels in the drying circuit, for the specific coals, should be studied and addressed in a more detailed design.

- Option 3: Dry the coal using a scheme similar to the Great River Energy (GRE) Clean Coal Power Initiative (CCPI) project approach. In the case of gasification where the drying requirements are greater than in PC plants, higher grade heat than is available from the cooling water exiting the condenser will be required. However, there are many sources of low-level waste heat in an IGCC plant and integration of this heat into the drying circuit is possible. Because of the tendency for low rank coals to spontaneously combust after the moisture is removed, it may be necessary to fluidize the coal bed with something other than air. Depending on the source of the fluidization gas, the process could become cost prohibitive.

- Option 4: Use the WTA process (German acronym for "fluidized bed dryer with integrated waste heat recovery") [44] proposed by RWE Power AG, which consists of a fluid bed dryer utilizing a heat pump-type cycle with recovered coal moisture used for fluidizing the coal bed and used as the working fluid [45]. This is the option presented by Shell at the 2005 GTC Conference, as mentioned above.

- Option 5: Use a process similar to the Integrated Drying and Gasification Combined Cycle (IDGCC) being developed in Australia.

- Option 6: Use a drying configuration practiced by Southern Company Services[46] where coal is dried in a closed-loop (CL) including a roll mill pulverizer, flash dryer, gas cooler to condense water vapor, and heater to heat the gas for drying. The oxygen concentration of the CL gas is monitored and nitrogen is fed as necessary to maintain an oxygen concentration below 11.3 percent for safety reasons. The source of heat is waste heat or IP steam. The water removed from the coal is collected in the cooler, treated, and used in the process.

Conventional coal drying methods would be suitable for this study, but there is an efficiency penalty involved with burning either syngas or natural gas as a heat source and there are additional CO_2 emissions generated by the process. Using steam as the heat source also impacts overall efficiency.

The GRE process has potential because of the many sources of low-grade heat in the IGCC process. However, the fluidization gas source would have to be identified assuming ambient air cannot be used because of the combustion tendencies of dried, low rank coals. One possibility would be using the HRSG exhaust gas, which contains 10-11 percent oxygen.

The RWE process has the advantage of using steam and coal moisture as the fluidizing medium thus eliminating the spontaneous combustion concerns. However, the vapor compressor imposes a significant auxiliary load. In Shell's GTC presentation the relative power and steam use are compared for three different technologies [47]. The results shown in Exhibit 3-1 assume 350 ton per hour (TPH) of as-received lignite coal with 53 percent moisture dried to 12 percent.

Exhibit 3-1 SCGP Lignite Coal Drying Options

Coal Feed, "dried" basis	Power Use, kW	Steam Use, lb/hr	Water Product, lb/hr
Conventional drying (rotary kiln)	3,180	449,000	0
Fluid bed simple	4,670	411,000	0
Fluid bed with WTA process	15,890	64,000	261,700

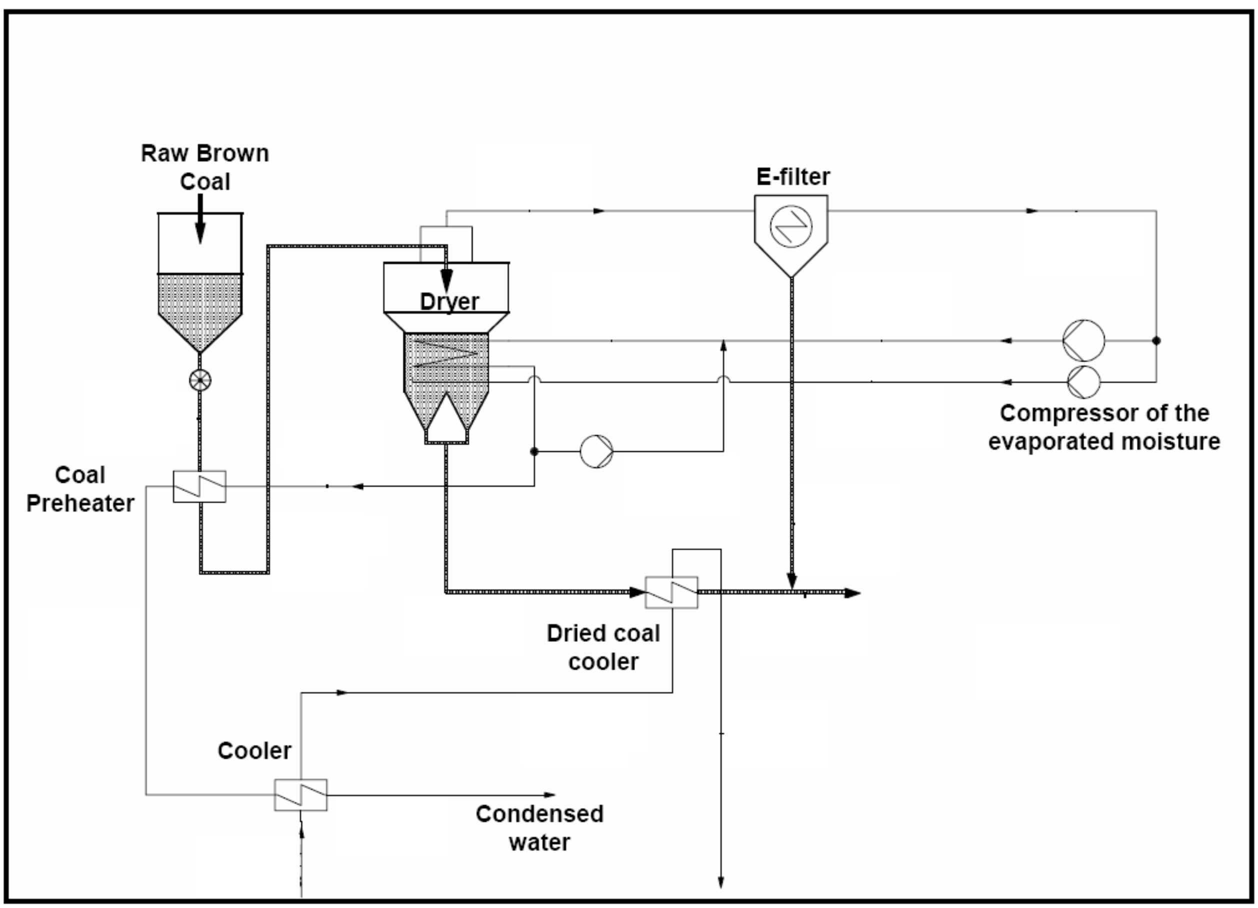
The IDGCC process is being commercialized by HRL Ltd. HRL has been trying to develop a project in Australia since 2002, originally at a scale of 400 MW and more recently at a scale of 600 MW [48]. The process utilizes hot syngas from an air blown fluidized bed gasifier (FBG) to dry brown coal prior to entering the gasifier. Sulfur is captured in the fluid bed and particulates are removed in a downstream candle filter. The warm, humidified syngas is then burned in a GT [49].

The technology is being developed for an air-blown FBG and has features that make it less attractive in the case of an entrained-flow, oxygen-blown gasifier like the Shell process. The coal is crushed to 10 mm top size and pressurized to 2.5 MPa (363 pounds per square inch [psi]) through a lock hopper system. The FBG can accept 10 mm coal, and at that size and high moisture content the coal will still flow through the lock hoppers. However, in the case of the Shell gasifier, the coal top size is significantly smaller (Shell does not specify the size, but states that conventional coal pulverizers are used, which likely results in an average coal size of 50-100 μm) and the coal must be dried prior to pressurizing to avoid lock hopper flow problems.

Where applicable, the WTA coal drying system was chosen for the traditional dry feed gasifiers largely because of its ability to recover the water from the coal in liquid state for use in the process and the fact that syngas is not used to provide heat for drying. In conventional dryers, the water is mixed with the heating gas and discharged to atmosphere as vapor. Recovery of the coal moisture in a liquid state results in a sizable electric auxiliary load.

The 'closed' WTA process has been demonstrated at pilot scale. Plans for a commercial demonstration of an 'open' version of the process have been delayed. In spite of the uncertainty of the commercial demonstration, the potential benefit of the technology was viewed to be significant enough to use the 'closed version' of the process in this study. A process schematic is shown in Exhibit 3-2, reprinted from Kakaras, Emm. et al. [50].

Exhibit 3-2 WTA Process Schematic



An effort was made to apply the WTA process to the TRIG™ IGCC cases. The PRB coal as received contains 26 percent moisture, and must only be dried to 18 percent moisture for the transport gasifier cases. Because of the low moisture delta (8 percent), there is a reduced amount of moisture available to provide the working fluid for the heat pump cycle requiring excessively high steam compressor discharge pressures (and subsequently temperatures) to produce the heat necessary to both vaporize the water and sensibly heat the coal. Consequently, the WTA process was not used for the TRIG™ cases, but rather the Southern Company Services system described in Option 6 above was paired with the associated transport gasifier technology.

For the TRIG™ IGCC systems, fluidized-bed roller mills simultaneously dry and crush the coal to 700 µm by a combination of flash drying and in bed heating, utilizing waste heat where possible.

3.1.3 Gasifier Modeling

Gasifier performance was modeled at the boundaries of the gasifier operation as an equilibrium reactor. Many literature references support this modeling strategy [44,51,52]. Gasifier vendors' input were used to determine the inputs to the gasifier, as well as the typical or desired configuration of the gasifier, high temperature heat recovery, and syngas cleaning processes. The boundaries of the gasifier model and the syngas compositions were generally provided or refined with estimates from the vendors and the temperature approaches to equilibrium were adjusted to match the syngas exiting these boundary conditions.

3.1.4 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) [53]. 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 GT, the ASU operates at or near the supply pressure from the GT's air compressor.

Residual Nitrogen Injection

The residual nitrogen that is available after gasifier oxygen and nitrogen requirements have been met is compressed and sent to the GT. Since all product streams are being compressed, the ASU air feed pressure is optimized to reduce the total power.

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

- Increased diluent increases mass flow through the turbine, thus increasing the power output of the GT while maintaining optimum firing temperatures for syngas operation.

- 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 thermal 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 4.2 to 4.8 megajoule per normal cubic meter (MJ/Nm^3) (115-132 British thermal unit per standard cubic foot [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 CT can be practiced by extracting some, or all, of the ASU's air requirement from the GT. Medium Btu syngas streams result in a higher mass flow than natural gas to provide the same heat content to the GT. Some GT designs may need to extract air to maintain stable compressor or turbine operation in response to increased fuel flow rates. Other GTs 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 GT. Extraction air temperature is normally in the range 399 to 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 heat recovery from the extracted air occurs by transferring heat to the nitrogen stream to be injected into the GT with a gas-to-gas heat exchanger.

Elevated Pressure ASU Experience in Gasification

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

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 GT. All of the nitrogen produced in the ASU is used in the GT. The original design did not allow for air extraction from the CT. After a CT 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 [54].

ASU Basis

For this study, air integration is used for the non-carbon capture cases only. In the CO_2 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 GT in the non-capture cases is determined through a process that includes the following constraints:

- The CT must be fully loaded; i.e., sufficient gas mass flow is supplied to maximize the turbine power output at the given elevation.
- The diluted syngas must meet heating value requirements specified by a CT vendor, which ranged from 4.2-4.8 MJ/Nm^3 (115-132 Btu/scf) (LHV).

The air extraction for the non-CO_2 capture case is shown in Exhibit 3-3. It was not a goal of this project to optimize the integration of the CT 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 [55,56].

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

Case No.	S1A	L1A	S2A	S3A	L3A	S4A
Air Extracted from GT, %	2.5	6.0	0.7	2.8	3.2	6.0
Air Provided to ASU, % of ASU Total	11.0	26.0	3.9	13.3	13.6	18.7

Air Separation Plant Process Description [57]

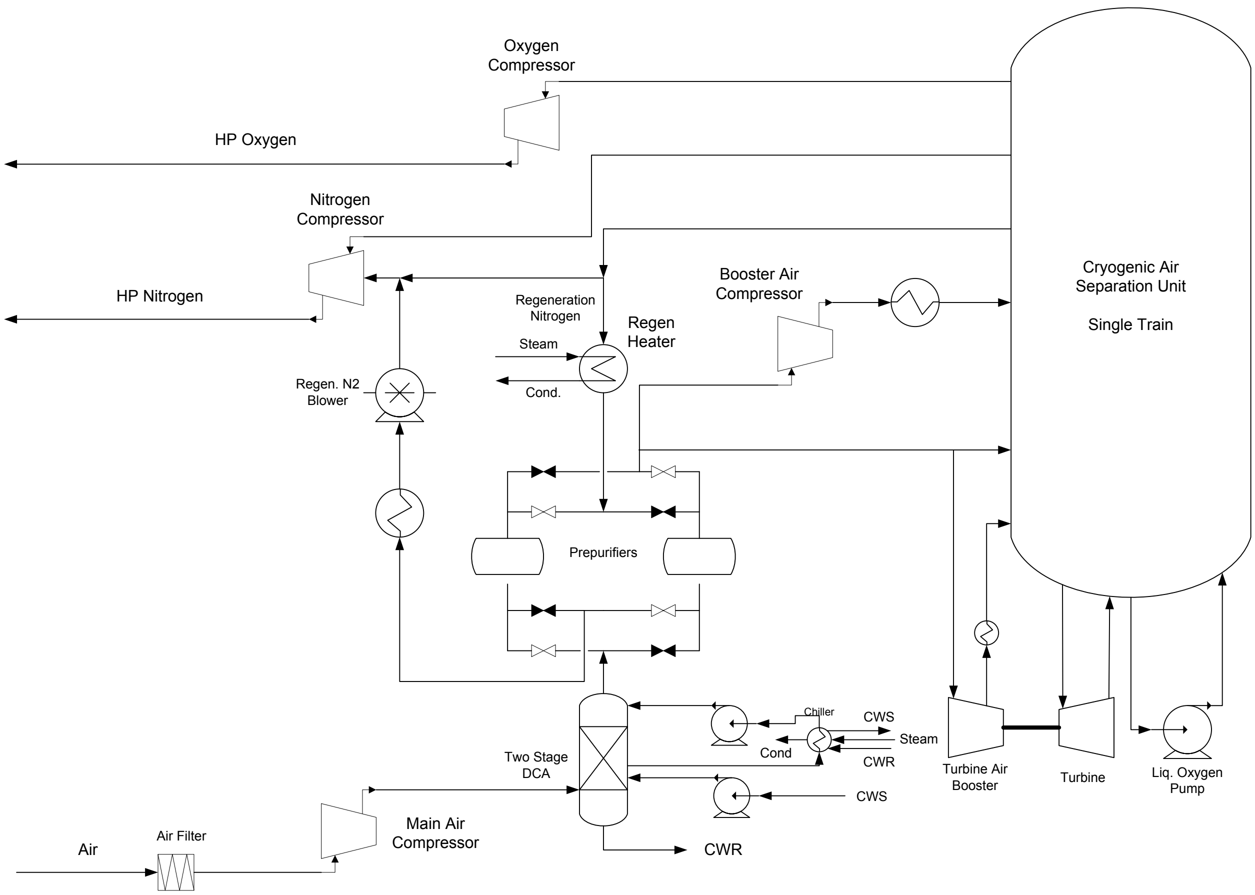
The air separation plant is designed to produce 95 mole percent O_2 for use in the gasifier. The plant is designed with two production trains, one for each gasifier. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as dilution in the GT combustor. A process schematic of a typical ASU is shown in Exhibit 3-4.

The air feed to the ASU can be supplied from two sources. A portion of the air can be extracted from the compressor of the GT (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, CO_2, 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.

Exhibit 3-4 Typical ASU Process Schematic



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 (LP) process steam at 0.45 MPa (65 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 HP 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. Both streams are compressed for use as CT diluent nitrogen. Some of the nitrogen stream is compressed further for use as transport gas in lockhoppers in dry feed systems.

3.1.5 High Temperature Syngas Cooling

The main configurations considered in this study for high temperature syngas cooling were determined from commercial or near commercial offerings by the different gasifier vendors and include: syngas coolers, syngas recycle quench, and water quench. High temperature syngas coolers are the most aggressive heat recovery approach, where high quality sensible heat is recovered from syngas. This increases plant efficiency at the cost of expensive heat exchangers requiring special materials of construction to resist corrosion and the high syngas temperatures.

The high temperature syngas cooling equipment varied by technology vendor with one utilizing waterwall heat exchangers and two others utilizing less expensive firetube heat exchangers. The fourth technology vendor chose not to include any high temperature heat exchanger.

Systems using high temperature syngas coolers can also utilize other syngas cooling methods to minimize the disadvantages of using these heat exchangers. The syngas recycle quench method returns a portion of cooled syngas to reduce the temperature of the raw syngas entering the syngas coolers. This approach reduces the temperatures entering the syngas coolers, potentially reducing costs by allowing for cheaper materials of construction. A similar amount of heat is recovered, which is a result of a proportional increase in the size of the syngas stream, which offsets the lower inlet temperatures to the syngas coolers. Extra equipment required for this configuration includes compressors, piping, and headers required to recycle the syngas.

Another option considered for lowering the inlet temperature to the syngas coolers is a water quench. This is a more reliable and less costly option as it relies on spraying water into the syngas to reduce its temperature entering the heat exchangers. A disadvantage is that the latent heat of vaporization of the quench water can only be recovered at low temperatures, which means in many cases that it goes to waste, reducing the efficiency of the plant. A water quench reduces the temperature entering the heat exchangers, similar to the syngas recycle quench, and can also be designed to help reduce corrosion and fouling in the heat exchangers by removing some of the particulates and acid gases exiting the gasifier. For CO_2 capture cases, the water added to the syngas is an additional benefit as it is required for the WGS reaction, which would otherwise be extracted from the steam cycle if it was not directly raised by the syngas. The individual chosen syngas cooling schemes are enumerated in the specific technology process descriptions.

3.1.6 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 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 prevent deposition on the catalyst by the addition of steam to the syngas stream to push the equilibrium towards a high conversion of CO. The H_2O:CO molar ratio is adjusted as necessary (with a minimum of 0.25 outlet steam:dry gas ratio) to achieve 90 percent overall CO_2 removal, if possible. 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 AGR step (sour gas shift [SGS]) or immediately downstream (sweet gas shift). If the CO converter is located downstream of the AGR, then the metallurgy of the unit is less stringent, but additional equipment must be added to the process, such as carbonyl sulfide (COS) hydrolysis unit. Products from the gasifier are quenched with water and contain a portion of the water vapor necessary to meet the water-to-gas criteria at the reactor outlet. If the CO converter is located downstream of the AGR, then the gasifier product would first have to be cooled, reducing the water content of the syngas. Then additional steam would have to be generated and re-injected into the shift reactor feed and the stream would have to be reheated to the catalyst operating temperature to encourage the WGS reaction. If the shift reactor is located upstream of the AGR step, these steps are avoided, but the choice of shift catalyst must consider its sulfur tolerance. Therefore, for this study the CO converter was located upstream of the AGR unit and is referred to as SGS, which also hydrolyzes the COS to H_2S for removal in the AGR.

Process Description - The SGS consists of two parallel paths of fixed-bed reactors. Each parallel path consists of two or three reactor stages in series to achieve a sufficient conversion to meet the CO_2 capture target, if possible.

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. The heat exchangers after the first SGS reactor are used to superheat shift steam. The heat exchanger after the second SGS reactor is a gas-gas exchanger used to preheat the syngas prior to the first SGS reactor.

3.1.7 COS Hydrolysis

The use of COS hydrolysis pretreatment in the feed to the AGR 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 CO_2 capture, the SGS reactors reduce COS to H_2S as discussed in Section 3.1.6.

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. 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.

3.1.8 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 [11]. The coal mercury content (0.081 ppm dry for PRB and 0.116 ppm dry for lignite) and carbon bed removal efficiency (95 percent) were discussed previously in Section 2.3. IGCC-specific design considerations are discussed below.

Carbon Bed Location – The packed carbon bed vessels are located upstream of the AGR process 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 [58]. Eastman Chemical also operates their beds ahead of their sulfur recovery unit (SRU) at a temperature of 30°C (86°F) [11].

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

Process Parameters – A superficial gas residence time of approximately 20 seconds was used based on Eastman Chemical's experience [11]. 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 [58] and was selected for this application.

The bed density of 30 pounds per cubic foot (lb/ft^3) was based on the Calgon Carbon Corporation HGR-P sulfur-impregnated pelletized activated carbon [59]. 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 [11]. 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 0.64 wt%. Mercury capacity of sulfur-impregnated carbon can be as high as 20 wt% [60]. The mercury laden carbon is considered to be a hazardous waste, and the disposal cost estimate reflects this categorization.

3.1.9 Acid Gas Removal Process Selection

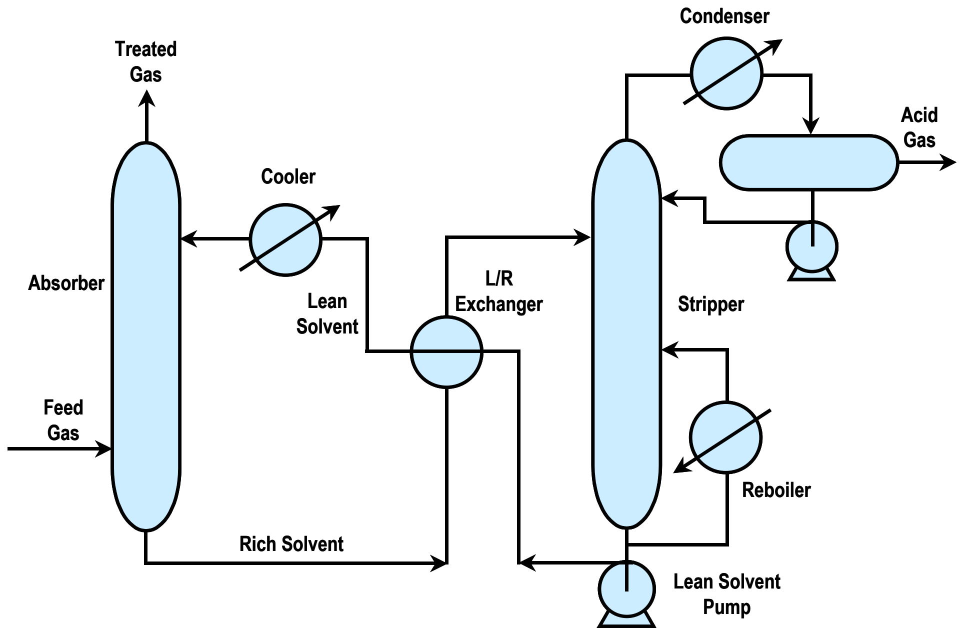
Gasification of coal to generate power produces a syngas that must be treated prior to further utilization. A portion of the treatment consists of AGR and sulfur recovery. The environmental target for these IGCC cases, 0.0128 lb sulfur dioxide per million British thermal units, is based on the EPRI CoalFleet values for bituminous coal [8] and 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. Because the low rank western coals have substantially less sulfur than eastern bituminous coal, the resulting sulfur emissions are significantly below the environmental target.

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 3-5 is a simplified diagram of the AGR process [61].

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 [66]. These processes can be separated into three general types: chemical reagents, physical solvents, and hybrid solvents. A summary of these common AGR processes is shown in Exhibit 3-6. The optimum technology choice for a particular IGCC plant depends on many factors such as gasifier operating pressure, availability of low/medium pressure steam, AGR requirements, and capital cost.

Exhibit 3-5 Flow Diagram for a Conventional AGR Unit



One process with potential in low-sulfur coal applications is CrystaSulf®, which is a nonaqueous process that effectively treats gas with too much H_2S to use a scavenger system but too little to use an amine/Claus approach. The niche market for CrystaSulf® is reported as 0.2-30 long tons per day (LTPD) [62]. According to the CrystaSulf® literature, the total treating costs for H_2S removal become greater than for amine systems above 30 LTPD [63]. CrystaSulf® was the proposed AGR technology for the cancelled Orlando Gasification CCPI Project. The estimated sulfur production rate for that project was 9.1 LTPD, which is well within the optimum range of the technology [64].

The sulfur production rates for the Low Rank IGCC cases are on the order of 50 LTPD. Since these values are significantly greater than the upper range established by CrystaTech, CrystaSulf® was not further considered for this study. The different classes of AGR processes are described generally below.

Chemical Solvents

Frequently used for AGR, 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.

Exhibit 3-6 Summary of Common AGR Processes

Solvent Type	Process	H_2S Selectivity	Solvent Circulation	Heat Input	Capital Cost	Pressure Sensitive	High Removal
Physical	Rectisol, Selexol	Good	High, decreases with increased pressure	Low	High	Yes	Yes, at high acid gas partial pressures
Mixed	Sulfinol, FLEXSORB	Good but more complicated to achieve	Intermediate	Intermediate	Intermediate	Yes, but to a lesser extent than physical solvents only	Yes, at optimum operating conditions
Chemical	Amines (MEA, DEA, MDEA)	Varies depending on amine selected, highest for MDEA	Low	High	Low	No	Yes, but with refrigeration

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 3-7 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 lower 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 are needed to remove undesirable reaction byproducts.

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 standard cubic feet (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.

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

Exhibit 3-7 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

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 (HP) and at or below ambient temperature while the regeneration step (dissolution) occurs by pressure letdown and indirect stripping with LP 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 3-8 is a simplified flow diagram for a physical reagent type AGR process [61]. Common physical solvent processes, along with their licensors, are listed in Exhibit 3-9.

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), 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.

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.

Exhibit 3-8 Physical Solvent AGR Process Simplified Flow Diagram

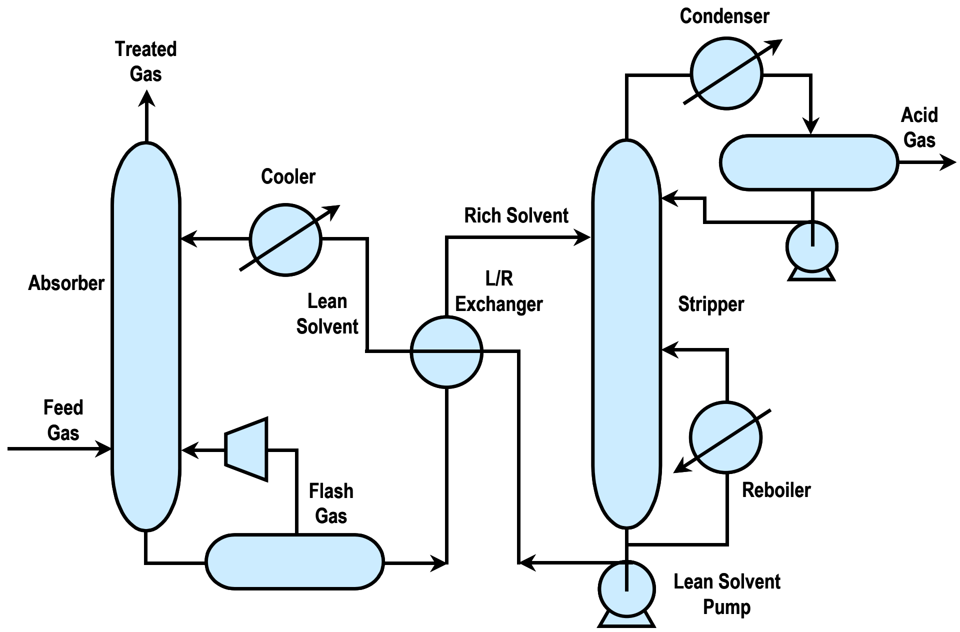


Exhibit 3-9 Common Physical Solvents Used in AGR Processes

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

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 3-10. 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 3-10 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 3-11 shows reported equilibrium solubility data for H_2S and CO_2 in various representative solvents [61]. The solubility is expressed as scf of gas per gallon liquid per atmosphere gas partial pressure.

The figure illustrates the relative solubility 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.

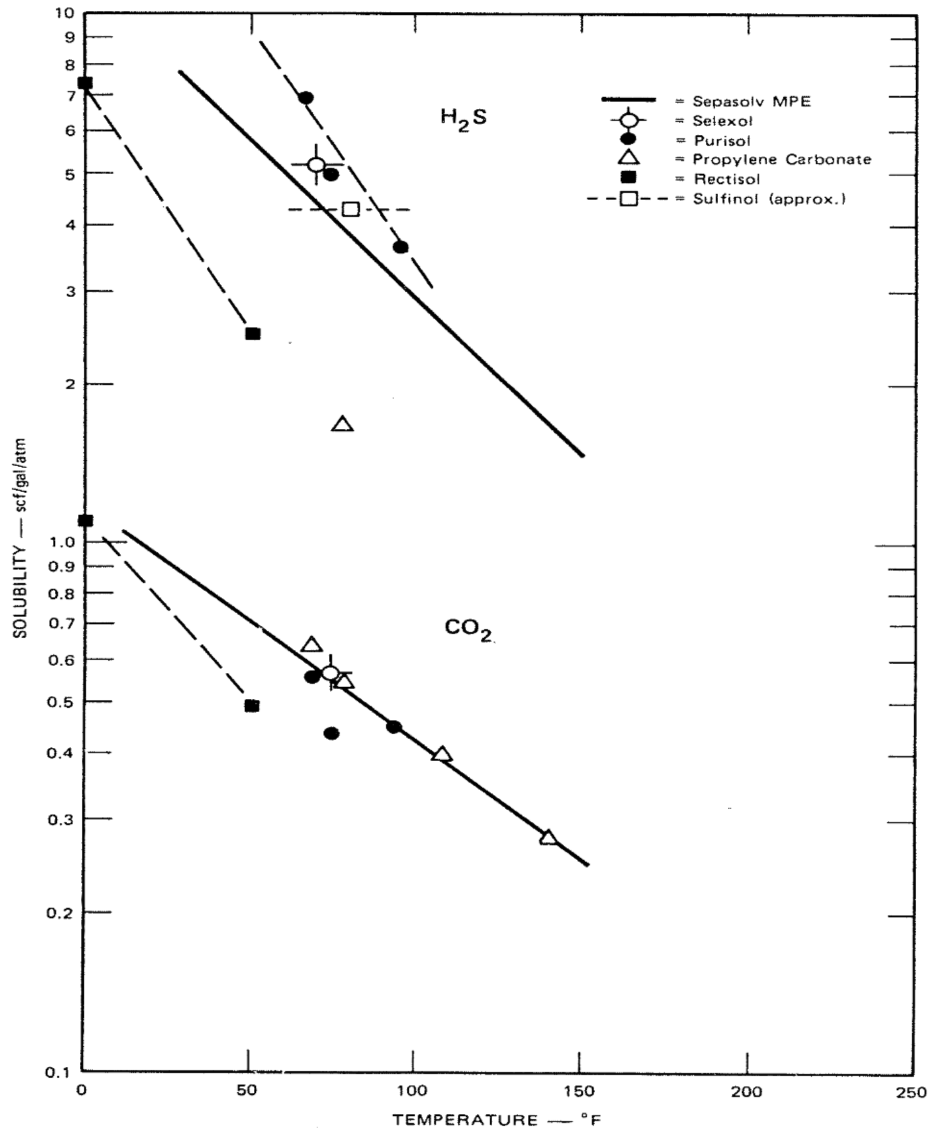
The ability of a process to selectively absorb H_2S may be further enhanced by the relative absorption rates of H_2S and CO_2. Thus, some processes, besides using equilibrium solubility differences, will use absorption rate differences between the two acid gases to achieve selectivity. This is particularly 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 CO_2 capture cases in this study as a common basis for comparison of these technologies and configurations. This decision was guided the design of current commercial chemical plants, mainly producing ammonia, that use the Selexol process to remove CO_2 in the process. 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 CT or is partially humidified prior to entering the CT.

Exhibit 3-11 Equilibrium Solubility Data on H_2S and CO_2 in Various Solvents



The amount of hydrogen remaining in 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. The balance of the hydrogen is co-sequestered with the CO_2, destroyed in the Claus plant burner, or recycled upstream of the AGR.

The CO_2 loaded solvent exits the CO_2 absorber and a portion is sent to the H_2S absorber and the remainder is sent to a series of flash drums for regeneration. Flash gas from the first flash drum is fed to a compressor and recycled to the CO_2 absorber. The CO_2 product stream is obtained from the remaining 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 CT.

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 in various precombustion applications. To maintain comparability between designs of other volumes of this study and to mimic commercial offerings as much as is practical, the Sulfinol-M process was chosen for all cases except the CoP design, in order to be consistent with the non-capture cases in the NETL Bituminous Baseline Study [65]. Previous vendor performance estimates for Sulfinol systems showed high removals for H_2S (99.77 percent) and CO_2 (97.5 percent). With the higher CO_2 and lower H_2S concentrations in the raw gas for the lower rank coals, it is necessary for the AGR to slip a significant amount of CO_2. The high slip is necessary to reduce the volume and increase the H_2S concentration of the acid gas stream to the Claus plant for adequate performance and minimum capital cost. The literature indicates that Sulfinol systems with very high CO_2 slips have been designed, but efforts to obtain an updated Sulfinol performance estimate from Shell have been unsuccessful to date.

The two-stage Selexol process is used in all cases that require CO_2 capture. Selexol was also used for CO_2 capture cases in the NETL Bituminous Baseline Study [65]. 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." [66].

3.1.10 Sulfur Recovery/Tail Gas Cleanup Process Selection

The Claus process is the main process used for gas treating and 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, a tail gas treating unit (TGTU) must be added to the conventional Claus process to recover sulfur with over 99.8 percent efficiency.

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 3-12 [66]. 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 HP steam usually follows the furnace. Sulfur is condensed in a condenser that follows the HP steam recovery section. LP 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

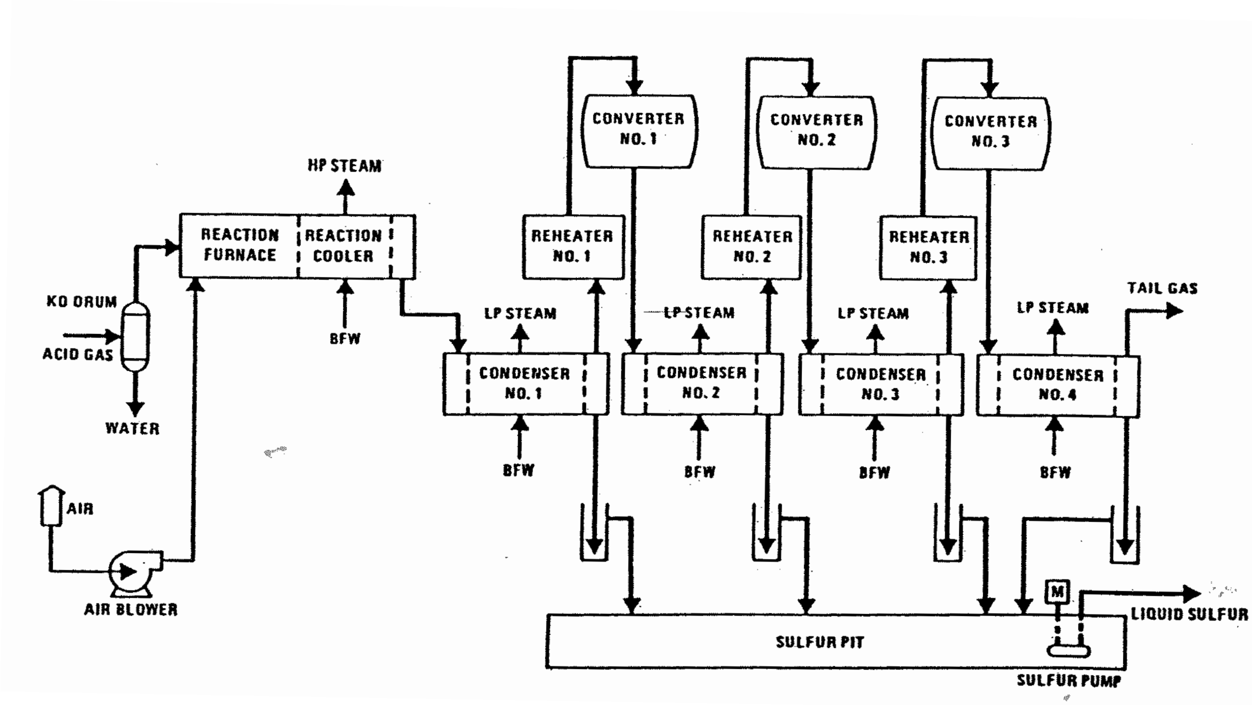
The Claus reaction is equilibrium limited, and sulfur conversion is sensitive to the reaction temperature. The highest sulfur conversion in the thermal zone is limited to about 75 percent. Typical furnace temperatures are in the range from 1093 to 1427°C (2000 to 2600°F), and as the temperature decreases,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

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.

Exhibit 3-12 Typical Three-Stage Claus Sulfur Plant



Oxygen-Blown Claus

Large diluent streams in the feed to the Claus plant, such as nitrogen (N_2) from combustion air, or a high CO_2 content in the feed gas, lead to higher cost of the Claus process 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 volume percent (vol%) 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 SRU. 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_4, 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. All cases in this study use a catalytic hydrogenation step with tail gas recycle to just upstream of the AGR. The Shell Puertollano plant treats the tail gas in a similar manner, but the recycle endpoint is not specified [43].

Flare Stack

A self-supporting, refractory-lined, carbon steel (CS) flare stack is typically provided to combust and dispose of unreacted gas during startup, shutdown, and upset conditions. However, in all 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.

3.1.11 Slag and Ash Handling

The slag handling system for slagging gasifiers, operating above the ash fusion temperature, is discussed in this section, specifically the Shell SCGP, Siemens SFG, and CoP gasification technologies. The non-slagging TRIG™ gasifier operates below the ash fusion temperature and most of the entrained ash is captured by a disengager and cyclone and recycled back to the gasifier to increase overall carbon conversion. Any remaining ash is removed by a high temperature high pressure barrier filter and continuously cooled and removed for possible reuse or disposal. Once the ash is separated and processed, the material handling is similar to that described for slagging gasifiers below.

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, generally through the use of lockhoppers, to a series of dewatering bins.

The general aspects of slag handling are the same for all slagging gasifier 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 different 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 enter 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.

3.1.12 Power Island

Combustion Turbine

The GT 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 (IGVs). 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 near term 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 FOAK applications, process contingencies were included in the cost estimates as described in Section 2.6. Performance typical of an advanced F class turbine on natural gas at ISO conditions is presented in Exhibit 3-13.

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.

Exhibit 3-13 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)

Combustion Turbine Package scope of Supply

The CT is typically supplied in several fully shop fabricated modules, complete with mechanical, electrical and control systems as required for CT operation. Site CT installation involves module interconnection, and linking CT modules to the plant systems.

CT Firing Temperature Control Issue for Low Calorific Value Fuel

A CT when fired on low calorific value (LCV) 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 [67]. 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. 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 nitrogen injection.

Combustion Turbine Syngas Fuel Requirements

Typical fuel specifications and contaminant levels for successful CT operation are provided in reference [68] and presented for F Class machines in Exhibit 3-14 and Exhibit 3-15. 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 these cases.

Exhibit 3-14 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 [69].
2. To ensure that the fuel gas supply to the CT 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 [68].
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 6 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 not recommended by the CT vendor and is considered only for non-carbon capture cases.

Exhibit 3-15 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

[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 CT gas fuel system

A high level analysis on the alkalinity of the coals, particularly the high sodium lignite coal, indicated that if all the sodium and potassium in the coal was partitioned to the gas phase and passed through the gas cleanup, the fuel would not meet the specified limits for the CT. For plants firing high alkali coals, quench cooling is preferable to syngas coolers to avoid any potential fouling problems. Sodium, in the form of sodium hydroxide, is converted mainly into sodium chloride or sodium carbonate when leaving the reactor, and can cause fouling on heat exchangers until the syngas is cooled below the respective melting points of 800°C and 850°C. The highly soluble species, such as the alkali salts, are removed in any water scrubbing or knockout (KO) drums and should not cause any limitations on the CT.

Pressurized syngas is combusted in several (14) parallel diffusion combustors and syngas dilution is used to limit NOx formation. As described in Section 3.1.4 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 4.2-4.8 MJ/Nm^3 (115-132 Btu/scf). In the cases discussed in this report, nitrogen dilution alone was sufficient for all cases except S2B, which required humidification. 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.

Disadvantages to using nitrogen as the primary diluent include:

- Significant auxiliary power is still required to further compress the large nitrogen flow from the ASU pressure to the GT pressure.
- The low quality heat, which is saved from avoiding 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 Volume 1 of this series of reports.

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 593°C (1,100°F) for non-CO_2 capture cases and 566°C (1,050°F) for capture cases.

Gross turbine power, as measured prior to the generator terminals, is 232 MW at ISO conditions. Turbine output is reduced at the elevated sites for this study because the compressor capacity on a mass flow basis is reduced because of the reduced ambient air density. The CT generator is a standard hydrogen-cooled machine with static exciter.

3.1.13 Steam Generation Island

Heat Recovery Steam Generator

The HRSG is a horizontal flow, drum-type, multi-pressure design that is matched to the characteristics of the CT exhaust when firing medium-Btu syngas. 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) in all IGCC cases.

The HP drum produces steam at main steam pressure, while the 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 FW 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 FW/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 CT 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 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 HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and nominally 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 HP 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 3.2 MPa/566°C (467 psia/1050°F) for the non-carbon capture cases or 3.2 MPa/538°C (467 psia/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 CL, 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 LP 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 kilovolt (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 CL oil seal system. The oil seal system consists of storage tank, pumps, filters, and pressure controls, all skid-mounted.

The STG 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, operator display interfacing, and datalink interfaces to the balance-of-plant distributed control system (DCS), and incorporates on-line repair capability.

Condensate System

The function of the condensate system is to pump condensate from both the air-cooled and water-cooled condensers to the deaerator, through the gland steam condenser and the low-temperature economizer section in the HRSG.

Feedwater System

The function of the FW system is to pump the various FW streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps (BFPs) 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 FW pumps are supplied with instrumentation to monitor and alarm on low oil pressure, or high bearing temperature. FW pump suction pressure and temperature are also monitored. In addition, the suction of each BFP is equipped with a startup strainer.

Cooling Systems

Exhaust steam from the steam turbine is split 50/50 to a surface condenser cooled with cooling water and to an air-cooled condenser using ambient air and forced convection. A decision to use a parallel wet/dry cooling system to reduce the plant water requirement was based primarily on the recently completed Xcel Energy Comanche 3 PC plant, which uses such a system. Parallel cooling has less of a performance impact on combined cycle systems than on PC systems; and with the relatively low ambient temperature, the performance impact from the parallel cooling, as compared to wet cooling, is minor.

The major impact of parallel cooling is a significant reduction in water requirement when compared to a wet cooling system. This impact is included in the water balance presented later in this report.

With this cooling system and the specific ambient temperature, a condenser pressure of 0.005 MPa (0.698 psia) (condensing temperature of 32°C [90°F]) is used in the model as compared to 0.007 MPa (0.983 psia) (condensing temperature of 38°C [101°F]) used in Volume 1 of this series.

The circulating water system is a closed-cycle cooling water system that supplies cooling water to the surface condenser to condense one-half of 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 CL 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 surface condenser and other applications is removed by a mechanical draft cooling tower.

The system consists of two 50 percent capacity vertical circulating water pumps (CWP), a mechanical draft evaporative cooling tower, and CS 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 water-cooled surface 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 air-cooled condenser utilizes ambient air and forced convection across tube bundles to condense the balance of the turbine exhaust steam.

Both condensers are 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 WGS 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, for redundancy, 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.

3.1.14 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.

3.1.15 Instrumentation and Control

An integrated plant-wide distributed control system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally DCS. The control room houses an array of multiple video monitor and keyboard units. The DCS incorporates plant monitoring and control functions for all the major plant equipment. 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 high speed redundant microprocessor to execute calculations and dynamic controls. 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 SHELL COAL GASIFICATION PROCESS IGCC CASES

This section contains an evaluation of plant designs for Cases S1A, S1B, L1A, and L1B, which are based on the SCGP. The non-capture (A) and CO_2 capture (B) cases are very similar in terms of process, equipment, scope and arrangement, except that CO_2 capture cases include SGS reactors, CO_2 absorption/regeneration and compression/transport systems.

Section 3.2.4 covers the results for the S1A and L1A non-capture case using PRB and lignite coal and Section 3.2.8 covers the S1B and L1B CO_2-capture cases. The sections are organized analogously as follows:

- Process and System Description provides an overview of the specific technology's operation.
- Block flow diagram (BFD) and stream table display results for major processes and streams
- Performance Results provides the main modeling results, 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 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs.

Process and System Description, Performance Results, Equipment List and Cost Estimates are repeated for the CO_2 capture cases in Section 3.2.8. If the information is identical to that presented for the non-capture cases, a reference is made to the earlier section rather than repeating the information.

3.2.1 Gasifier Background

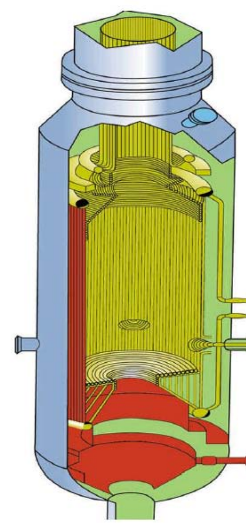
Development and Current Status – Development of the Shell gasification process for partial oxidation of oil and gas began in the early 1950s. More than 75 commercial Shell partial-oxidation plants have been built worldwide to convert a variety of hydrocarbon liquids and gases to carbon monoxide and hydrogen.

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 hrs 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 hrs from 1978 to 1983, and successfully gasified over 27,200 tonnes (30,000 tons) of coal.

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 230 tonnes/day (250 tpd) and to gasify high-moisture, high-ash lignite at the rate of 360 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 HP 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 1,800 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 IGCC design is the use of extraction air from the CT air compressor to feed the oxygen plant.



Gasifier Capacity – The large gasifier operating at the Buggenum plant in the Netherlands has a bituminous coal-handling capacity of 1,630 tonnes/day (1,800 tpd) and produces dry gas at a rate of 158,580 normal cubic meter per hour (Nm^3/hr) (5.6 million standard cubic feet per hour [scf/hr]) with an energy content of about 1,790 million kilojoules per hour (MMkJ/hr) (1,700 million British thermal units per hour [MMBtu/hr]) (HHV). This gasifier was sized to match the fuel gas requirements for the Siemens/Kraftwerk Union V-94.2 CT and could easily be scaled up to match advanced F Class turbine requirements, requiring one gasifier for each CT.

Distinguishing Characteristics – The SCGP uses a dry feed, entrained flow, slagging, single stage, up-flow gasifier to produce syngas at HPs and temperatures. The gasifier uses a membrane wall design to control the reactor vessel wall temperature, increasing operational flexibility. The dry feeding system helps achieve high carbon conversion and higher cold gas efficiencies compared to slurry fed systems. Multiple burner design allows a wider range of gasifier scalability. The syngas outlet is separated from the slag outlet allowing the application of higher ash coals proven with up to 30 percent ash content in the burner feed. The Shell process also uses a gas quench at the gasifier outlet to further mitigate problems associated with any remaining sticky fly ash/slag particulates.

Entrained-flow slagging gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers without a slagging area. 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.

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. The SCGP produces a high temperature syngas, with very little methane, and uses high temperature synthesis gas coolers (SGC) to recover a large amount of this heat. The high gasification temperatures improve operational reliability by reducing the amount of tars exiting the gasifier. The high operating temperature produced by all entrained-flow slagging processes can result in relatively high capital and maintenance costs, but can be partially avoided by adding different syngas cooling schemes such as a water quench, as in the CO_2 capture cases, where the reduction in heat recovery is mitigated by the shift steam requirement downstream. Shell's gasifier also employs a cooled membrane wall to help control gasifier temperature, which requires fewer changeouts than an uncooled refractory. Buggenum operating experience has confirmed that one yearly maintenance turnaround is sufficient to achieve high reliability plant operation.

Important Coal Characteristics – One main consideration for coal-fired in the Shell gasifier is the ash characteristics. The ash content has to be minimum 8 wt% on burner feed and can be adjusted using slag and ash recycle or fresh ash (as needed). The syngas outlet is separated from slag outlet allowing application of higher ash coals - up to 30 percent ash content in burner feed is proven. A wide variety of different coals have been tested on the Shell gasifier, 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, slag and ash management. Solids handling requirements (coal, slag and ash) impact maintenance needs.

3.2.2 Key System Assumptions

System assumptions for Cases S1A and L1A and S1B and L1B, SCGP IGCC using PRB and lignite coal with and without CO_2 capture, are compiled in Exhibit 3-16.

Exhibit 3-16 Case S1A/L1A and S1B/L1B Plant Study Configuration Matrix

Case	S1A / L1A	S1B / L1B
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.780 / 0.736	0.773 / 0.736
Carbon Conversion, %	99.5	99.5
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	10,389 (279) / 9,384 (252)	10,476 (281) / 9,397 (252)
Nominal 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)	36 (1.4)	36 (1.4)
Combustion Turbine	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)
Gasifier Technology	Shell (SCGP)	Shell (SCGP)
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Subbituminous / Lignite	Subbituminous / Lignite
Coal Feed Moisture Content, %	6 / 12	6 / 12
COS Hydrolysis	Yes	Yes (Part of WGS)
Water Gas Shift	No	Yes
H_2S Separation	Sulfinol-M	Selexol (1st Stage)
Sulfur Removal, %	99.9	99.7
CO_2 Separation	None	Selexol (2nd Stage)
CO_2 Removal, %	N/A	90
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) and N_2 Dilution	MNQC (LNB) and N_2 Dilution

Balance of Plant – All Cases

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 water 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 CT Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local 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	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.

3.2.3 Sparing Philosophy

The sparing philosophy 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 ASUs (2 x 50%).
- Two trains of coal drying and dry feed systems (2 x 50%).
- Two trains of gasification, including gasifier, SGC, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Sulfinol-M acid gas removal in non-capture cases and two trains of two-stage Selexol in CO_2 capture cases (2 x 50%).
- One train of Claus-based sulfur recovery (1 x 100%).
- Two CT/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.2.4 SCGP IGCC Non-Capture Case (S1A and L1A) Process Description

In this section the overall SCGP for Case S1A and L1A is described. The process does not change with fuel type so a single description is provided. The system description follows the BFD in Exhibit 3-18 and stream numbers reference the same exhibit. The tables in Exhibit 3-19 and Exhibit 3-20 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 PRB coal used in this study contains 25.77 percent total moisture on an as-received basis and the NDL contains 36.08 percent moisture. It was assumed that the PRB coal must be dried to 6 percent moisture and the lignite to 12 percent to allow for smooth flow through the dry feed system; however, fluidization tests would need to be completed on actual coal samples for actual design and operation.

The raw coal is crushed in the coal mill then delivered to a surge hopper with an approximate 2-hour capacity, which in turn delivers the coal to the coal pre-heater. The WTA coal drying process includes a water-heated, horizontal, rotary-kiln coal pre-heater, a fluidized bed coal dryer and a water-cooled, horizontal, rotary-kiln coal cooler. The moisture driven from the coal in the fluid bed dryer passes through a baghouse for particulate removal and then is split into two streams. The smaller of the two streams is compressed and used as the fluidizing medium in the coal dryer. The bulk of the removed moisture is compressed and the high temperature vapor passes through internal coils in the dryer to provide the heat to drive off the coal moisture and then exits the dryer as liquid water. The warm water is used in the coal pre-heater before being used as cooling tower makeup water. The vapor compressor consumes the vast majority of the WTA process auxiliary load.

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.

Gasifier

There are two Shell dry feed, pressurized, up flow, entrained, slagging gasifiers, operating at 4.24 MPa (615 psia) and processing a total of 5,908 tonne/day (6,513 tpd) of as-received coal in the PRB case and 8,274 tonne/day (9,121 tpd) in the lignite case. Coal reacts with oxygen in a reducing environment to produce principally hydrogen and carbon monoxide with little CO_2 formed.

Raw Gas Cooling/Particulate Removal

High-temperature heat recovery in each gasifier train is accomplished in three steps, including the gasifier membrane wall, which maintains a protective ash layer over the membrane wall and thus permits the reaction temperature of roughly 1400°C (2,550°F). The product gas from the gasifier is cooled using a syngas recycle quench to lower the temperature below the ash melting point. Syngas then goes through a raw gas cooler, which lowers the gas temperature to a minimum of 230°C (450°F), and contributes to the production of HP steam for use in the steam cycle.

The solids are removed as slag and as ash. Liquid slag is solidified in a water bath and removed via a lock hopper system. Ash carried over with the syngas is removed in a ceramic candle filter. The ash is removed similarly via a lock hopper system. Cyclones can be implemented in specific designs depending on plant size and coal operating characteristics. The syngas scrubber removes any possibility of remaining PM passing the candle filter further downstream, by protecting against leakage from the filter seals or any undetected candle breakage that would allow large particulates into the scrubber.

Syngas Scrubber/Sour Water Stripper

The raw synthesis gas exiting the ceramic particulate filter enters the scrubber for removal of chlorides and any remaining particulates. The quench scrubber washes the syngas in a counter-current flow in two packed beds. 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 ammonia, sulfur, 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 SGCs. 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 SRU. Part of the stripper water is sent to wastewater treatment, avoiding accumulation of salts, to be reused in the scrubber section.

COS Hydrolysis, Mercury Removal and AGR

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 AGR process; however, because COS is not readily removed, it is first catalytically converted to H_2S in a COS hydrolysis unit.

Following the water scrubber, the gas is fed to the COS hydrolysis reactor at above 177°C (350°F). 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, 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 then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.8).

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 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 the Shell non-CO_2 capture applications.

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 LP 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 about 15 percent of the CO_2 along with the H_2S and COS. The acid gas is fed to the SRU. The residual CO_2 passes through the SRU, the hydrogenation reactor and is recycled to the AGR. 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 SRU is a Claus bypass type SRU utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting 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 tail gas recycle results in an overall sulfur recovery exceeding 99 percent, producing 43 tonne/day (47 tpd) of sulfur in the PRB case and 52 tonne/day (57 tpd) in the lignite case.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. Feed for each case consists of acid gas from both the acid gas cleanup unit and a vent stream from the sour water stripper in the gasifier section.

In the furnace waste heat boiler 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 LP steam header.

Power Block

Clean syngas exiting the Sulfinol absorber is reheated, diluted with nitrogen from the ASU, and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and a portion of the air requirement for the ASU. The exhaust gas exits the CT around 593°C (1,100°F) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) 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 nominal 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

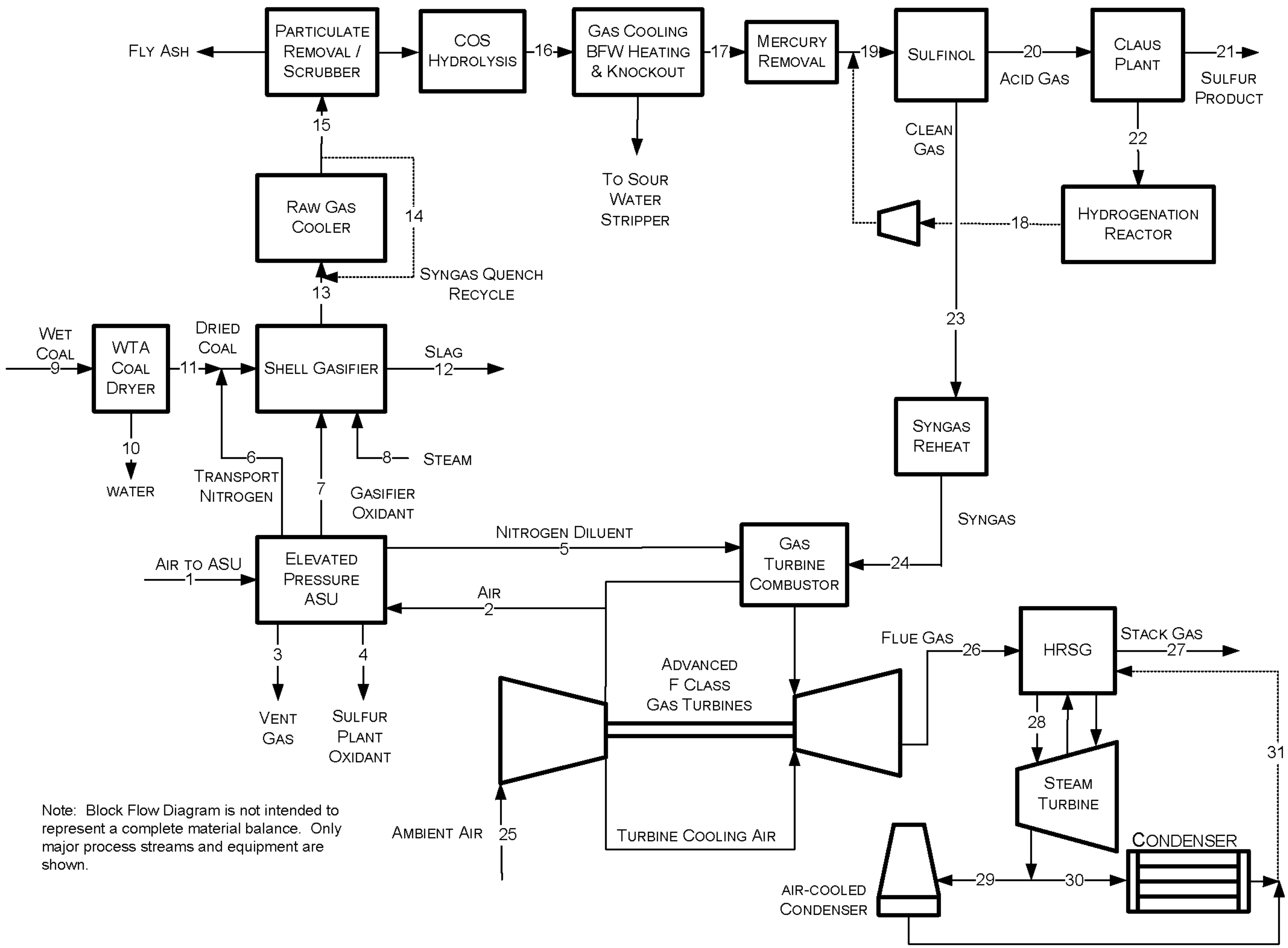
Air Separation Unit

The ASU is designed to produce approximately 3,653 tonne/day (4,026 tpd) in the PRB case and 4,150 tonne/day (4,574 tpd) in the lignite case of 95 mole percent (mol%) O_2 for use in the gasifier and SRU. The plant is designed with two production trains. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as diluent in the CT combustor or as a coal transport fluid. Air extraction is taken from the CT compressor to reduce the size of the main air compressor.

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14, and 3.1.15.

Exhibit 3-18 Case S1A and L1A Process Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 3-19 Case S1A Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0093	0.0291	0.0318	0.0023	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0104	0.0104	0.0104
CH_4	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	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5994	0.5994	0.5994
CO_2	0.0003	0.0003	0.0102	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0335	0.0335	0.0335
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0005	0.0005
H_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	0.2593	0.2593	0.2593
H_2O	0.0064	0.0064	0.1937	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0309	0.0309	0.0309
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0030	0.0030
N_2	0.7759	0.7759	0.5163	0.0178	0.9920	0.9920	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0607	0.0607	0.0607
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0022	0.0022	0.0022
O_2	0.2081	0.2081	0.2507	0.9504	0.0054	0.0054	0.9504	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	20,415	2,522	736	46	16,606	866	4,684	0	0	2,874	0	0	16,119	7,423	16,119
V-L Flowrate (kg/hr)	589,886	72,887	20,300	1,466	465,982	24,300	150,725	0	0	51,774	0	0	348,649	160,563	348,649
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	246,170	0	194,396	20,772	0	0	0
Temperature (°C)	6	411	21	32	196	195	32	---	6	33	71	1,454	1,454	245	232
Pressure (MPa, abs)	0.09	1.43	0.11	0.86	2.65	5.62	0.86	---	0.09	0.55	0.09	4.24	4.24	4.24	3.96
Enthalpy (kJ/kg)[A]	15.26	434.33	40.10	26.67	202.63	199.69	26.67	---	---	140.14	---	---	2,292.13	400.31	382.35
Density (kg/m^3)	1.1	7.2	1.6	11.0	18.9	39.8	11.0	---	---	985.3	---	---	6.3	21.0	20.1
V-L Molecular Weight	28.895	28.895	27.587	32.181	28.061	28.061	32.181	---	---	18.015	---	---	21.630	21.630	21.630
V-L Flowrate (lb_{mol}/hr)	45,007	5,561	1,622	100	36,610	1,909	10,326	0	0	6,336	0	0	35,537	16,366	35,536
V-L Flowrate (lb/hr)	1,300,475	160,689	44,754	3,232	1,027,315	53,571	332,292	0	0	114,143	0	0	768,639	353,981	768,639
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	542,713	0	428,570	45,794	0	0	0
Temperature (°F)	42	771	70	90	385	383	90	---	42	92	160	2,650	2,650	473	450
Pressure (psia)	13.0	207.6	16.4	125.0	385.0	815.0	125.0	---	13.0	80.1	12.7	614.7	614.7	615.0	574.7
Enthalpy (Btu/lb)[A]	6.6	186.7	17.2	11.5	87.1	85.9	11.5	---	---	60.2	---	---	985.4	172.1	164.4
Density (lb/ft^3)	0.070	0.452	0.097	0.687	1.183	2.485	0.687	---	---	61.510	---	---	0.396	1.311	1.257
	A - Reference conditions are 32.02 F & 0.089 PSIA														

Exhibit 3-19 Case S1A Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
V-L Mole Fraction																
Ar	0.0098	0.0108	0.0091	0.0107	0.0008	0.0000	0.0063	0.0109	0.0109	0.0093	0.0091	0.0091	0.0000	0.0000	0.0000	0.0000
CH_4	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	0.0000	0.0000
CO	0.5639	0.6178	0.0027	0.6103	0.0299	0.0000	0.0649	0.6182	0.6182	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0319	0.0350	0.4801	0.0406	0.4222	0.0000	0.2729	0.0354	0.0354	0.0003	0.0832	0.0832	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.2440	0.2673	0.1276	0.2656	0.0142	0.0000	0.0298	0.2690	0.2690	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0879	0.0030	0.0323	0.0030	0.0224	0.0000	0.3822	0.0028	0.0028	0.0064	0.0396	0.0396	1.0000	1.0000	1.0000	1.0000
H_2S	0.0033	0.0036	0.0041	0.0036	0.2650	0.0000	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0571	0.0625	0.3441	0.0661	0.2455	0.0000	0.2410	0.0637	0.0637	0.7759	0.7583	0.7583	0.0000	0.0000	0.0000	0.0000
NH_3	0.0021	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	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2081	0.1098	0.1098	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0011	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	17,135	15,640	200	15,834	213	0	285	15,621	15,621	100,352	123,127	123,127	34,784	18,472	18,472	37,460
V-L Flowrate (kg/hr)	366,944	340,056	6,431	346,380	7,634	0	7,966	338,746	338,746	2,899,687	3,631,528	3,631,528	626,641	332,787	332,787	674,848
Solids Flowrate (kg/hr)	0	0	0	0	0	1,788	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	177	35	49	37	40	176	138	42	196	6	589	132	561	32	32	33
Pressure (MPa, abs)	3.79	3.69	0.32	3.62	0.4	0.370	0.370	3.597	3.563	0.090	0.093	0.090	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	426.53	45.20	93.62	44.60	54.4	---	780.053	55.279	271.387	15.260	694.591	195.610	3,502.487	2,306.994	2,306.994	140.562
Density (kg/m^3)	21.6	31.3	3.9	30.8	5.8	5,284.2	3.0	29.7	19.6	1.1	0.4	0.8	35.1	0.04	0.04	995.0
V-L Molecular Weight	21.415	21.742	32.185	21.876	36	---	27.918	21.686	21.686	28.895	29.494	29.494	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	37,775	34,481	440	34,908	470	0	629	34,438	34,438	221,239	271,449	271,449	76,685	40,725	40,725	82,585
V-L Flowrate (lb/hr)	808,973	749,695	14,177	763,637	16,829	0	17,561	746,808	746,808	6,392,716	8,006,150	8,006,150	1,381,506	733,670	733,670	1,487,785
Solids Flowrate (lb/hr)	0	0	0	0	0	3,943	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	351	95	120	98	104	348	280	108	385	42	1,092	270	1,042	90	90	92
Pressure (psia)	549.7	534.7	46.5	524.7	60.0	53.6	53.6	521.7	516.7	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	183.4	19.4	40.3	19.2	23.4	---	335.4	23.8	116.7	6.6	298.6	84.1	1,505.8	991.8	991.8	60.4
Density (lb/ft^3)	1.345	1.952	0.242	1.920	0.362	329.882	0.190	1.853	1.221	0.070	0.024	0.049	2.192	0.002	0.002	62.115

Exhibit 3-20 Case L1A Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0093	0.0293	0.0318	0.0023	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0100	0.0100	0.0100
CH_4	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	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5272	0.5272	0.5272
CO_2	0.0003	0.0003	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0643	0.0643	0.0643
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0004	0.0004
H_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	0.2477	0.2477	0.2477
H_2O	0.0062	0.0062	0.1878	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0801	0.0801	0.0801
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0032	0.0032	0.0032
N_2	0.7761	0.7761	0.5200	0.0178	0.9920	0.9920	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0658	0.0658	0.0658
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0014	0.0014
O_2	0.2082	0.2082	0.2525	0.9504	0.0054	0.0054	0.9504	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	20,814	5,237	830	38	18,733	1,116	5,335	0	0	5,237	0	0	19,089	6,742	19,089
V-L Flowrate (kg/hr)	601,490	151,347	22,953	1,225	525,667	31,304	171,673	0	0	94,342	0	0	418,721	147,880	418,721
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	344,772	0	250,430	34,686	0	0	0
Temperature (°C)	4	408	21	32	196	195	32	---	4	32	71	1,371	1,371	245	232
Pressure (MPa, abs)	0.10	1.52	0.11	0.86	2.65	5.62	0.86	---	0.10	0.34	0.09	4.24	4.24	4.24	3.96
Enthalpy (kJ/kg)[A]	13.75	431.19	40.37	26.67	202.62	199.68	26.67	---	---	135.07	---	---	2,286.86	499.79	482.15
Density (kg/m^3)	1.2	7.7	1.5	11.0	18.9	39.8	11.0	---	---	986.5	---	---	6.8	21.4	20.5
V-L Molecular Weight	28.898	28.898	27.657	32.181	28.061	28.061	32.181	---	---	18.015	---	---	21.935	21.935	21.935
V-L Flowrate (lb_{mol}/hr)	45,888	11,546	1,830	84	41,299	2,459	11,761	0	0	11,545	0	0	42,084	14,863	42,084
V-L Flowrate (lb/hr)	1,326,060	333,663	50,603	2,700	1,158,897	69,013	378,475	0	0	207,989	0	0	923,122	326,020	923,122
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	760,093	0	552,104	76,470	0	0	0
Temperature (°F)	40	767	70	90	385	383	90	---	40	90	160	2,500	2,500	472	450
Pressure (psia)	13.8	220.4	16.4	125.0	385.0	815.0	125.0	---	13.8	50.0	13.5	614.7	614.7	615.0	574.7
Enthalpy (Btu/lb)[A]	5.9	185.4	17.4	11.5	87.1	85.8	11.5	---	---	58.1	---	---	983.2	214.9	207.3
Density (lb/ft^3)	0.074	0.482	0.097	0.687	1.183	2.485	0.687	---	---	61.584	---	---	0.422	1.335	1.280

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-20 Case L1A Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
V-L Mole Fraction																
Ar	0.0097	0.0109	0.0045	0.0108	0.0005	0.0000	0.0038	0.0110	0.0110	0.0093	0.0090	0.0090	0.0000	0.0000	0.0000	0.0000
CH_4	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	0.0000	0.0000
CO	0.5068	0.5728	0.0060	0.5620	0.0181	0.0000	0.0774	0.5734	0.5734	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0621	0.0702	0.6341	0.0813	0.5955	0.0000	0.4628	0.0706	0.0706	0.0003	0.0868	0.0868	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.2381	0.2691	0.0982	0.2659	0.0093	0.0000	0.0161	0.2713	0.2713	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.1153	0.0016	0.0323	0.0016	0.0079	0.0000	0.2502	0.0015	0.0015	0.0062	0.0415	0.0415	1.0000	1.0000	1.0000	1.0000
H_2S	0.0034	0.0038	0.0041	0.0038	0.1869	0.0000	0.0013	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0633	0.0715	0.2208	0.0745	0.1817	0.0000	0.1864	0.0722	0.0722	0.7761	0.7565	0.7565	0.0000	0.0000	0.0000	0.0000
NH_3	0.0013	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	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2082	0.1062	0.1062	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0018	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	19,855	17,568	352	17,910	367	0	417	17,543	17,543	106,961	130,591	130,591	39,860	19,306	19,306	39,167
V-L Flowrate (kg/hr)	432,511	391,337	12,445	403,595	14,075	0	13,601	389,520	389,520	3,090,914	3,854,769	3,854,769	718,096	347,804	347,804	705,610
Solids Flowrate (kg/hr)	0	0	0	0	0	2,157	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	177	35	49	35	40	176	138	42	196	4	589	132	561	32	32	33
Pressure (MPa, abs)	3.79	3.69	0.32	3.62	0.4	0.370	0.370	3.597	3.563	0.095	0.099	0.095	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	477.51	40.71	86.59	39.57	42.3	---	490.944	51.058	265.393	13.748	697.962	198.353	3,502.136	2,321.555	2,321.555	140.358
Density (kg/m^3)	22.0	32.1	4.3	32.0	6.2	5,283.3	3.6	30.5	20.0	1.2	0.4	0.8	35.1	0.04	0.04	995.0
V-L Molecular Weight	21.784	22.276	35.359	22.535	38	---	32.625	22.204	22.204	28.898	29.518	29.518	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	43,772	38,731	776	39,484	809	0	919	38,675	38,675	235,808	287,903	287,903	87,877	42,563	42,563	86,349
V-L Flowrate (lb/hr)	953,523	862,751	27,437	889,774	31,030	0	29,986	858,744	858,744	6,814,298	8,498,311	8,498,311	1,583,131	766,778	766,778	1,555,604
Solids Flowrate (lb/hr)	0	0	0	0	0	4,756	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	350	95	120	94	104	349	280	108	385	40	1,092	270	1,042	90	90	92
Pressure (psia)	549.7	534.7	46.5	524.7	60.0	53.6	53.6	521.7	516.7	13.8	14.3	13.8	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	205.3	17.5	37.2	17.0	18.2	---	211.1	22.0	114.1	5.9	300.1	85.3	1,505.6	998.1	998.1	60.3
Density (lb/ft^3)	1.374	2.006	0.266	1.996	0.386	329.828	0.222	1.902	1.251	0.074	0.025	0.052	2.192	0.002	0.002	62.116

3.2.5 Case S1A and L1A Performance Results

The non-capture SCGP IGCC plant using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 573 megawatt electric (MWe) at a net plant efficiency of 42.0 percent (HHV basis). The same plant configuration using lignite coal at the North Dakota site (elevation 1,900 ft) produces a net output of 617 MWe at a net plant efficiency of 41.8 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 3-21, which includes auxiliary power requirements. The ASU accounts for approximately 74 percent of the total auxiliary load, distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. Coal handling and drying account for approximately 10 percent of the auxiliary load. The cooling water system, including the CWPs and cooling tower fan, and the air-cooled condenser account for about 5 percent of the auxiliary load. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-21 Case S1A and L1A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	S1A	L1A
Gas Turbine Power	423,900	449,400
Steam Turbine Power	272,800	303,200
TOTAL POWER, kWe	**696,700**	**752,600**
AUXILIARY LOAD SUMMARY, kWe		
Coal Handling	500	600
Coal Milling	2,530	3,550
Slag Handling	540	900
WTA Coal Dryer Compressor	8,680	12,120
WTA Coal Dryer Auxiliaries	570	800
Air Separation Unit Auxiliaries	1,000	1,000
Air Separation Unit Main Air Compressor	52,530	52,190
Oxygen Compressor	8,250	9,400
Nitrogen Compressors	30,220	34,460
Boiler Feedwater Pumps	3,890	4,450
Condensate Pump	220	230
Syngas Recycle Compressor	840	760
Circulating Water Pump	1,970	2,230
Ground Water Pumps	160	170
Cooling Tower Fans	1,280	1,370
Air Cooled Condenser Fans	3,230	3,210
Scrubber Pumps	10	90
Acid Gas Removal	260	450
Gas Turbine Auxiliaries	1,000	1,000
Steam Turbine Auxiliaries	100	100
Claus Plant/TGTU Auxiliaries	250	250
Claus Plant TG Recycle Compressor	540	920
Miscellaneous Balance of Plant[1]	3,000	3,000
Transformer Losses	2,450	2,650
TOTAL AUXILIARIES, kWe	**124,020**	**135,900**
NET POWER, kWe	**572,680**	**616,700**
Net Plant Efficiency, % (HHV)	42.0%	41.8%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,563 (8,116)	8,605 (8,156)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	**1,445 (1,370)**	**1,519 (1,440)**
CONSUMABLES		
As-Received Coal Feed, kg/hr (lb/hr)	246,170 (542,713)	344,772 (760,093)
Thermal Input, kWt	1,362,134	1,474,011
Raw Water Withdrawal, m^3/min (gpm)	6.8 (1,792)	7.1 (1,879)
Raw Water Consumption, m^3/min (gpm)	5.1 (1,336)	5.2 (1,362)

[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 PM were presented in Section 2.3. A summary of the plant air emissions for the non-capture cases is presented in Exhibit 3-22.

Exhibit 3-22 Cases S1A and L1A Air Emissions

	kg/GJ (lb/10^6 Btu)		Tonne/year (ton/year) 80% capacity factor		kg/MWh (lb/MWh)	
	S1A	**L1A**	**S1A**	**L1A**	**S1A**	**L1A**
SO_2	0.001 (0.002)	0.001 (0.002)	33 (37)	37 (40)	0.007 (0.015)	0.007 (0.015)
NO_X	0.027 (0.062)	0.027 (0.063)	912 (1,005)	1,001 (1,103)	0.187 (0.412)	0.190 (0.418)
Particulates	0.003 (0.0071)	0.003 (0.0071)	105 (116)	114 (125)	0.021 (0.047)	0.022 (0.047)
Hg	1.51E-7 (3.51E-7)	2.41E-7 (5.60E-7)	0.005 (0.006)	0.009 (0.010)	1.06E-6 (2.34E-6)	1.70E-6 (3.74E-6)
CO_2 gross	91.9 (213.8)	94.0 (218.6)	3,158,977 (3,482,176)	3,494,523 (3,852,052)	647 (1,426)	663 (1,461)
CO_2 net					787 (1,735)	809 (1,783)

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 5 ppmv in both cases. This results in a concentration in the flue gas of less than 1 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 and recycled upstream of the AGR to capture most of the remaining sulfur. Because the environmental target was set based on higher sulfur bituminous coal, the resulting SO_2 emissions with lower sulfur western coals are substantially less than the environmental target.

NOx emissions are limited to 15 parts per million volume, dry (ppmvd) (as NO_2 @ 15 percent O_2) by the use of low NOx burners and nitrogen dilution of the fuel gas. 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 NOx 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 two cases is shown in Exhibit 3-23. 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 and as CO_2 in the stack gas and ASU vent gas.

Exhibit 3-23 Case S1A and L1A Carbon Balance

Carbon In, kg/hr (lb/hr)			Carbon Out, kg/hr (lb/hr)		
	S1A	**L1A**		**S1A**	**L1A**
Coal	123,253 (271,726)	136,370 (300,645)	**Slag**	616 (1,359)	682 (1,503)
Air (CO_2)	476 (1,049)	503 (1,110)	**Stack Gas**	123,022 (271,217)	136,089 (300,025)
			ASU Vent	90 (199)	103 (226)
Total	**123,729 (272,775)**	**136,874 (301,755)**	**Total**	**123,729 (272,775)**	**136,874 (301,755)**

Exhibit 3-24 shows the sulfur balance for the non-capture case. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-24 Cases S1A and L1A Sulfur Balance

Sulfur In, kg/hr (lb/hr)			Sulfur Out, kg/hr (lb/hr)		
	S1A	**L1A**		**S1A**	**L1A**
Coal	1,791 (3,948)	2,160 (4,761)	**Elemental Sulfur**	1,788 (3,943)	2,157 (4,756)
			Stack Gas	2 (5)	3 (6)
Total	**1,791 (3,948)**	**2,160 (4,761)**	**Total**	**1,791 (3,948)**	**2,160 (4,761)**

Exhibit 3-25 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 coal moisture from the drying process and syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is discharged from the process to a permitted outfall. The difference between the withdrawal and discharge is the consumption.

Exhibit 3-25 Case S1A and L1A Water Balance

Water Use	Water Demand m^3/min (gpm)		Internal Recycle m^3/min (gpm)		Raw Water Withdrawal m^3/min (gpm)		Process Water Discharge m^3/min (gpm)		Raw Water Consumption m3/min (gpm)	
	S1A	L1A	S1A	L1A	S1A	L1A	S1A	L1A	S1A	L1A
Slag Handling	**0.45 (119)**	**0.75 (199)**	**0.4 (112)**	**0.7 (179)**	**0.03 (7)**	**0.08 (20)**	**0 (0)**	**0 (0)**	**0.03 (7)**	**0.08 (20)**
SWS Blowdown	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0.00 (1.1)**	**0.01 (1.8)**	**0.00 (-1.1)**	**-0.01 (-1.8)**
Condenser Makeup	**0.15 (41)**	**0.17 (44)**	**0 (0)**	**0 (0)**	**0.15 (41)**	**0.17 (44)**	**0 (0)**	**0 (0)**	**0.15 (41)**	**0.17 (44)**
BFW Makeup	0.15 (41)	0.17 (44)			0.15 (41)	0.17 (44)				
Cooling Tower	**7.66 (2,024)**	**8.68 (2,293)**	**1.1 (280)**	**1.8 (478)**	**6.60 (1,744)**	**6.87 (1,815)**	**1.72 (455)**	**1.95 (516)**	**4.88 (1,289)**	**4.92 (1,300)**
Water from Coal Drying			0.9 (228)	1.6 (416)	-0.86 (-228)	-1.57 (-416)				
BFW Blowdown			0.2 (41)	0.2 (44)	-0.15 (-41)	-0.17 (-44)				
SWS Blowdown			0.0 (11)	0.1 (18)	-0.04 (-11)	-0.07 (-18)				
Total	**8.3 (2,184)**	**9.6 (2,536)**	**1.5 (392)**	**2.5 (657)**	**6.8 (1,792)**	**7.1 (1,879)**	**1.73 (456)**	**1.96 (518)**	**5.06 (1,336)**	**5.16 (1,362)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-26 and Exhibit 3-27:

- Coal gasification and ASU
- Syngas cleanup
- Combined cycle power generation

An overall plant energy balance is provided in tabular form in Exhibit 3-28 for the two cases. The power out is the combined CT and steam turbine power after generator losses.

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Exhibit 3-26 Case S1A Heat and Mass Balance

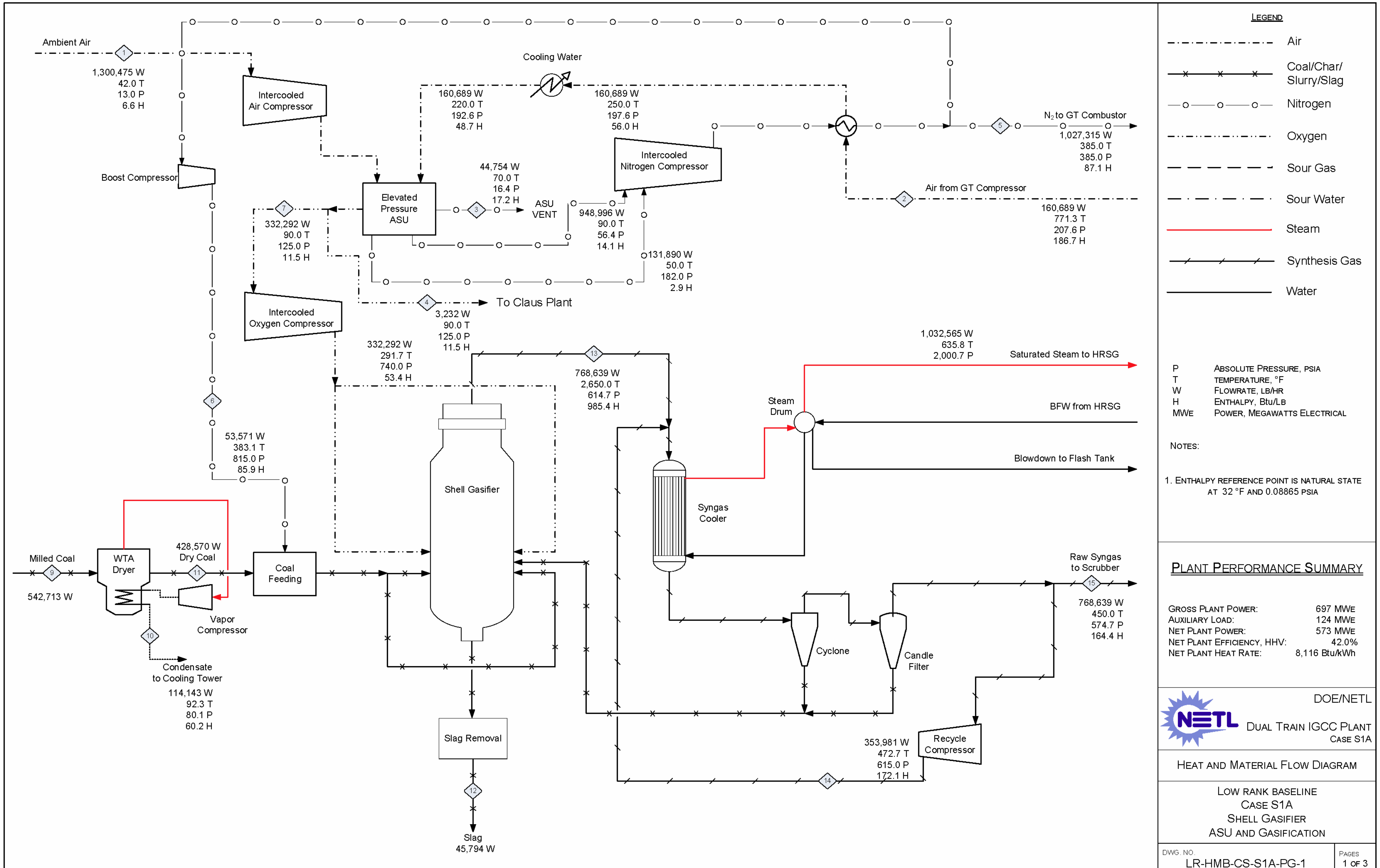


Exhibit 3-26 Case S1A Heat and Mass Balance (Continued)

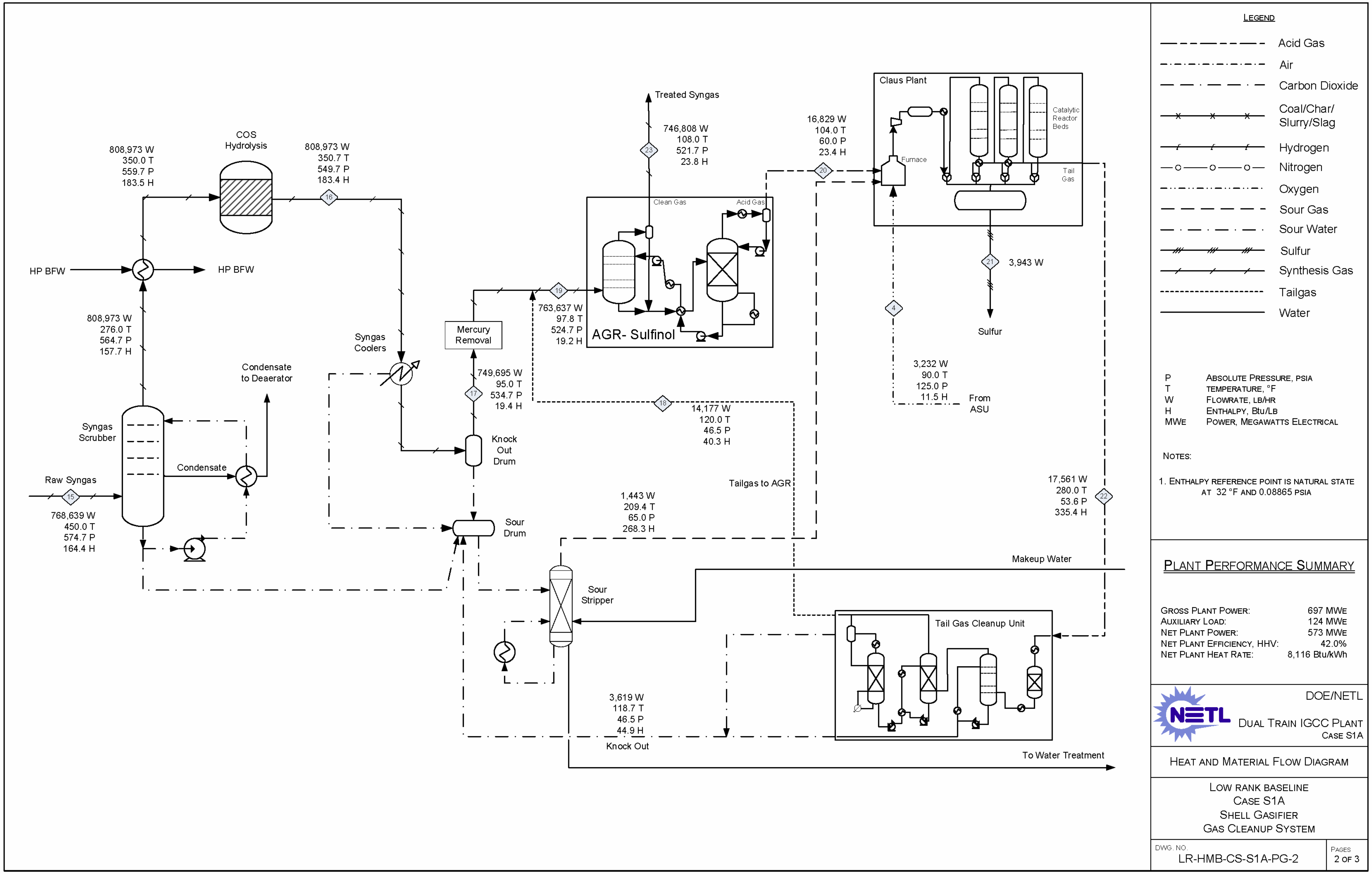


Exhibit 3-26 Case S1A Heat and Mass Balance (Continued)

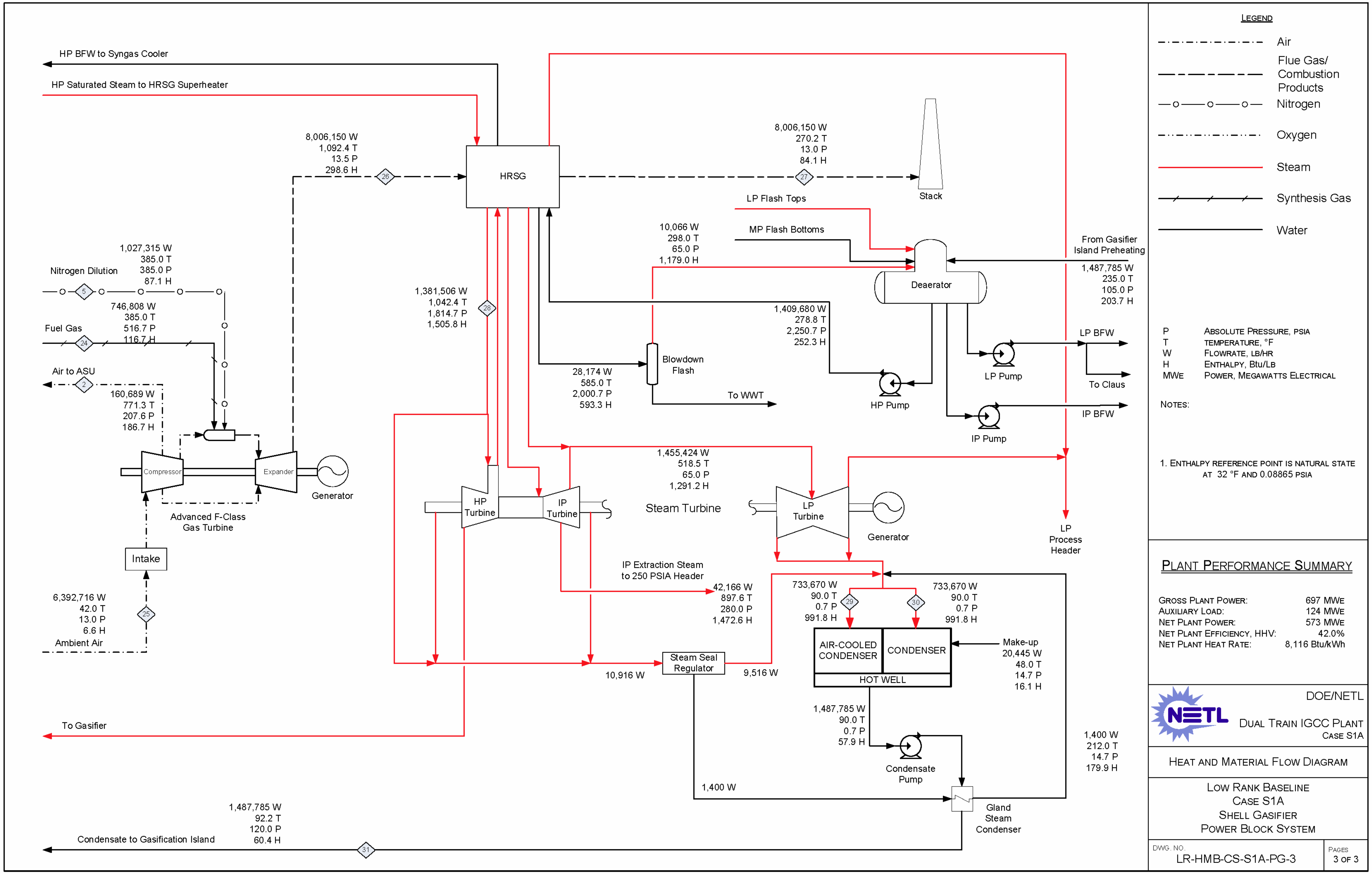
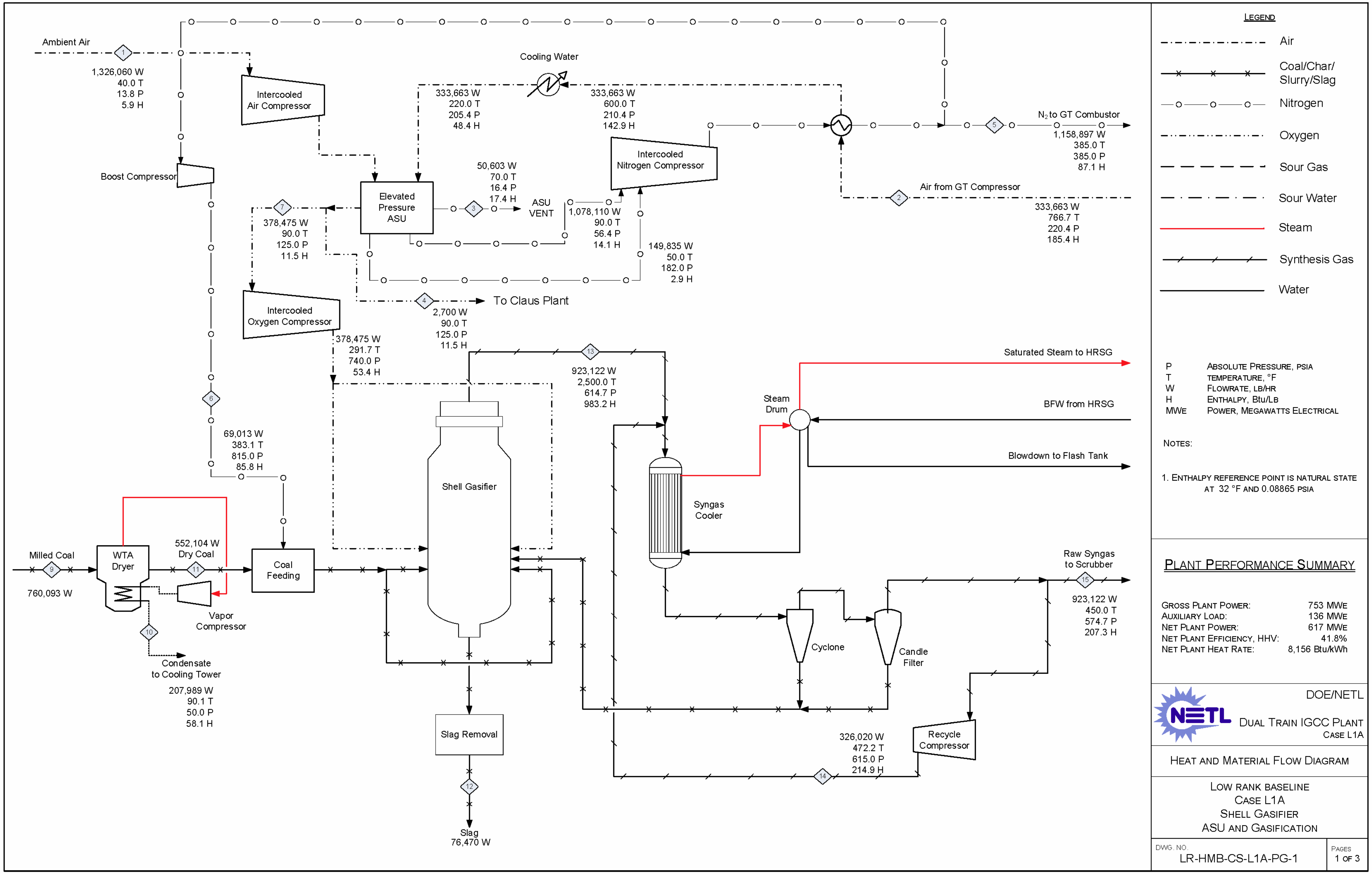


Exhibit 3-27 Case L1A Heat and Mass Balance



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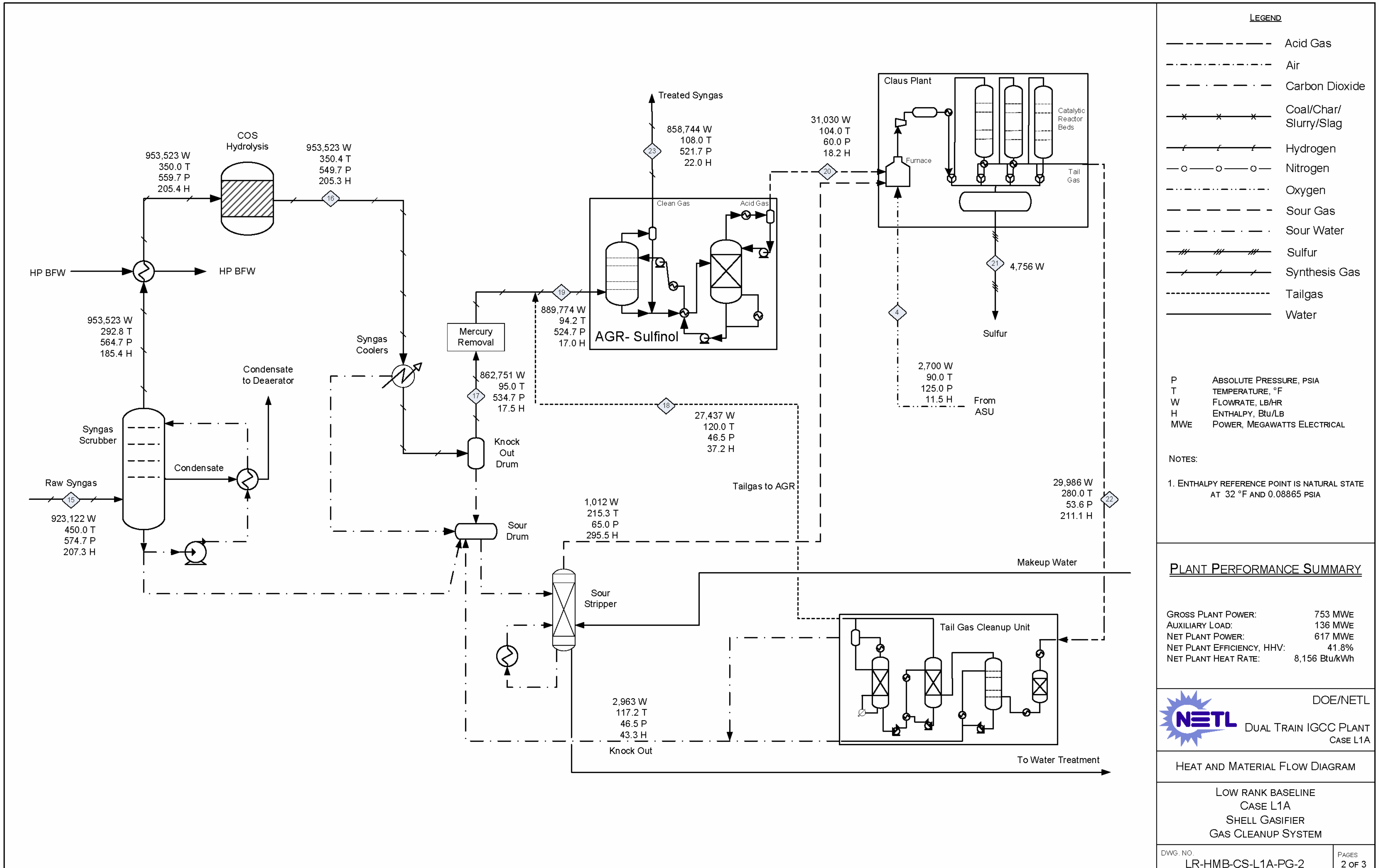

Exhibit 3-27 Case L1A Heat and Mass Balance (Continued)

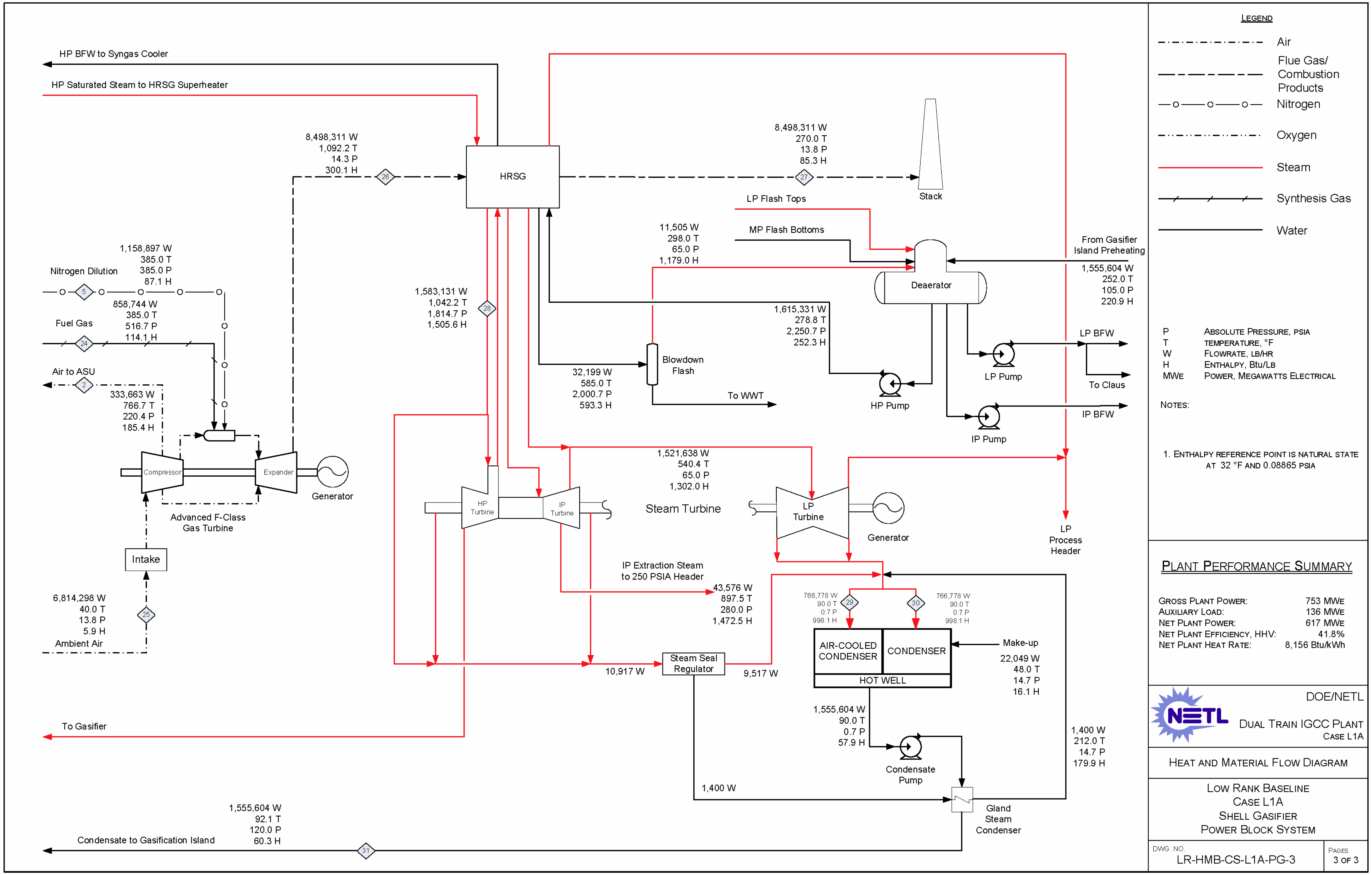

Exhibit 3-28 Cases S1A and L1A Energy Balance

	HHV		Sensible + Latent		Power		Total	
	S1A	L1A	S1A	L1A	S1A	L1A	S1A	L1A
Heat In GJ/hr (MMBtu/hr)								
Coal	4,904 (4,648)	5,306 (5,030)	2.5 (2.4)	3.1 (2.9)	0 (0)	0 (0)	4,906 (4,650)	5,310 (5,032)
ASU Air	0 (0)	0 (0)	9.0 (8.5)	8.3 (7.8)	0 (0)	0 (0)	9 (9)	8 (8)
GT Air	0 (0)	0 (0)	44.2 (41.9)	42.5 (40.3)	0 (0)	0 (0)	44 (42)	42 (40)
Raw Water Makeup	0 (0)	0 (0)	9.4 (8.9)	7.9 (7.5)	0 (0)	0 (0)	9 (9)	8 (8)
Auxiliary Power	0 (0)	0 (0)	0 (0)	0 (0)	446 (423)	489 (464)	446 (423)	489 (464)
Totals	**4,904 (4,648)**	**5,306 (5,030)**	**65.2 (61.8)**	**61.7 (58.5)**	**446 (423)**	**489 (464)**	**5,415 (5,133)**	**5,857 (5,552)**
Heat Out GJ/hr (MMBtu/hr)								
ASU Intercoolers	0 (0)	0 (0)	190 (181)	198 (188)	0 (0)	0 (0)	190 (181)	198 (188)
ASU Vent	0 (0)	0 (0)	0.8 (0.8)	0.9 (0.9)	0 (0)	0 (0)	1 (1)	1 (1)
Slag	20 (19)	22 (21)	36.0 (34.1)	55.5 (52.6)	0 (0)	0 (0)	56 (53)	78 (74)
Sulfur	17 (16)	20 (19)	0.2 (0.2)	0.2 (0.2)	0 (0)	0 (0)	17 (16)	20 (19)
Cooling Tower Blowdown	0 (0)	0 (0)	9.6 (9.1)	10.6 (10.0)	0 (0)	0 (0)	10 (9)	11 (10)
HRSG Flue Gas	0 (0)	0 (0)	710 (673)	765 (725)	0 (0)	0 (0)	710 (673)	765 (725)
Condenser	0 (0)	0 (0)	1,445 (1,369)	1,520 (1,441)	0 (0)	0 (0)	1,445 (1,369)	1,520 (1,441)
Auxiliary Cooling Load	0 (0)	0 (0)	25 (24)	86 (81)	0 (0)	0 (0)	25 (24)	86 (81)
Process Losses	0 (0)	0 (0)	453 (429)	470 (445)	0 (0)	0 (0)	453 (429)	470 (445)
Power	0 (0)	0 (0)	0 (0)	0 (0)	2,508 (2,377)	2,709 (2,568)	2,508 (2,377)	2,709 (2,568)
Totals	**37 (35)**	**42 (40)**	**2,870 (2,721)**	**3,106 (2,944)**	**2,508 (2,377)**	**2,709 (2,568)**	**5,415 (5,133)**	**5,857 (5,552)**

3.2.6 Case S1A and L1A Equipment Lists

Major equipment items for the SCGP 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	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	73 tonne (80 ton)	2	1
9	Feeder	Vibratory	200 tonne/hr (220 tph)	281 tonne/hr (310 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	408 tonne/hr (450 tph)	572 tonne/hr (630 tph)	1	0
11	Crusher Tower	N/A	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	200 tonne (220 ton)	281 tonne (310 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	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	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	408 tonne/hr (450 tph)	572 tonne/hr (630 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	408 tonne/hr (450 tph)	572 tonne/hr (630 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	907 tonne (1,000 ton)	1,270 tonne (1,400 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	91 tonne/hr (100 tph)	127 tonne/hr (140 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	272 tonne/hr (300 tph)	381 tonne/hr (420 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	544 tonne (600 ton)	762 tonne (840 ton)	1	0
4	Weigh Feeder	Belt	136 tonne/hr (150 tph)	191 tonne/hr (210 tph)	2	0
5	Pulverizer	Rotary	136 tonne/hr (150 tph)	191 tonne/hr (210 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	272 tonne (300 ton)	381 tonne (420 ton)	2	0
7	Coal Preheater	Water Heated Horizontal Rotary Kiln	Coal feed: 272 tonne/hr (300 tph) Heat duty: 30.1 GJ/hr (28.6 MMBtu/hr)	Coal feed: 381 tonne/hr (420 tph) Heat duty: 47 GJ/hr (44 MMBtu/hr)	1	0
8	Coal Dryer	Fluidized Bed with Internal Coils	Coal feed: 136 tonne/hr (150 tph) Heat duty: 75.8 GJ/hr (71.8 MMBtu/hr) Bed diameter: 11.9 m (39 ft)	Coal feed: 191 tonne/hr (210 tph) Heat duty: 136 GJ/hr (129 MMBtu/hr) Bed diameter: 14.0 m (46 ft)	2	0
9	Steam Compressor	Reciprocating, Multi-Stage	567 m^3/min (20,040 scfm) Suction - 0.09 MPa (13 psia) Discharge - 0.72 MPa (105 psia)	1034 m^3/min (36,510 scfm) Suction - 0.10 MPa (13.8 psia) Discharge - 0.52 MPa (75 psia)	2	0
10	Dryer Exhaust Filter	Hot Baghouse	Steam - 28,486 kg/hr (62,800 lb/hr) Temperature - 107°C (225°F)	Steam - 51,891 kg/hr (114,400 lb/hr) Temperature - 107°C (225°F)	2	0

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
11	Dry Coal Cooler	Water Cooled Horizontal Rotary Kiln	214 tonne/hr (236 tph) Heat duty - 12 GJ/hr (12 MMBtu/hr)	275 tonne/hr (304 tph) Heat duty - 17 GJ/hr (16 MMBtu/hr)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	594,310 liters (157,000 gal)	639,735 liters (169,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,208 lpm @ 91 m H_2O (1,640 gpm @ 300 ft H_2O)	6,511 lpm @ 91 m H_2O (1,720 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	412,769 kg/hr (910,000 lb/hr)	441,345 kg/hr (973,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,022 lpm @ 27 m H_2O (270 gpm @ 90 ft H_2O)	568 lpm @ 27 m H_2O (150 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,095 lpm @ 1,890 m H_2O (1,610 gpm @ 6,200 ft H_2O)	HP water: 7,003 lpm @ 1,890 m H_2O (1,850 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,514 lpm @ 223 m H_2O (400 gpm @ 730 ft H_2O)	IP water: 1,703 lpm @ 223 m H_2O (450 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	133 GJ/hr (126 MMBtu/hr) each	171 GJ/hr (162 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	47,696 lpm @ 21 m H_2O (12,600 gpm @ 70 ft H_2O)	61,324 lpm @ 21 m H_2O (16,200 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	1,893 lpm @ 18 m H_2O (500 gpm @ 60 ft H_2O)	2,006 lpm @ 18 m H_2O (530 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	3,823 lpm @ 268 m H_2O (1,010 gpm @ 880 ft H_2O)	4,013 lpm @ 268 m H_2O (1,060 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	416 lpm @ 49 m H_2O (110 gpm @ 160 ft H_2O)	606 lpm @ 49 m H_2O (160 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	196,841 liter (52,000 gal)	283,906 liter (75,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	189 lpm (50 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	3,266 tonne/day, 4.2 MPa (3,600 tpd, 615 psia)	4,536 tonne/day, 4.2 MPa (5,000 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	279,866 kg/hr (617,000 lb/hr) Heat duty: 510 GJ/hr (484 MMBtu/hr)	311,618 kg/hr (687,000 lb/hr) Heat duty: 577 GJ/hr (547 MMBtu/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	279,866 kg/hr (617,000 lb/hr) Design efficiency 90%	311,618 kg/hr (687,000 lb/hr) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	ceramic filters	ceramic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical up flow	191,870 kg/hr (423,000 lb/hr)	230,425 kg/hr (508,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	187,334 kg/hr (413,000 lb/hr)	215,910 kg/hr (476,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	186,880 kg/hr, 35°C, 3.6 MPa (412,000 lb/hr, 95°F, 525 psia)	215,456 kg/hr, 35°C, 3.6 MPa (475,000 lb/hr, 95°F, 525 psia)	2	0
8	Synthesis Gas Reheater	Shell and tube	186,426 kg/hr (411,000 lb/hr)	214,096 kg/hr (472,000 lb/hr)	2	0

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
9	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	191,870 kg/hr (423,000 lb/hr) syngas	230,425 kg/hr (508,000 lb/hr) syngas	2	0
10	ASU Main Air Compressor	Centrifugal, multi-stage	4,446 m^3/min @ 1.3 MPa (157,000 scfm @ 190 psia)	4,531 m^3/min @ 1.3 MPa (160,000 scfm @ 190 psia)	2	0
11	Cold Box	Vendor design	1,996 tonne/day (2,200 tpd) of 95% purity oxygen	2,268 tonne/day (2,500 tpd) of 95% purity oxygen	2	0
12	Oxygen Compressor	Centrifugal, multi-stage	1,019 m^3/min (36,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	1,161 m^3/min (41,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
13	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,341 m^3/min (118,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	3,794 m^3/min (134,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
14	Secondary Nitrogen Compressor	Centrifugal, single-stage	453 m^3/min (16,000 scfm) Suction - 2.7 MPa (390 psia) Discharge - 5.7 MPa (820 psia)	538 m^3/min (19,000 scfm) Suction - 2.7 MPa (390 psia) Discharge - 5.7 MPa (820 psia)	2	0
15	Transport Nitrogen Boost Compressor	Centrifugal, single-stage	187 m^3/min (6,600 scfm) Suction - 2.7 MPa (389 psia) Discharge - 5.6 MPa (815 psia)	244 m^3/min (8,600 scfm) Suction - 2.7 MPa (389 psia) Discharge - 5.6 MPa (815 psia)	2	0
16	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	39,916 kg/hr, 411°C, 1.4 MPa (88,000 lb/hr, 771°F, 208 psia)	83,461 kg/hr, 408°C, 1.5 MPa (184,000 lb/hr, 767°F, 220 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	186,880 kg/hr (412,000 lb/hr) 35°C (95°F) 3.7 MPa (535 psia)	215,456 kg/hr (475,000 lb/hr) 35°C (95°F) 3.7 MPa (535 psia)	2	0
2	Sulfur Plant	Claus type	47 tonne/day (52 tpd)	57 tonne/day (63 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	201,849 kg/hr (445,000 lb/hr) 177°C (350°F) 3.9 MPa (560 psia)	237,682 kg/hr (524,000 lb/hr) 177°C (350°F) 3.9 MPa (560 psia)	2	0
4	Acid Gas Removal Plant	Sulfinol	190,509 kg/hr (420,000 lb/hr) 37°C (98°F) 3.6 MPa (525 psia)	221,807 kg/hr (489,000 lb/hr) 35°C (94°F) 3.6 MPa (525 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	7,966 kg/hr (17,561 lb/hr) 232°C (450°F) 0.3 MPa (48.6 psia)	13,601 kg/hr (29,986 lb/hr) 232°C (450°F) 0.3 MPa (48.6 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	6,344 kg/hr (13986 lb/hr)	12,257 kg/hr (27023 lb/hr)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	S1A Design Condition	L1A Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	210 MW	225 MW	2	0
2	Gas Turbine Generator	TEWAC	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	250 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.6 m (20 ft) diameter	76 m (250 ft) high x 8.6 m (20 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 344,652 kg/hr, 12.4 MPa/561°C (759,828 lb/hr, 1,800 psig/1,042°F) Reheat steam - 337,721 kg/hr, 3.1 MPa/561°C (744,547 lb/hr, 452 psig/1,042°F)	Main steam - 394,953 kg/hr, 12.4 MPa/561°C (870,722 lb/hr, 1,800 psig/1,042°F) Reheat steam - 387,959 kg/hr, 3.1 MPa/561°C (855,304 lb/hr, 452 psig/1,042°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Steam Turbine	Commercially available	287 MW 12.4 MPa/561°C/561°C (1,800 psig/ 1,042°F/1,042°F)	319 MW 12.4 MPa/561°C/561°C (1,800 psig/ 1,042°F/1,042°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	320 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	833 GJ/hr (790 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 8°C (47°F), Water temperature rise 11°C (20°F)	1	0

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
4	Air-cooled Condenser	---	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	833 GJ/hr (790 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 4°C (40°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Circulating Water Pumps	Vertical, wet pit	196,841 lpm @ 30 m (52,000 gpm @ 100 ft)	223,339 lpm @ 30 m (59,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,097 GJ/hr (1,040 MMBtu/hr) heat duty	2°C (36°F) wet bulb / 8°C (47°F) CWT / 19°C (67°F) HWT / 1,245 GJ/hr (1,180 MMBtu/hr) heat duty	1	0

ACCOUNT 10 SLAG/ASH RECOVERY AND HANDLING

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	Slag Quench Tank	Water bath	219,554 liters (58,000 gal)	363,400 liters (96,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	19 tonne/hr (21 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/hr (13 tph)	19 tonne/hr (21 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	132,489 liters (35,000 gal)	219,554 liters (58,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	60,567 liters (16,000 gal)	98,421 liters (26,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	19 tonne/hr (21 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	19 tonne/hr (21 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	19 tonne/hr (21 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	185,485 liters (49,000 gal)	310,404 liters (82,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	76 lpm @ 14 m H_2O (20 gpm @ 46 ft H_2O)	2	2
11	Grey Water Storage Tank	Field erected	60,567 liters (16,000 gal)	98,421 liters (26,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 433 m H_2O (60 gpm @ 1,420 ft H_2O)	341 lpm @ 433 m H_2O (90 gpm @ 1,420 ft H_2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	1,361 tonne (1,500 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	163 tonne/hr (180 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	S1A Design Conditions	L1A Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	24 kV/345 kV, 250 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 320 MVA, 3-ph, 60 Hz	24 kV/345 kV, 350 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 55 MVA, 3-ph, 60 Hz	345 kV/13.8 kV, 60 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 28 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	S1A Design Conditions	L1A 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 S1A and L1A Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-29 shows the TPC summary organized by cost account for the PRB coal case (S1A) and Exhibit 3-33 shows the same information for the lignite coal case (L1A). A more detailed breakdown of the capital costs is shown in Exhibit 3-30 for S1A and Exhibit 3-34 for L1A. Exhibit 3-31 and Exhibit 3-35 show the addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-32 shows the initial and annual O&M costs for Case S1A and Exhibit 3-36 shows the same information for Case L1A.

The estimated TOC of the SCGP with no CO_2 capture using PRB coal is $3,056/kW and using lignite coal is $3,094/kW. Process contingency represents about 2 percent, project contingency represents 11 percent, and owner's costs represent 18 percent of TOC for the two cases. The COE is 83.2 mills/kWh in the PRB case and 83.5 mills/kWh in the lignite case.

Exhibit 3-29 Case S1A Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S1A - Shell IGCC w/o CO2										
	Plant Size:	572.7	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$15,272	$2,838	$11,843	$0	$0	$29,953	$2,719	$0	$6,534	$39,206	$68
2	COAL & SORBENT PREP & FEED	$114,839	$9,569	$19,594	$0	$0	$144,001	$12,493	$0	$31,299	$187,793	$328
3	FEEDWATER & MISC. BOP SYSTEMS	$7,631	$6,907	$6,754	$0	$0	$21,292	$1,996	$0	$5,177	$28,466	$50
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$177,839	$0	$76,848	$0	$0	$254,687	$22,725	$35,634	$47,895	$360,940	$630
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$149,195	$0	w/equip.	$0	$0	$149,195	$14,461	$0	$16,366	$180,022	$314
4.4-4.9	Other Gasification Equipment	$15,912	$9,909	$11,552	$0	$0	$37,373	$3,560	$0	$8,957	$49,890	$87
	SUBTOTAL 4	$342,946	$9,909	$88,401	$0	$0	$441,256	$40,746	$35,634	$73,217	$590,853	$1,032
5A	GAS CLEANUP & PIPING	$44,251	$2,654	$40,865	$0	$0	$87,771	$8,483	$81	$19,398	$115,732	$202
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$202
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$4
	SUBTOTAL 6	$85,752	$806	$7,162	$0	$0	$93,720	$8,883	$4,601	$11,092	$118,296	$207
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,735	$0	$4,655	$0	$0	$37,390	$3,555	$0	$4,094	$45,039	$79
7.2-7.9	SCR System, Ductwork and Stack	$3,449	$2,459	$3,253	$0	$0	$9,162	$850	$0	$1,630	$11,642	$20
	SUBTOTAL 7	$36,185	$2,459	$7,908	$0	$0	$46,552	$4,405	$0	$5,725	$56,681	$99
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,830	$0	$4,943	$0	$0	$33,773	$3,241	$0	$3,701	$40,715	$71
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$35,457	$992	$12,090	$0	$0	$48,540	$4,701	$0	$10,904	$64,145	$112
	SUBTOTAL 8	$64,287	$992	$17,034	$0	$0	$82,313	$7,941	$0	$14,605	$104,860	$183
9	COOLING WATER SYSTEM	$5,692	$5,857	$4,875	$0	$0	$16,424	$1,525	$0	$3,692	$21,640	$38
10	ASH/SPENT SORBENT HANDLING SYS	$18,383	$1,419	$9,122	$0	$0	$28,924	$2,775	$0	$3,463	$35,163	$61
11	ACCESSORY ELECTRIC PLANT	$27,278	$10,483	$20,837	$0	$0	$58,598	$5,040	$0	$12,002	$75,640	$132
12	INSTRUMENTATION & CONTROL	$10,120	$1,862	$6,520	$0	$0	$18,501	$1,677	$925	$3,516	$24,619	$43
13	IMPROVEMENTS TO SITE	$3,238	$1,909	$7,990	$0	$0	$13,137	$1,297	$0	$4,330	$18,764	$33
14	BUILDINGS & STRUCTURES	$0	$6,373	$7,345	$0	$0	$13,718	$1,249	$0	$2,453	$17,420	$30
	TOTAL COST	$775,873	$64,038	$256,248	$0	$0	$1,096,159	$101,228	$41,241	$196,504	$1,435,132	$2,506

Exhibit 3-30 Case S1A Total Plant Cost Details

Client: USDOE/NETL — **Report Date:** 2009-Oct-09
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S1A - Shell IGCC w/o CO2
Plant Size: 572.7 MW,net — **Estimate Type:** Conceptual — **Cost Base (Jun)** 2007 ($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	$4,010	$0	$1,960	$0	$0	$5,970	$535	$0	$1,301	$7,806	$14
1.2	Coal Stackout & Reclaim	$5,182	$0	$1,256	$0	$0	$6,439	$564	$0	$1,401	$8,404	$15
1.3	Coal Conveyors & Yd Crush	$4,818	$0	$1,243	$0	$0	$6,061	$532	$0	$1,319	$7,912	$14
1.4	Other Coal Handling	$1,261	$0	$288	$0	$0	$1,548	$135	$0	$337	$2,020	$4
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	$2,838	$7,096	$0	$0	$9,934	$952	$0	$2,177	$13,064	$23
	SUBTOTAL 1.	**$15,272**	**$2,838**	**$11,843**	**$0**	**$0**	**$29,953**	**$2,719**	**$0**	**$6,534**	**$39,206**	**$68**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$46,233	$2,777	$6,737	$0	$0	$55,747	$4,810	$0	$12,111	$72,669	$127
2.2	Prepared Coal Storage & Feed	$1,988	$476	$312	$0	$0	$2,775	$237	$0	$602	$3,615	$6
2.3	Dry Coal Injection System	$65,414	$759	$6,075	$0	$0	$72,248	$6,223	$0	$15,694	$94,165	$164
2.4	Misc.Coal Prep & Feed	$1,204	$876	$2,627	$0	$0	$4,708	$433	$0	$1,028	$6,169	$11
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	$4,681	$3,843	$0	$0	$8,523	$789	$0	$1,863	$11,175	$20
	SUBTOTAL 2.	**$114,839**	**$9,569**	**$19,594**	**$0**	**$0**	**$144,001**	**$12,493**	**$0**	**$31,299**	**$187,793**	**$328**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,854	$4,900	$2,587	$0	$0	$10,341	$958	$0	$2,260	$13,559	$24
3.2	Water Makeup & Pretreating	$311	$32	$174	$0	$0	$517	$49	$0	$170	$736	$1
3.3	Other Feedwater Subsystems	$1,561	$528	$475	$0	$0	$2,564	$230	$0	$559	$3,353	$6
3.4	Service Water Systems	$178	$366	$1,272	$0	$0	$1,816	$177	$0	$598	$2,591	$5
3.5	Other Boiler Plant Systems	$955	$370	$917	$0	$0	$2,242	$213	$0	$491	$2,945	$5
3.6	FO Supply Sys & Nat Gas	$303	$571	$533	$0	$0	$1,407	$136	$0	$308	$1,851	$3
3.7	Waste Treatment Equipment	$435	$0	$265	$0	$0	$700	$68	$0	$230	$998	$2
3.8	Misc. Power Plant Equipment	$1,036	$139	$532	$0	$0	$1,706	$165	$0	$561	$2,432	$4
	SUBTOTAL 3.	**$7,631**	**$6,907**	**$6,754**	**$0**	**$0**	**$21,292**	**$1,996**	**$0**	**$5,177**	**$28,466**	**$50**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$177,839	$0	$76,848	$0	$0	$254,687	$22,725	$35,634	$47,895	$360,940	$630
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$149,195	$0	w/equip.	$0	$0	$149,195	$14,461	$0	$16,366	$180,022	$314
4.4	LT Heat Recovery & FG Saturation	$15,912	$0	$6,049	$0	$0	$21,961	$2,143	$0	$4,821	$28,925	$51
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	Flare Stack System	$0	$921	$375	$0	$0	$1,296	$124	$0	$284	$1,704	$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	$8,988	$5,129	$0	$0	$14,117	$1,292	$0	$3,852	$19,261	$34
	SUBTOTAL 4.	**$342,946**	**$9,909**	**$88,401**	**$0**	**$0**	**$441,256**	**$40,746**	**$35,634**	**$73,217**	**$590,853**	**$1,032**

Exhibit 3-30 Case S1A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
					TOTAL PLANT COST SUMMARY							
	Case:	Case S1A - Shell IGCC w/o CO2										
	Plant Size:	572.7	MW,net	Estimate Type:		Conceptual				Cost Base (Jun)	2007	($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 System	$34,171	$0	$28,995	$0	$0	$63,165	$6,109	$0	$13,855	$83,129	$145
5A.2	Elemental Sulfur Plant	$4,852	$967	$6,260	$0	$0	$12,078	$1,173	$0	$2,650	$15,902	$28
5A.3	Mercury Removal	$920	$0	$700	$0	$0	$1,620	$156	$81	$371	$2,229	$4
5A.4	COS Hydrolysis	$2,912	$0	$3,802	$0	$0	$6,714	$653	$0	$1,473	$8,840	$15
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$1,397	$235	$132	$0	$0	$1,765	$167	$0	$386	$2,318	$4
5A.7	Fuel Gas Piping	$0	$722	$505	$0	$0	$1,227	$114	$0	$268	$1,609	$3
5A.9	HGCU Foundations	$0	$731	$471	$0	$0	$1,202	$110	$0	$394	$1,706	$3
	SUBTOTAL 5A.	**$44,251**	**$2,654**	**$40,865**	**$0**	**$0**	**$87,771**	**$8,483**	**$81**	**$19,398**	**$115,732**	**$202**
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	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$202
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$4
	SUBTOTAL 6.	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$207**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,735	$0	$4,655	$0	$0	$37,390	$3,555	$0	$4,094	$45,039	$79
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,768	$1,294	$0	$0	$3,062	$269	$0	$666	$3,997	$7
7.4	Stack	$3,449	$0	$1,296	$0	$0	$4,745	$455	$0	$520	$5,720	$10
7.9	HRSG,Duct & Stack Foundations	$0	$691	$664	$0	$0	$1,355	$126	$0	$444	$1,925	$3
	SUBTOTAL 7.	**$36,185**	**$2,459**	**$7,908**	**$0**	**$0**	**$46,552**	**$4,405**	**$0**	**$5,725**	**$56,681**	**$99**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,830	$0	$4,943	$0	$0	$33,773	$3,241	$0	$3,701	$40,715	$71
8.2	Turbine Plant Auxiliaries	$200	$0	$459	$0	$0	$659	$64	$0	$72	$795	$1
8.3a	Condenser & Auxiliaries	$2,973	$0	$950	$0	$0	$3,923	$375	$0	$430	$4,728	$8
8.3b	Air Cooled Condenser	$27,249	$0	$5,463	$0	$0	$32,711	$3,271	$0	$7,197	$43,179	$75
8.4	Steam Piping	$5,035	$0	$3,542	$0	$0	$8,577	$737	$0	$2,329	$11,643	$20
8.9	TG Foundations	$0	$992	$1,677	$0	$0	$2,669	$253	$0	$877	$3,799	$7
	SUBTOTAL 8.	**$64,287**	**$992**	**$17,034**	**$0**	**$0**	**$82,313**	**$7,941**	**$0**	**$14,605**	**$104,860**	**$183**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,928	$0	$714	$0	$0	$4,642	$442	$0	$763	$5,847	$10
9.2	Circulating Water Pumps	$1,021	$0	$57	$0	$0	$1,079	$91	$0	$175	$1,345	$2
9.3	Circ.Water System Auxiliaries	$93	$0	$13	$0	$0	$106	$10	$0	$17	$134	$0
9.4	Circ.Water Piping	$0	$3,885	$1,007	$0	$0	$4,893	$442	$0	$1,067	$6,402	$11
9.5	Make-up Water System	$191	$0	$274	$0	$0	$465	$45	$0	$102	$612	$1
9.6	Component Cooling Water Sys	$459	$549	$390	$0	$0	$1,398	$131	$0	$306	$1,834	$3
9.9	Circ.Water System Foundations	$0	$1,423	$2,419	$0	$0	$3,841	$364	$0	$1,262	$5,467	$10
	SUBTOTAL 9.	**$5,692**	**$5,857**	**$4,875**	**$0**	**$0**	**$16,424**	**$1,525**	**$0**	**$3,692**	**$21,640**	**$38**

Exhibit 3-30 Case S1A Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 2009-Oct-09
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S1A - Shell IGCC w/o CO2
Plant Size: 572.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,999	$0	$7,890	$0	$0	$23,888	$2,295	$0	$2,618	$28,802	$50
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$540	$0	$588	$0	$0	$1,128	$109	$0	$186	$1,423	$2
10.7	Ash Transport & Feed Equipment	$725	$0	$175	$0	$0	$900	$84	$0	$148	$1,131	$2
10.8	Misc. Ash Handling Equipment	$1,119	$1,372	$410	$0	$0	$2,901	$276	$0	$476	$3,653	$6
10.9	Ash/Spent Sorbent Foundation	$0	$48	$60	$0	$0	$108	$10	$0	$35	$153	$0
	SUBTOTAL 10.	**$18,383**	**$1,419**	**$9,122**	**$0**	**$0**	**$28,924**	**$2,775**	**$0**	**$3,463**	**$35,163**	**$61**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$919	$0	$909	$0	$0	$1,828	$175	$0	$200	$2,203	$4
11.2	Station Service Equipment	$3,872	$0	$349	$0	$0	$4,221	$389	$0	$461	$5,071	$9
11.3	Switchgear & Motor Control	$7,159	$0	$1,302	$0	$0	$8,460	$785	$0	$1,387	$10,632	$19
11.4	Conduit & Cable Tray	$0	$3,325	$10,970	$0	$0	$14,296	$1,383	$0	$3,920	$19,598	$34
11.5	Wire & Cable	$0	$6,354	$4,175	$0	$0	$10,528	$765	$0	$2,823	$14,117	$25
11.6	Protective Equipment	$0	$653	$2,375	$0	$0	$3,028	$296	$0	$499	$3,822	$7
11.7	Standby Equipment	$228	$0	$222	$0	$0	$450	$43	$0	$74	$567	$1
11.8	Main Power Transformers	$15,101	$0	$139	$0	$0	$15,239	$1,153	$0	$2,459	$18,851	$33
11.9	Electrical Foundations	$0	$151	$396	$0	$0	$546	$52	$0	$180	$778	$1
	SUBTOTAL 11.	**$27,278**	**$10,483**	**$20,837**	**$0**	**$0**	**$58,598**	**$5,040**	**$0**	**$12,002**	**$75,640**	**$132**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$999	$0	$667	$0	$0	$1,666	$158	$83	$286	$2,193	$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	$230	$0	$147	$0	$0	$377	$36	$19	$86	$518	$1
12.7	Computer & Accessories	$5,329	$0	$171	$0	$0	$5,500	$505	$275	$628	$6,907	$12
12.8	Instrument Wiring & Tubing	$0	$1,862	$3,806	$0	$0	$5,667	$481	$283	$1,608	$8,039	$14
12.9	Other I & C Equipment	$3,562	$0	$1,730	$0	$0	$5,292	$498	$265	$908	$6,963	$12
	SUBTOTAL 12.	**$10,120**	**$1,862**	**$6,520**	**$0**	**$0**	**$18,501**	**$1,677**	**$925**	**$3,516**	**$24,619**	**$43**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$102	$2,171	$0	$0	$2,273	$226	$0	$750	$3,248	$6
13.2	Site Improvements	$0	$1,807	$2,401	$0	$0	$4,208	$415	$0	$1,387	$6,011	$10
13.3	Site Facilities	$3,238	$0	$3,417	$0	$0	$6,655	$656	$0	$2,193	$9,505	$17
	SUBTOTAL 13.	**$3,238**	**$1,909**	**$7,990**	**$0**	**$0**	**$13,137**	**$1,297**	**$0**	**$4,330**	**$18,764**	**$33**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,427	$3,458	$0	$0	$5,885	$541	$0	$964	$7,390	$13
14.3	Administration Building	$0	$828	$601	$0	$0	$1,429	$127	$0	$233	$1,790	$3
14.4	Circulation Water Pumphouse	$0	$163	$86	$0	$0	$249	$22	$0	$41	$311	$1
14.5	Water Treatment Buildings	$0	$260	$254	$0	$0	$513	$46	$0	$84	$644	$1
14.6	Machine Shop	$0	$424	$290	$0	$0	$714	$63	$0	$117	$894	$2
14.7	Warehouse	$0	$684	$442	$0	$0	$1,126	$100	$0	$184	$1,410	$2
14.8	Other Buildings & Structures	$0	$409	$318	$0	$0	$727	$65	$0	$158	$950	$2
14.9	Waste Treating Building & Str.	$0	$914	$1,746	$0	$0	$2,660	$248	$0	$582	$3,489	$6
	SUBTOTAL 14.	**$0**	**$6,373**	**$7,345**	**$0**	**$0**	**$13,718**	**$1,249**	**$0**	**$2,453**	**$17,420**	**$30**
	TOTAL COST	**$775,873**	**$64,038**	**$256,248**	**$0**	**$0**	**$1,096,159**	**$101,228**	**$41,241**	**$196,504**	**$1,435,132**	**$2,506**

Exhibit 3-31 Case S1A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$13,195	$23
1 Month Variable O&M	$3,363	$6
25% of 1 Months Fuel Cost at 100% CF	$754	$1
2% of TPC	$28,703	$50
Total	**$46,014**	**$80**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,151	$11
0.5% of TPC (spare parts)	$7,176	$13
Total	**$13,326**	**$23**
Initial Cost for Catalyst and Chemicals	**$799**	**$1**
Land	**$900**	**$2**
Other Owner's Costs	**$215,270**	**$376**
Financing Costs	**$38,749**	**$68**
Total Owner's Costs	**$315,058**	**$550**
Total Overnight Cost (TOC)	**$1,750,189**	**$3,056**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$1,995,216**	**$3,484**

Exhibit 3-32 Case S1A Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES						
Case S1A - Shell IGCC w/o CO2					Cost Base (Jun):	2007
					Heat Rate-net (Btu/kWh):	8115
					MWe-net:	573
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$5,918,913	$10.335
Maintenance Labor Cost					$15,192,490	$26.529
Administrative & Support Labor					$5,277,851	$9.216
Property Taxes and Insurance					$28,702,632	$50.120
TOTAL FIXED OPERATING COSTS					**$55,091,886**	**$96.200**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$28,677,180**	**$0.00715**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	1,290	1.08	**$0**	**$407,294**	**$0.00010**
Chemicals						
MU & WT Chem.(lbs)	0	7,683	0.17	$0	$388,246	$0.00010
Carbon (Mercury Removal) (lb)	64,000	88	1.05	$67,211	$26,884	$0.00001
COS Catalyst (m3)	257	0.18	2,397.36	$616,357	$123,271	$0.00003
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0	$0.00000
Sulfinol Solution (gal)	11,507	8	10.05	$115,630	$22,945	$0.00001
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.	0.72	131.27	$0	$27,465	$0.00001
Subtotal Chemicals				**$799,198**	**$588,813**	**$0.00015**
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	88	0.42	$0	$10,677	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	550	16.23	$0	$2,603,499	$0.00065
Subtotal Waste Disposal				**$0**	**$2,614,176**	**$0.00065**
By-products & Emissions						
Sulfur (tons)	0	47	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$799,198**	**$32,287,462**	**$0.00805**
Fuel (ton)	0	6,513	15.22	**$0**	**$28,937,267**	**$0.00721**

Exhibit 3-33 Case L1A Total Plant Cost Summary

Client: USDOE/NETL — **Report Date:** 2010-Jan-20
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L1A - Shell IGCC w/o CO2
Plant Size: 616.7 MW,net — **Estimate Type:** Conceptual — **Cost Base (Jun)** 2007 ($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	$18,819	$3,497	$14,594	$0	$0	**$36,910**	$3,350	$0	$8,052	**$48,312**	$78
2	COAL & SORBENT PREP & FEED	$140,634	$11,900	$24,207	$0	$0	**$176,741**	$15,335	$0	$38,415	**$230,491**	$374
3	FEEDWATER & MISC. BOP SYSTEM	$8,213	$7,525	$7,209	$0	$0	**$22,947**	$2,150	$0	$5,559	**$30,656**	$50
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (S	$183,394	$0	$79,368	$0	$0	**$262,762**	$23,441	$36,845	$49,395	**$372,443**	$604
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$161,830	$0	w/equip.	$0	$0	**$161,830**	$15,686	$0	$17,752	**$195,268**	$317
4.4-4.9	Other Gasification Equipment	$17,853	$11,411	$13,127	$0	$0	**$42,390**	$4,036	$0	$10,174	**$56,600**	$92
	SUBTOTAL 4	**$363,076**	**$11,411**	**$92,495**	**$0**	**$0**	**$466,982**	**$43,163**	**$36,845**	**$77,321**	**$624,311**	**$1,012**
5A	GAS CLEANUP & PIPING	$49,333	$2,938	$45,661	$0	$0	**$97,932**	$9,465	$88	$21,641	**$129,126**	$209
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	**$92,021**	$8,724	$4,601	$10,535	**$115,881**	$188
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$4
	SUBTOTAL 6	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$192**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,161	$0	$4,857	$0	$0	**$39,019**	$3,710	$0	$4,273	**$47,001**	$76
7.2-7.9	SCR System, Ductwork and Stack	$3,447	$2,457	$3,250	$0	$0	**$9,154**	$849	$0	$1,629	**$11,632**	$19
	SUBTOTAL 7	**$37,608**	**$2,457**	**$8,108**	**$0**	**$0**	**$48,173**	**$4,559**	**$0**	**$5,902**	**$58,633**	**$95**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$31,044	$0	$5,379	$0	$0	**$36,423**	$3,495	$0	$3,992	**$43,910**	$71
8.2-8.9	Turbine Plant Auxiliaries and Steam Pip	$37,097	$1,072	$12,854	$0	$0	**$51,022**	$4,935	$0	$11,495	**$67,452**	$109
	SUBTOTAL 8	**$68,140**	**$1,072**	**$18,233**	**$0**	**$0**	**$87,445**	**$8,430**	**$0**	**$15,487**	**$111,362**	**$181**
9	COOLING WATER SYSTEM	$6,199	$6,318	$5,258	$0	$0	**$17,774**	$1,650	$0	$3,991	**$23,415**	$38
10	ASH/SPENT SORBENT HANDLING S	$25,382	$1,887	$12,592	$0	$0	**$39,861**	$3,824	$0	$4,759	**$48,444**	$79
11	ACCESSORY ELECTRIC PLANT	$28,874	$10,987	$21,847	$0	$0	**$61,708**	$5,304	$0	$12,626	**$79,638**	$129
12	INSTRUMENTATION & CONTROL	$10,381	$1,910	$6,688	$0	$0	**$18,979**	$1,720	$949	$3,607	**$25,255**	$41
13	IMPROVEMENTS TO SITE	$3,359	$1,980	$8,288	$0	$0	**$13,627**	$1,345	$0	$4,492	**$19,464**	$32
14	BUILDINGS & STRUCTURES	$0	$6,624	$7,665	$0	$0	**$14,289**	$1,302	$0	$2,551	**$18,142**	$29
	TOTAL COST	**$845,770**	**$71,311**	**$280,008**	**$0**	**$0**	**$1,197,089**	**$110,482**	**$42,483**	**$215,494**	**$1,565,547**	**$2,539**

Exhibit 3-34 Case L1A Total Plant Cost Details

Client: USDOE/NETL — **Report Date:** 2010-Jan-20

Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L1A - Shell IGCC w/o CO2

Plant Size: 616.7 MW,net — **Estimate Type:** Conceptual — **Cost Base (Jun)** 2007 ($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	$4,942	$0	$2,415	$0	$0	$7,357	$659	$0	$1,603	$9,619	$16
1.2	Coal Stackout & Reclaim	$6,386	$0	$1,548	$0	$0	$7,934	$695	$0	$1,726	$10,356	$17
1.3	Coal Conveyors & Yd Crush	$5,937	$0	$1,532	$0	$0	$7,469	$656	$0	$1,625	$9,750	$16
1.4	Other Coal Handling	$1,553	$0	$354	$0	$0	$1,908	$167	$0	$415	$2,490	$4
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	$3,497	$8,744	$0	$0	$12,242	$1,173	$0	$2,683	$16,098	$26
	SUBTOTAL 1.	**$18,819**	**$3,497**	**$14,594**	**$0**	**$0**	**$36,910**	**$3,350**	**$0**	**$8,052**	**$48,312**	**$78**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$57,744	$3,469	$8,414	$0	$0	$69,627	$6,008	$0	$15,127	$90,762	$147
2.2	Prepared Coal Storage & Feed	$2,400	$574	$376	$0	$0	$3,351	$287	$0	$727	$4,365	$7
2.3	Dry Coal Injection System	$78,986	$917	$7,335	$0	$0	$87,238	$7,514	$0	$18,950	$113,702	$184
2.4	Misc.Coal Prep & Feed	$1,504	$1,094	$3,282	$0	$0	$5,880	$540	$0	$1,284	$7,705	$12
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	$5,846	$4,800	$0	$0	$10,646	$986	$0	$2,326	$13,958	$23
	SUBTOTAL 2.	**$140,634**	**$11,900**	**$24,207**	**$0**	**$0**	**$176,741**	**$15,335**	**$0**	**$38,415**	**$230,491**	**$374**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$3,147	$5,404	$2,853	$0	$0	$11,404	$1,057	$0	$2,492	$14,953	$24
3.2	Water Makeup & Pretreating	$322	$34	$180	$0	$0	$535	$51	$0	$176	$762	$1
3.3	Other Feedwater Subsystems	$1,722	$582	$524	$0	$0	$2,827	$254	$0	$616	$3,698	$6
3.4	Service Water Systems	$184	$379	$1,316	$0	$0	$1,879	$183	$0	$619	$2,681	$4
3.5	Other Boiler Plant Systems	$988	$383	$949	$0	$0	$2,319	$220	$0	$508	$3,047	$5
3.6	FO Supply Sys & Nat Gas	$317	$598	$558	$0	$0	$1,472	$142	$0	$323	$1,937	$3
3.7	Waste Treatment Equipment	$450	$0	$274	$0	$0	$724	$71	$0	$238	$1,033	$2
3.8	Misc. Power Plant Equipment	$1,084	$145	$557	$0	$0	$1,786	$172	$0	$587	$2,545	$4
	SUBTOTAL 3.	**$8,213**	**$7,525**	**$7,209**	**$0**	**$0**	**$22,947**	**$2,150**	**$0**	**$5,559**	**$30,656**	**$50**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (S	$183,394	$0	$79,368	$0	$0	$262,762	$23,441	$36,845	$49,395	$372,443	$604
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$161,830	$0	w/equip.	$0	$0	$161,830	$15,686	$0	$17,752	$195,268	$317
4.4	LT Heat Recovery & FG Saturation	$17,853	$0	$6,787	$0	$0	$24,639	$2,405	$0	$5,409	$32,453	$53
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	Flare Stack System	$0	$1,042	$424	$0	$0	$1,467	$141	$0	$321	$1,929	$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	$10,368	$5,916	$0	$0	$16,284	$1,491	$0	$4,444	$22,219	$36
	SUBTOTAL 4.	**$363,076**	**$11,411**	**$92,495**	**$0**	**$0**	**$466,982**	**$43,163**	**$36,845**	**$77,321**	**$624,311**	**$1,012**

Exhibit 3-34 Case L1A Total Plant Cost Details (Continued)

Client: USDOE/NETL — **Report Date:** 2010-Jan-20

Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L1A - Shell IGCC w/o CO2

Plant Size: 616.7 MW,net — **Estimate Type:** Conceptual — **Cost Base (Jun)** 2007 ($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	Sulfinol System	$38,030	$0	$32,269	$0	$0	$70,300	$6,799	$0	$15,420	$92,518	$150
5A.2	Elemental Sulfur Plant	$5,501	$1,096	$7,097	$0	$0	$13,695	$1,330	$0	$3,005	$18,030	$29
5A.3	Mercury Removal	$996	$0	$758	$0	$0	$1,754	$169	$88	$402	$2,413	$4
5A.4	COS Hydrolysis	$3,312	$0	$4,326	$0	$0	$7,638	$743	$0	$1,676	$10,057	$16
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$1,494	$251	$141	$0	$0	$1,886	$179	$0	$413	$2,478	$4
5A.7	Fuel Gas Piping	$0	$790	$553	$0	$0	$1,344	$125	$0	$294	$1,762	$3
5A.9	HGCU Foundations	$0	$800	$516	$0	$0	$1,316	$121	$0	$431	$1,868	$3
	SUBTOTAL 5A.	**$49,333**	**$2,938**	**$45,661**	**$0**	**$0**	**$97,932**	**$9,465**	**$88**	**$21,641**	**$129,126**	**$209**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$188
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$4
	SUBTOTAL 6.	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$192**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,161	$0	$4,857	$0	$0	$39,019	$3,710	$0	$4,273	$47,001	$76
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,767	$1,292	$0	$0	$3,059	$269	$0	$666	$3,993	$6
7.4	Stack	$3,447	$0	$1,295	$0	$0	$4,741	$454	$0	$520	$5,715	$9
7.9	HRSG,Duct & Stack Foundations	$0	$691	$663	$0	$0	$1,354	$126	$0	$444	$1,924	$3
	SUBTOTAL 7.	**$37,608**	**$2,457**	**$8,108**	**$0**	**$0**	**$48,173**	**$4,559**	**$0**	**$5,902**	**$58,633**	**$95**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$31,044	$0	$5,379	$0	$0	$36,423	$3,495	$0	$3,992	$43,910	$71
8.2	Turbine Plant Auxiliaries	$216	$0	$495	$0	$0	$711	$70	$0	$78	$859	$1
8.3a	Condenser & Auxiliaries	$3,083	$0	$985	$0	$0	$4,068	$389	$0	$446	$4,903	$8
8.3b	Air Cooled Condenser	$28,258	$0	$5,665	$0	$0	$33,923	$3,392	$0	$7,463	$44,779	$73
8.4	Steam Piping	$5,539	$0	$3,896	$0	$0	$9,436	$811	$0	$2,562	$12,808	$21
8.9	TG Foundations	$0	$1,072	$1,812	$0	$0	$2,883	$273	$0	$947	$4,104	$7
	SUBTOTAL 8.	**$68,140**	**$1,072**	**$18,233**	**$0**	**$0**	**$87,445**	**$8,430**	**$0**	**$15,487**	**$111,362**	**$181**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,291	$0	$780	$0	$0	$5,071	$483	$0	$833	$6,387	$10
9.2	Circulating Water Pumps	$1,116	$0	$65	$0	$0	$1,181	$99	$0	$192	$1,472	$2
9.3	Circ.Water System Auxiliaries	$100	$0	$14	$0	$0	$115	$11	$0	$19	$145	$0
9.4	Circ.Water Piping	$0	$4,191	$1,087	$0	$0	$5,278	$477	$0	$1,151	$6,906	$11
9.5	Make-up Water System	$197	$0	$282	$0	$0	$479	$46	$0	$105	$630	$1
9.6	Component Cooling Water Sys	$495	$592	$421	$0	$0	$1,508	$141	$0	$330	$1,979	$3
9.9	Circ.Water System Foundations	$0	$1,535	$2,609	$0	$0	$4,144	$393	$0	$1,361	$5,898	$10
	SUBTOTAL 9.	**$6,199**	**$6,318**	**$5,258**	**$0**	**$0**	**$17,774**	**$1,650**	**$0**	**$3,991**	**$23,415**	**$38**

Exhibit 3-34 Case L1A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL							**Report Date:**	2010-Jan-20		
	Project:	Low Rank Western Coal Baseline Study										
					TOTAL PLANT COST SUMMARY							
	Case:	Case L1A - Shell IGCC w/o CO2										
	Plant Size:	616.7	MW,net	**Estimate Type:**			Conceptual		**Cost Base (Jun)**	2007	($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**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$22,213	$0	$10,954	$0	$0	$33,167	$3,187	$0	$3,635	$39,989	$65
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$718	$0	$782	$0	$0	$1,500	$145	$0	$247	$1,892	$3
10.7	Ash Transport & Feed Equipment	$963	$0	$232	$0	$0	$1,196	$112	$0	$196	$1,503	$2
10.8	Misc. Ash Handling Equipment	$1,488	$1,823	$545	$0	$0	$3,855	$367	$0	$633	$4,856	$8
10.9	Ash/Spent Sorbent Foundation	$0	$64	$80	$0	$0	$143	$13	$0	$47	$204	$0
	SUBTOTAL 10.	**$25,382**	**$1,887**	**$12,592**	**$0**	**$0**	**$39,861**	**$3,824**	**$0**	**$4,759**	**$48,444**	**$79**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$961	$0	$951	$0	$0	$1,912	$183	$0	$209	$2,304	$4
11.2	Station Service Equipment	$4,056	$0	$366	$0	$0	$4,422	$408	$0	$483	$5,312	$9
11.3	Switchgear & Motor Control	$7,499	$0	$1,364	$0	$0	$8,863	$822	$0	$1,453	$11,137	$18
11.4	Conduit & Cable Tray	$0	$3,483	$11,492	$0	$0	$14,975	$1,448	$0	$4,106	$20,529	$33
11.5	Wire & Cable	$0	$6,656	$4,373	$0	$0	$11,029	$801	$0	$2,958	$14,788	$24
11.6	Protective Equipment	$0	$689	$2,507	$0	$0	$3,196	$312	$0	$526	$4,035	$7
11.7	Standby Equipment	$236	$0	$231	$0	$0	$467	$45	$0	$77	$588	$1
11.8	Main Power Transformers	$16,121	$0	$147	$0	$0	$16,268	$1,231	$0	$2,625	$20,123	$33
11.9	Electrical Foundations	$0	$159	$418	$0	$0	$577	$55	$0	$190	$822	$1
	SUBTOTAL 11.	**$28,874**	**$10,987**	**$21,847**	**$0**	**$0**	**$61,708**	**$5,304**	**$0**	**$12,626**	**$79,638**	**$129**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,025	$0	$684	$0	$0	$1,709	$162	$85	$293	$2,250	$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	$236	$0	$151	$0	$0	$387	$37	$19	$88	$531	$1
12.7	Computer & Accessories	$5,466	$0	$175	$0	$0	$5,641	$518	$282	$644	$7,085	$11
12.8	Instrument Wiring & Tubing	$0	$1,910	$3,904	$0	$0	$5,814	$493	$291	$1,649	$8,247	$13
12.9	Other I & C Equipment	$3,654	$0	$1,774	$0	$0	$5,428	$511	$271	$932	$7,142	$12
	SUBTOTAL 12.	**$10,381**	**$1,910**	**$6,688**	**$0**	**$0**	**$18,979**	**$1,720**	**$949**	**$3,607**	**$25,255**	**$41**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$105	$2,253	$0	$0	$2,358	$234	$0	$778	$3,370	$5
13.2	Site Improvements	$0	$1,875	$2,491	$0	$0	$4,366	$431	$0	$1,439	$6,235	$10
13.3	Site Facilities	$3,359	$0	$3,545	$0	$0	$6,904	$681	$0	$2,275	$9,860	$16
	SUBTOTAL 13.	**$3,359**	**$1,980**	**$8,288**	**$0**	**$0**	**$13,627**	**$1,345**	**$0**	**$4,492**	**$19,464**	**$32**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,586	$3,684	$0	$0	$6,270	$577	$0	$1,027	$7,874	$13
14.3	Administration Building	$0	$847	$615	$0	$0	$1,462	$130	$0	$239	$1,831	$3
14.4	Circulation Water Pumphouse	$0	$167	$88	$0	$0	$255	$22	$0	$42	$319	$1
14.5	Water Treatment Buildings	$0	$269	$262	$0	$0	$531	$48	$0	$87	$666	$1
14.6	Machine Shop	$0	$434	$297	$0	$0	$730	$65	$0	$119	$914	$1
14.7	Warehouse	$0	$700	$452	$0	$0	$1,152	$102	$0	$188	$1,442	$2
14.8	Other Buildings & Structures	$0	$419	$326	$0	$0	$746	$67	$0	$162	$975	$2
14.9	Waste Treating Building & Str.	$0	$937	$1,791	$0	$0	$2,729	$254	$0	$597	$3,580	$6
	SUBTOTAL 14.	**$0**	**$6,624**	**$7,665**	**$0**	**$0**	**$14,289**	**$1,302**	**$0**	**$2,551**	**$18,142**	**$29**
	TOTAL COST	**$845,770**	**$71,311**	**$280,008**	**$0**	**$0**	**$1,197,089**	**$110,482**	**$42,483**	**$215,494**	**$1,565,547**	**$2,539**

Exhibit 3-35 Case L1A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$13,821	$22
1 Month Variable O&M	$3,711	$6
25% of 1 Months Fuel Cost at 100% CF	$757	$1
2% of TPC	$31,311	$51
Total	**$49,601**	**$80**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,199	$10
0.5% of TPC (spare parts)	$7,828	$13
Total	**$14,027**	**$23**
Initial Cost for Catalyst and Chemicals	**$1,024**	**$2**
Land	**$900**	**$1**
Other Owner's Costs	**$234,832**	**$381**
Financing Costs	**$42,270**	**$69**
Total Owner's Costs	**$342,653**	**$556**
Total Overnight Cost (TOC)	**$1,908,200**	**$3,094**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$2,175,349**	**$3,527**

Exhibit 3-36 Case L1A Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES						
Case L1A - Shell IGCC w/o CO2					Cost Base (Jun):	2007
					Heat Rate-net (Btu/kWh):	8156
					MWe-net:	617
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$5,918,913	$9.598
Maintenance Labor Cost					$16,194,989	$26.261
Administrative & Support Labor					$5,528,476	$8.965
Property Taxes and Insurance					$31,310,940	$50.772
TOTAL FIXED OPERATING COSTS					**$58,953,318**	**$95.595**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$30,180,929**	**$0.00698**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	1,353	1.08	**$0**	**$427,306**	**$0.00010**
Chemicals						
MU & WT Chem.(lbs)	0	8,060	0.17	$0	$407,323	$0.00009
Carbon (Mercury Removal) (lb)	71,689	98	1.05	$75,286	$30,114	$0.00001
COS Catalyst (m3)	298	0.20	2,397.36	$714,200	$142,840	$0.00003
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0	$0.00000
Sulfinol Solution (gal)	23,349	16	10.05	$234,627	$46,573	$0.00001
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.	0.85	131.27	$0	$32,615	$0.00001
Subtotal Chemicals				**$1,024,112**	**$659,465**	**$0.00015**
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	98	0.42	$0	$11,960	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	918	16.23	$0	$4,347,545	$0.00101
Subtotal Waste Disposal				**$0**	**$4,359,504**	**$0.00101**
By-products & Emissions						
Sulfur (tons)	0	57	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,024,112**	**$35,627,205**	**$0.00824**
Fuel (ton)	0	9,121	10.92	**$0**	**$29,082,622**	**$0.00673**

3.2.8 SCGP IGCC CO_2 Capture Cases (S1B and L1B) Process Description

Cases S1B and L1B are configured to produce electric power with CO_2 capture. The plant configurations are similar to Cases S1A and L1A with the major differences being the addition of WGS, the use of a two-stage Selexol AGR plant instead of Sulfinol and subsequent compression of the captured CO_2 stream. The gross power output is constrained by the capacity of the two CTs, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Cases S1A and L1A.

The process description for Cases S1B and L1B is similar to Cases S1A and L1A with several notable exceptions to accommodate CO_2 capture. A BFD for the CO_2 capture case is shown in Exhibit 3-37 and stream tables are shown in Exhibit 3-38. Instead of repeating the entire process description, only differences from the non-capture cases are reported here.

Coal Preparation and Feed Systems

No differences from non-capture cases.

Gasification

The gasification process is the same as the non-capture cases except the coal feed (as-received) to the gasifiers is 6,379 tonne/day (7,032 tpd)for the PRB case and 8,861 tonne/day (9,768 tpd) for the lignite case.

Raw Gas Cooling/Particulate Removal

Specifically for the Shell technology for switching to carbon capture, the high temperature section of the raw gas cooler is replaced by a direct contact water quench, which cools the gas to 363°C (685°F), simultaneously increasing the water content of the syngas for the downstream WGS reaction.

Sour Water Stripper

No differences from non-capture cases.

SGS

The SGS process was described in Section 3.1.6. The water concentration in the syngas is controlled by varying the exit temperature of the water scrubber upstream of the shift reactors and is augmented by injection of shift steam. The hot syngas exiting the first stage of SGS is used to superheat steam. One more stage of SGS (for a total of two) results in approximately 97 percent overall conversion of CO to CO_2. The warm syngas from the second stage of SGS is cooled to preheat the syngas prior to the first stage of SGS. The SGS catalyst 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 AGR

Mercury removal is the same as in the non-capture cases.

The AGR process in the CO_2 capture cases 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, a CO_2-rich stream and an acid gas feed to the Claus plant. The acid gas contains about 17 percent H_2S and 66 percent CO_2 with the balance primarily H_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 two pressure levels. The LP stream is compressed from 0.12 MPa (17 psia) to 1.0 MPa (150 psia) and then combined with the HP stream. The combined stream is further compressed to a SC condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dew point of -40ºC (-40°F) using a thermal swing adsorptive dryer. The raw CO_2 stream from the Selexol process contains over 99 percent CO_2. The dehydrated CO_2 is transported to the plant fence line and is sequestration ready.

Claus Unit

The Claus plant is the same as the non-capture cases except 46 tonne/day (51 tpd) of sulfur are produced in the PRB case and 55 tonne/day (61 tpd) in the lignite case.

Power Block

Clean syngas from the AGR plant is reheated to 196°C (385°F) using HP BFW, diluted with nitrogen, and then enters the CT burner. The exhaust gas exits the CT at a nominal 566°C (1,050°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) 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 nominal 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle. There is no air integration between the CT and the ASU in either capture case.

ASU

The same elevated pressure ASU is used as in non-capture cases except the output is 3,933 tonne/day (4,335 tpd) of 95 mol% oxygen to the gasifier and Claus plant for the PRB case and 4,447 tonne/day (4,902 tpd) for the lignite case

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14, and 3.1.15.

Exhibit 3-37 Case S1B and L1B Process Flow Diagram

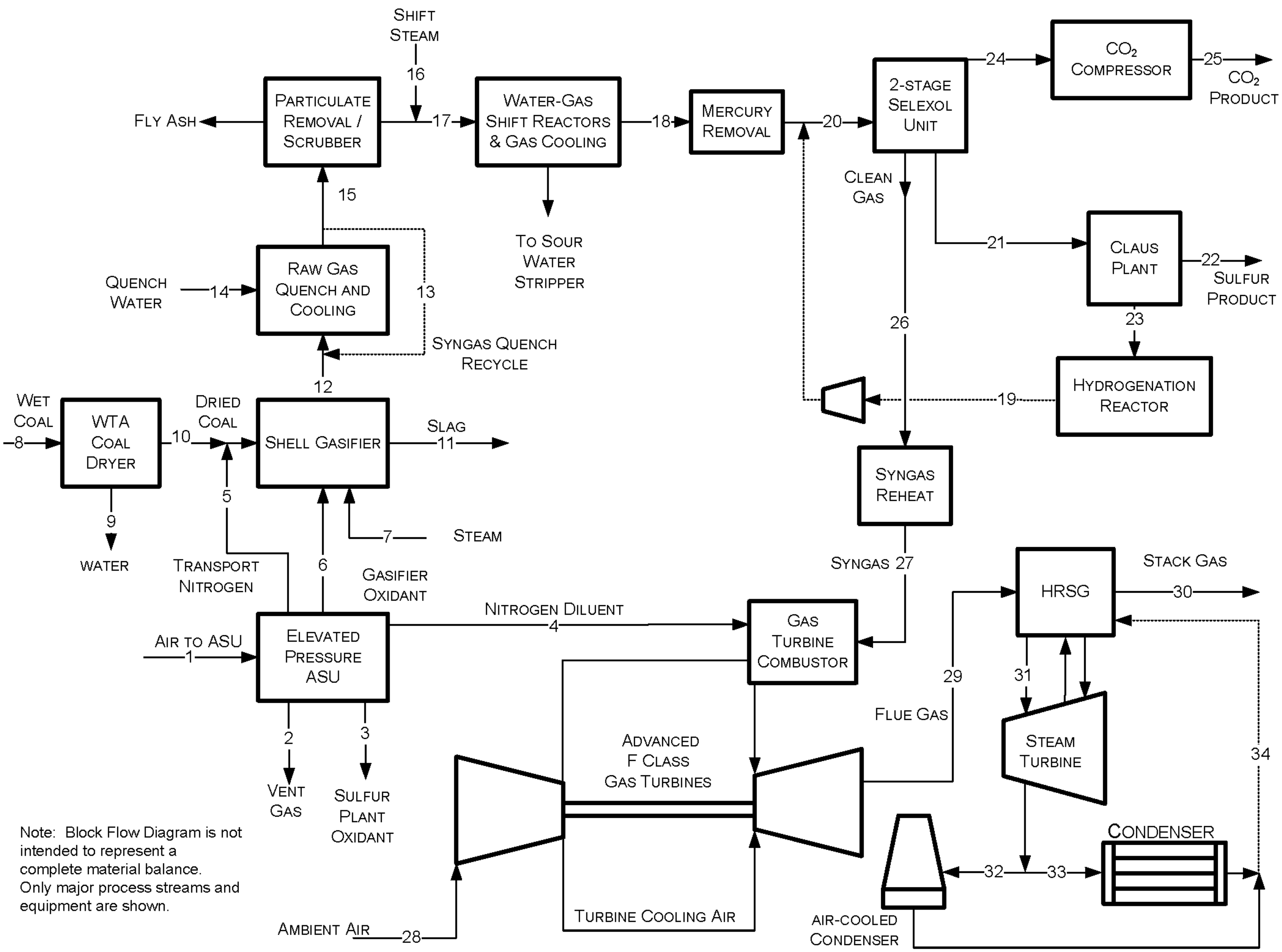

Exhibit 3-38 Case S1B Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
V-L Mole Fraction																	
Ar	0.0093	0.0160	0.0318	0.0023	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0104	0.0060	0.0000	0.0060	0.0000	0.0051
CH_4	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	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6016	0.3470	0.0000	0.3470	0.0000	0.2969
CO_2	0.0003	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0318	0.0183	0.0000	0.0183	0.0000	0.0157
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0003	0.0000	0.0003	0.0000	0.0003
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2616	0.1508	0.0000	0.1508	0.0000	0.1291
H_2O	0.0064	0.0975	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0279	0.4386	0.9981	0.4386	1.0000	0.5196
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0017	0.0000	0.0017	0.0000	0.0015
N_2	0.7759	0.7523	0.0178	0.9920	0.9920	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0604	0.0348	0.0000	0.0348	0.0000	0.0298
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0029	0.0024	0.0019	0.0024	0.0000	0.0021
O_2	0.2081	0.1291	0.9504	0.0054	0.0054	0.9504	0.0000	0.0000	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	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	24,697	1,577	78	17,093	935	5,014	0	0	3,103	0	0	17,390	6,685	12,763	30,153	4,420	35,237
V-L Flowrate (kg/hr)	713,612	43,868	2,517	479,643	26,236	161,348	0	0	55,901	0	0	375,047	134,128	229,913	604,961	79,634	696,534
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	265,792	0	209,891	22,427	0	0	0	0	0	0
Temperature (°C)	6	18	32	196	197	32	---	6	33	71	1,427	1,427	246	170	232	288	232
Pressure (MPa, abs)	0.09	0.11	0.86	2.65	5.62	0.86	---	0.09	0.55	0.09	4.24	4.24	4.24	0.79	3.93	4.14	3.79
Enthalpy (kJ/kg)^A	15.26	36.45	26.67	202.64	201.76	26.67	---	---	139.92	---	---	2,242.88	1,346.50	668.41	1,325.51	2,956.19	1,527.21
Density (kg/m^3)	1.1	1.4	11.0	18.9	39.6	11.0	---	---	985.3	---	---	6.4	20.3	838.4	19.3	18.2	18.6
V-L Molecular Weight	28.895	27.826	32.181	28.061	28.061	32.181	---	---	18.015	---	---	21.567	20.063	18.013	20.063	18.015	19.767
V-L Flowrate (lb_{mol}/hr)	54,447	3,476	172	37,684	2,061	11,054	0	0	6,841	0	0	38,338	14,739	28,139	66,477	9,745	77,683
V-L Flowrate (lb/hr)	1,573,246	96,713	5,550	1,057,431	57,841	355,711	0	0	123,241	0	0	826,838	295,701	506,872	1,333,710	175,564	1,535,594
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	585,970	0	462,730	49,444	0	0	0	0	0	0
Temperature (°F)	42	64	90	385	387	90	---	42	92	160	2,600	2,600	474	338	450	550	449
Pressure (psia)	13.0	16.4	125.0	384.0	815.0	125.0	---	13.0	80.0	13.0	614.7	614.7	615.0	115.0	569.7	600.0	549.7
Enthalpy (Btu/lb)^A	6.6	15.7	11.5	87.1	86.7	11.5	---	---	60.2	---	---	964.3	578.9	287.4	569.9	1,270.9	656.6
Density (lb/ft^3)	0.070	0.089	0.687	1.180	2.475	0.687	---	---	61.513	---	---	0.401	1.265	52.337	1.205	1.135	1.160

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-38 Case S1B Stream Table (Continued)

	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
V-L Mole Fraction																	
Ar	0.0066	0.0094	0.0067	0.0022	0.0000	0.0071	0.0002	0.0002	0.0106	0.0106	0.0093	0.0091	0.0091	0.0000	0.0000	0.0000	0.0000
CH_4	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	0.0000	0.0000	0.0000
CO	0.0097	0.0035	0.0096	0.0035	0.0000	0.0403	0.0002	0.0002	0.0153	0.0153	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.3970	0.6359	0.4011	0.6588	0.0000	0.4434	0.9919	0.9948	0.0490	0.0490	0.0003	0.0089	0.0089	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.5440	0.1223	0.5391	0.1254	0.0000	0.0549	0.0046	0.0046	0.8617	0.8617	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0017	0.1381	0.0017	0.0382	0.0000	0.3856	0.0029	0.0000	0.0001	0.0001	0.0064	0.1208	0.1208	1.0000	1.0000	1.0000	1.0000
H_2S	0.0022	0.0065	0.0023	0.1657	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0387	0.0843	0.0395	0.0060	0.0000	0.0638	0.0002	0.0002	0.0632	0.0632	0.7759	0.7549	0.7549	0.0000	0.0000	0.0000	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	0.0000	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	0.2081	0.1062	0.1062	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	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	27,106	390	27,442	376	0	515	10,004	9,975	17,062	17,062	100,352	127,026	127,026	25,110	17,107	17,107	39,134
V-L Flowrate (kg/hr)	550,130	13,168	562,339	13,525	0	15,427	437,535	437,012	111,279	111,279	2,899,687	3,490,609	3,490,609	452,359	308,189	308,189	705,016
Solids Flowrate (kg/hr)	0	0	0	0	1,928	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	35	49	34	48	176	232	16	72	31	196	6	561	132	533	32	32	33
Pressure (MPa, abs)	3.43	0.07	3.36	0.16	0.1	0.085	1.032	15.270	3.238	3.203	0.090	0.093	0.090	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	43.64	234.02	42.61	94.11	---	861.747	5.232	-95.273	135.215	893.518	15.260	830.526	341.308	3,430.159	2,284.211	2,284.211	140.266
Density (kg/m^3)	27.8	0.9	27.5	2.2	5,284.6	0.6	20.1	461.3	8.3	5.3	1.1	0.4	0.7	36.8	0.04	0.04	995.0
V-L Molecular Weight	20.296	33.776	20.492	35.946	---	29.941	43.735	43.809	6.522	6.522	28.895	27.479	27.479	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	59,758	859	60,500	830	0	1,136	22,056	21,992	37,615	37,615	221,239	280,045	280,045	55,358	37,715	37,715	86,276
V-L Flowrate (lb/hr)	1,212,830	29,030	1,239,745	29,817	0	34,010	964,599	963,447	245,329	245,329	6,392,716	7,695,476	7,695,476	997,281	679,441	679,441	1,554,294
Solids Flowrate (lb/hr)	0	0	0	0	4,251	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	95	120	94	119	348	450	60	162	87	385	42	1,042	270	992	90	90	92
Pressure (psia)	497.6	10.6	487.6	23.7	17.3	12.3	149.7	2,214.7	469.6	464.6	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	18.8	100.6	18.3	40.5	---	370.5	2.2	-41.0	58.1	384.1	6.6	357.1	146.7	1,474.7	982.0	982.0	60.3
Density (lb/ft^3)	1.733	0.058	1.718	0.138	330	0.038	1.254	28.796	0.515	0.330	0.070	0.023	0.046	2.297	0.002	0.002	62.116

Exhibit 3-39 Case L1B Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
V-L Mole Fraction																	
Ar	0.0093	0.0093	0.0318	0.0023	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0100	0.0058	0.0000	0.0058	0.0000	0.0055
CH_4	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	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5271	0.3057	0.0000	0.3057	0.0000	0.2869
CO_2	0.0003	0.0025	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0643	0.0373	0.0000	0.0373	0.0000	0.0350
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0004	0.0002	0.0000	0.0002	0.0000	0.0002
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2477	0.1436	0.0000	0.1436	0.0000	0.1348
H_2O	0.0062	0.0466	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0802	0.4666	1.0000	0.4666	1.0000	0.4993
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0032	0.0018	0.0000	0.0018	0.0000	0.0017
N_2	0.7761	0.8746	0.0178	0.9922	0.9922	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0658	0.0382	0.0000	0.0382	0.0000	0.0358
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0008	0.0000	0.0008	0.0000	0.0007
O_2	0.2082	0.0670	0.9504	0.0053	0.0053	0.9504	0.0000	0.0000	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	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	27,921	3,603	44	17,365	1,195	5,714	0	0	5,608	0	0	20,444	6,518	14,814	35,257	1,619	37,556
V-L Flowrate (kg/hr)	806,854	100,755	1,429	487,271	33,525	183,875	0	0	101,037	0	0	448,453	132,242	266,870	715,323	29,158	756,739
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	369,238	0	268,201	37,148	0	0	0	0	0	0
Temperature (°C)	4	16	32	196	197	32	---	4	32	71	1,371	1,371	245	171	232	288	233
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	5.62	0.86	---	0.10	0.34	0.09	4.24	4.24	4.24	0.79	3.93	4.14	3.79
Enthalpy (kJ/kg)[A]	13.75	34.65	26.67	202.62	201.73	26.67	---	---	134.94	---	---	2,286.87	1,394.66	674.27	1,374.03	2,956.19	1,457.26
Density (kg/m^3)	1.2	1.4	11.0	18.9	39.6	11.0	---	---	986.5	---	---	6.8	20.6	838.7	19.6	18.2	18.9
V-L Molecular Weight	28.898	27.966	32.181	28.060	28.060	32.181	---	---	18.015	---	---	21.936	20.289	18.015	20.289	18.015	20.150
V-L Flowrate (lb_{mol}/hr)	61,555	7,943	98	38,284	2,634	12,597	0	0	12,364	0	0	45,071	14,370	32,658	77,729	3,568	82,797
V-L Flowrate (lb/hr)	1,778,809	222,127	3,150	1,074,248	73,910	405,375	0	0	222,748	0	0	988,670	291,544	588,347	1,577,017	64,283	1,668,325
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	814,029	0	591,281	81,896	0	0	0	0	0	0
Temperature (°F)	40	61	90	385	387	90	---	40	90	160	2,500	2,500	474	339	450	550	451
Pressure (psia)	13.8	16.4	125.0	384.0	815.0	125.0	---	13.8	50.0	13.5	614.7	614.7	615.0	115.0	569.7	600.0	549.7
Enthalpy (Btu/lb)[A]	5.9	14.9	11.5	87.1	86.7	11.5	---	---	58.0	---	---	983.2	599.6	289.9	590.7	1,270.9	626.5
Density (lb/ft^3)	0.074	0.085	0.687	1.179	2.475	0.687	---	---	61.586	---	---	0.422	1.287	52.359	1.225	1.135	1.177
	A - Reference conditions are 32.02 F & 0.089 PSIA																

Exhibit 3-39 Case L1B Stream Table (Continued)

	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34
V-L Mole Fraction																	
Ar	0.0070	0.0060	0.0070	0.0022	0.0000	0.0049	0.0002	0.0002	0.0112	0.0112	0.0093	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000
CH_4	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	0.0000	0.0000	0.0000
CO	0.0101	0.0060	0.0100	0.0036	0.0000	0.0790	0.0002	0.0002	0.0161	0.0161	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.4026	0.6471	0.4068	0.6513	0.0000	0.4546	0.9920	0.9949	0.0502	0.0502	0.0003	0.0093	0.0093	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0001	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.5302	0.1626	0.5261	0.1193	0.0000	0.0588	0.0044	0.0044	0.8484	0.8484	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0017	0.1381	0.0017	0.0382	0.0000	0.3698	0.0029	0.0000	0.0001	0.0001	0.0062	0.1201	0.1201	1.0000	1.0000	1.0000	1.0000
H_2S	0.0024	0.0068	0.0025	0.1784	0.0000	0.0054	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0459	0.0334	0.0458	0.0068	0.0000	0.0273	0.0002	0.0002	0.0740	0.0740	0.7761	0.7541	0.7541	0.0000	0.0000	0.0000	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	0.0000	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	0.2082	0.1073	0.1073	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	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	29,315	419	29,676	417	0	512	10,972	10,940	18,287	18,287	106,961	134,709	134,709	26,245	18,526	18,526	39,107
V-L Flowrate (kg/hr)	608,290	13,763	621,022	15,053	0	15,448	479,908	479,329	126,060	126,060	3,090,914	3,704,245	3,704,245	472,820	333,743	333,743	704,530
Solids Flowrate (kg/hr)	0	0	0	0	2,307	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	35	49	35	48	177	232	16	72	31	216	4	560	132	532	32	32	33
Pressure (MPa, abs)	3.43	0.07	3.36	0.16	0.1	0.085	0.931	15.270	3.238	3.234	0.095	0.099	0.095	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	42.51	240.64	41.58	93.85	---	832.551	6.361	-95.603	127.658	930.527	13.748	827.700	339.845	3,427.809	2,290.992	2,290.992	140.266
Density (kg/m^3)	28.4	0.9	28.1	2.2	5,282.6	0.6	18.0	462.1	8.7	5.4	1.2	0.4	0.8	36.9	0.04	0.04	995.0
V-L Molecular Weight	20.750	32.869	20.927	36.063	---	30.157	43.740	43.816	6.893	6.893	28.898	27.498	27.498	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	64,628	923	65,425	920	0	1,129	24,189	24,118	40,316	40,316	235,808	296,983	296,983	57,861	40,842	40,842	86,217
V-L Flowrate (lb/hr)	1,341,049	30,342	1,369,120	33,187	0	34,057	1,058,017	1,056,739	277,916	277,916	6,814,298	8,166,462	8,166,462	1,042,389	735,778	735,778	1,553,224
Solids Flowrate (lb/hr)	0	0	0	0	5,086	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	95	120	94	119	350	450	60	161	87	420	40	1,040	270	990	90	90	92
Pressure (psia)	497.6	10.6	487.6	23.7	17.3	12.3	135.0	2,214.7	469.6	469.0	13.8	14.3	13.8	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	18.3	103.5	17.9	40.3	---	357.9	2.7	-41.1	54.9	400.1	5.9	355.8	146.1	1,473.7	984.9	984.9	60.3
Density (lb/ft^3)	1.774	0.056	1.756	0.138	330	0.038	1.123	28.851	0.545	0.339	0.074	0.024	0.048	2.301	0.002	0.002	62.116

3.2.9 Case S1B and L1B Performance Results

The Case S1B and L1B modeling assumptions were presented previously in Exhibit 3-16.

The SCGP IGCC plant with CO_2 capture and using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 472 MWe at a net plant efficiency of 32.1 percent (HHV basis). The same plant configuration using lignite coal at the NDL site (elevation 1,900 ft) produces a net output of 500 MWe at a net plant efficiency of 31.7 percent (HHV basis).

Overall performance for the plants is summarized in Exhibit 3-40, which includes auxiliary power requirements. The ASU accounts for approximately 55 percent of the total auxiliary load in both cases, distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The coal drying process accounts for approximately 6 percent. CO_2 compression accounts for about 17 percent and the AGR process accounts for about 9.6 percent of the auxiliary load in both cases. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-40 Case S1B and L1B Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	S1B	L1B
Gas Turbine Power	430,900	456,600
Steam Turbine Power	232,500	256,700
TOTAL POWER, kWe	**663,400**	**713,300**
AUXILIARY LOAD SUMMARY, kWe		
Coal Handling	510	620
Coal Milling	2,730	3,800
Slag Handling	580	970
WTA Coal Dryer Compressor	9,370	12,980
WTA Coal Dryer Auxiliaries	620	850
Air Separation Unit Auxiliaries	1,000	1,000
Air Separation Unit Main Air Compressor	63,550	70,010
Oxygen Compressor	8,830	10,070
Nitrogen Compressors	33,340	34,630
CO_2 Compressor	31,560	35,250
Boiler Feedwater Pumps	3,260	3,300
Condensate Pump	230	230
Quench Water Pump	760	880
Syngas Recycle Compressor	820	800
Circulating Water Pump	2,730	3,410
Ground Water Pumps	310	350
Cooling Tower Fans	1,780	2,090
Air Cooled Condenser Fans	2,960	3,040
Scrubber Pumps	20	30
Acid Gas Removal	18,400	20,180
Gas Turbine Auxiliaries	1,000	1,000
Steam Turbine Auxiliaries	100	100
Claus Plant/TGTU Auxiliaries	250	250
Claus Plant TG Recycle Compressor	1,530	1,640
Miscellaneous Balance of Plant[1]	3,000	3,000
Transformer Losses	2,550	2,760
TOTAL AUXILIARIES, kWe	**191,790**	**213,240**
NET POWER, kWe	**471,610**	**500,060**
Net Plant Efficiency, % (HHV)	32.1%	31.7%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,227 (10,641)	11,365 (10,772)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	**1,319 (1,250)**	**1,435 (1,360)**
CONSUMABLES		
As-Received Coal Feed, kg/hr (lb/hr)	265,792 (585,970)	369,238 (814,029)
Thermal Input, kWt	1,470,704	1,578,608
Raw Water Withdrawal, m^3/min (gpm)	12.9 (3,404)	14.8 (3,917)
Raw Water Consumption, m^3/min (gpm)	10.5 (2,767)	11.8 (3,124)

[1] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, CO_2, and PM were presented in Section 2.3. A summary of the plant air emissions for the CO_2 capture cases is presented in Exhibit 3-41.

Exhibit 3-41 Case S1B and L1B Air Emissions

	kg/GJ ($lb/10^6$ Btu)		Tonne/year (ton/year) 80% capacity factor		kg/MWh (lb/MWh)	
	S1B	**L1B**	**S1B**	**L1B**	**S1B**	**L1B**
SO_2	0.000 (0.001)	0.000 (0.001)	14 (15)	17 (18)	0.003 (0.007)	0.003 (0.007)
NO_X	0.022 (0.050)	0.021 (0.049)	802 (885)	841 (927)	0.173 (0.381)	0.168 (0.371)
Particulates	0.003 (0.0071)	0.003 (0.0071)	113 (125)	122 (134)	0.024 (0.054)	0.024 (0.054)
Hg	1.51E-7 (3.51E-7)	2.41E-7 (5.60E-7)	0.006 (0.006)	0.010 (0.011)	1.20E-6 (2.66E-6)	1.92E-6 (4.23E-6)
CO_2 gross	9.4 (21.9)	9.7 (22.5)	348,874 (384,567)	384,547 (423,890)	75 (165)	77 (170)
CO_2 net					106 (233)	110 (242)

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. Just as in the non-capture cases, the SO_2 emission are significantly less than the environmental targets of Section 2.3. The clean syngas exiting the AGR process has a sulfur concentration of approximately 2 ppmv. This results in a concentration in the flue gas of less than 0.3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The tail gas is hydrogenated and recycled upstream of the AGR.

NOx emissions are limited to 15 ppmvd (as NO_2 @ 15 percent O_2) by the use of low NOx burners and nitrogen dilution of the fuel gas. 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 NOx 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.

Slightly greater than 92 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 3-42. 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, CO_2 in the stack gas and ASU vent gas, and the captured CO_2 product. 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
90 percent (both cases S1B and L1B)

Exhibit 3-42 Cases S1B and L1B Carbon Balance

Carbon In, kg/hr (lb/hr)			Carbon Out, kg/hr (lb/hr)		
	S1B	**L1B**		**S1B**	**L1B**
Coal	133,077 (293,384)	146,047 (321,979)	**Slag**	665 (1,467)	730 (1,610)
Air (CO_2)	492 (1,086)	531 (1,171)	**Stack Gas**	13,586 (29,953)	14,976 (33,016)
			ASU Vent	97 (214)	110 (242)
			CO_2 Product	119,220 (262,836)	130,763 (288,282)
Total	**133,569 (294,470)**	**146,578 (323,150)**	**Total**	**133,569 (294,470)**	**146,578 (323,150)**

Exhibit 3-43 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, sulfur emitted in the stack gas, and sulfur that is sequestered with the CO_2 product. Sulfur in the slag is considered negligible.

Exhibit 3-43 Cases S1B and L1B Sulfur Balance

Sulfur In, kg/hr (lb/hr)			Sulfur Out, kg/hr (lb/hr)		
	S1B	**L1B**		**S1B**	**L1B**
Coal	1,934 (4,263)	2,313 (5,099)	**Elemental Sulfur**	1,928 (4,251)	2,307 (5,086)
			Stack Gas	1 (2)	1 (3)
			CO_2 Product	4 (9)	5 (11)
			Convergence Tolerance[1]	0 (0)	0 (0)
Total	**1,934 (4,263)**	**2,313 (5,099)**	**Total**	**1,934 (4,263)**	**2,313 (5,099)**

Exhibit 3-44 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 from the coal drying process and as syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is discharged from the process to a permitted outfall. The difference between the withdrawal and discharge is the consumption.

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-45 and Exhibit 3-46:

- Coal gasification and ASU
- Syngas cleanup
- Combined cycle power generation

An overall plant energy balance is provided in tabular form in Exhibit 3-47 for the two cases. The power out is the combined CT and steam turbine power after generator losses.

Exhibit 3-44 Cases S1B and L1B Water Balance

Water Use	Water Demand m^3/min (gpm)		Internal Recycle m^3/min (gpm)		Raw Water Withdrawal m^3/min (gpm)		Process Water Discharge m^3/min (gpm)		Raw Water Consumption m^3/min (gpm)	
	S1B	L1B	S1B	L1B	S1B	L1B	S1B	L1B	S1B	L1B
Slag Handling	**0.49 (128)**	**0.81 (213)**	**0.49 (128)**	**0.81 (213)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**
Quench/Wash	**3.84 (1014)**	**4.45 (1177)**	**1.74 (460)**	**1.45 (383)**	**2.10 (554)**	**3.01 (794)**	**0 (0)**	**0 (0)**	**2.10 (554)**	**3.01 (794)**
SWS Blowdown	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0.02 (6)**	**0.02 (6)**	**-0.02 (-6)**	**-0.02 (-6)**
Condenser Makeup	**1.48 (391)**	**0.62 (163)**	**0 (0)**	**0 (0)**	**1.48 (391)**	**0.62 (163)**	**0 (0)**	**0 (0)**	**1.48 (391)**	**0.62 (163)**
Shift Steam	1.33 (351)	0.49 (129)			1.33 (351)	0.49 (129)				
BFW Makeup	0.15 (40)	0.13 (35)			0.15 (40)	0.13 (35)				
Cooling Tower	**10.62 (2,804)**	**13.25 (3,500)**	**1.31 (345)**	**2.04 (540)**	**9.31 (2,459)**	**11.20 (2,960)**	**2.39 (631)**	**2.98 (787)**	**6.92 (1,828)**	**8.22 (2,173)**
Water from Coal Drying			0.93 (246)	1.69 (445)	-0.93 (-246)	-1.69 (-445)				
BFW Blowdown			0.15 (40)	0.13 (35)	-0.15 (-40)	-0.13 (-35)				
SWS Blowdown			0.22 (59)	0.23 (60)	-0.22 (-59)	-0.23 (-60)				
Total	**16.4 (4,338)**	**19.1 (5,052)**	**3.5 (934)**	**4.30 (1135)**	**12.9 (3,404)**	**14.83 (3,917)**	**2.4 (637)**	**3.00 (793)**	**10.5 (2,767)**	**11.83 (3,124)**

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Exhibit 3-45 Case S1B Heat and Mass Balance

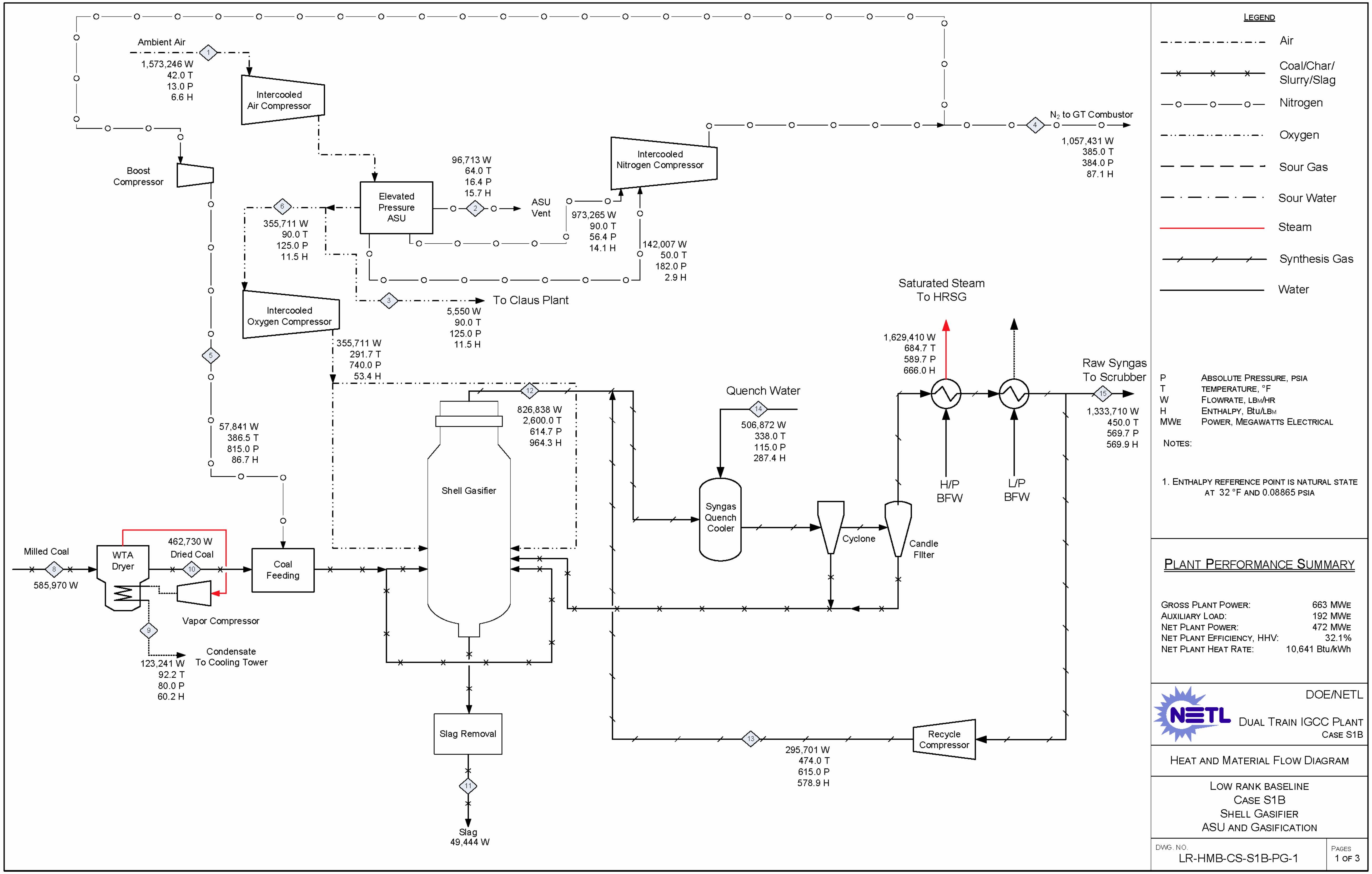


Exhibit 3-45 Case S1B Heat and Mass Balance (Continued)

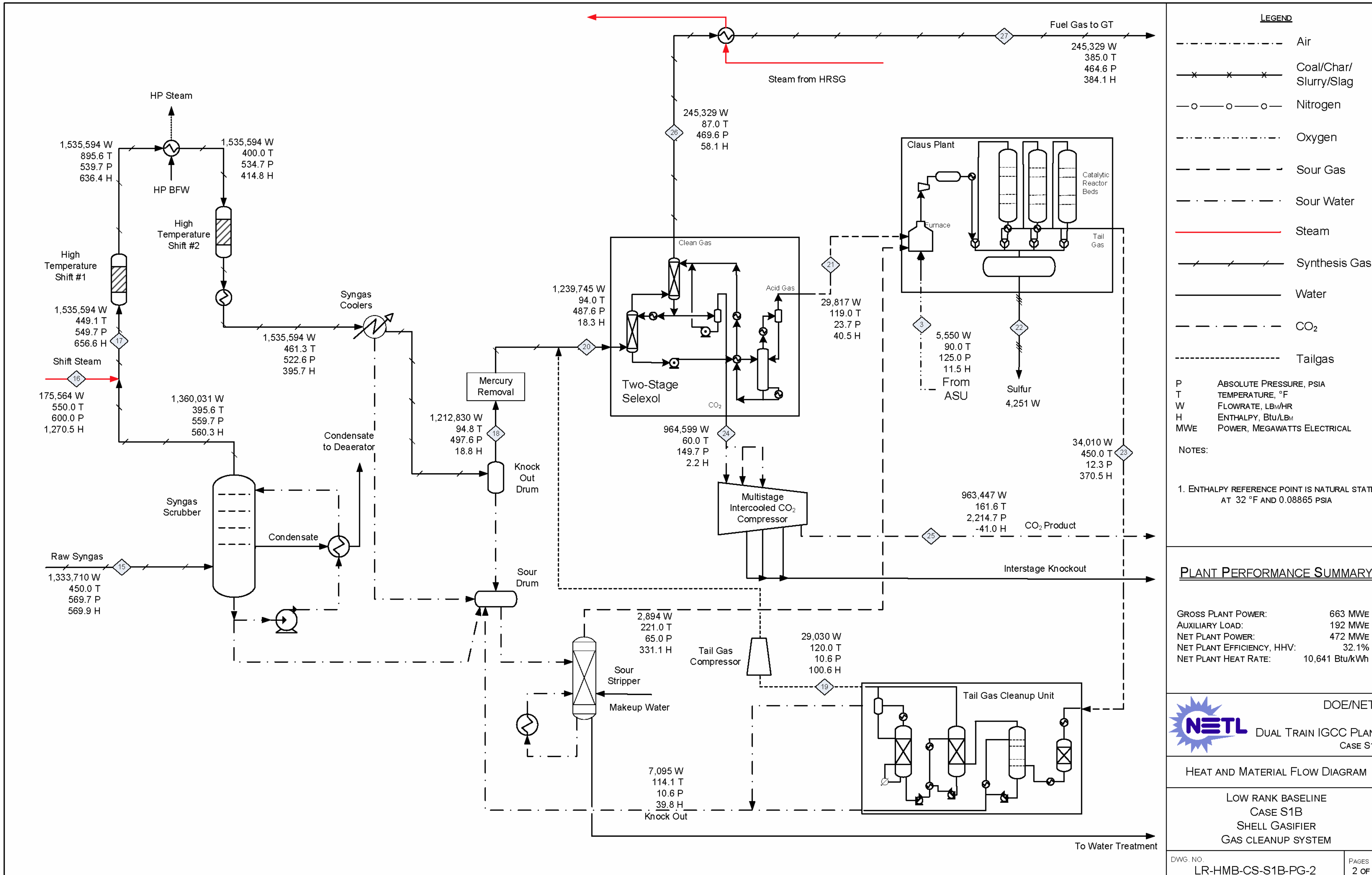


Exhibit 3-45 Case S1B Heat and Mass Balance (Continued)

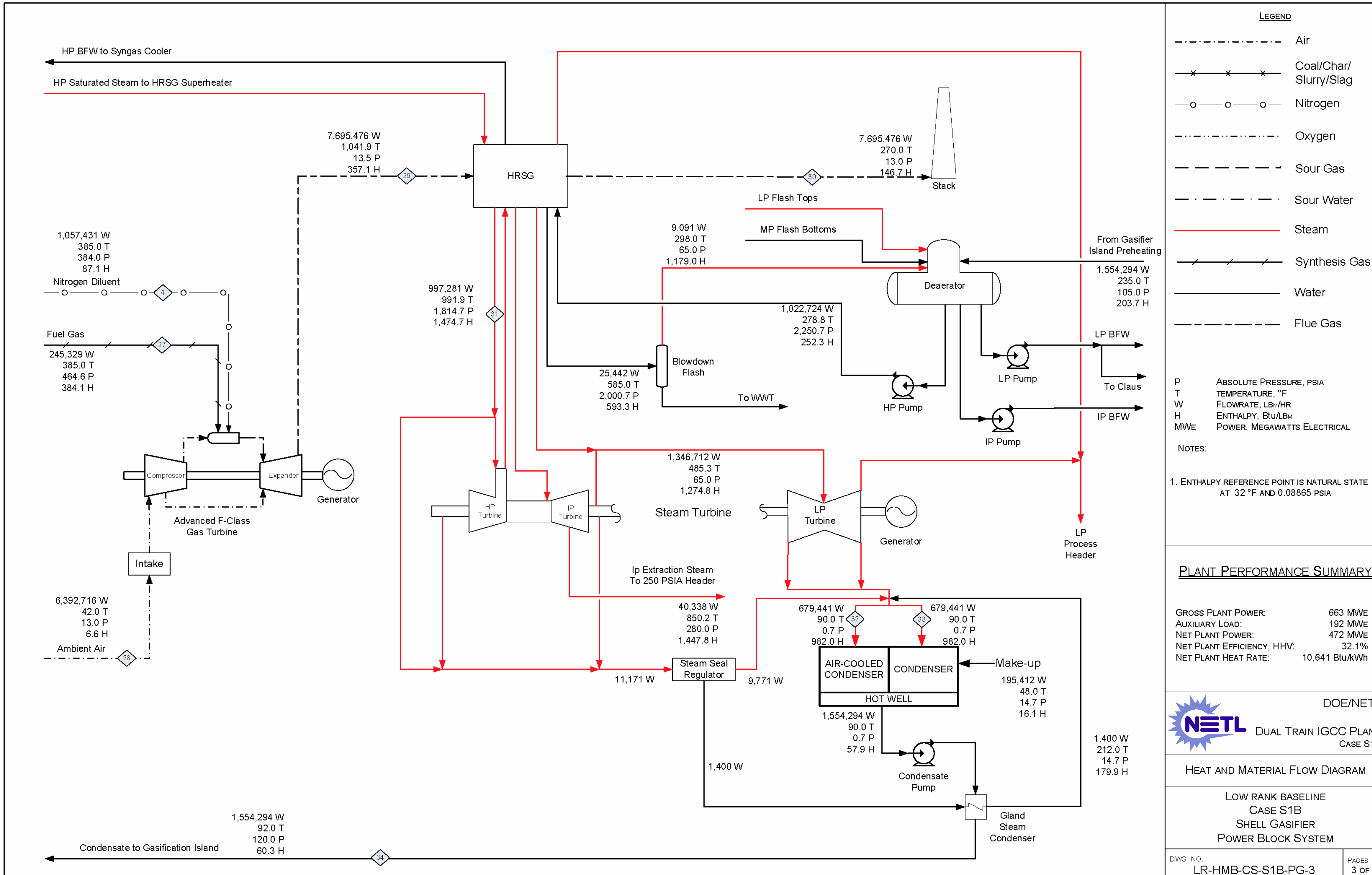


Exhibit 3-46 Case L1B Heat and Mass Balance

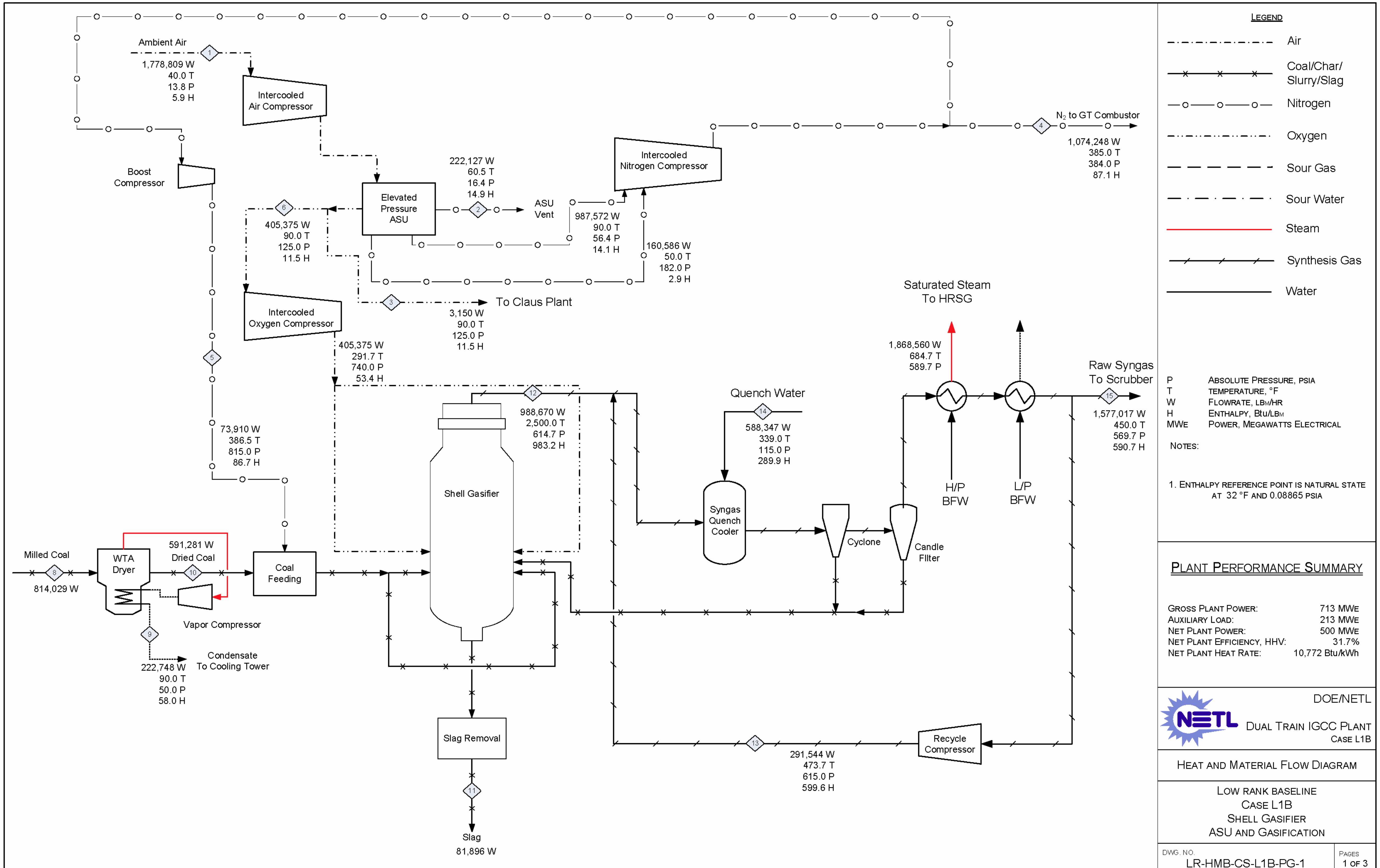


Exhibit 3-46 Case L1B Heat and Mass Balance (Continued)

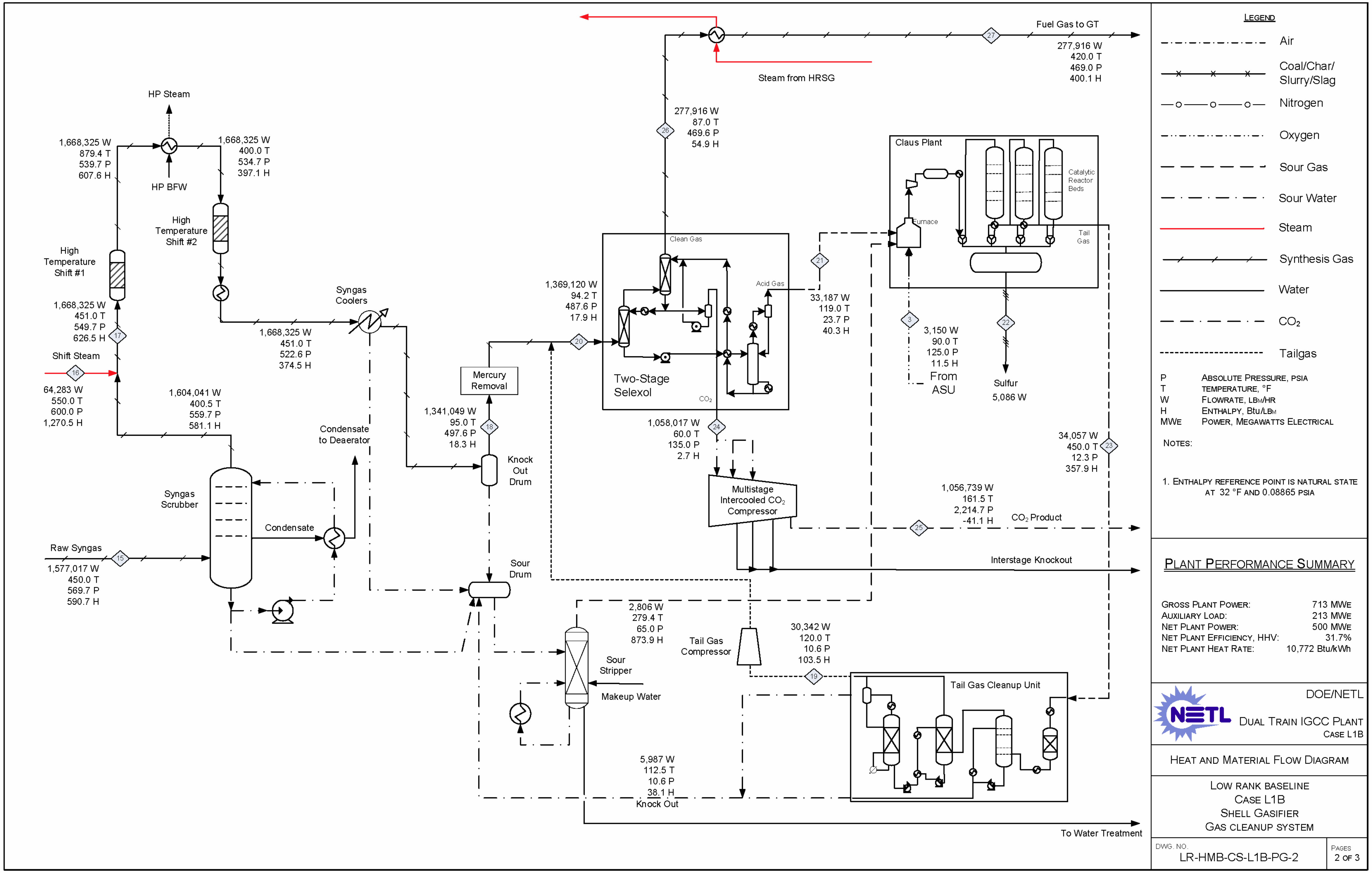


Exhibit 3-46 Case L1B Heat and Mass Balance (Continued)

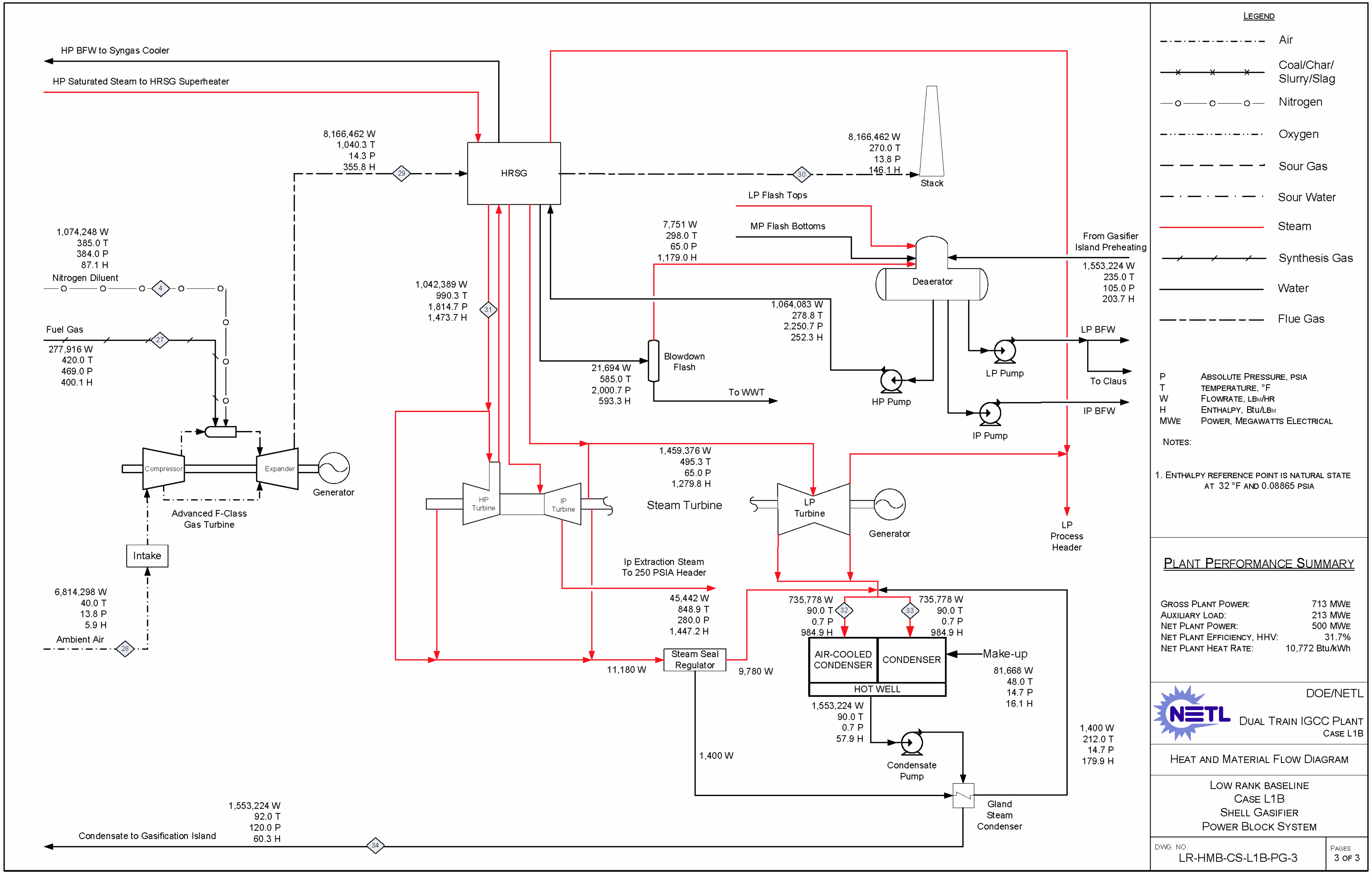


Exhibit 3-47 Cases S1B and L1B Energy Balance

	HHV		Sensible + Latent		Power		Total	
	S1B	L1B	S1B	L1B	S1B	L1B	S1B	L1B
Heat In GJ/hr (MMBtu/hr)								
Coal	5,295 (5,018)	5,683 (5,386)	2.7 (2.6)	3.3 (3.1)	0 (0)	0 (0)	5,297 (5,021)	5,686 (5,390)
ASU Air	0 (0)	0 (0)	10.9 (10.3)	11.1 (10.5)	0 (0)	0 (0)	11 (10)	11 (11)
GT Air	0 (0)	0 (0)	44.2 (41.9)	42.5 (40.3)	0 (0)	0 (0)	44 (42)	42 (40)
Raw Water Makeup	0 (0)	0 (0)	17.9 (17.0)	16.5 (15.6)	0 (0)	0 (0)	18 (17)	16 (16)
Auxiliary Power	0 (0)	0 (0)	0 (0)	0 (0)	690 (654)	768 (728)	690 (654)	768 (728)
Totals	**5,295 (5,018)**	**5,683 (5,386)**	**75.8 (71.8)**	**73.4 (69.5)**	**690 (654)**	**768 (728)**	**6,061 (5,744)**	**6,524 (6,184)**
Heat Out GJ/hr (MMBtu/hr)								
ASU Intercoolers	0 (0)	0 (0)	217 (206)	231 (219)	0 (0)	0 (0)	217 (206)	231 (219)
ASU Vent	0 (0)	0 (0)	1.6 (1.5)	3.5 (3.3)	0 (0)	0 (0)	2 (1)	3 (3)
Slag	22 (21)	24 (23)	37.9 (35.9)	59.5 (56.4)	0 (0)	0 (0)	60 (57)	83 (79)
Sulfur	18 (17)	21 (20)	0.2 (0.2)	0.3 (0.2)	0 (0)	0 (0)	18 (17)	22 (21)
CO_2	0 (0)	0 (0)	-41.6 (-39.5)	-45.8 (-43.4)	0 (0)	0 (0)	-42 (-39)	-46 (-43)
CO_2 Comp Intercoolers	0 (0)	0 (0)	153.3 (145.3)	170.5 (161.6)	0 (0)	0 (0)	153 (145)	170 (162)
Cooling Tower Blowdown	0 (0)	0 (0)	13.3 (12.6)	16.1 (15.3)	0 (0)	0 (0)	13 (13)	16 (15)
HRSG Flue Gas	0 (0)	0 (0)	1,191 (1,129)	1,259 (1,193)	0 (0)	0 (0)	1,191 (1,129)	1,259 (1,193)
Condenser	0 (0)	0 (0)	1,316 (1,248)	1,436 (1,361)	0 (0)	0 (0)	1,316 (1,248)	1,436 (1,361)
Auxiliary Cooling Load	0 (0)	0 (0)	162 (154)	399 (378)	0 (0)	0 (0)	162 (154)	399 (378)
Process Losses	0 (0)	0 (0)	581 (551)	382 (362)	0 (0)	0 (0)	581 (551)	382 (362)
Power	0 (0)	0 (0)	0 (0)	0 (0)	2,388 (2,264)	2,568 (2,434)	2,388 (2,264)	2,568 (2,434)
Totals	**40 (38)**	**45 (43)**	**3,633 (3,443)**	**3,911 (3,707)**	**2,388 (2,264)**	**2,568 (2,434)**	**6,061 (5,744)**	**6,524 (6,184)**

3.2.10 Case S1B and L1B Equipment List

Major equipment items for the SCGP 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	S1B Design Conditions	L1B Design Condition	Operating Qty	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	73 tonne (80 ton)	2	1
9	Feeder	Vibratory	218 tonne/hr (240 tph)	308 tonne/hr (340 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	435 tonne/hr (480 tph)	608 tonne/hr (670 tph)	1	0
11	Crusher Tower	N/A	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	218 tonne (240 ton)	308 tonne (340 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	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	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	435 tonne/hr (480 tph)	608 tonne/hr (670 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	N/A	1	0

Equipment No.	Description	Type	S1B Design Conditions	L1B Design Condition	Operating Qty	Spares
17	Conveyor No. 5	Belt w/ tripper	435 tonne/hr (480 tph)	608 tonne/hr (670 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	998 tonne (1,100 ton)	1,361 tonne (1,500 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	100 tonne/hr (110 tph)	136 tonne/hr (150 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	290 tonne/hr (320 tph)	408 tonne/hr (450 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	581 tonne (640 ton)	816 tonne (900 ton)	1	0
4	Weigh Feeder	Belt	145 tonne/hr (160 tph)	200 tonne/hr (220 tph)	2	0
5	Pulverizer	Rotary	145 tonne/hr (160 tph)	200 tonne/hr (220 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	290 tonne (320 ton)	408 tonne (450 ton)	2	0
7	Coal Preheater	Water Heated Horizontal Rotary Kiln	Coal feed: 290 tonne/hr (320 tph) Heat duty: 32.5 GJ/hr (30.8 MMBtu/hr)	Coal feed: 408 tonne/hr (450 tph) Heat duty: 50 GJ/hr (48 MMBtu/hr)	1	0
8	Coal Dryer	Fluidized Bed with Internal Coils	Coal feed: 145 tonne/hr (160 tph) Heat duty: 81.8 GJ/hr (77.6 MMBtu/hr) Bed diameter: 12.5 m (41 ft)	Coal feed: 200 tonne/hr (220 tph) Heat duty: 146 GJ/hr (138 MMBtu/hr) Bed diameter: 14.6 m (48 ft)	2	0

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
9	Steam Compressor	Reciprocating, Multi-Stage	612 m^3/min (21,630 scfm) Suction - 0.09 MPa (13 psia) Discharge - 0.72 MPa (105.0 psia)	1107 m^3/min (39,100 scfm) Suction - 0.10 MPa (13.8 psia) Discharge - 0.52 MPa (75 psia)	2	0
10	Dryer Exhaust Filter	Hot Baghouse	Steam - 30,754 kg/hr (67,800 lb/hr) Temperature - 107°C (225°F)	Steam - 55,565 kg/hr (122,500 lb/hr) Temperature - 107°C (225°F)	2	0
11	Dry Coal Cooler	Water Cooled Horizontal Rotary Kiln	231 tonne/hr (255 tph) Heat duty - 13 GJ/hr (13 MMBtu/hr)	295 tonne/hr (325 tph) Heat duty - 18 GJ/hr (18 MMBtu/hr)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	582,953 liters (154,000 gal)	507,245 liters (134,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,511 lpm @ 91 m H_2O (1,720 gpm @ 300 ft H_2O)	6,511 lpm @ 91 m H_2O (1,720 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	467,200 kg/hr (1,030,000 lb/hr)	479,447 kg/hr (1,057,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,590 lpm @ 27 m H_2O (420 gpm @ 90 ft H_2O)	1,476 lpm @ 27 m H_2O (390 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 4,429 lpm @ 1,890 m H_2O (1,170 gpm @ 6,200 ft H_2O)	HP water: 4,618 lpm @ 1,890 m H_2O (1,220 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 2,423 lpm @ 223 m H_2O (640 gpm @ 730 ft H_2O)	IP water: 1,249 lpm @ 223 m H_2O (330 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	308 GJ/hr (292 MMBtu/hr) each	455 GJ/hr (431 MMBtu/hr) each	2	0

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	110,155 lpm @ 21 m H_2O (29,100 gpm @ 70 ft H_2O)	163,151 lpm @ 21 m H_2O (43,100 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	3,596 lpm @ 18 m H_2O (950 gpm @ 60 ft H_2O)	4,126 lpm @ 18 m H_2O (1,090 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,385 lpm @ 268 m H_2O (630 gpm @ 880 ft H_2O)	2,763 lpm @ 268 m H_2O (730 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	3,255 lpm @ 49 m H_2O (860 gpm @ 160 ft H_2O)	3,331 lpm @ 49 m H_2O (880 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,570,946 liter (415,000 gal)	1,593,658 liter (421,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	908 lpm (240 gpm)	416 lpm (110 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	3,538 tonne/day, 4.2 MPa (3,900 tpd, 615 psia)	4,899 tonne/day, 4.2 MPa (5,400 tpd, 615 psia)	2	0
2	Quench	Vertical with water mist spray nozzles	Raw Gas - 28,096 m^3/hr @ 4.2 MPa (992,210 cuft/hr @ 610 psia) Water - 114,957 kg/hr (253,436 lb/hr)	Raw Gas - 31,598 m^3/hr @ 4.2 MPa (1,115,882 cuft/hr @ 610 psia) Water - 133,435 kg/hr (294,174 lb/hr)	2	0
3	Synthesis Gas Cooler	Convective spiral-wound tube boiler	406,419 kg/hr (896,000 lb/hr) Heat duty: 165 GJ/hr (157 MMBtu/hr)	466,293 kg/hr (1,028,000 lb/hr) Heat duty: 191 GJ/hr (181 MMBtu/hr)	2	0
4	Synthesis Gas Cyclone	High efficiency	406,419 kg/hr (896,000 lb/hr) Design efficiency 90%	466,293 kg/hr (1,028,000 lb/hr) Design efficiency 90%	2	0
6	Syngas Scrubber Including Sour Water Stripper	Vertical up flow	332,937 kg/hr (734,000 lb/hr)	393,265 kg/hr (867,000 lb/hr)	2	0
7	Raw Gas Coolers	Shell and tube with condensate drain	346,998 kg/hr (765,000 lb/hr)	416,398 kg/hr (918,000 lb/hr)	8	0
8	Raw Gas Knockout Drum	Vertical with mist eliminator	303,000 kg/hr, 35°C, 3.5 MPa (668,000 lb/hr, 95°F, 503 psia)	334,751 kg/hr, 35°C, 3.5 MPa (738,000 lb/hr, 95°F, 503 psia)	2	0
10	Synthesis Gas Reheater	Shell and tube	61,235 kg/hr (135,000 lb/hr)	69,400 kg/hr (153,000 lb/hr)	2	0

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
11	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	332,937 kg/hr (734,000 lb/hr) syngas	393,265 kg/hr (867,000 lb/hr) syngas	2	0
12	ASU Main Air Compressor	Centrifugal, multi-stage	5,352 m^3/min @ 1.3 MPa (189,000 scfm @ 190 psia)	6,060 m^3/min @ 1.3 MPa (214,000 scfm @ 190 psia)	2	0
13	Cold Box	Vendor design	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2,449 tonne/day (2,700 tpd) of 95% purity oxygen	2	0
14	Oxygen Compressor	Centrifugal, multi-stage	1,076 m^3/min (38,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	1,246 m^3/min (44,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
15	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,426 m^3/min (121,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	3,455 m^3/min (122,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
16	Secondary Nitrogen Compressor	Centrifugal, single-stage	510 m^3/min (18,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.7 MPa (820 psia)	566 m^3/min (20,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.7 MPa (820 psia)	2	0

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
17	Transport Nitrogen Boost Compressor	Centrifugal, single-stage	204 m^3/min (7,200 scfm) Suction - 2.6 MPa (384 psia) Discharge - 5.6 MPa (815 psia)	261 m^3/min (9,200 scfm) Suction - 2.6 MPa (384 psia) Discharge - 5.6 MPa (815 psia)	2	0
18	Syngas Dilution Nitrogen Boost Compressor	Centrifugal, single-stage	1,478 m^3/min (52,200 scfm) Suction - 2.6 MPa (384 psia) Discharge - 3.2 MPa (469 psia)	1,781 m^3/min (62,900 scfm) Suction - 2.6 MPa (384 psia) Discharge - 3.2 MPa (469 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	302,546 kg/hr (667,000 lb/hr) 35°C (95°F) 3.4 MPa (498 psia)	334,751 kg/hr (738,000 lb/hr) 35°C (95°F) 3.4 MPa (498 psia)	2	0
2	Sulfur Plant	Claus type	51 tonne/day (56 tpd)	61 tonne/day (67 tpd)	1	0
3	WGS Reactors	Fixed bed, catalytic	383,286 kg/hr (845,000 lb/hr) 232°C (450°F) 3.8 MPa (550 psia)	416,398 kg/hr (918,000 lb/hr) 232°C (450°F) 3.8 MPa (550 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 197 GJ/hr (187 MMBtu/hr)	Exchanger 1: 204 GJ/hr (193 MMBtu/hr)	4	0
5	AGR Plant	Two-stage Selexol	309,350 kg/hr (682,000 lb/hr) 34°C (94°F) 3.4 MPa (488 psia)	341,555 kg/hr (753,000 lb/hr) 35°C (94°F) 3.4 MPa (488 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	16,970 kg/hr (37,411 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	16,993 kg/hr (37,463 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	13,441 kg/hr (29,633 lb/hr)	14,019 kg/hr (30,906 lb/hr)	1	0

ACCOUNT 5B CO$_2$ COMPRESSION

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	CO$_2$ Compressor	Integrally geared, multi-stage centrifugal	1,082 m^3/min @ 15.3 MPa (38,200 scfm @ 2,215 psia)	1,186 m^3/min @ 15.3 MPa (41,900 scfm @ 2,215 psia)	4	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	215 MW	230 MW	2	0
2	Gas Turbine Generator	TEWAC	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.7 m (20 ft) diameter	76 m (250 ft) high x 8.7 m (20 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 248,798 kg/hr, 12.4 MPa/533°C (548,505 lb/hr, 1,800 psig/992°F) Reheat steam - 312,480 kg/hr, 3.1 MPa/533°C (688,900 lb/hr, 452 psig/992°F)	Main steam - 260,051 kg/hr, 12.4 MPa/532°C (573,314 lb/hr, 1,800 psig/990°F) Reheat steam - 358,821 kg/hr, 3.1 MPa/532°C (791,066 lb/hr, 452 psig/990°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Steam Turbine	Commercially available	245 MW 12.4 MPa/533°C/533°C (1,800 psig/ 992°F/992°F)	270 MW 12.4 MPa/532°C/532°C (1,800 psig/ 990°F/990°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	270 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	300 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	728 GJ/hr (690 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 8°C (47°F), Water temperature rise 11°C (20°F)	1	0
4	Air-cooled Condenser	---	728 GJ/hr (690 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 4°C (40°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Circulating Water Pumps	Vertical, wet pit	272,550 lpm @ 30 m (72,000 gpm @ 100 ft)	340,687 lpm @ 30 m (90,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 1530 GJ/hr (1450 MMBtu/hr) heat duty	2°C (36°F) wet bulb / 8°C (47°F) CWT / 19°C (67°F) HWT / 1899 GJ/hr (1800 MMBtu/hr) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	Slag Quench Tank	Water bath	234,696 liters (62,000 gal)	389,897 liters (103,000 gal)	2	0
2	Slag Crusher	Roll	13 tonne/hr (14 tph)	21 tonne/hr (23 tph)	2	0
3	Slag Depressurizer	Proprietary	13 tonne/hr (14 tph)	21 tonne/hr (23 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	140,060 liters (37,000 gal)	234,696 liters (62,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	64,352 liters (17,000 gal)	105,992 liters (28,000 gal)	2	
6	Slag Conveyor	Drag chain	13 tonne/hr (14 tph)	21 tonne/hr (23 tph)	2	0
7	Slag Separation Screen	Vibrating	13 tonne/hr (14 tph)	21 tonne/hr (23 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	13 tonne/hr (14 tph)	21 tonne/hr (23 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	200,627 liters (53,000 gal)	333,116 liters (88,000 gal)	2	0

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	76 lpm @ 14 m H_2O (20 gpm @ 46 ft H_2O)	2	2
11	Grey Water Storage Tank	Field erected	64,352 liters (17,000 gal)	105,992 liters (28,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 433 m H_2O (60 gpm @ 1,420 ft H_2O)	379 lpm @ 433 m H_2O (100 gpm @ 1,420 ft H_2O)	2	2
13	Slag Storage Bin	Vertical, field erected	907 tonne (1,000 tons)	1,451 tonne (1,600 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	172 tonne/hr (190 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	S1B Design Condition	L1B Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 270 MVA, 3-ph, 60 Hz	24 kV/345 kV, 300 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 81 MVA, 3-ph, 60 Hz	345 kV/13.8 kV, 91 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 47 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 53 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	S1B Design Condition	L1B 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 S1B and L1B Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-48 shows the TPC summary organized by cost account for the PRB coal case (S1B) and Exhibit 3-52 shows the same information for the lignite coal case (L1B). A more detailed breakdown of the capital costs is shown in Exhibit 3-49 for S1B and Exhibit 3-53 for L1B. Exhibit 3-50 and Exhibit 3-54 show the calculation and addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-51 shows the initial and annual O&M costs for Case S1B and Exhibit 3-55 shows the same information for Case L1B.

The estimated TOC of SCGP with CO_2 capture using PRB coal is $4,253/kW and using lignite coal is $4,378/kW. Process contingency represents about 3 percent, project contingency 12 percent, and owner's costs 18 percent of TOC for both cases. The COE is 119.7 mills/kWh in the PRB case and 121.9 mills/kWh in the lignite case.

Exhibit 3-48 Case S1B Total Plant Cost Summary

	Client:	USDOE/NETL								**Report Date:**	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S1B - Shell IGCC w/ CO2										
	Plant Size:	471.6	MW,net	**Estimate Type:**		Conceptual			**Cost Base (Jun)**	2007	($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	$16,015	$2,976	$12,420	$0	$0	**$31,412**	$2,851	$0	$6,853	**$41,115**	$87
2	COAL & SORBENT PREP & FEED	$120,801	$10,066	$20,611	$0	$0	**$151,477**	$13,141	$0	$32,924	**$197,542**	$419
3	FEEDWATER & MISC. BOP SYSTEMS	$7,824	$6,231	$7,649	$0	$0	**$21,705**	$2,046	$0	$5,466	**$29,217**	$62
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$154,035	$0	$65,678	$0	$0	**$219,713**	$19,628	$30,204	$41,437	**$310,981**	$659
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$182,062	$0	w/equip.	$0	$0	**$182,062**	$17,647	$0	$19,971	**$219,680**	$466
4.4-4.9	Other Gasification Equipment	$24,921	$10,768	$15,384	$0	$0	**$51,072**	$4,892	$0	$11,994	**$67,958**	$144
	SUBTOTAL 4	**$361,019**	**$10,768**	**$81,062**	**$0**	**$0**	**$452,848**	**$42,168**	**$30,204**	**$73,401**	**$598,620**	**$1,269**
5A	GAS CLEANUP & PIPING	$85,262	$3,037	$70,594	$0	$0	**$158,893**	$15,346	$25,676	$40,132	**$240,047**	$509
5B	CO2 COMPRESSION	$18,189	$0	$10,541	$0	$0	**$28,730**	$2,766	$0	$6,299	**$37,795**	$80
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	**$98,610**	$9,348	$9,861	$11,782	**$129,600**	$275
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$5
	SUBTOTAL 6	**$92,027**	**$806**	**$7,475**	**$0**	**$0**	**$100,308**	**$9,507**	**$9,861**	**$12,339**	**$132,015**	**$280**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,403	$0	$4,465	$0	$0	**$35,869**	$3,410	$0	$3,928	**$43,207**	$92
7.2-7.9	SCR System, Ductwork and Stack	$3,524	$2,513	$3,324	$0	$0	**$9,361**	$868	$0	$1,666	**$11,895**	$25
	SUBTOTAL 7	**$34,928**	**$2,513**	**$7,789**	**$0**	**$0**	**$45,230**	**$4,279**	**$0**	**$5,594**	**$55,102**	**$117**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,807	$0	$4,350	$0	$0	**$30,157**	$2,893	$0	$3,305	**$36,355**	$77
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$32,695	$883	$10,769	$0	$0	**$44,347**	$4,309	$0	$9,892	**$58,547**	$124
	SUBTOTAL 8	**$58,502**	**$883**	**$15,119**	**$0**	**$0**	**$74,504**	**$7,202**	**$0**	**$13,197**	**$94,903**	**$201**
9	COOLING WATER SYSTEM	$7,191	$7,127	$6,051	$0	$0	**$20,369**	$1,892	$0	$4,564	**$26,824**	$57
10	ASH/SPENT SORBENT HANDLING SYS	$19,291	$1,481	$9,573	$0	$0	**$30,345**	$2,911	$0	$3,632	**$36,888**	$78
11	ACCESSORY ELECTRIC PLANT	$31,184	$12,483	$24,269	$0	$0	**$67,936**	$5,844	$0	$14,034	**$87,815**	$186
12	INSTRUMENTATION & CONTROL	$10,989	$2,022	$7,081	$0	$0	**$20,092**	$1,821	$1,005	$3,818	**$26,736**	$57
13	IMPROVEMENTS TO SITE	$3,322	$1,958	$8,196	$0	$0	**$13,476**	$1,331	$0	$4,442	**$19,249**	$41
14	BUILDINGS & STRUCTURES	$0	$6,408	$7,287	$0	$0	**$13,694**	$1,246	$0	$2,455	**$17,396**	$37
	TOTAL COST	**$866,544**	**$68,758**	**$295,716**	**$0**	**$0**	**$1,231,019**	**$114,350**	**$66,745**	**$229,150**	**$1,641,264**	**$3,480**

Exhibit 3-49 Case S1B Total Plant Cost Summary Details

Client: USDOE/NETL **Report Date:** 2009-Oct-09

Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S1B - Shell IGCC w/ CO2

Plant Size: 471.6 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($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	$4,206	$0	$2,055	$0	$0	$6,261	$561	$0	$1,364	$8,186	$17
1.2	Coal Stackout & Reclaim	$5,435	$0	$1,318	$0	$0	$6,752	$592	$0	$1,469	$8,813	$19
1.3	Coal Conveyors & Yd Crush	$5,053	$0	$1,304	$0	$0	$6,357	$558	$0	$1,383	$8,298	$18
1.4	Other Coal Handling	$1,322	$0	$302	$0	$0	$1,624	$142	$0	$353	$2,119	$4
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	$2,976	$7,442	$0	$0	$10,418	$999	$0	$2,283	$13,700	$29
	SUBTOTAL 1.	**$16,015**	**$2,976**	**$12,420**	**$0**	**$0**	**$31,412**	**$2,851**	**$0**	**$6,853**	**$41,115**	**$87**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$48,633	$2,922	$7,086	$0	$0	$58,641	$5,060	$0	$12,740	$76,442	$162
2.2	Prepared Coal Storage & Feed	$2,091	$500	$328	$0	$0	$2,919	$250	$0	$634	$3,802	$8
2.3	Dry Coal Injection System	$68,810	$799	$6,390	$0	$0	$75,999	$6,546	$0	$16,509	$99,054	$210
2.4	Misc.Coal Prep & Feed	$1,267	$922	$2,764	$0	$0	$4,952	$455	$0	$1,081	$6,489	$14
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	$4,924	$4,042	$0	$0	$8,966	$830	$0	$1,959	$11,756	$25
	SUBTOTAL 2.	**$120,801**	**$10,066**	**$20,611**	**$0**	**$0**	**$151,477**	**$13,141**	**$0**	**$32,924**	**$197,542**	**$419**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,263	$3,887	$2,052	$0	$0	$8,203	$760	$0	$1,792	$10,755	$23
3.2	Water Makeup & Pretreating	$491	$51	$274	$0	$0	$816	$78	$0	$268	$1,162	$2
3.3	Other Feedwater Subsystems	$1,238	$418	$377	$0	$0	$2,034	$183	$0	$443	$2,660	$6
3.4	Service Water Systems	$281	$578	$2,006	$0	$0	$2,865	$279	$0	$943	$4,088	$9
3.5	Other Boiler Plant Systems	$1,506	$584	$1,447	$0	$0	$3,537	$335	$0	$774	$4,647	$10
3.6	FO Supply Sys & Nat Gas	$303	$571	$533	$0	$0	$1,407	$136	$0	$308	$1,851	$4
3.7	Waste Treatment Equipment	$686	$0	$418	$0	$0	$1,104	$108	$0	$363	$1,575	$3
3.8	Misc. Power Plant Equipment	$1,057	$141	$542	$0	$0	$1,740	$168	$0	$573	$2,481	$5
	SUBTOTAL 3.	**$7,824**	**$6,231**	**$7,649**	**$0**	**$0**	**$21,705**	**$2,046**	**$0**	**$5,466**	**$29,217**	**$62**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$154,035	$0	$65,678	$0	$0	$219,713	$19,628	$30,204	$41,437	$310,981	$659
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$182,062	$0	w/equip.	$0	$0	$182,062	$17,647	$0	$19,971	$219,680	$466
4.4	LT Heat Recovery & FG Saturation	$24,921	$0	$9,474	$0	$0	$34,395	$3,357	$0	$7,550	$45,302	$96
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	Flare Stack System	$0	$1,428	$581	$0	$0	$2,009	$193	$0	$440	$2,642	$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	$9,340	$5,329	$0	$0	$14,669	$1,343	$0	$4,003	$20,014	$42
	SUBTOTAL 4.	**$361,019**	**$10,768**	**$81,062**	**$0**	**$0**	**$452,848**	**$42,168**	**$30,204**	**$73,401**	**$598,620**	**$1,269**

Exhibit 3-49 Case S1B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S1B - Shell IGCC w/ CO2										
	Plant Size:	471.6	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$69,120	$0	$58,650	$0	$0	$127,770	$12,357	$25,554	$33,136	$198,817	$422
5A.2	Elemental Sulfur Plant	$5,103	$1,017	$6,584	$0	$0	$12,704	$1,234	$0	$2,788	$16,725	$35
5A.3	Mercury Removal	$1,388	$0	$1,056	$0	$0	$2,444	$236	$122	$560	$3,362	$7
5A.4	Shift Reactors	$7,422	$0	$2,988	$0	$0	$10,410	$998	$0	$2,282	$13,690	$29
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$2,228	$375	$211	$0	$0	$2,815	$267	$0	$616	$3,698	$8
5A.6	Fuel Gas Piping	$0	$817	$572	$0	$0	$1,390	$129	$0	$304	$1,822	$4
5A.9	HGCU Foundations	$0	$828	$534	$0	$0	$1,361	$125	$0	$446	$1,932	$4
	SUBTOTAL 5A.	**$85,262**	**$3,037**	**$70,594**	**$0**	**$0**	**$158,893**	**$15,346**	**$25,676**	**$40,132**	**$240,047**	**$509**
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$18,189	$0	$10,541	$0	$0	$28,730	$2,766	$0	$6,299	$37,795	$80
	SUBTOTAL 5B.	**$18,189**	**$0**	**$10,541**	**$0**	**$0**	**$28,730**	**$2,766**	**$0**	**$6,299**	**$37,795**	**$80**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	$98,610	$9,348	$9,861	$11,782	$129,600	$275
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$92,027**	**$806**	**$7,475**	**$0**	**$0**	**$100,308**	**$9,507**	**$9,861**	**$12,339**	**$132,015**	**$280**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,403	$0	$4,465	$0	$0	$35,869	$3,410	$0	$3,928	$43,207	$92
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,807	$1,322	$0	$0	$3,128	$275	$0	$681	$4,084	$9
7.4	Stack	$3,524	$0	$1,324	$0	$0	$4,849	$465	$0	$531	$5,844	$12
7.9	HRSG,Duct & Stack Foundations	$0	$706	$678	$0	$0	$1,384	$129	$0	$454	$1,967	$4
	SUBTOTAL 7.	**$34,928**	**$2,513**	**$7,789**	**$0**	**$0**	**$45,230**	**$4,279**	**$0**	**$5,594**	**$55,102**	**$117**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,807	$0	$4,350	$0	$0	$30,157	$2,893	$0	$3,305	$36,355	$77
8.2	Turbine Plant Auxiliaries	$178	$0	$408	$0	$0	$586	$57	$0	$64	$708	$2
8.3a	Condenser & Auxiliaries	$2,805	$0	$896	$0	$0	$3,701	$354	$0	$405	$4,460	$9
8.3b	Air Cooled Condenser	$25,704	$0	$5,153	$0	$0	$30,857	$3,086	$0	$6,788	$40,731	$86
8.4	Steam Piping	$4,008	$0	$2,820	$0	$0	$6,828	$587	$0	$1,854	$9,268	$20
8.9	TG Foundations	$0	$883	$1,492	$0	$0	$2,375	$225	$0	$780	$3,381	$7
	SUBTOTAL 8.	**$58,502**	**$883**	**$15,119**	**$0**	**$0**	**$74,504**	**$7,202**	**$0**	**$13,197**	**$94,903**	**$201**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,957	$0	$902	$0	$0	$5,858	$558	$0	$962	$7,378	$16
9.2	Circulating Water Pumps	$1,283	$0	$79	$0	$0	$1,362	$115	$0	$222	$1,698	$4
9.3	Circ.Water System Auxiliaries	$113	$0	$16	$0	$0	$129	$12	$0	$21	$163	$0
9.4	Circ.Water Piping	$0	$4,723	$1,224	$0	$0	$5,948	$538	$0	$1,297	$7,782	$17
9.5	Make-up Water System	$281	$0	$402	$0	$0	$684	$66	$0	$150	$899	$2
9.6	Component Cooling Water Sys	$558	$667	$474	$0	$0	$1,699	$159	$0	$372	$2,230	$5
9.9	Circ.Water System Foundations	$0	$1,737	$2,952	$0	$0	$4,689	$445	$0	$1,540	$6,674	$14
	SUBTOTAL 9.	**$7,191**	**$7,127**	**$6,051**	**$0**	**$0**	**$20,369**	**$1,892**	**$0**	**$4,564**	**$26,824**	**$57**

Exhibit 3-49 Case S1B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S1B - Shell IGCC w/ CO2										
	Plant Size:	471.6	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$16,803	$0	$8,287	$0	$0	$25,090	$2,411	$0	$2,750	$30,251	$64
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$564	$0	$614	$0	$0	$1,177	$114	$0	$194	$1,485	$3
10.7	Ash Transport & Feed Equipment	$756	$0	$182	$0	$0	$939	$88	$0	$154	$1,180	$3
10.8	Misc. Ash Handling Equipment	$1,168	$1,431	$428	$0	$0	$3,027	$288	$0	$497	$3,812	$8
10.9	Ash/Spent Sorbent Foundation	$0	$50	$63	$0	$0	$112	$11	$0	$37	$160	$0
	SUBTOTAL 10.	**$19,291**	**$1,481**	**$9,573**	**$0**	**$0**	**$30,345**	**$2,911**	**$0**	**$3,632**	**$36,888**	**$78**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$893	$0	$883	$0	$0	$1,776	$170	$0	$195	$2,140	$5
11.2	Station Service Equipment	$4,675	$0	$421	$0	$0	$5,096	$470	$0	$557	$6,122	$13
11.3	Switchgear & Motor Control	$8,642	$0	$1,572	$0	$0	$10,214	$947	$0	$1,674	$12,835	$27
11.4	Conduit & Cable Tray	$0	$4,015	$13,244	$0	$0	$17,258	$1,669	$0	$4,732	$23,659	$50
11.5	Wire & Cable	$0	$7,670	$5,040	$0	$0	$12,710	$923	$0	$3,408	$17,042	$36
11.6	Protective Equipment	$0	$653	$2,375	$0	$0	$3,028	$296	$0	$499	$3,822	$8
11.7	Standby Equipment	$223	$0	$217	$0	$0	$440	$42	$0	$72	$554	$1
11.8	Main Power Transformers	$16,752	$0	$134	$0	$0	$16,886	$1,277	$0	$2,724	$20,887	$44
11.9	Electrical Foundations	$0	$146	$382	$0	$0	$528	$51	$0	$174	$752	$2
	SUBTOTAL 11.	**$31,184**	**$12,483**	**$24,269**	**$0**	**$0**	**$67,936**	**$5,844**	**$0**	**$14,034**	**$87,815**	**$186**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,085	$0	$724	$0	$0	$1,809	$171	$90	$311	$2,382	$5
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	$249	$0	$160	$0	$0	$409	$39	$20	$94	$562	$1
12.7	Computer & Accessories	$5,787	$0	$185	$0	$0	$5,972	$548	$299	$682	$7,501	$16
12.8	Instrument Wiring & Tubing	$0	$2,022	$4,133	$0	$0	$6,154	$522	$308	$1,746	$8,730	$19
12.9	Other I & C Equipment	$3,868	$0	$1,878	$0	$0	$5,747	$541	$287	$986	$7,561	$16
	SUBTOTAL 12.	**$10,989**	**$2,022**	**$7,081**	**$0**	**$0**	**$20,092**	**$1,821**	**$1,005**	**$3,818**	**$26,736**	**$57**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$104	$2,228	$0	$0	$2,332	$232	$0	$769	$3,332	$7
13.2	Site Improvements	$0	$1,854	$2,463	$0	$0	$4,317	$426	$0	$1,423	$6,166	$13
13.3	Site Facilities	$3,322	$0	$3,505	$0	$0	$6,827	$673	$0	$2,250	$9,750	$21
	SUBTOTAL 13.	**$3,322**	**$1,958**	**$8,196**	**$0**	**$0**	**$13,476**	**$1,331**	**$0**	**$4,442**	**$19,249**	**$41**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,205	$3,142	$0	$0	$5,347	$492	$0	$876	$6,714	$14
14.3	Administration Building	$0	$856	$621	$0	$0	$1,477	$132	$0	$241	$1,850	$4
14.4	Circulation Water Pumphouse	$0	$160	$85	$0	$0	$245	$21	$0	$40	$306	$1
14.5	Water Treatment Buildings	$0	$410	$400	$0	$0	$810	$73	$0	$132	$1,016	$2
14.6	Machine Shop	$0	$438	$300	$0	$0	$738	$66	$0	$121	$924	$2
14.7	Warehouse	$0	$707	$457	$0	$0	$1,164	$103	$0	$190	$1,457	$3
14.8	Other Buildings & Structures	$0	$422	$329	$0	$0	$751	$67	$0	$164	$982	$2
14.9	Waste Treating Building & Str.	$0	$944	$1,804	$0	$0	$2,748	$256	$0	$601	$3,605	$8
	SUBTOTAL 14.	**$0**	**$6,408**	**$7,287**	**$0**	**$0**	**$13,694**	**$1,246**	**$0**	**$2,455**	**$17,396**	**$37**
	TOTAL COST	$866,544	$68,758	$295,716	$0	$0	$1,231,019	$114,350	$66,745	$229,150	$1,641,264	$3,480

Exhibit 3-50 Case S1B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$13,825	$29
1 Month Variable O&M	$3,642	$8
25% of 1 Months Fuel Cost at 100% CF	$814	$2
2% of TPC	$32,825	$70
Total	**$51,106**	**$108**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,943	$15
0.5% of TPC (spare parts)	$8,206	$17
Total	**$15,150**	**$32**
Initial Cost for Catalyst and Chemicals	**$6,959**	**$15**
Land	**$900**	**$2**
Other Owner's Costs	**$246,190**	**$522**
Financing Costs	**$44,314**	**$94**
Total Owner's Costs	**$364,619**	**$773**
Total Overnight Cost (TOC)	**$2,005,883**	**$4,253**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$2,286,707**	**$4,849**

Exhibit 3-51 Case S1B Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES		
Case S1B - Shell IGCC w/ CO2	Cost Base (Jun):	2007
	Heat Rate-net (Btu/kWh):	10641
	MWe-net:	472
	Capacity Factor (%):	80

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	34.65	$/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	$6,313,507	$13.387
Maintenance Labor Cost	$15,805,936	$33.515
Administrative & Support Labor	$5,529,861	$11.725
Property Taxes and Insurance	$32,825,287	$69.603
TOTAL FIXED OPERATING COSTS	**$60,474,591**	**$128.230**

VARIABLE OPERATING COSTS

Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost	Annual Cost $	$/kWh-net
Maintenance Material Cost					**$29,588,685**	**$0.00895**
Water (/1000 gallons)	0	2,451	1.08	**$0**	**$774,109**	**$0.00023**
Chemicals						
MU & WT Chem.(lbs)	0	14,602	0.17	$0	$737,906	$0.00022
Carbon (Mercury Removal) (lb)	116,627	160	1.05	$122,478	$48,991	$0.00001
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	6,034	4.13	498.83	$3,009,845	$601,969	$0.00018
Selexol Solution (gal)	285,640	91	13.40	$3,827,073	$355,483	$0.00011
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.	0.77	131.27	$0	$29,430	$0.00001
Subtotal Chemicals				**$6,959,397**	**$1,773,780**	**$0.00054**
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	160	0.42	$0	$19,457	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	593	16.23	$0	$2,811,013	$0.00085
Subtotal Waste Disposal				**$0**	**$2,830,470**	**$0.00086**
By-products & Emissions						
Sulfur (tons)	0	51	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$6,959,397**	**$34,967,044**	**$0.01058**
Fuel (ton)	0	7,032	15.22	**$0**	**$31,243,745**	**$0.00945**

Exhibit 3-52 Case L1B Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2010-Jan-20	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case L1B - Shell IGCC w/ CO2										
	Plant Size:	500.1	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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	$19,636	$3,649	$15,228	$0	$0	**$38,513**	$3,496	$0	$8,402	**$50,410**	$101
2	COAL & SORBENT PREP & FEED	$147,143	$12,451	$25,327	$0	$0	**$184,922**	$16,045	$0	$40,193	**$241,160**	$482
3	FEEDWATER & MISC. BOP SYSTEMS	$8,297	$6,517	$8,203	$0	$0	**$23,016**	$2,171	$0	$5,817	**$31,004**	$62
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$162,263	$0	$69,450	$0	$0	**$231,713**	$20,694	$32,004	$43,666	**$328,076**	$656
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$198,128	$0	w/equip.	$0	$0	**$198,128**	$19,204	$0	$21,733	**$239,066**	$478
4.4-4.9	Other Gasification Equipment	$26,410	$12,329	$16,813	$0	$0	**$55,552**	$5,316	$0	$13,093	**$73,961**	$148
	SUBTOTAL 4	**$386,801**	**$12,329**	**$86,263**	**$0**	**$0**	**$485,393**	**$45,214**	**$32,004**	**$78,493**	**$641,103**	**$1,282**
5A	GAS CLEANUP & PIPING	$91,544	$3,296	$75,944	$0	$0	**$170,784**	$16,495	$27,522	$43,117	**$257,918**	$516
5B	CO2 COMPRESSION	$20,109	$0	$11,415	$0	$0	**$31,524**	$3,034	$0	$6,912	**$41,470**	$83
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	**$98,609**	$9,348	$9,861	$11,782	**$129,599**	$259
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$5
	SUBTOTAL 6	**$92,026**	**$806**	**$7,475**	**$0**	**$0**	**$100,307**	**$9,507**	**$9,861**	**$12,339**	**$132,014**	**$264**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,673	$0	$4,646	$0	$0	**$37,319**	$3,548	$0	$4,087	**$44,954**	$90
7.2-7.9	SCR System, Ductwork and Stack	$3,522	$2,511	$3,322	$0	$0	**$9,355**	$867	$0	$1,665	**$11,887**	$24
	SUBTOTAL 7	**$36,195**	**$2,511**	**$7,967**	**$0**	**$0**	**$46,673**	**$4,416**	**$0**	**$5,751**	**$56,840**	**$114**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$27,623	$0	$4,708	$0	$0	**$32,332**	$3,102	$0	$3,543	**$38,977**	$78
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$34,547	$949	$11,364	$0	$0	**$46,860**	$4,555	$0	$10,446	**$61,862**	$124
	SUBTOTAL 8	**$62,171**	**$949**	**$16,072**	**$0**	**$0**	**$79,192**	**$7,657**	**$0**	**$13,989**	**$100,839**	**$202**
9	COOLING WATER SYSTEM	$8,339	$8,139	$6,908	$0	$0	**$23,386**	$2,172	$0	$5,228	**$30,786**	$62
10	ASH/SPENT SORBENT HANDLING SYS	$26,501	$1,960	$13,147	$0	$0	**$41,608**	$3,992	$0	$4,965	**$50,565**	$101
11	ACCESSORY ELECTRIC PLANT	$33,167	$13,157	$25,566	$0	$0	**$71,890**	$6,181	$0	$14,839	**$92,909**	$186
12	INSTRUMENTATION & CONTROL	$11,243	$2,068	$7,244	$0	$0	**$20,556**	$1,863	$1,028	$3,907	**$27,353**	$55
13	IMPROVEMENTS TO SITE	$3,438	$2,027	$8,484	$0	$0	**$13,949**	$1,377	$0	$4,598	**$19,924**	$40
14	BUILDINGS & STRUCTURES	$0	$6,664	$7,603	$0	$0	**$14,267**	$1,299	$0	$2,553	**$18,120**	$36
	TOTAL COST	**$946,611**	**$76,524**	**$322,846**	**$0**	**$0**	**$1,345,980**	**$124,918**	**$70,414**	**$251,103**	**$1,792,415**	**$3,584**

Exhibit 3-53 Case L1B Total Plant Cost Summary Details

Client: USDOE/NETL **Report Date:** 2010-Jan-20
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L1B - Shell IGCC w/ CO2
Plant Size: 500.1 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($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	$5,157	$0	$2,520	$0	$0	$7,676	$688	$0	$1,673	$10,037	$20
1.2	Coal Stackout & Reclaim	$6,663	$0	$1,615	$0	$0	$8,279	$726	$0	$1,801	$10,805	$22
1.3	Coal Conveyors & Yd Crush	$6,195	$0	$1,598	$0	$0	$7,794	$684	$0	$1,696	$10,173	$20
1.4	Other Coal Handling	$1,621	$0	$370	$0	$0	$1,991	$174	$0	$433	$2,598	$5
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	$3,649	$9,124	$0	$0	$12,773	$1,224	$0	$2,799	$16,797	$34
	SUBTOTAL 1.	**$19,636**	**$3,649**	**$15,228**	**$0**	**$0**	**$38,513**	**$3,496**	**$0**	**$8,402**	**$50,410**	**$101**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$60,417	$3,629	$8,803	$0	$0	$72,849	$6,286	$0	$15,827	$94,963	$190
2.2	Prepared Coal Storage & Feed	$2,511	$601	$394	$0	$0	$3,506	$300	$0	$761	$4,567	$9
2.3	Dry Coal Injection System	$82,642	$959	$7,675	$0	$0	$91,276	$7,861	$0	$19,828	$118,965	$238
2.4	Misc.Coal Prep & Feed	$1,574	$1,145	$3,433	$0	$0	$6,152	$565	$0	$1,344	$8,061	$16
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	$6,117	$5,022	$0	$0	$11,138	$1,032	$0	$2,434	$14,604	$29
	SUBTOTAL 2.	**$147,143**	**$12,451**	**$25,327**	**$0**	**$0**	**$184,922**	**$16,045**	**$0**	**$40,193**	**$241,160**	**$482**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,329	$4,000	$2,112	$0	$0	$8,441	$782	$0	$1,845	$11,068	$22
3.2	Water Makeup & Pretreating	$542	$57	$303	$0	$0	$901	$86	$0	$296	$1,284	$3
3.3	Other Feedwater Subsystems	$1,274	$431	$388	$0	$0	$2,093	$188	$0	$456	$2,737	$5
3.4	Service Water Systems	$310	$639	$2,216	$0	$0	$3,165	$309	$0	$1,042	$4,516	$9
3.5	Other Boiler Plant Systems	$1,664	$645	$1,598	$0	$0	$3,907	$371	$0	$856	$5,134	$10
3.6	FO Supply Sys & Nat Gas	$317	$598	$558	$0	$0	$1,472	$142	$0	$323	$1,937	$4
3.7	Waste Treatment Equipment	$758	$0	$462	$0	$0	$1,220	$119	$0	$402	$1,740	$3
3.8	Misc. Power Plant Equipment	$1,103	$148	$566	$0	$0	$1,817	$175	$0	$598	$2,589	$5
	SUBTOTAL 3.	**$8,297**	**$6,517**	**$8,203**	**$0**	**$0**	**$23,016**	**$2,171**	**$0**	**$5,817**	**$31,004**	**$62**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$162,263	$0	$69,450	$0	$0	$231,713	$20,694	$32,004	$43,666	$328,076	$656
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$198,128	$0	w/equip.	$0	$0	$198,128	$19,204	$0	$21,733	$239,066	$478
4.4	LT Heat Recovery & FG Saturation	$26,410	$0	$10,040	$0	$0	$36,450	$3,557	$0	$8,001	$48,008	$96
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	Flare Stack System	$0	$1,599	$651	$0	$0	$2,250	$216	$0	$493	$2,959	$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	$10,730	$6,122	$0	$0	$16,852	$1,543	$0	$4,599	$22,993	$46
	SUBTOTAL 4.	**$386,801**	**$12,329**	**$86,263**	**$0**	**$0**	**$485,393**	**$45,214**	**$32,004**	**$78,493**	**$641,103**	**$1,282**

Exhibit 3-53 Case L1B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL							Report Date:	2010-Jan-20		
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case L1B - Shell IGCC w/ CO2										
	Plant Size:	500.1	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$74,094	$0	$62,870	$0	$0	$136,964	$13,246	$27,393	$35,521	$213,123	$426
5A.2	Elemental Sulfur Plant	$5,754	$1,147	$7,423	$0	$0	$14,324	$1,391	$0	$3,143	$18,858	$38
5A.3	Mercury Removal	$1,465	$0	$1,115	$0	$0	$2,580	$249	$129	$592	$3,549	$7
5A.4	Shift Reactors	$7,788	$0	$3,135	$0	$0	$10,923	$1,047	$0	$2,394	$14,364	$29
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$2,444	$411	$232	$0	$0	$3,086	$293	$0	$676	$4,055	$8
5A.6	Fuel Gas Piping	$0	$864	$605	$0	$0	$1,469	$136	$0	$321	$1,926	$4
5A.9	HGCU Foundations	$0	$875	$564	$0	$0	$1,439	$132	$0	$471	$2,042	$4
	SUBTOTAL 5A.	**$91,544**	**$3,296**	**$75,944**	**$0**	**$0**	**$170,784**	**$16,495**	**$27,522**	**$43,117**	**$257,918**	**$516**
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$20,109	$0	$11,415	$0	$0	$31,524	$3,034	$0	$6,912	$41,470	$83
	SUBTOTAL 5B.	**$20,109**	**$0**	**$11,415**	**$0**	**$0**	**$31,524**	**$3,034**	**$0**	**$6,912**	**$41,470**	**$83**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	$98,609	$9,348	$9,861	$11,782	$129,599	$259
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$92,026**	**$806**	**$7,475**	**$0**	**$0**	**$100,307**	**$9,507**	**$9,861**	**$12,339**	**$132,014**	**$264**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,673	$0	$4,646	$0	$0	$37,319	$3,548	$0	$4,087	$44,954	$90
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,805	$1,321	$0	$0	$3,126	$275	$0	$680	$4,081	$8
7.4	Stack	$3,522	$0	$1,323	$0	$0	$4,845	$464	$0	$531	$5,840	$12
7.9	HRSG,Duct & Stack Foundations	$0	$706	$678	$0	$0	$1,383	$129	$0	$454	$1,966	$4
	SUBTOTAL 7.	**$36,195**	**$2,511**	**$7,967**	**$0**	**$0**	**$46,673**	**$4,416**	**$0**	**$5,751**	**$56,840**	**$114**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$27,623	$0	$4,708	$0	$0	$32,332	$3,102	$0	$3,543	$38,977	$78
8.2	Turbine Plant Auxiliaries	$191	$0	$439	$0	$0	$630	$62	$0	$69	$761	$2
8.3a	Condenser & Auxiliaries	$2,973	$0	$950	$0	$0	$3,923	$375	$0	$430	$4,728	$9
8.3b	Air Cooled Condenser	$27,249	$0	$5,463	$0	$0	$32,711	$3,271	$0	$7,197	$43,179	$86
8.4	Steam Piping	$4,134	$0	$2,908	$0	$0	$7,043	$605	$0	$1,912	$9,559	$19
8.9	TG Foundations	$0	$949	$1,604	$0	$0	$2,553	$242	$0	$839	$3,634	$7
	SUBTOTAL 8.	**$62,171**	**$949**	**$16,072**	**$0**	**$0**	**$79,192**	**$7,657**	**$0**	**$13,989**	**$100,839**	**$202**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,766	$0	$1,049	$0	$0	$6,815	$649	$0	$1,120	$8,584	$17
9.2	Circulating Water Pumps	$1,500	$0	$99	$0	$0	$1,599	$135	$0	$260	$1,993	$4
9.3	Circ.Water System Auxiliaries	$129	$0	$18	$0	$0	$148	$14	$0	$24	$186	$0
9.4	Circ.Water Piping	$0	$5,400	$1,400	$0	$0	$6,800	$615	$0	$1,483	$8,897	$18
9.5	Make-up Water System	$306	$0	$438	$0	$0	$744	$71	$0	$163	$978	$2
9.6	Component Cooling Water Sys	$637	$762	$542	$0	$0	$1,942	$182	$0	$425	$2,549	$5
9.9	Circ.Water System Foundations	$0	$1,977	$3,361	$0	$0	$5,339	$506	$0	$1,753	$7,598	$15
	SUBTOTAL 9.	**$8,339**	**$8,139**	**$6,908**	**$0**	**$0**	**$23,386**	**$2,172**	**$0**	**$5,228**	**$30,786**	**$62**

Exhibit 3-53 Case L1B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL							**Report Date:**	2010-Jan-20		
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case L1B - Shell IGCC w/ CO2										
	Plant Size:	500.1	MW,net	**Estimate Type:**		Conceptual		**Cost Base (Jun)**		2007	($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**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$23,209	$0	$11,445	$0	$0	$34,654	$3,330	$0	$3,798	$41,782	$84
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$746	$0	$812	$0	$0	$1,558	$151	$0	$256	$1,965	$4
10.7	Ash Transport & Feed Equipment	$1,001	$0	$241	$0	$0	$1,242	$116	$0	$204	$1,562	$3
10.8	Misc. Ash Handling Equipment	$1,545	$1,894	$566	$0	$0	$4,005	$381	$0	$658	$5,044	$10
10.9	Ash/Spent Sorbent Foundation	$0	$66	$83	$0	$0	$149	$14	$0	$49	$212	$0
	SUBTOTAL 10.	**$26,501**	**$1,960**	**$13,147**	**$0**	**$0**	**$41,608**	**$3,992**	**$0**	**$4,965**	**$50,565**	**$101**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$932	$0	$922	$0	$0	$1,853	$177	$0	$203	$2,233	$4
11.2	Station Service Equipment	$4,926	$0	$444	$0	$0	$5,370	$495	$0	$587	$6,452	$13
11.3	Switchgear & Motor Control	$9,108	$0	$1,656	$0	$0	$10,764	$998	$0	$1,764	$13,527	$27
11.4	Conduit & Cable Tray	$0	$4,231	$13,957	$0	$0	$18,188	$1,759	$0	$4,987	$24,934	$50
11.5	Wire & Cable	$0	$8,084	$5,311	$0	$0	$13,395	$973	$0	$3,592	$17,960	$36
11.6	Protective Equipment	$0	$689	$2,507	$0	$0	$3,196	$312	$0	$526	$4,035	$8
11.7	Standby Equipment	$230	$0	$225	$0	$0	$455	$43	$0	$75	$574	$1
11.8	Main Power Transformers	$17,971	$0	$141	$0	$0	$18,112	$1,370	$0	$2,922	$22,404	$45
11.9	Electrical Foundations	$0	$153	$402	$0	$0	$555	$53	$0	$183	$791	$2
	SUBTOTAL 11.	**$33,167**	**$13,157**	**$25,566**	**$0**	**$0**	**$71,890**	**$6,181**	**$0**	**$14,839**	**$92,909**	**$186**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,110	$0	$741	$0	$0	$1,851	$175	$93	$318	$2,437	$5
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	$255	$0	$164	$0	$0	$419	$40	$21	$96	$575	$1
12.7	Computer & Accessories	$5,921	$0	$190	$0	$0	$6,110	$561	$306	$698	$7,674	$15
12.8	Instrument Wiring & Tubing	$0	$2,068	$4,228	$0	$0	$6,296	$534	$315	$1,786	$8,932	$18
12.9	Other I & C Equipment	$3,958	$0	$1,922	$0	$0	$5,879	$553	$294	$1,009	$7,736	$15
	SUBTOTAL 12.	**$11,243**	**$2,068**	**$7,244**	**$0**	**$0**	**$20,556**	**$1,863**	**$1,028**	**$3,907**	**$27,353**	**$55**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$108	$2,306	$0	$0	$2,414	$240	$0	$796	$3,449	$7
13.2	Site Improvements	$0	$1,919	$2,550	$0	$0	$4,469	$441	$0	$1,473	$6,382	$13
13.3	Site Facilities	$3,438	$0	$3,628	$0	$0	$7,067	$697	$0	$2,329	$10,092	$20
	SUBTOTAL 13.	**$3,438**	**$2,027**	**$8,484**	**$0**	**$0**	**$13,949**	**$1,377**	**$0**	**$4,598**	**$19,924**	**$40**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,340	$3,334	$0	$0	$5,674	$522	$0	$929	$7,125	$14
14.3	Administration Building	$0	$874	$634	$0	$0	$1,508	$134	$0	$246	$1,888	$4
14.4	Circulation Water Pumphouse	$0	$164	$87	$0	$0	$251	$22	$0	$41	$314	$1
14.5	Water Treatment Buildings	$0	$453	$442	$0	$0	$895	$81	$0	$146	$1,122	$2
14.6	Machine Shop	$0	$447	$306	$0	$0	$753	$67	$0	$123	$943	$2
14.7	Warehouse	$0	$722	$466	$0	$0	$1,188	$105	$0	$194	$1,488	$3
14.8	Other Buildings & Structures	$0	$433	$337	$0	$0	$769	$69	$0	$168	$1,006	$2
14.9	Waste Treating Building & Str.	$0	$967	$1,848	$0	$0	$2,815	$262	$0	$615	$3,693	$7
	SUBTOTAL 14.	**$0**	**$6,664**	**$7,603**	**$0**	**$0**	**$14,267**	**$1,299**	**$0**	**$2,553**	**$18,120**	**$36**
	TOTAL COST	**$946,611**	**$76,524**	**$322,846**	**$0**	**$0**	**$1,345,980**	**$124,918**	**$70,414**	**$251,103**	**$1,792,415**	**$3,584**

Exhibit 3-54 Case L1B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$14,586	$29
1 Month Variable O&M	$4,058	$8
25% of 1 Months Fuel Cost at 100% CF	$811	$2
2% of TPC	$35,848	$72
Total	**$55,303**	**$111**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,987	$14
0.5% of TPC (spare parts)	$8,962	$18
Total	**$15,949**	**$32**
Initial Cost for Catalyst and Chemicals	**$7,538**	**$15**
Land	**$900**	**$2**
Other Owner's Costs	**$268,862**	**$538**
Financing Costs	**$48,395**	**$97**
Total Owner's Costs	**$396,948**	**$794**
Total Overnight Cost (TOC)	**$2,189,363**	**$4,378**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$2,495,874**	**$4,991**

Exhibit 3-55 Case L1B Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES						
Case L1B - Shell IGCC w/ CO2					Cost Base (Jun):	2007
					Heat Rate-net (Btu/kWh):	10,772
					MWe-net:	500
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$6,313,507	$12.625
Maintenance Labor Cost					$17,024,604	$34.045
Administrative & Support Labor					$5,834,528	$11.668
Property Taxes and Insurance					$35,848,299	$71.688
TOTAL FIXED OPERATING COSTS					**$65,020,938**	**$130.026**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$31,416,690**	**$0.00896**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	2,820	1.08	**$0**	**$890,771**	**$0.00025**
Chemicals						
MU & WT Chem.(lbs)	0	16,802	0.17	$0	$849,113	$0.00024
Carbon (Mercury Removal) (lb)	126,002	173	1.05	$132,324	$52,930	$0.00002
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	6,431	4.40	498.83	$3,207,993	$641,599	$0.00018
Selexol Solution (gal)	313,293	100	13.40	$4,197,575	$389,897	$0.00011
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.	0.90	131.27	$0	$34,681	$0.00001
Subtotal Chemicals				**$7,537,892**	**$1,968,219**	**$0.00056**
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	173	0.42	$0	$21,021	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	983	16.23	$0	$4,656,048	$0.00133
Subtotal Waste Disposal				**$0**	**$4,677,069**	**$0.00133**
By-products & Emissions						
Sulfur (tons)	0	61	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$7,537,892**	**$38,952,749**	**$0.01112**
Fuel (ton)	0	9,768	10.92	**$0**	**$31,146,334**	**$0.00889**

3.3 TRIG™ IGCC CASES

This section contains an evaluation of plant designs for Cases S2A and S2B, which are based on the TRIG™ transport gasifier, developed by Kellogg Brown and Root (KBR) and Southern Company. Cases S2A and S2B are very similar in terms of process, equipment, scope and arrangement, except that Case S2B includes SGS reactors, CO_2 absorption/regeneration and compression/transport systems.

Section 3.3.4 covers the results for the S2A non-capture case using PRB coal and Section 3.3.8 covers the S2B CO_2-capture case using PRB coal. The sections are organized analogously as follows:

- Process and System Description provides an overview of the specific technology's operation.
- BFD and stream table display results for major processes and streams
- Performance Results provides the main modeling results, 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 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs.

Process and System Description, Performance Results, Equipment List and Cost Estimates are repeated for Case S2B in Section 3.3.8. If the information is identical to that presented for the non-capture cases, a reference is made to the earlier section rather than repeating the information.

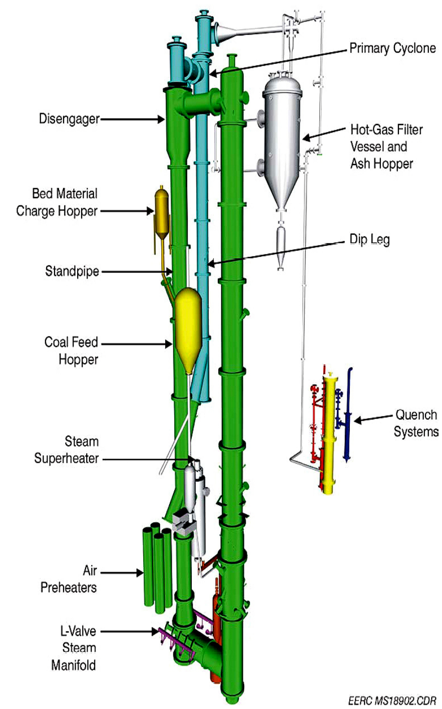
3.3.1 Gasifier Background

Development and Current Status – The Transport Gasifier for IGCC applications is based on technology developed by KBR for fluid catalytic cracking for refineries. First deployed commercially in the late 1930's in the petroleum refining industry, the transport gasifier has undergone major development, particularly coal applications for IGCC power generation at the Power Systems Development Facility (PSDF), near Willsonville, Alabama. The large scale pilot facility was established in 1995 to reduce the capital cost and increase the efficiency of advanced coal-based power generation, while meeting strict environmental standards and providing data for commercial scale up.

With the collaboration of the U.S. Department of Energy (DOE), EPRI, Southern Company, KBR, Siemens-Westinghouse, and Peabody Holding company, the TRIG™ gasifier at the PSDF has been operated for over 15,000 hours, testing multiple fuels, including PRB and lignite coals, in both air blown and oxygen blown operation. Gasification was carried out under conditions of 871°C (1,600°F) to 982°C (1,800°F), pressures of up to 1.72 MPa_g (250 psig) and at coal feed rates from 1,130 kg/hr (2,500 lb/hr) to 2,270 kg/hr (5,000 lb/hr).

Based on the experience from the PSDF, Southern Company was prepared to construct an air-blown, 275 MW Orlando Gasification Project firing PRB coal with co-funding from the DOE CCPI-2 Program. All major contracts with the plant owners and partners were signed by January 2006 and the FEED and updated costs were completed in March 2007, with an estimated startup in 2010. The project was converted to a natural gas feed during the construction phase because of uncertainty surrounding possible greenhouse gas (GHG) regulation for the state of Florida.

Current projects utilizing this technology include the Mississippi air-blown IGCC owned by the Mississippi Power Company, proposed to generate 582 MW firing Mississippi lignite coal, with $133 million (M) of federal tax credits under the Energy Policy Act of 2005. Co-funding from the cancelled DOE CCPI-2 project in Orlando was transferred to this project. The FEED and updated cost estimate was prepared by Southern Company and KBR with planned commercial operation in June 2013.



Gasifier Capacity – Commercial scale units are in the design and construction phases, and the largest current TRIG™ installation is at the PSDF run by Southern Company, processing up to 50 tonne/day (55 tpd) of coal. The FEED work, which was completed for the cancelled Orlando Gasification Project, indicated gasification of 2,990 tonne/day (3,300 tpd) of PRB coal that would have been used to fire a GE 7FA CT. This scale up is consistent with the size of the two gasifiers used for each of the TRIG™ cases in this study.

Distinguishing Characteristics – The TRIG™ gasifier is a dry feed, fast CFB, non-slagging, single stage gasifier producing syngas at moderate temperatures. The entire gasifier is constructed from refractory lined piping and vessels. Advantages of the TRIG™ coal gasification technology is it's a small footprint with a high thermal throughput, the ability to process a variety of high ash, high melting point coals, and its relatively high overall carbon conversion. The transport gasifier operates at higher circulation rates, velocities, and riser densities than a conventional circulating bed, resulting in higher throughput, mixing, heat and mass transfer. The dry feed non-slagging gasifier allows the firing of high moisture and ash fuels such as sub-bituminous and lignite coals.

The high circulation rates of the transport gasifier results in a lower per pass carbon conversion compared to other gasifier technologies, but the unreacted carbon, along with the ash, is separated and recirculated to increase the overall carbon conversion. Larger coal particle sizes (up to 0.75" top size) are acceptable because of the high recirculation rate, which reduces the necessary coal preparation compared to other dry feed gasifier technologies. Ash removal is controlled to maintain a constant gasifier bed inventory, which aids in transport, and is removed at the gasifier pressure, flowing through an ash cooler, then though a proprietary continuous pressure let-down system. The ash is then moisturized with stripped water from the SWS to minimize dust emissions while it is being landfilled. Because of the non-slagging design and dust removal, no black or gray water systems are required for transporting or disposing of these wastes. Due to the thorough mixing in the gasifier, the opportunity exists for in-situ sulfur capture by injecting limestone during the gasification process, although that was not considered in this study.

The high efficiency of the TRIG™ gasifier, associated with the lower gasification temperature, helps reduce the operating cost of the gasifier, but creates more methane when compared to other gasifiers. Higher methane content increases the heating value of the fuel and is associated with high cold gas efficiencies, but can become a problem if high CO_2 removal is required. Because of this, the TRIG™ CO_2 capture case achieves less than 90 percent overall carbon capture.

Important Coal Characteristics – The TRIG™ gasifier is able to fire lower rank coals with high moisture and ash content and high ash fusion temperatures because of its non-slagging ash removal system. Dry feeding also reduces the negative effects of high ash content relative to slurry feed gasifiers, which are limited by solids content in the slurry.

3.3.2 Key System Assumptions

System assumptions for Cases S2A and S2B TRIG™ IGCC using PRB coal, with and without CO_2 capture, are compiled in Exhibit 3-56.

Exhibit 3-56 Case S2A and S2B Plant Study Configuration Matrix

Case	S2A	S2B
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.654	0.661
Carbon Conversion, %	98.0	98.0
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	9,490 (255)	9,460 (254)
Nominal Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1,800/1,050/1,050)	12.4/538/538 (1,800/1,000/1,000)
Condenser Pressure, mm Hg (in Hg)	36 (1.4)	36 (1.4)
Combustion Turbine	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)
Gasifier Technology	TRIG™	TRIG™
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Subbituminous	Subbituminous
Coal Feed Moisture Content, %	18	18
COS Hydrolysis	Yes	Yes (Part of WGS)
Water Gas Shift	No	Yes
H_2S Separation	Sulfinol-M	Selexol (1st Stage)
Sulfur Removal, %	99.9	99.8
CO_2 Separation	None	Selexol (2nd Stage)
CO_2 Removal, %	N/A	83
Sulfur Recovery	Claus Plant with Tail Gas Treatment / Elemental Sulfur	Claus Plant with Tail Gas Treatment / Elemental Sulfur
Particulate Control	Cyclone, Candle Filter, and AGR Absorber	Cyclone, Candle Filter, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB) and N_2 Dilution	MNQC (LNB) and N_2 Dilution

Balance of Plant – All Cases

The balance of plant assumptions are common to all cases and are presented in Exhibit 3-57.

Exhibit 3-57 Balance of Plant Assumptions

Cooling water 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 CT Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and 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 GPD)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

3.3.3 Sparing Philosophy

The sparing philosophy for Cases S2A and S2B 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 ASUs (2 x 50%).
- Two trains of coal drying and dry feed systems (2 x 50%).
- Two trains of gasification, including gasifier, SGC, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Sulfinol-M acid gas removal in non-capture cases and two trains of two-stage Selexol in CO_2 capture cases (2 x 50%).
- One train of Claus-based sulfur recovery (1 x 100%).
- Two CT/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.3.4 TRIG™ IGCC Non-Capture Case (S2A) Process Description

In this section the overall TRIG™ gasification process for Case S2A is described. The system description follows the BFD in Exhibit 3-58, and the tables in Exhibit 3-59 provide process data for the numbered streams.

Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and generally described in Section 3.1.1. The TRIG™ gasifier drying process described for the Orlando Gasification Project [70] utilizes flash dryers with the pulverizers. A closed loop of gas, containing less than 11.3 percent oxygen [71] to meet fire code standards, is heated, preferably with medium pressure steam, to provide the heat to dry the coal. While the Orlando Project paper [46] does not indicate coal moisture levels, the study paper [71] indicates the PRB coal is dried from 28 to 18 percent. After the coal and drying gas are separated, the gas is cooled below its dew point to remove moisture before being reheated. The condensed water is treated and used in the process.

The main motivation to dry the coal is to enable transport into the gasifier. The TRIG™ gasifier accommodates a larger coal particle (700 micron top side) than the dry-feed, entrained-flow gasifier (approximately 70 micron), enabling the transport of coal with 18 percent moisture.

For these reasons, and to be consistent with plans for the Orlando project, it was decided to dry the PRB coal to 18 percent and not use the WTA process, but rather use a system like that described for the Orlando project to realize some of the coal handling and gasification benefits of the transport gasifier.

Gasifier

There are two parallel TRIG™ dry feed, pressurized, up flow, transport gasifiers, operating at 4.2 MPa (615 psia) and processing a total of 5,935 tonne/day (6,542 tpd) of as-received PRB Coal that reacts with oxygen and steam in a reducing environment at a temperature of 982°C (1,800°F) to produce principally hydrogen and carbon monoxide along with comparatively high concentrations of methane (~5 vol%) due to the low gasification temperatures.

Raw Gas Cooling/Particulate Removal

High-temperature heat recovery in each gasifier train is performed by raw gas coolers in three sections, a superheater, an evaporator, and an economizer, which lower the raw gas temperature from 982°C (1,800°F) to 343°C (650°F). Particulates are removed using high temperature, HP rigid, barrier-type filter elements and pulsed with recycled syngas to clean the filters of the trapped ash. The collected particulates are cooled and depressurized using a continuous fine ash removal system and conveyed to the ash silo for disposal. The syngas is further cooled to 260°C (500°F) before entering further gas treatment, with much of the heat recovered by indirect cooling by BFW.

Sour Water Stripper

Water condensed during the cooling of the raw gas, along with all other sour water from the plant are sent to the sour water stripper, which removes NH_3, SO_2, and other impurities from the waste stream. The sour gas stripper consists of a sour drum that accumulates sour water that 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 SRU. 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 AGR process; however, because COS is not readily removed, it is first catalytically converted to H_2S in a COS hydrolysis unit.

The cooled raw gas is fed to the COS hydrolysis reactor where the COS in the sour gas is hydrolyzed with steam, over a catalyst bed, into H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the AGR process, 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 then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.8).

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 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 the non-CO_2 capture applications.

The sour syngas is fed directly into a 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 rich solvent at LP 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 about 15 percent of the CO_2 along with the H_2S and COS. The acid gas is fed to the SRU. The residual CO_2 passes through the SRU, the hydrogenation reactor and is recycled upstream of the AGR system.

Claus Unit

The SRU is a Claus bypass type SRU utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting 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 combinations of Claus technology and tail gas recycle results in an overall sulfur recovery exceeding 99 percent, producing 43 tonne/day (48 tpd) of sulfur.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. Feed for each case consists of acid gas from both the acid gas cleanup unit and a vent stream from the sour water stripper in the gasifier section.

In the furnace waste heat boiler 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 LP steam header.

Power Block

Clean syngas exiting the Sulfinol absorber reheated and diluted with nitrogen from the ASU, and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and a portion of the air requirements for the ASU. The exhaust gas exits the CT at 586°C (1,087°F) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) and is discharged through the plant stack. The steam generated in the

HRSG is used to power a steam turbine using a nominal 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

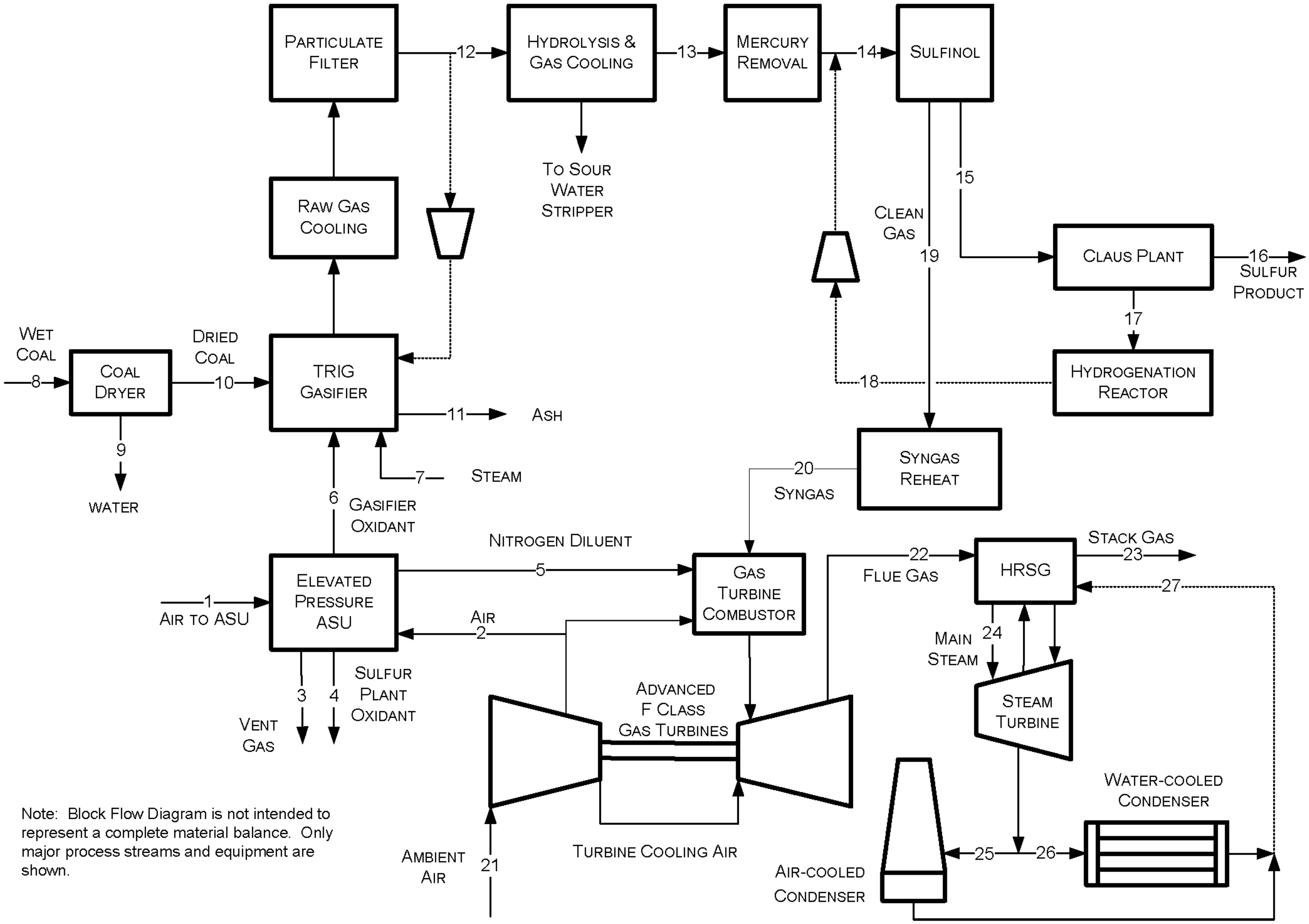
Air Separation Unit

The ASU is designed to produce approximately 3,098 tonne/day (3,415 tpd) of 95 mol% O_2 for use in the gasifier and SRU. The plant is designed with two production trains. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as dilution in the CT combustor or as a coal transport fluid. Air extraction is taken from the CT compressor to reduce the size of the main air compressor.

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14, and 3.1.15.

Exhibit 3-58 Case S2A Process Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 3-59 Case S2A Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13
V-L Mole Fraction													
Ar	0.0093	0.0093	0.0291	0.0360	0.0023	0.0360	0.0000	0.0000	0.0000	0.0000	0.0000	0.0079	0.0093
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0532	0.0628
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3426	0.4051
CO_2	0.0003	0.0003	0.0102	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1618	0.1915
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2712	0.3206
H_2O	0.0064	0.0064	0.1937	0.0000	0.0002	0.0000	1.0000	0.0000	1.0000	0.0000	0.0000	0.1518	0.0016
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0029	0.0037
N_2	0.7759	0.7759	0.5163	0.0140	0.9920	0.0140	0.0000	0.0000	0.0000	0.0000	0.0000	0.0046	0.0055
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0039	0.0000
O_2	0.2081	0.2081	0.2507	0.9500	0.0054	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	18,706	750	624	55	13,225	3,951	3,355	0	1,349	0	0	18,112	15,320
V-L Flowrate (kg/hr)	540,510	21,680	17,220	1,769	371,104	127,326	60,443	0	24,303	0	0	388,909	338,660
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	247,297	0	223,864	22,724	0	0
Temperature (°C)	6	411	21	32	196	32	343	6	16	71	982	260	35
Pressure (MPa, abs)	0.09	1.43	0.11	0.86	2.65	0.86	5.10	0.09	0.10	0.10	4.24	4.02	3.81
Enthalpy (kJ/kg)^A	15.26	434.33	40.10	26.59	202.64	26.59	3,062.93	---	67.41	---	---	705.74	38.93
Density (kg/m^3)	1.1	7.2	1.6	11.0	18.9	11.0	20.1	---	1,002.0	---	---	19.4	33.3
V-L Molecular Weight	28.895	28.895	27.587	32.229	28.061	32.229	18.015	---	18.015	---	---	21.472	22.106
V-L Flowrate (lb_{mol}/hr)	41,240	1,654	1,376	121	29,156	8,710	7,397	0	2,974	0	0	39,931	33,774
V-L Flowrate (lb/hr)	1,191,622	47,797	37,963	3,900	818,144	280,705	133,255	0	53,579	0	0	857,398	746,618
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	545,197	0	493,536	50,098	0	0
Temperature (°F)	42	771	70	90	385	90	650	42	61	160	1,800	500	95
Pressure (psia)	13.0	207.6	16.4	125.0	384.0	125.0	740.0	13.0	14.5	14.6	615.0	582.5	552.5
Enthalpy (Btu/lb)^A	6.6	186.7	17.2	11.4	87.1	11.4	1,316.8	---	29.0	---	---	303.4	16.7
Density (lb/ft^3)	0.070	0.452	0.097	0.688	1.180	0.688	1.257	---	62.556	---	---	1.212	2.082

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-59 Case S2A Stream Table (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27
V-L Mole Fraction													
Ar	0.0003	0.0000	0.0031	0.0032	0.0094	0.0094	0.0093	0.0090	0.0090	0.0000	0.0000	0.0000	0.0000
CH_4	0.0024	0.0000	0.0012	0.0000	0.0627	0.0627	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0074	0.0000	0.0578	0.0061	0.4047	0.4047	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.8648	0.0000	0.6575	0.7300	0.1914	0.1914	0.0003	0.0824	0.0824	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0065	0.0000	0.0122	0.0680	0.3230	0.3230	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0046	0.0000	0.2151	0.1381	0.0015	0.0015	0.0064	0.0613	0.0613	1.0000	1.0000	1.0000	1.0000
H_2S	0.1033	0.0000	0.0007	0.0018	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0107	0.0000	0.0513	0.0527	0.0073	0.0073	0.7759	0.7385	0.7385	0.0000	0.0000	0.0000	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	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2081	0.1089	0.1089	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	553	0	675	657	15,335	15,335	100,835	123,065	123,065	34,631	15,671	15,671	35,201
V-L Flowrate (kg/hr)	23,339	0	24,382	24,042	337,748	337,748	2,913,623	3,600,794	3,600,794	623,885	282,309	282,309	634,155
Solids Flowrate (kg/hr)	0	1,797	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	48	174	232	49	31	196	6	588	132	560	32	32	33
Pressure (MPa, abs)	0.16	0.1	0.085	0.073	3.238	3.203	0.090	0.093	0.090	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	45.44	---	512.471	217.046	34.170	283.546	15.260	734.275	230.852	3,498.933	2,301.992	2,301.992	140.856
Density (kg/m^3)	2.6	---	0.7	1.0	28.6	17.9	1.1	0.4	0.8	35.2	0.04	0.04	995.0
V-L Molecular Weight	42.235	---	36.126	36.591	22.025	22.025	28.895	29.259	29.259	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	1,218	0	1,488	1,449	33,807	33,807	222,302	271,312	271,312	76,348	34,548	34,548	77,605
V-L Flowrate (lb/hr)	51,453	0	53,754	53,003	744,606	744,606	6,423,439	7,938,393	7,938,393	1,375,430	622,384	622,384	1,398,073
Solids Flowrate (lb/hr)	0	3,962	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	119	344	450	120	87	385	42	1,090	270	1,040	90	90	92
Pressure (psia)	23.7	17.3	12.3	10.6	469.6	464.6	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	19.5	---	220.3	93.3	14.7	121.9	6.6	315.7	99.2	1,504.3	989.7	989.7	60.6
Density (lb/ft^3)	0.162	---	0.046	0.063	1.787	1.120	0.070	0.024	0.050	2.197	0.002	0.002	62.114

3.3.5 Case S2A Performance Results

The non-capture TRIG™ IGCC plant using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 545 MWe at a net plant efficiency of 39.9 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 3-60, which includes auxiliary power requirements. The ASU accounts for approximately 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 CWPs and cooling tower fan, and the air-cooled condenser account for about 5 percent of the auxiliary load, the coal drying process accounts for 3 percent of the auxiliary load, and the BFW pumps account for an additional 4 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-60 Case S2A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	S2A
Gas Turbine Power	419,100
Steam Turbine Power	233,600
TOTAL POWER, kWe	**652,700**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	500
Coal Crushing	690
Ash Handling	590
Coal Dryer Circulation Blower	2,420
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	48,130
Oxygen Compressor	6,160
Nitrogen Compressors	26,380
Boiler Feedwater Pumps	3,840
Condensate Pump	210
Syngas Recycle Compressors	1,440
Circulating Water Pump	1,920
Ground Water Pumps	190
Cooling Tower Fans	1,250
Air Cooled Condenser Fans	2,730
Acid Gas Removal	740
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	2,470
Miscellaneous Balance of Plant[1]	3,000
Transformer Losses	2,270
TOTAL AUXILIARIES, kWe	**107,280**
NET POWER, kWe	**545,420**
Net Plant Efficiency, % (HHV)	39.9%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,032 (8,560)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	1,224 (1,160)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	247,297 (545,197)
Thermal Input, kWt	1,368,368
Raw Water Withdrawal, m^3/min (gpm)	7.7 (2,045)
Raw Water Consumption, m^3/min (gpm)	6.0 (1,598)

[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 PM were presented in Section 2.3. A summary of the plant air emissions for Case S2A is presented in Exhibit 3-61.

Exhibit 3-61 Cases S2A Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	28 (31)	0.006 (0.013)
NO_X	0.025 (0.059)	875 (965)	0.191 (0.422)
Particulates	0.003 (0.0071)	105 (116)	0.023 (0.051)
Hg	1.51E-7 (3.51E-7)	0.005 (0.006)	1.14E-6 (2.51E-6)
CO_2 gross	90.5 (210.6)	3,125,929 (3,445,747)	683 (1,507)
CO_2 net			818 (1,803)

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 5 ppmv in both cases. This results in a concentration in the flue gas of less than 1 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 and recycled to the AGR to capture most of the remaining sulfur. Because the environmental target was set based on higher sulfur bituminous coal, the resulting SO_2 emissions with lower sulfur western coals are substantially less than the environmental target.

NOx emissions are limited to 15 ppmvd (as NO_2 @ 15 percent O_2) by the use of low NOx burners and nitrogen dilution of the fuel gas. 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 NOx 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 this case is shown in Exhibit 3-62. 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 ash and as CO_2 in the stack gas and ASU vent gas.

Exhibit 3-62 Case S2A Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	123,817 (272,970)	**Slag/Ash**	2,476 (5,459)
Air (CO_2)	471 (1,038)	**Stack Gas**	121,735 (268,379)
		ASU Vent	77 (169)
Total	124,288 (274,008)	**Total**	124,288 (274,008)

Exhibit 3-63 shows the sulfur balance for the non capture case. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the ash is considered to be negligible.

Exhibit 3-63 Case S2A Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	1,799 (3,966)	**Elemental Sulfur**	1,797 (3,962)
		Stack Gas	2 (4)
Total	1,799 (3,966)	**Total**	1,799 (3,966)

Exhibit 3-64 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 coal moisture from the drying process and syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is discharged from the process to a permitted outfall. The difference between the withdrawal and discharge is the consumption.

Exhibit 3-64 Case S2A Water Balance

Water Use	Water Demand m^3/min (gpm)	Internal Recycle m^3/min (gpm)	Raw Water Withdrawal m^3/min (gpm)	Process Water Discharge m^3/min (gpm)	Raw Water Consumption m^3/min (gpm)
	S2A	S2A	S2A	S2A	S2A
Slag Handling	**0.49 (130)**	**0.49 (130)**	**0 (0)**	**0 (0)**	**0 (0)**
SWS Blowdown	**0 (0)**	**0 (0)**	**0 (0)**	**0.01 (2)**	**-0.01 (-2)**
Condenser Makeup	**1.16 (307)**	**0 (0)**	**1.16 (307)**	**0 (0)**	**1.16 (307)**
Gasifier Steam	1.01 (267)		1.01 (267)		
BFW Makeup	0.15 (40)		0.15 (40)		
Cooling Tower Makeup	**7.49 (1,978)**	**0.91 (240)**	**6.58 (1,738)**	**1.68 (445)**	**4.89 (1,293)**
Coal Drying		0.41 (107)	-0.41 (-107)		
BFW Blowdown		0.15 (40)	-0.15 (-40)		
SWS Blowdown		0.08 (20)	-0.08 (-20)		
SWS Excess Water		0.28 (73)	-0.28 (-73)		
Total	**9.1 (2,415)**	**1.4 (370)**	**7.7 (2,045)**	**1.7 (447)**	**6.1 (1,598)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-65:

- Coal gasification and ASU
- Syngas cleanup
- Power block

An overall plant energy balance is provided in tabular form in Exhibit 3-66 based on 0°C (32°F) reference conditions. The power out is the combined CT and steam turbine power after generator losses.

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Exhibit 3-65 Case S2A Heat and Mass Balance

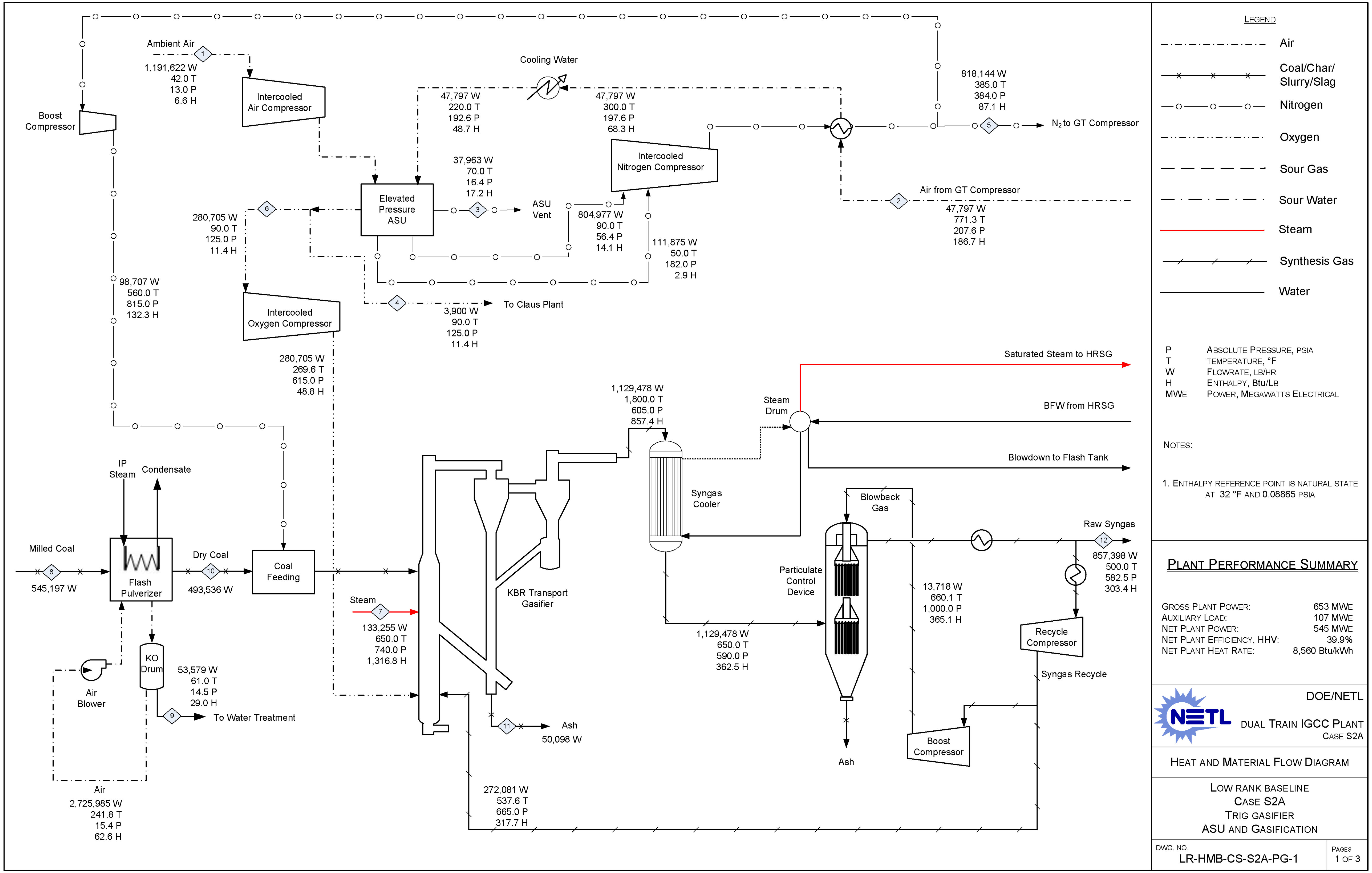
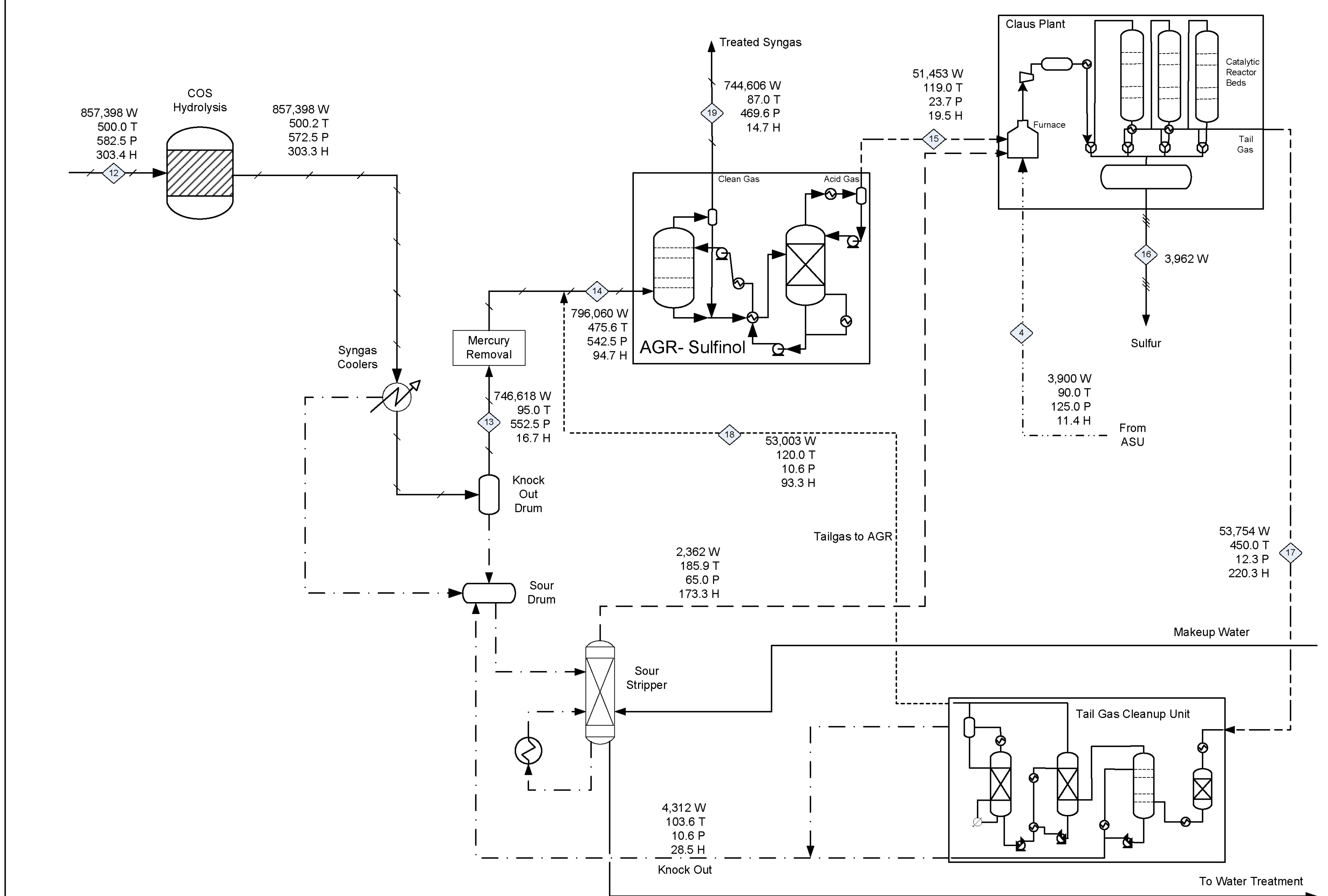


Exhibit 3-65 Case S2A Heat and Mass Balance (Continued)



LEGEND

- Acid Gas
- Air
- Carbon Dioxide
- Coal/Char/ Slurry/Slag
- Hydrogen
- Nitrogen
- Oxygen
- Sour Gas
- Sour Water
- Sulfur
- Synthesis Gas
- Tailgas
- Water

P	ABSOLUTE PRESSURE, PSIA
T	TEMPERATURE, °F
W	FLOWRATE, LB/HR
H	ENTHALPY, Btu/LB
MWE	POWER, MEGAWATTS ELECTRICAL

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32 °F AND 0.08865 PSIA

PLANT PERFORMANCE SUMMARY

GROSS PLANT POWER:	653 MWE
AUXILIARY LOAD:	107 MWE
NET PLANT POWER:	545 MWE
NET PLANT EFFICIENCY, HHV:	39.9%
NET PLANT HEAT RATE:	8,560 Btu/kWh

DOE/NETL

DUAL TRAIN IGCC PLANT
CASE S2A

HEAT AND MATERIAL FLOW DIAGRAM

LOW RANK BASELINE
CASE S2A
TRIG GASIFIER
GAS CLEANUP SYSTEM

DWG. NO. LR-HMB-CS-S2A-PG-2

PAGES 2 OF 3

Exhibit 3-65 Case S2A Heat and Mass Balance (Continued)

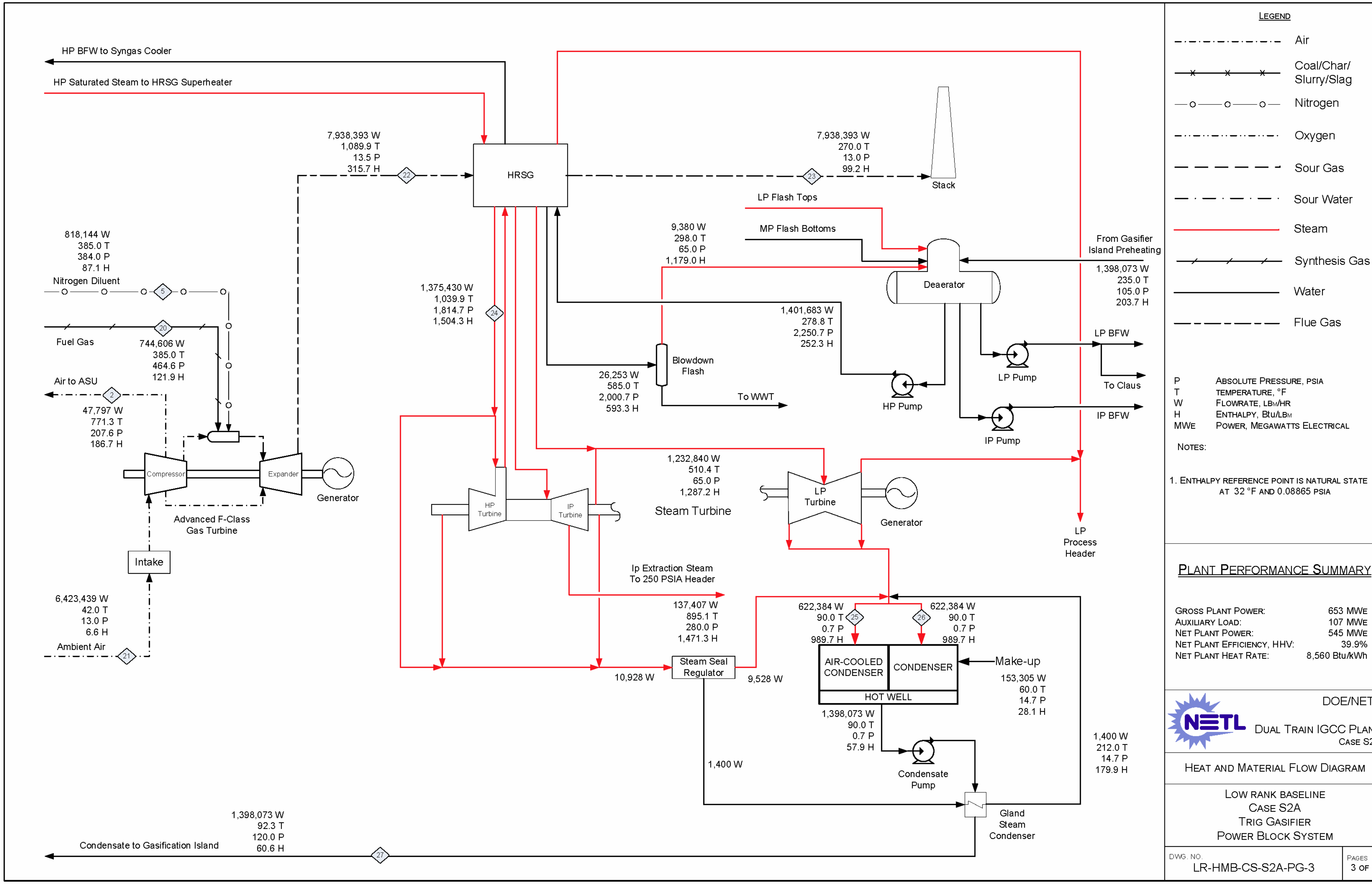


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Exhibit 3-66 Case S2A Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	4,926 (4,669)	2.5 (2.4)	0 (0)	4,929 (4,671)
ASU Air	0 (0)	8.2 (7.8)	0 (0)	8 (8)
GT Air	0 (0)	44.5 (42.1)	0 (0)	44 (42)
Raw Water Makeup	0 (0)	10.8 (10.2)	0 (0)	11 (10)
Auxiliary Power	0 (0)	0 (0)	386 (366)	386 (366)
Totals	**4,926 (4,669)**	**66.0 (62.6)**	**386 (366)**	**5,378 (5,098)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Intercoolers	0 (0)	170 (161)	0 (0)	170 (161)
ASU Vent	0 (0)	0.7 (0.7)	0 (0)	1 (1)
Slag	81 (77)	23.6 (22.4)	0 (0)	105 (99)
Sulfur	17 (16)	0.2 (0.2)	0 (0)	17 (16)
Cooling Tower Blowdown	0 (0)	9.4 (8.9)	0 (0)	9 (9)
HRSG Flue Gas	0 (0)	831 (788)	0 (0)	831 (788)
Condenser	0 (0)	1,219 (1,155)	0 (0)	1,219 (1,155)
Auxiliary Cooling Load	0 (0)	67 (64)	0 (0)	67 (64)
Electrical Generator Loss	0 (0)	0 (0)	36 (34)	36 (34)
Process Losses	0 (0)	574 (544)	0 (0)	574 (544)
Power	0 (0)	0 (0)	2,350 (2,227)	2,350 (2,227)
Totals	**98 (93)**	**2,895 (2,744)**	**2,386 (2,261)**	**5,378 (5,098)**

3.3.6 Case S2A Equipment Lists

Major equipment items for the TRIG™ gasifier with no CO_2 capture using PRB coal 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	S2A 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/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (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/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	2	1
9	Feeder	Vibratory	200 tonne/hr (220 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	408 tonne/hr (450 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	200 tonne (220 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	408 tonne/hr (450 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	408 tonne/hr (450 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	907 tonne (1,000 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	45 tonne/hr (50 tph)	6	0
2	Coal Mill Hydraulic Unit	Hot gas (350F) enters the bottom of the mill for drying and conveying	272 tonne (300 ton)	2	0
3	Cyclonic Baghouse	Gas Recycled to Dryer, Coal to Feeder	Coal - 91 tonne (100 ton) Recycle Gas -226,687 kg/hr (499,760 lb/hr)	6	0
4	Discharge Feeder	Rotary	45 tonne/hr (50 tph)	6	0
5	Coal Feed Storage Bin	Vertical Hopper	45 tonne/hr (50 tph)	6	0
6	Coal Feed Lock Vessel	Vertical Hopper	45 tonne/hr (50 tph)	6	0
7	Coal Feed Conveyor	Vertical Hopper	91 tonne (100 ton)	6	0
8	Drying Recycle Cooler	Water cooled shell and tube	226,687 kg/hr (499,760 lb/hr)	6	0
9	Moisture Separator Drum	Cyclonic	226,687 kg/hr (499,760 lb/hr)	6	0
10	Baghouse Exhaust Blower	Centrifugal	Recycle Gas- 226,687 kg/hr (499,760 lb/hr) 2,420 kWe	6	0
11	Drying Heater	Steam heated shell and tube	Recycle Gas- 226,687 kg/hr (499,760 lb/hr) 110 MMBtu/hr	6	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	586,739 liters (155,000 gal)	2	0
2	Condensate Pumps	Vertical canned	5,867 lpm @ 91 m H_2O (1,550 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	435,449 kg/hr (960,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,363 lpm @ 27 m H_2O (360 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,057 lpm @ 1,890 m H_2O (1,600 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,022 lpm @ 223 m H_2O (270 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	145 GJ/hr (137 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	51,860 lpm @ 21 m H_2O (13,700 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	2,158 lpm @ 18 m H_2O (570 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,158 lpm @ 268 m H_2O (570 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	984 lpm @ 49 m H_2O (260 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	476,962 liter (126,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	2	0
19	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	S2A Design Condition	Operating Qty	Spares
1	Gasifier	TRIG™ dry feed, circulating fast-fluidized bed	3,266 tonne/day, 4.2 MPa (3,600 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Vertical down flow heat exchanger with evaporator, superheater, and economizer stages	281,681 kg/hr (621,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	281,681 kg/hr (621,000 lb/hr) 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 up flow	285,310 kg/hr (629,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	186,426 kg/hr (411,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	186,426 kg/hr, 35°C, 3.8 MPa (411,000 lb/hr, 95°F, 553 psia)	2	0
11	Synthesis Gas Reheater	Shell and tube	185,973 kg/hr (410,000 lb/hr)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	285,310 kg/hr (629,000 lb/hr) syngas	2	0

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
13	ASU Main Air Compressor	Centrifugal, multi-stage	4,049 m^3/min @ 1.3 MPa (143,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	1,724 tonne/day (1,900 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	850 m^3/min (30,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 4.3 MPa (620 psia)	2	0
16	Primary Nitrogen Compressor	Centrifugal, multi-stage	2,832 m^3/min (100,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
17	Secondary Nitrogen Compressor	Centrifugal, single-stage	396 m^3/min (14,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
18	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	11,793 kg/hr, 411°C, 1.4 MPa (26,000 lb/hr, 771°F, 208 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	186,426 kg/hr (411,000 lb/hr) 35°C (95°F) 3.8 MPa (553 psia)	2	0
2	Sulfur Plant	Claus type	47 tonne/day (52 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	214,096 kg/hr (472,000 lb/hr) 260°C (500°F) 4.0 MPa (580 psia)	2	0
4	Acid Gas Removal Plant	Sulfinol	198,673 kg/hr (438,000 lb/hr) 246°C (476°F) 3.7 MPa (543 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	24,382 kg/hr (53,754 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	22,446 kg/hr (49,485 lb/hr)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	210 MW	2	0
2	Gas Turbine Generator	TEWAC	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.4 m (20 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 343,137 kg/hr, 12.4 MPa/560°C (756,486 lb/hr, 1,800 psig/1,040°F) Reheat steam - 302,892 kg/hr, 3.1 MPa/560°C (667,763 lb/hr, 452 psig/1,040°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Steam Turbine	Commercially available	246 MW 12.4 MPa/560°C/560°C (1,800 psig/ 1,040°F/1,040°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	270 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	675 GJ/hr (640 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	1	0
4	Air-cooled Condenser	---	675 GJ/hr (640 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Circulating Water Pumps	Vertical, wet pit	193,056 lpm @ 30 m (51,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) WB / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,076 GJ/hr (1,020 MMBtu/hr) heat duty	1	0

ACCOUNT 10 ASH RECOVERY AND HANDLING

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	Coarse Ash Depressurization and Cooling	Proprietary	Fine Ash - 3 tonne/hr (3 tph)	2	0
2	Makeup Solids Storage Bin	Vertical, shop fabricated	30 tonnes (33 tons)	2	0
3	Makeup Solids Storage Bin Vent Filter	Pulsed Fabric Filter	180 Nm^3/hr (106 scfm)	2	0
4	Coarse Ash Conveyor	Dense Phase	3 tonne/hr (3 tph)	2	0
5	Fine Ash Depressurization and Cooling	Proprietary	Coarse Ash - 10 tonne/hr (11 tph)	2	0
6	Ash Storage Silo	Reinforced concrete	2,999 tonne (3,306 tons)	1	0
7	Ash Silo Vent Filter	Pulsed Fabric Filter	2,883 Nm^3/hr (1,696 scfm)	1	0
8	Storage Silo Discharge Feeder	Rotary	300 tonne/hr (331 tph)	2	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	S2A Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 270 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 46 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	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	S2A 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 <u>Case S2A Cost Estimating</u>

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-67 shows the TPC summary organized by cost account for the Case S2A. A more detailed breakdown of the capital costs is shown in Exhibit 3-68. Exhibit 3-69 shows the calculation and addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-70 shows the initial and annual O&M costs for Case S2A.

The estimated TOC of the TRIG™ IGCC plant with no CO_2 capture using PRB coal is $2,728/kW. Process contingency represents 3 percent, project contingency 11 percent, and owner's costs 18 percent of the TOC. The COE is 74.5 mills/kWh.

Exhibit 3-67 Case S2A Total Plant Cost Summary

Client: USDOE/NETL **Report Date:** 2009-Oct-15
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S2A - TRIG IGCC w/o CO2
Plant Size: 545.4 MW,net **Estimate Type:** Conceptual **Cost Base (June)** 2007 ($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	$15,315	$2,846	$11,877	$0	$0	**$30,038**	$2,727	$0	$6,553	**$39,317**	$72
2	COAL & SORBENT PREP & FEED	$74,930	$6,218	$12,637	$0	$0	**$93,784**	$8,134	$0	$20,384	**$122,302**	$224
3	FEEDWATER & MISC. BOP SYSTEMS	$7,748	$6,933	$6,960	$0	$0	**$21,641**	$2,030	$0	$5,280	**$28,950**	$53
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (TRIG)	$121,159	$0	$51,615	$0	$0	**$172,774**	$15,430	$39,698	$34,951	**$262,852**	$482
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$128,334	$0	w/equip.	$0	$0	**$128,334**	$12,439	$0	$14,077	**$154,850**	$284
4.4-4.9	Flare Stack System	$6,797	$10,047	$8,147	$0	$0	**$24,990**	$2,351	$0	$6,240	**$33,581**	$62
	SUBTOTAL 4	**$256,290**	**$10,047**	**$59,761**	**$0**	**$0**	**$326,097**	**$30,220**	**$39,698**	**$55,268**	**$451,284**	**$827**
5A	GAS CLEANUP & PIPING	$45,807	$2,736	$42,230	$0	$0	**$90,773**	$8,773	$77	$20,060	**$119,683**	$219
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	**$92,022**	$8,724	$4,601	$10,535	**$115,882**	$212
6.2-6.9	Combustion Turbine Foundations	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$4
	SUBTOTAL 6	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$217**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,744	$0	$4,656	$0	$0	**$37,399**	$3,556	$0	$4,096	**$45,051**	$83
7.2-7.9	Ductwork, Stack and Foundations	$3,358	$2,394	$3,135	$0	$0	**$8,886**	$824	$0	$1,580	**$11,290**	$21
	SUBTOTAL 7	**$36,101**	**$2,394**	**$7,791**	**$0**	**$0**	**$46,286**	**$4,380**	**$0**	**$5,676**	**$56,341**	**$103**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,881	$0	$4,366	$0	$0	**$30,247**	$2,902	$0	$3,315	**$36,464**	$67
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$32,245	$886	$11,177	$0	$0	**$44,307**	$4,281	$0	$9,994	**$58,583**	$107
	SUBTOTAL 8	**$58,125**	**$886**	**$15,543**	**$0**	**$0**	**$74,554**	**$7,183**	**$0**	**$13,309**	**$95,046**	**$174**
9	COOLING WATER SYSTEM	$5,635	$5,789	$4,842	$0	$0	**$16,266**	$1,510	$0	$3,657	**$21,434**	$39
10	ASH/SPENT SORBENT HANDLING SYS	$19,451	$1,492	$9,652	$0	$0	**$30,596**	$2,935	$0	$3,662	**$37,192**	$68
11	ACCESSORY ELECTRIC PLANT	$25,693	$9,805	$19,553	$0	$0	**$55,052**	$4,734	$0	$11,261	**$71,046**	$130
12	INSTRUMENTATION & CONTROL	$9,819	$1,806	$6,326	$0	$0	**$17,951**	$1,627	$898	$3,412	**$23,887**	$44
13	IMPROVEMENTS TO SITE	$3,139	$1,850	$7,746	$0	$0	**$12,736**	$1,257	$0	$4,198	**$18,191**	$33
14	BUILDINGS & STRUCTURES	$0	$6,105	$6,984	$0	$0	**$13,089**	$1,192	$0	$2,346	**$16,626**	$30
	TOTAL COST	**$643,805**	**$59,713**	**$219,065**	**$0**	**$0**	**$922,584**	**$85,586**	**$45,274**	**$166,155**	**$1,219,598**	**$2,236**

Exhibit 3-68 Case S2A Total Plant Cost Details

	Client:	USDOE/NETL								Report Date:	2009-Oct-15	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S2A - TRIG IGCC w/o CO2										
	Plant Size:	545.4	MW,net	Estimate Type:		Conceptual		Cost Base (June)		2007	($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											
1.1	Coal Receive & Unload	$4,022	$0	$1,965	$0	$0	$5,987	$536	$0	$1,305	$7,828	$14
1.2	Coal Stackout & Reclaim	$5,197	$0	$1,260	$0	$0	$6,457	$566	$0	$1,405	$8,428	$15
1.3	Coal Conveyors & Yd Crush	$4,832	$0	$1,247	$0	$0	$6,079	$534	$0	$1,322	$7,935	$15
1.4	Other Coal Handling	$1,264	$0	$288	$0	$0	$1,553	$136	$0	$338	$2,026	$4
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	$2,846	$7,116	$0	$0	$9,962	$955	$0	$2,183	$13,101	$24
	SUBTOTAL 1.	**$15,315**	**$2,846**	**$11,877**	**$0**	**$0**	**$30,038**	**$2,727**	**$0**	**$6,553**	**$39,317**	**$72**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$30,142	$1,811	$4,392	$0	$0	$36,345	$3,136	$0	$7,896	$47,377	$87
2.2	Prepared Coal Storage & Feed	$1,428	$342	$224	$0	$0	$1,993	$170	$0	$433	$2,596	$5
2.3	Dry Coal Injection System	$42,648	$495	$3,961	$0	$0	$47,103	$4,057	$0	$10,232	$61,392	$113
2.4	Misc.Coal Prep & Feed	$713	$519	$1,555	$0	$0	$2,786	$256	$0	$608	$3,650	$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	$3,052	$2,505	$0	$0	$5,557	$515	$0	$1,214	$7,286	$13
	SUBTOTAL 2.	**$74,930**	**$6,218**	**$12,637**	**$0**	**$0**	**$93,784**	**$8,134**	**$0**	**$20,384**	**$122,302**	**$224**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,842	$4,880	$2,576	$0	$0	$10,297	$954	$0	$2,250	$13,502	$25
3.2	Water Makeup & Pretreating	$342	$36	$191	$0	$0	$568	$54	$0	$187	$809	$1
3.3	Other Feedwater Subsystems	$1,555	$525	$473	$0	$0	$2,553	$229	$0	$556	$3,339	$6
3.4	Service Water Systems	$195	$403	$1,397	$0	$0	$1,995	$195	$0	$657	$2,847	$5
3.5	Other Boiler Plant Systems	$1,049	$407	$1,007	$0	$0	$2,463	$234	$0	$539	$3,236	$6
3.6	FO Supply Sys & Nat Gas	$291	$550	$513	$0	$0	$1,354	$130	$0	$297	$1,781	$3
3.7	Waste Treatment Equipment	$478	$0	$291	$0	$0	$769	$75	$0	$253	$1,097	$2
3.8	Misc. Power Plant Equipment	$997	$133	$512	$0	$0	$1,642	$159	$0	$540	$2,340	$4
	SUBTOTAL 3.	**$7,748**	**$6,933**	**$6,960**	**$0**	**$0**	**$21,641**	**$2,030**	**$0**	**$5,280**	**$28,950**	**$53**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (TRIG)	$121,159	$0	$51,615	$0	$0	$172,774	$15,430	$39,698	$34,951	$262,852	$482
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$128,334	$0	w/equip.	$0	$0	$128,334	$12,439	$0	$14,077	$154,850	$284
4.4	LT Heat Recovery & FG Saturation	$6,797	$0	$2,584	$0	$0	$9,380	$915	$0	$2,059	$12,355	$23
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	Flare Stack System	$0	$1,038	$422	$0	$0	$1,460	$140	$0	$320	$1,920	$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	$9,009	$5,140	$0	$0	$14,149	$1,295	$0	$3,861	$19,305	$35
	SUBTOTAL 4.	**$256,290**	**$10,047**	**$59,761**	**$0**	**$0**	**$326,097**	**$30,220**	**$39,698**	**$55,268**	**$451,284**	**$827**

Exhibit 3-68 Case S2A Total Plant Cost Details (Continued)

Client:	USDOE/NETL			Report Date:	2009-Oct-15
Project:	Low Rank Western Coal Baseline Study				
	TOTAL PLANT COST SUMMARY				
Case:	Case S2A - TRIG IGCC w/o CO2				
Plant Size:	545.4 MW,net	Estimate Type:	Conceptual	Cost Base (June)	2007 ($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	Sulfinol System	$35,180	$0	$29,851	$0	$0	$65,031	$6,289	$0	$14,264	$85,584	$157
5A.2	Elemental Sulfur Plant	$4,867	$970	$6,280	$0	$0	$12,117	$1,177	$0	$2,659	$15,953	$29
5A.3	Mercury Removal	$879	$0	$669	$0	$0	$1,548	$150	$77	$355	$2,130	$4
5A.4	COS Hydrolysis	$3,272	$0	$4,272	$0	$0	$7,544	$734	$0	$1,656	$9,933	$18
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,609	$271	$152	$0	$0	$2,032	$193	$0	$445	$2,669	$5
5A.6	Fuel Gas Piping	$0	$743	$520	$0	$0	$1,263	$117	$0	$276	$1,657	$3
5A.9	HGCU Foundations	$0	$752	$485	$0	$0	$1,237	$114	$0	$405	$1,757	$3
	SUBTOTAL 5A.	**$45,807**	**$2,736**	**$42,230**	**$0**	**$0**	**$90,773**	**$8,773**	**$77**	**$20,060**	**$119,683**	**$219**
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	$85,752	$0	$6,269	$0	$0	$92,022	$8,724	$4,601	$10,535	$115,882	$212
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$4
	SUBTOTAL 6.	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$217**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,744	$0	$4,656	$0	$0	$37,399	$3,556	$0	$4,096	$45,051	$83
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,721	$1,228	$0	$0	$2,949	$259	$0	$642	$3,849	$7
7.4	Stack	$3,358	$0	$1,261	$0	$0	$4,619	$443	$0	$506	$5,567	$10
7.9	HRSG,Duct & Stack Foundations	$0	$673	$646	$0	$0	$1,319	$123	$0	$432	$1,874	$3
	SUBTOTAL 7.	**$36,101**	**$2,394**	**$7,791**	**$0**	**$0**	**$46,286**	**$4,380**	**$0**	**$5,676**	**$56,341**	**$103**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,881	$0	$4,366	$0	$0	$30,247	$2,902	$0	$3,315	$36,464	$67
8.2	Turbine Plant Auxiliaries	$179	$0	$409	$0	$0	$588	$58	$0	$65	$710	$1
8.3a	Condenser & Auxiliaries	$2,661	$0	$850	$0	$0	$3,511	$336	$0	$385	$4,231	$8
8.3b	Air Cooled Condenser	$24,385	$0	$4,889	$0	$0	$29,274	$2,927	$0	$6,440	$38,642	$71
8.4	Steam Piping	$5,020	$0	$3,531	$0	$0	$8,551	$735	$0	$2,321	$11,607	$21
8.9	TG Foundations	$0	$886	$1,498	$0	$0	$2,383	$226	$0	$783	$3,392	$6
	SUBTOTAL 8.	**$58,125**	**$886**	**$15,543**	**$0**	**$0**	**$74,554**	**$7,183**	**$0**	**$13,309**	**$95,046**	**$174**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,875	$0	$705	$0	$0	$4,580	$436	$0	$752	$5,768	$11
9.2	Circulating Water Pumps	$1,008	$0	$56	$0	$0	$1,064	$90	$0	$173	$1,326	$2
9.3	Circ.Water System Auxiliaries	$92	$0	$13	$0	$0	$105	$10	$0	$17	$132	$0
9.4	Circ.Water Piping	$0	$3,840	$996	$0	$0	$4,836	$437	$0	$1,055	$6,328	$12
9.5	Make-up Water System	$207	$0	$296	$0	$0	$504	$48	$0	$110	$662	$1
9.6	Component Cooling Water Sys	$453	$542	$386	$0	$0	$1,381	$129	$0	$302	$1,813	$3
9.9	Circ.Water System Foundations	$0	$1,406	$2,391	$0	$0	$3,797	$360	$0	$1,247	$5,404	$10
	SUBTOTAL 9.	**$5,635**	**$5,789**	**$4,842**	**$0**	**$0**	**$16,266**	**$1,510**	**$0**	**$3,657**	**$21,434**	**$39**

Exhibit 3-68 Case S2A Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 2009-Oct-15
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S2A - TRIG IGCC w/o CO2
Plant Size: 545.4 MW,net **Estimate Type:** Conceptual **Cost Base (June)** 2007 ($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$16,945	$0	$8,357	$0	$0	$25,302	$2,431	$0	$2,773	$30,506	$56
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$568	$0	$618	$0	$0	$1,186	$115	$0	$195	$1,496	$3
10.7	Ash Transport & Feed Equipment	$762	$0	$184	$0	$0	$946	$88	$0	$155	$1,189	$2
10.8	Misc. Ash Handling Equipment	$1,176	$1,442	$431	$0	$0	$3,049	$290	$0	$501	$3,840	$7
10.9	Ash/Spent Sorbent Foundation	$0	$50	$63	$0	$0	$113	$11	$0	$37	$161	$0
	SUBTOTAL 10.	**$19,451**	**$1,492**	**$9,652**	**$0**	**$0**	**$30,596**	**$2,935**	**$0**	**$3,662**	**$37,192**	**$68**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$885	$0	$875	$0	$0	$1,759	$168	$0	$193	$2,120	$4
11.2	Station Service Equipment	$3,616	$0	$326	$0	$0	$3,941	$363	$0	$430	$4,735	$9
11.3	Switchgear & Motor Control	$6,684	$0	$1,216	$0	$0	$7,900	$733	$0	$1,295	$9,927	$18
11.4	Conduit & Cable Tray	$0	$3,105	$10,243	$0	$0	$13,348	$1,291	$0	$3,660	$18,299	$34
11.5	Wire & Cable	$0	$5,933	$3,898	$0	$0	$9,831	$714	$0	$2,636	$13,181	$24
11.6	Protective Equipment	$0	$624	$2,269	$0	$0	$2,893	$283	$0	$476	$3,652	$7
11.7	Standby Equipment	$221	$0	$216	$0	$0	$436	$42	$0	$72	$550	$1
11.8	Main Power Transformers	$14,288	$0	$133	$0	$0	$14,420	$1,091	$0	$2,327	$17,838	$33
11.9	Electrical Foundations	$0	$144	$378	$0	$0	$522	$50	$0	$172	$744	$1
	SUBTOTAL 11.	**$25,693**	**$9,805**	**$19,553**	**$0**	**$0**	**$55,052**	**$4,734**	**$0**	**$11,261**	**$71,046**	**$130**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$969	$0	$647	$0	$0	$1,616	$153	$81	$278	$2,128	$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	$223	$0	$143	$0	$0	$366	$35	$18	$84	$502	$1
12.7	Computer & Accessories	$5,170	$0	$166	$0	$0	$5,336	$490	$267	$609	$6,702	$12
12.8	Instrument Wiring & Tubing	$0	$1,806	$3,692	$0	$0	$5,499	$466	$275	$1,560	$7,800	$14
12.9	Other I & C Equipment	$3,456	$0	$1,678	$0	$0	$5,134	$483	$257	$881	$6,755	$12
	SUBTOTAL 12.	**$9,819**	**$1,806**	**$6,326**	**$0**	**$0**	**$17,951**	**$1,627**	**$898**	**$3,412**	**$23,887**	**$44**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$99	$2,105	$0	$0	$2,204	$219	$0	$727	$3,149	$6
13.2	Site Improvements	$0	$1,752	$2,328	$0	$0	$4,080	$403	$0	$1,345	$5,827	$11
13.3	Site Facilities	$3,139	$0	$3,313	$0	$0	$6,452	$636	$0	$2,126	$9,215	$17
	SUBTOTAL 13.	**$3,139**	**$1,850**	**$7,746**	**$0**	**$0**	**$12,736**	**$1,257**	**$0**	**$4,198**	**$18,191**	**$33**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,211	$3,150	$0	$0	$5,362	$493	$0	$878	$6,733	$12
14.3	Administration Building	$0	$808	$586	$0	$0	$1,395	$124	$0	$228	$1,746	$3
14.4	Circulation Water Pumphouse	$0	$159	$84	$0	$0	$244	$21	$0	$40	$305	$1
14.5	Water Treatment Buildings	$0	$286	$279	$0	$0	$564	$51	$0	$92	$707	$1
14.6	Machine Shop	$0	$414	$283	$0	$0	$697	$62	$0	$114	$872	$2
14.7	Warehouse	$0	$668	$431	$0	$0	$1,099	$97	$0	$179	$1,376	$3
14.8	Other Buildings & Structures	$0	$400	$312	$0	$0	$712	$64	$0	$155	$930	$2
14.9	Waste Treating Building & Str.	$0	$894	$1,709	$0	$0	$2,603	$243	$0	$569	$3,415	$6
	SUBTOTAL 14.	**$0**	**$6,105**	**$6,984**	**$0**	**$0**	**$13,089**	**$1,192**	**$0**	**$2,346**	**$16,626**	**$30**
	TOTAL COST	**$643,805**	**$59,713**	**$219,065**	**$0**	**$0**	**$922,584**	**$85,586**	**$45,274**	**$166,155**	**$1,219,598**	**$2,236**

Exhibit 3-69 Case S2A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$10,339	$19
1 Month Variable O&M	$2,696	$5
25% of 1 Months Fuel Cost at 100% CF	$757	$1
2% of TPC	$24,392	$45
Total	**$38,184**	**$70**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,218	$11
0.5% of TPC (spare parts)	$6,098	$11
Total	**$12,316**	**$23**
Initial Cost for Catalyst and Chemicals	**$1,197**	**$2**
Land	**$900**	**$2**
Other Owner's Costs	**$182,940**	**$335**
Financing Costs	**$32,929**	**$60**
Total Owner's Costs	**$268,466**	**$492**
Total Overnight Cost (TOC)	**$1,488,063**	**$2,728**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$1,696,392**	**$3,110**

Exhibit 3-70 Case S2A Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (June)	2007
Case S2A - TRIG IGCC w/o CO2					Heat Rate-net(Btu/kWh):	8560
					MWe-net:	545
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$5,918,913	$10.852
Maintenance Labor Cost					$10,623,062	$19.477
Administrative & Support Labor					$4,135,494	$7.582
Property Taxes and Insurance					$24,391,958	$44.721
TOTAL FIXED OPERATING COSTS					**$45,069,427**	**$82.633**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$21,823,035**	**$0.00571**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	1,472	1.08	**$0**	**$465,056**	**$0.00012**
Chemicals						
MU & WT Chem. (lb)	0	8,772	0.17	$0	$443,307	$0.00012
Carbon (Mercury Removal) (lb)	89,744	123	1.05	$94,246	$37,698	$0.00001
COS Catalyst (m3)	272	0.19	2,397.36	$651,525	$130,305	$0.00003
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0	$0.00000
Sulfinol Solution (gal)	44,892	31	10.05	$451,105	$89,526	$0.00002
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.	0.72	131.27	$0	$27,586	$0.00001
Subtotal Chemicals				**$1,196,876**	**$728,423**	**$0.00019**
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	123	0.42	$0	$14,972	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	601	16.23	$0	$2,848,202	$0.00075
Subtotal Waste Disposal				**$0**	**$2,863,174**	**$0.00075**
By-products & Emissions						
Sulfur (tons)	0	48	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,196,876**	**$25,879,688**	**$0.00677**
Fuel (ton)	0	6,542	15.22	**$0**	**$29,069,719**	**$0.00761**

3.3.8 TRIG™ IGCC CO_2 Capture Cases (S2B) Process Description

Case S2B is configured to produce electric power with CO_2 capture. The plant configurations are similar to Cases S2A with the major differences being the addition of WGS, the use of a two-stage Selexol AGR plant instead of Sulfinol and subsequent compression of the captured CO_2 stream. The gross power output is constrained by the capacity of the two CTs, 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 S2A.

The process description for Case S2B is similar to Case S2A with several notable exceptions to accommodate CO_2 capture. A BFD for the CO_2 capture case is shown in Exhibit 3-71 and stream tables are shown in Exhibit 3-72. Instead of repeating the entire process description, only differences from Cases S2A are reported here.

Coal Preparation and Feed Systems

No differences from Case S2A.

Gasification

The gasification process is the same as Case S2A except the coal feed (as-received) to the two gasifiers is 6,292 tonne/day (6,935 tpd).

Raw Gas Cooling/Particulate Removal

No differences from Case S2A.

Sour Water Stripper

No differences from Case S2A.

Sour Gas Shift

The SGS process was described in Section 3.1.6. In Case S2B steam is added to the cooled raw gas to drive the equilibrium. The hot syngas between shift stages is used to superheat the added steam. Three total stages of SGS results in 98.7 percent overall conversion of the CO to CO_2. The warm syngas from the last stage of SGS is cooled to maintain the inlet syngas temperature to the first stage of SGS. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the last stage of SGS, the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and AGR

Mercury removal is the same as in Case S2A.

The AGR process in Case S2B 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, a CO_2-rich stream and an acid gas feed to the Claus plant. The acid gas contains about 18 percent H_2S and 65 percent CO_2 with the balance primarily H_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 two pressure levels. The LP stream is compressed from 0.12 MPa (17 psia) to 1.0 MPa (150 psia) and then combined with the HP stream. The combined stream is further compressed to a SC condition at 15.3 MPa (2,215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dew point of -40ºC (-40°F) using a thermal swing adsorptive dryer. The raw CO_2 stream from the Selexol process contains over 99 percent CO_2. The dehydrated CO_2 is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.6.

Claus Unit

The Claus plant is the same as Cases S2A except 46 tonne/day (50 tpd) of sulfur are produced.

Power Block

Clean syngas from the AGR plant is saturated and then reheated to 196°C (385°F) using HP BFW. The conditioned syngas is humidified and then diluted with nitrogen before it enters the CT burner. The exhaust gas exits the CT at 562°C (1,044°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) and is discharged through the plant stack. The steam produced in the HRSG is used to power a steam turbine with a nominal 12.4MPa/538°C/538°C (1,800 psig/1,000°F/1,000°F) steam cycle. There is no air integration between the CT and the ASU in the capture case.

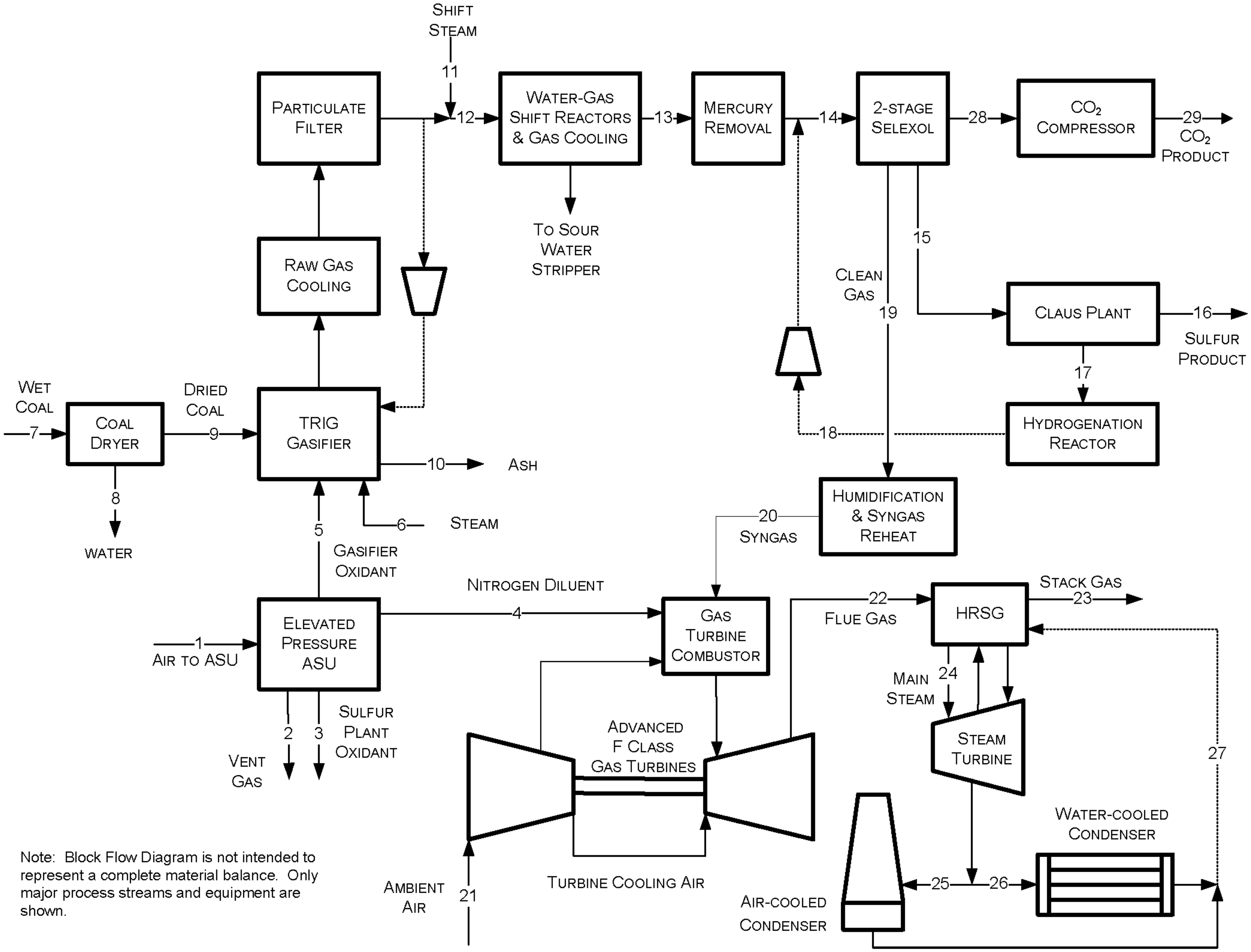
ASU

The same elevated pressure ASU is used as in Cases S2A except the output is 3,324 tonne/day (3,664 tpd) of 95 mol% oxygen.

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14, and 3.1.15.

Exhibit 3-71 Case S2B Process Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 3-72 Case S2B Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0093	0.0237	0.0318	0.0023	0.0360	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0052	0.0067	0.0067
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0336	0.0436	0.0429
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2242	0.0038	0.0039
CO_2	0.0003	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1049	0.4228	0.4261
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1761	0.5150	0.5109
H_2O	0.0064	0.1540	0.0000	0.0002	0.0000	1.0000	0.0000	1.0000	0.0000	0.0000	1.0000	0.4484	0.0016	0.0016
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0026	0.0026
N_2	0.7759	0.6137	0.0178	0.9920	0.0140	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0039	0.0052
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0025	0.0000	0.0000
O_2	0.2081	0.2005	0.9504	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	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	20,872	843	66	14,034	4,231	3,557	0	1,455	0	0	10,253	29,511	22,771	23,132
V-L Flowrate (kg/hr)	603,087	23,325	2,117	393,817	136,368	64,074	0	26,217	0	0	184,714	598,379	476,930	488,394
Solids Flowrate (kg/hr)	0	0	0	0	0	0	262,152	0	237,311	24,089	0	0	0	0
Temperature (°C)	6	20	32	196	32	343	6	16	71	982	288	230	35	35
Pressure (MPa, abs)	0.09	0.11	0.86	2.62	0.86	5.10	0.09	0.10	0.10	4.24	4.14	4.02	3.73	3.66
Enthalpy (kJ/kg)[A]	15.26	38.58	26.67	202.66	26.59	3,062.93	---	65.08	---	---	2,955.16	1,341.87	39.70	39.05
Density (kg/m^3)	1.1	1.5	11.0	18.7	11.0	20.1	---	1,002.6	---	---	18.2	20.2	31.4	31.1
V-L Molecular Weight	28.895	27.685	32.181	28.061	32.229	18.015	---	18.015	---	---	18.015	20.276	20.945	21.113
V-L Flowrate (lb_{mol}/hr)	46,014	1,857	145	30,941	9,328	7,841	0	3,208	0	0	22,604	65,062	50,202	50,998
V-L Flowrate (lb/hr)	1,329,580	51,423	4,668	868,218	300,640	141,259	0	57,798	0	0	407,225	1,319,200	1,051,450	1,076,726
Solids Flowrate (lb/hr)	0	0	0	0	0	0	577,946	0	523,182	53,107	0	0	0	0
Temperature (°F)	42	68	90	385	90	650	42	60	160	1,800	550	446	95	94
Pressure (psia)	13.0	16.4	125.0	380.0	125.0	740.0	13.0	14.5	14.6	615.0	600.0	582.5	540.4	530.4
Enthalpy (Btu/lb)[A]	6.6	16.6	11.5	87.1	11.4	1,316.8	---	28.0	---	---	1,270.5	576.9	17.1	16.8
Density (lb/ft^3)	0.070	0.093	0.687	1.167	0.688	1.257	---	62.589	---	---	1.135	1.260	1.958	1.939

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-72 Case S2B Stream Table (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction															
Ar	0.0020	0.0000	0.0063	0.0074	0.0111	0.0085	0.0093	0.0088	0.0088	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
CH_4	0.0239	0.0000	0.0055	0.0000	0.0698	0.0538	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0022	0.0022
CO	0.0013	0.0000	0.1128	0.0076	0.0064	0.0049	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
CO_2	0.6511	0.0000	0.3578	0.5528	0.0542	0.0418	0.0003	0.0145	0.0145	0.0000	0.0000	0.0000	0.0000	0.9908	0.9935
COS	0.0001	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.1105	0.0000	0.0590	0.2189	0.8497	0.6545	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0041	0.0041
H_2O	0.0350	0.0000	0.3947	0.1381	0.0001	0.2298	0.0064	0.1454	0.1454	1.0000	1.0000	1.0000	1.0000	0.0027	0.0000
H_2S	0.1753	0.0000	0.0008	0.0018	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0007	0.0000	0.0625	0.0735	0.0087	0.0067	0.7759	0.7272	0.7272	0.0000	0.0000	0.0000	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2081	0.1041	0.1041	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0004	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	341	0	492	418	13,822	17,944	100,835	126,897	126,897	32,509	12,936	12,936	40,195	8,969	8,945
V-L Flowrate (kg/hr)	12,277	0	13,917	12,493	84,121	158,381	2,913,623	3,465,821	3,465,821	585,655	233,055	233,055	724,125	391,997	391,563
Solids Flowrate (kg/hr)	0	1,903	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	48	177	232	49	31	196	6	562	132	534	32	32	33	16	72
Pressure (MPa, abs)	0.16	0.12	0.1	0.073	3.309	3.216	0.090	0.093	0.090	12.512	0.005	0.005	0.827	1.032	15.270
Enthalpy (kJ/kg)[A]	90.08	---	919.2	263.386	145.239	1,851.859	15.260	881.971	384.653	3,432.690	2,295.131	2,295.131	140.154	5.022	-94.557
Density (kg/m^3)	2.2	---	0.6	0.8	7.9	7.3	1.1	0.4	0.8	36.7	0.04	0.04	995.0	20.1	459.1
V-L Molecular Weight	36.008	---	28	29.884	6.086	8.826	28.895	27.312	27.312	18.015	18.015	18.015	18.015	43.706	43.775
V-L Flowrate (lb_{mol}/hr)	752	0	1,084	922	30,473	39,560	222,302	279,760	279,760	71,670	28,520	28,520	88,615	19,773	19,720
V-L Flowrate (lb/hr)	27,066	0	30,682	27,543	185,455	349,170	6,423,439	7,640,828	7,640,828	1,291,148	513,797	513,797	1,596,423	864,205	863,250
Solids Flowrate (lb/hr)	0	4,196	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	119	350	450	120	87	385	42	1,044	270	994	90	90	92	60	162
Pressure (psia)	23.7	17.3	12.3	10.6	480.0	466.4	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0	149.7	2,214.7
Enthalpy (Btu/lb)[A]	38.7	---	395.2	113.2	62.4	796.2	6.6	379.2	165.4	1,475.8	986.7	986.7	60.3	2.2	-40.7
Density (lb/ft^3)	0.138	---	0.036	0.051	0.492	0.454	0.070	0.023	0.047	2.293	0.002	0.002	62.117	1.253	28.658

3.3.9 Case S2B Performance Results

The Case S2B modeling assumptions were presented previously in Exhibit 3-56.

The TRIG™ IGCC plant with CO_2 capture and using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 461 MWe at a net plant efficiency of 31.8 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 3-73, which includes auxiliary power requirements. The ASU accounts for approximately 57 percent of the total auxiliary load, distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. CO_2 compression accounts for about 18 percent and the AGR process about 10 percent of the auxiliary load. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-73 Case S2B Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	S2B
Gas Turbine Power	426,400
Steam Turbine Power	194,900
TOTAL POWER, kWe	**621,300**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	510
Coal Crushing	730
Ash Handling	630
Coal Dryer Circulation Blower	2,560
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	53,710
Oxygen Compressor	6,600
Nitrogen Compressors	30,060
CO_2 Compressor	28,290
Boiler Feedwater Pumps	3,960
Condensate Pump	240
Syngas Recycle Compressors	1,550
Circulating Water Pump	2,020
Ground Water Pumps	280
Cooling Tower Fans	1,320
Air Cooled Condenser Fans	2,230
Acid Gas Removal	16,480
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	1,600
Miscellaneous Balance of Plant[1]	3,000
Transformer Losses	2,330
TOTAL AUXILIARIES, kWe	**160,450**
NET POWER, kWe	**460,850**
Net Plant Efficiency, % (HHV)	31.8%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,331 (10,740)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	992 (940)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	262,152 (577,946)
Thermal Input, kWt	1,450,564
Raw Water Withdrawal, m^3/min (gpm)	11.3 (2,989)
Raw Water Consumption, m^3/min (gpm)	9.5 (2,517)

[1] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, CO_2, and PM were presented in Section 2.3. A summary of the plant air emissions for Case S2B is presented in Exhibit 3-74.

Exhibit 3-74 Case S2B Air Emissions

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.000 (0.001)	13 (15)	0.003 (0.007)
NO_X	0.021 (0.049)	770 (849)	0.177 (0.390)
Particulates	0.003 (0.0071)	112 (123)	0.026 (0.057)
Hg	1.51E-7 (3.51E-7)	0.006 (0.006)	1.27E-6 (2.80E-6)
CO_2 gross	15.5 (36.0)	566,135 (624,057)	130 (287)
CO_2 net			175 (386)

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. Just as in the non-capture cases, the SO_2 emission are significantly less than the environmental targets of Section 2.3. The clean syngas exiting the AGR process has a sulfur concentration of approximately 2 ppmv. This results in a concentration in the flue gas of less than 0.3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The tail gas is hydrogenated and recycled to the gasifier.

NOx emissions are limited to 15 ppmvd (as NO_2 @ 15 percent O_2) by the use of humidification and nitrogen dilution of the fuel gas and low NOx burners. 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 NOx 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.

More than 92 percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration. In the TRIG™ case, because of the considerable methane content, which is not removed by the AGR, and because not all the CO is converted to CO_2 in the shift reactors, the overall CO_2 removal is less than the target 90 percent. The high methane concentrations are a result of the lower gasification temperatures, which result in a higher cold gas efficiency (CGE), which is particularly important for power generation applications. It is technologically possible to remove the last marginal amounts of carbon to achieve 90% overall capture, though these approaches are either unjustifiably detrimental to the performance of the plant, or outside the parameters of this study. These possibilities include steam reforming of the methane, increasing the solvent circulation rate in the Selexol AGR to increase its CO_2 removal, although with diminishing returns, or co-sequestering CO_2 and sulfur, using different AGR solvents that can achieve higher CO_2 removals.

The carbon balance for the plant is shown in Exhibit 3-75. 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 ash, CO_2 in the stack gas and ASU vent gas, and the captured CO_2 product. 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
83.2 percent

Exhibit 3-75 Case S2B Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	131,255 (289,367)	**Slag/Ash**	2,625 (5,787)
Air (CO_2)	479 (1,057)	**Stack Gas**	22,047 (48,606)
		ASU Vent	82 (181)
		CO_2 Product	106,980 (235,850)
Total	131,734 (290,424)	**Total**	131,734 (290,424)

Exhibit 3-76 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, sulfur emitted in the stack gas and sulfur that is co-sequestered with the CO_2 product. Sulfur in the ash is considered negligible.

Exhibit 3-76 Case S2B Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	1,907 (4,204)	**Elemental Sulfur**	1,903 (4,196)
		Stack Gas	1 (2)
		CO_2 Product	3 (6)
Total	1,907 (4,204)	**Total**	1,907 (4,204)

Exhibit 3-77 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 from the coal drying process and as syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is discharged from the process to a permitted outfall. The difference between the withdrawal and discharge is the consumption.

Exhibit 3-77 Case S2B Water Balance

Water Use	Water Demand m^3/min (gpm)	Internal Recycle m^3/min (gpm)	Raw Water Withdrawal m^3/min (gpm)	Process Water Discharge m^3/min (gpm)	Raw Water Consumption m^3/min (gpm)
	S2B	S2B	S2B	S2B	S2B
Slag Handling	**0.52 (138)**	**0.5 (138)**	**0 (0)**	**0 (0)**	**0 (0)**
Humidifier	**1.28 (337)**	**1.3 (337)**	**0 (0)**	**0 (0)**	**0 (0)**
SWS Blowdown	**0 (0)**	**0 (0)**	**0 (0)**	**0.02 (5)**	**-0.02 (-5)**
Condenser Makeup	**4.31 (1,138)**	**0 (0)**	**4.31 (1,138)**	**0 (0)**	**4.31 (1,138)**
Gasifier Steam	1.07 (283)		1.07 (283)		
Shift Steam	3.08 (814)		3.08 (814)		
BFW Makeup	0.15 (41)		0.15 (41)		
Cooling Tower Makeup	**7.86 (2,077)**	**0.85 (225)**	**7.01 (1,852)**	**1.77 (467)**	**5.24 (1,384)**
Coal Drying		0.44 (116)	-0.44 (-116)		
BFW Blowdown		0.15 (41)	-0.15 (-41)		
SWS Blowdown		0.19 (49)	-0.19 (-49)		
SWS Excess Water		0.07 (20)	-0.07 (-20)		
Total	**14.0 (3,690)**	**2.7 (700)**	**11.3 (2,989)**	**1.8 (472)**	**9.5 (2,517)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-78:

- Coal gasification and ASU
- Syngas cleanup
- Power block

An overall plant energy balance is provided in tabular form in Exhibit 3-79 based on 0°C (32°F) reference conditions. The power out is the combined CT and steam turbine power after generator losses.

Exhibit 3-78 Case S2B Heat and Mass Balance

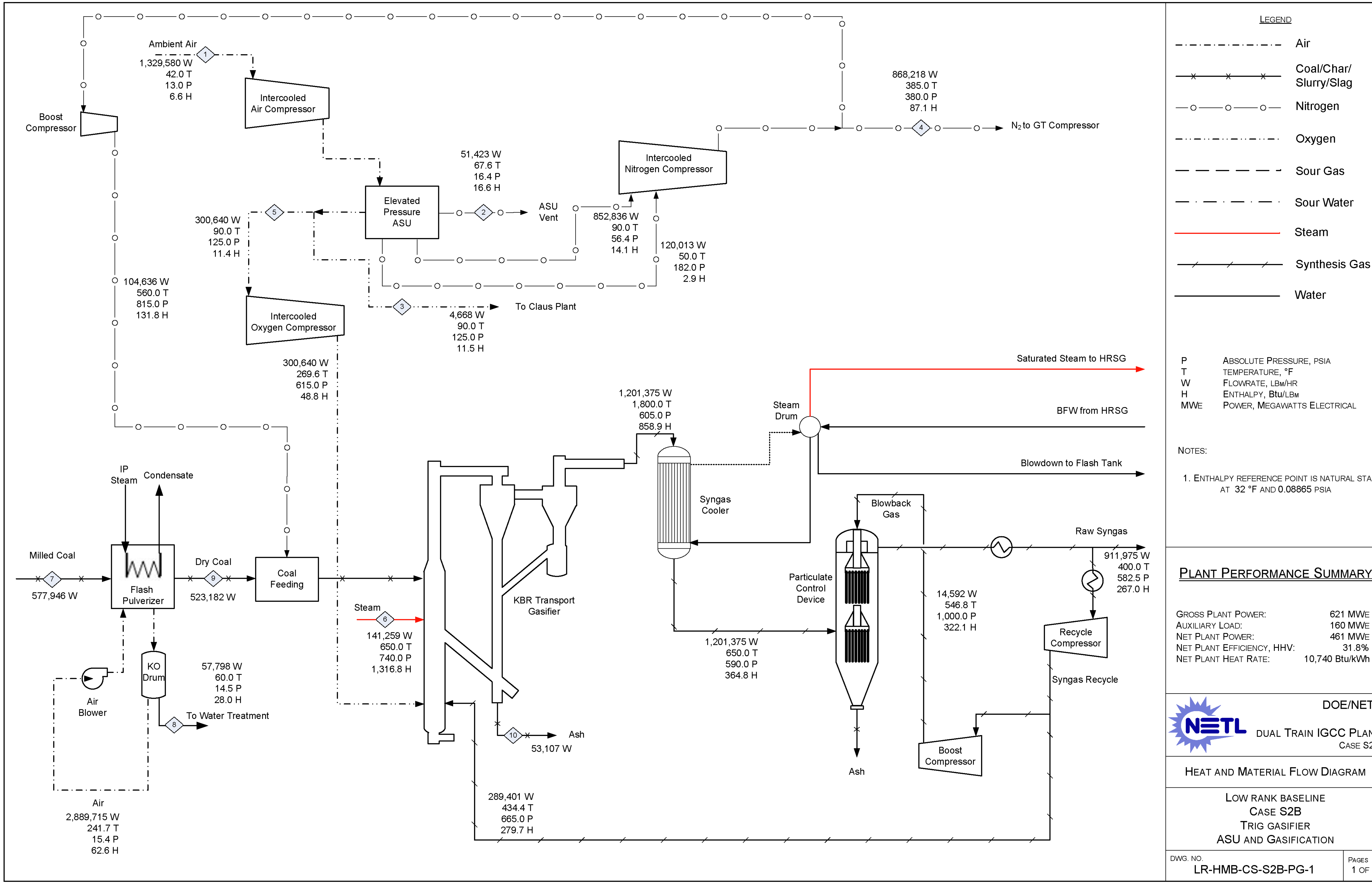


Exhibit 3-78 Case S2B Heat and Mass Balance (Continued)

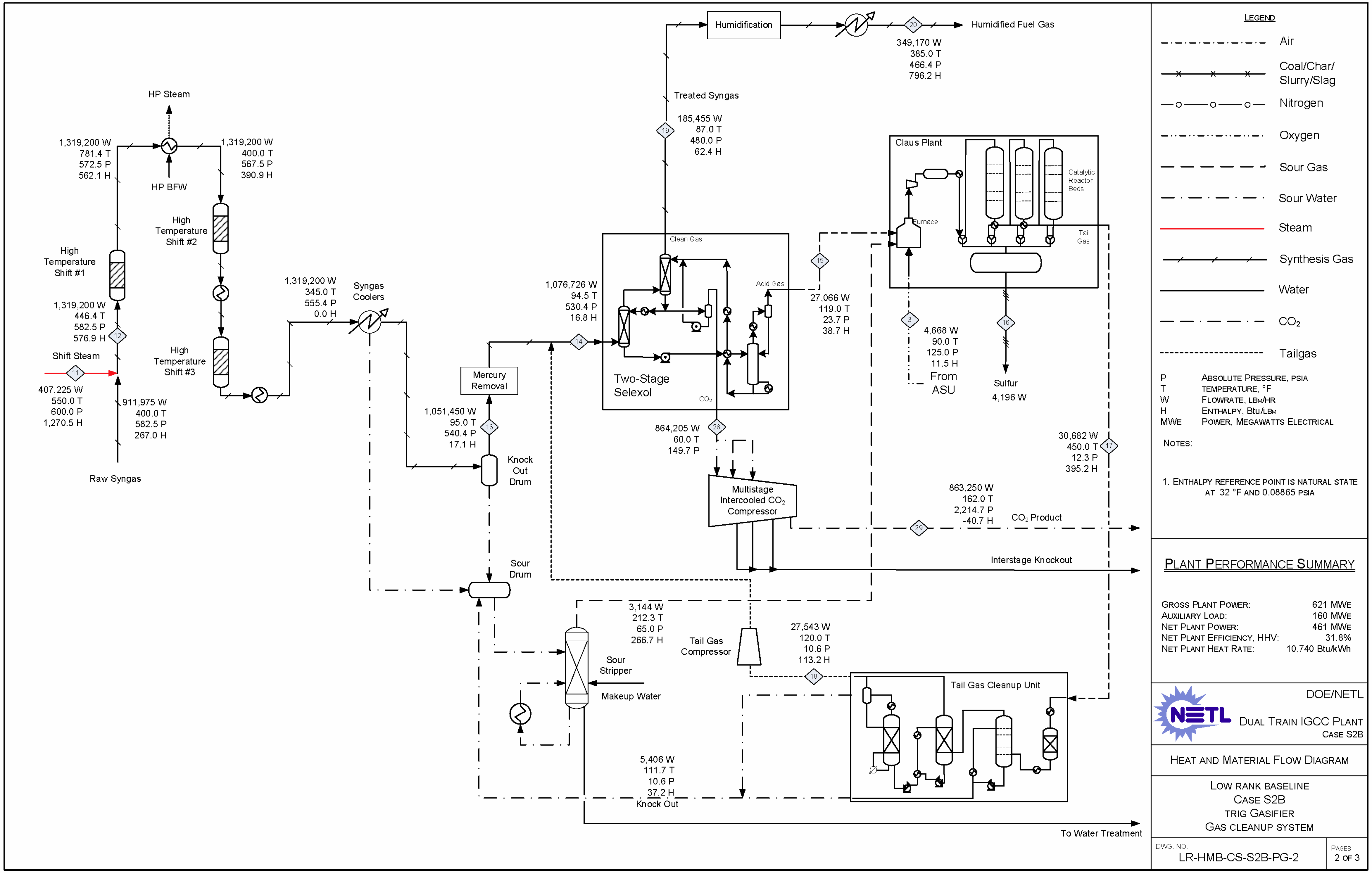


Exhibit 3-78 Case S2B Heat and Mass Balance (Continued)

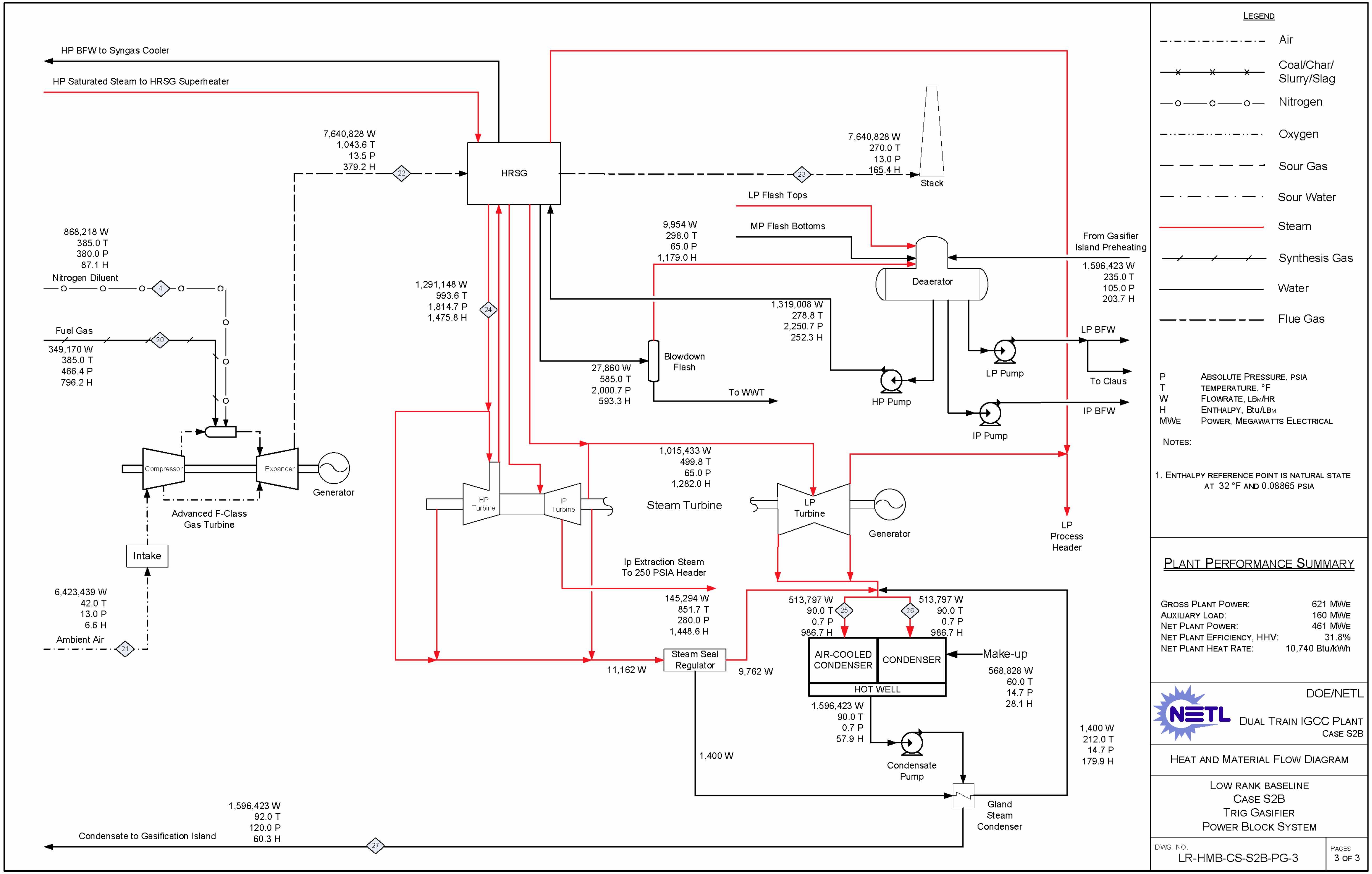


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Exhibit 3-79 Case S2B Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,222 (4,950)	2.7 (2.5)	0 (0)	5,225 (4,952)
ASU Air	0 (0)	9.2 (8.7)	0 (0)	9 (9)
GT Air	0 (0)	44.5 (42.1)	0 (0)	44 (42)
Raw Water Makeup	0 (0)	15.7 (14.9)	0 (0)	16 (15)
Auxiliary Power	0 (0)	0 (0)	578 (547)	578 (547)
Totals	**5,222 (4,950)**	**72.1 (68.3)**	**578 (547)**	**5,872 (5,565)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Intercoolers	0 (0)	185 (176)	0 (0)	185 (176)
ASU Vent	0 (0)	0.9 (0.9)	0 (0)	1 (1)
Slag	86 (82)	25.0 (23.7)	0 (0)	111 (105)
Sulfur	18 (17)	0.2 (0.2)	0 (0)	18 (17)
CO_2	0 (0)	-37.0 (-35.1)	0 (0)	-37 (-35)
CO_2 Comp Intercoolers	0 (0)	137.0 (129.9)	0 (0)	137 (130)
Cooling Tower Blowdown	0 (0)	9.9 (9.3)	0 (0)	10 (9)
HRSG Flue Gas	0 (0)	1,333 (1,264)	0 (0)	1,333 (1,264)
Condenser	0 (0)	989 (937)	0 (0)	989 (937)
Auxiliary Cooling	0 (0)	32 (30)	0 (0)	32 (30)
Electrical Generator Loss	0 (0)	0 (0)	34 (32)	34 (32)
Process Losses	0 (0)	822 (779)	0 (0)	822 (779)
Power	0 (0)	0 (0)	2,237 (2,120)	2,237 (2,120)
Totals	**104 (98)**	**3,497 (3,315)**	**2,271 (2,152)**	**5,872 (5,565)**

3.3.10 Case S2B Equipment List

Major equipment items for the TRIG™ 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	S2B 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/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (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/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	2	1
9	Feeder	Vibratory	218 tonne/hr (240 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	435 tonne/hr (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/hr (480 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	435 tonne/hr (480 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	998 tonne (1,100 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	45 tonne/hr (50 tph)	6	0
2	Coal Mill Hydraulic Unit	Hot gas 177°C (350°F) enters the bottom of the mill for drying and conveying	290 tonne (320 ton)	2	0
3	Cyclonic Baghouse	Gas Recycled to Dryer, Coal to Feeder	Coal - 100 tonne (110 ton) Recycle Gas -240,304 kg/hr (529,780 lb/hr)	6	0
4	Discharge Feeder	Rotary	45 tonne/hr (50 tph)	6	0
5	Coal Feed Storage Bin	Vertical Hopper	45 tonne/hr (50 tph)	6	0
6	Coal Feed Lock Vessel	Vertical Hopper	45 tonne/hr (50 tph)	6	0
7	Coal Feed Conveyor	Vertical Hopper	100 tonne (110 ton)	6	0
8	Drying Recycle Cooler	Water cooled shell and tube	240,304 kg/hr (529,780 lb/hr)	6	0
9	Moisture Separator Drum	Cyclonic	240,304 kg/hr (529,780 lb/hr)	6	0
10	Baghouse Exhaust Blower	Centrifugal	Recycle Gas- 240,304 kg/hr (529,780 lb/hr) 2,560 kWe	6	0
11	Drying Heater	Steam heated shell and tube	Recycle Gas- 240,304 kg/hr (529,780 lb/hr) 120 MMBtu/hr	6	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	594,310 liters (157,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,700 lpm @ 91 m H_2O (1,770 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	498,044 kg/hr (1,098,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	1,060 lpm @ 27 m H_2O (280 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 5,716 lpm @ 1,890 m H_2O (1,510 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,817 lpm @ 223 m H_2O (480 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	210 GJ/hr (199 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	74,951 lpm @ 21 m H_2O (19,800 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	3,142 lpm @ 18 m H_2O (830 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	3,142 lpm @ 268 m H_2O (830 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	3,445 lpm @ 49 m H_2O (910 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,650,440 liter (436,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,855 lpm (490 gpm)	2	0
19	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	S2B Design Condition	Operating Qty	Spares
1	Gasifier	TRIG™ dry feed, circulating fast-fluidized bed	3,447 tonne/day, 4.2 MPa (3,800 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Vertical down flow heat exchanger with evaporator, superheater, and economizer stages	299,825 kg/hr (661,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	299,825 kg/hr (661,000 lb/hr) 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 up flow	227,703 kg/hr (502,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	262,630 kg/hr (579,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	262,176 kg/hr, 35°C, 3.7 MPa (578,000 lb/hr, 95°F, 540 psia)	2	0
8	Saturation Water Economizers	Shell and tube	262,630 kg/hr (579,000 lb/hr)	2	0
9	Fuel Gas Saturator	Vertical tray tower	87,090 kg/hr, 239°C, 3.3 MPa (192,000 lb/hr, 462°F, 480 psia)	2	0
10	Saturator Water Pump	Centrifugal	1,893 lpm @ 12 m H_2O (500 gpm @ 40 ft H_2O)	2	2

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
11	Synthesis Gas Reheater	Shell and tube	46,266 kg/hr (102,000 lb/hr)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	227,703 kg/hr (502,000 lb/hr) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	4,531 m^3/min @ 1.3 MPa (160,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	1,814 tonne/day (2,000 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	934 m^3/min (33,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 4.3 MPa (620 psia)	2	0
16	Primary Nitrogen Compressor	Centrifugal, multi-stage	2,010 m^3/min (71,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.6 MPa (380 psia)	2	0
17	Secondary Nitrogen Compressor	Centrifugal, single-stage	368 m^3/min (13,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.7 MPa (820 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	262,176 kg/hr (578,000 lb/hr) 35°C (95°F) 3.7 MPa (540 psia)	2	0
2	Sulfur Plant	Claus type	50 tonne/day (55 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	329,308 kg/hr (726,000 lb/hr) 232°C (450°F) 4.0 MPa (580 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 131 GJ/hr (124 MMBtu/hr) Exchanger 2: 19 GJ/hr (18 MMBtu/hr)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	268,527 kg/hr (592,000 lb/hr) 35°C (94°F) 3.7 MPa (530 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	15,309 kg/hr (33,750 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	12,626 kg/hr (27,835 lb/hr)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	CO_2 Compressor	Integrally geared, multi-stage centrifugal	971 m^3/min @ 15.3 MPa (34,300 scfm @ 2,215 psia)	4	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	215 MW	2	0
2	Gas Turbine Generator	TEWAC	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.6 m (20 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 322,110 kg/hr, 12.4 MPa/534°C (710,131 lb/hr, 1,800 psig/994°F) Reheat steam - 279,722 kg/hr, 3.1 MPa/534°C (616,681 lb/hr, 452 psig/994°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Steam Turbine	Commercially available	205 MW 12.4 MPa/534°C/534°C (1,800 psig/ 994°F/994°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	Surface Condenser	Single pass, divided waterbox including vacuum pumps	549 GJ/hr (520 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	1	0
4	Air-cooled Condenser	---	549 GJ/hr (520 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Circulating Water Pumps	Vertical, wet pit	200,627 lpm @ 30 m (53,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) WB / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,129 GJ/hr (1,070 MMBtu/hr) heat duty	1	0

ACCOUNT 10 ASH RECOVERY AND HANDLING

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	Coarse Ash Depressurization and Cooling	Proprietary	Fine Ash - 3 tonne/hr (3 tph)	2	0
2	Makeup Solids Storage Bin	Vertical, shop fabricated	32 tonnes (35 tons)	2	0
3	Makeup Solids Storage Bin Vent Filter	Pulsed Fabric Filter	190 Nm^3/hr (112 scfm)	2	0
4	Coarse Ash Conveyor	Dense Phase	3 tonne/hr (3 tph)	2	0
5	Fine Ash Depressurization and Cooling	Proprietary	Coarse Ash - 11 tonne/hr (12 tph)	2	0
6	Ash Storage Silo	Reinforced concrete	3,180 tonne (3,505 tons)	1	0
7	Ash Silo Vent Filter	Pulsed Fabric Filter	3,055 Nm^3/hr (1,797 scfm)	1	0
8	Storage Silo Discharge Feeder	Rotary	318 tonne/hr (351 tph)	2	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	S2B Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 67 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 41 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	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	S2B 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 S2B Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-80 shows the TPC summary organized by cost account with a more detailed breakdown of the capital costs shown in Exhibit 3-81. Exhibit 3-82 shows the calculation and addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-83 shows the initial and annual O&M costs for Case S2B.

The estimated TOC of the TRIG™ IGCC plant with CO_2 capture using PRB coal is $3,691/kW. Process contingency represents 4 percent, project contingency 11 percent, and owner's costs 18 percent of the TOC. The COE is 105.2 mills/kWh.

Exhibit 3-80 Case S2B Total Plant Cost Summary

Client:	USDOE/NETL			Report Date:	2009-Oct-15
Project:	Low Rank Western Coal Baseline Study				

TOTAL PLANT COST SUMMARY

Case:	Case S2B - TRIG IGCC w/ CO2						
Plant Size:	460.9 MW,net	Estimate Type:	Conceptual	Cost Base (June)	2007	($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	$15,879	$2,951	$12,314	$0	$0	**$31,144**	$2,827	$0	$6,794	**$40,765**	$88
2	COAL & SORBENT PREP & FEED	$77,809	$6,484	$13,276	$0	$0	**$97,568**	$8,464	$0	$21,207	**$127,239**	$276
3	FEEDWATER & MISC. BOP SYSTEMS	$8,217	$6,965	$7,732	$0	$0	**$22,915**	$2,154	$0	$5,676	**$30,746**	$67
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$125,998	$0	$53,847	$0	$0	**$179,845**	$16,058	$41,465	$36,371	**$273,739**	$594
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	$128,018	$0	w/equip.	$0	$0	**$128,018**	$12,409	$0	$14,043	**$154,470**	$335
4.4-4.9	Other Gasification Equipment	$9,189	$10,292	$9,200	$0	$0	**$28,681**	$2,709	$0	$7,073	**$38,463**	$83
	SUBTOTAL 4	**$263,206**	**$10,292**	**$63,047**	**$0**	**$0**	**$336,544**	**$31,175**	**$41,465**	**$57,487**	**$466,672**	**$1,013**
5A	GAS CLEANUP & PIPING	$76,834	$2,672	$64,176	$0	$0	**$143,682**	$13,879	$23,255	$36,288	**$217,105**	$471
5B	CO2 REMOVAL & COMPRESSION	$16,750	$0	$9,707	$0	$0	**$26,457**	$2,547	$0	$5,801	**$34,805**	$76
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	**$98,610**	$9,348	$9,861	$11,782	**$129,600**	$281
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$5
	SUBTOTAL 6	**$92,027**	**$806**	**$7,475**	**$0**	**$0**	**$100,308**	**$9,507**	**$9,861**	**$12,339**	**$132,015**	**$286**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,608	$0	$4,494	$0	$0	**$36,103**	$3,433	$0	$3,954	**$43,489**	$94
7.2-7.9	Ductwork and Stack	$3,430	$2,445	$3,203	$0	$0	**$9,078**	$842	$0	$1,614	**$11,534**	$25
	SUBTOTAL 7	**$35,038**	**$2,445**	**$7,697**	**$0**	**$0**	**$45,181**	**$4,274**	**$0**	**$5,568**	**$55,023**	**$119**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,780	$0	$3,777	$0	$0	**$26,557**	$2,548	$0	$2,911	**$32,016**	$69
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$28,346	$776	$10,012	$0	$0	**$39,134**	$3,773	$0	$8,865	**$51,772**	$112
	SUBTOTAL 8	**$51,126**	**$776**	**$13,789**	**$0**	**$0**	**$65,691**	**$6,321**	**$0**	**$11,776**	**$83,788**	**$182**
9	COOLING WATER SYSTEM	$5,860	$5,932	$5,047	$0	$0	**$16,839**	$1,564	$0	$3,784	**$22,187**	$48
10	ASH/SPENT SORBENT HANDLING SYS	$20,179	$1,541	$10,013	$0	$0	**$31,732**	$3,044	$0	$3,796	**$38,573**	$84
11	ACCESSORY ELECTRIC PLANT	$28,954	$11,504	$22,461	$0	$0	**$62,920**	$5,413	$0	$12,976	**$81,309**	$176
12	INSTRUMENTATION & CONTROL	$10,732	$1,974	$6,915	$0	$0	**$19,621**	$1,778	$981	$3,729	**$26,110**	$57
13	IMPROVEMENTS TO SITE	$3,220	$1,898	$7,945	$0	$0	**$13,063**	$1,290	$0	$4,306	**$18,659**	$40
14	BUILDINGS & STRUCTURES	$0	$6,068	$6,854	$0	$0	**$12,922**	$1,176	$0	$2,324	**$16,423**	$36
	TOTAL COST	**$705,833**	**$62,309**	**$258,448**	**$0**	**$0**	**$1,026,590**	**$95,414**	**$75,563**	**$193,851**	**$1,391,417**	**$3,019**

Exhibit 3-81 Case S2B Total Plant Cost Summary Details

	Client:	USDOE/NETL								Report Date:	2009-Oct-15	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S2B - TRIG IGCC w/ CO2										
	Plant Size:	460.9	MW,net	Estimate Type:		Conceptual		Cost Base (June)		2007	($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	$4,170	$0	$2,038	$0	$0	$6,208	$556	$0	$1,353	$8,117	$18
1.2	Coal Stackout & Reclaim	$5,389	$0	$1,306	$0	$0	$6,695	$587	$0	$1,456	$8,738	$19
1.3	Coal Conveyors & Yd Crush	$5,010	$0	$1,293	$0	$0	$6,302	$553	$0	$1,371	$8,227	$18
1.4	Other Coal Handling	$1,311	$0	$299	$0	$0	$1,610	$141	$0	$350	$2,101	$5
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	$2,951	$7,378	$0	$0	$10,329	$990	$0	$2,264	$13,583	$29
	SUBTOTAL 1.	**$15,879**	**$2,951**	**$12,314**	**$0**	**$0**	**$31,144**	**$2,827**	**$0**	**$6,794**	**$40,765**	**$88**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$31,325	$1,882	$4,564	$0	$0	$37,771	$3,259	$0	$8,206	$49,237	$107
2.2	Prepared Coal Storage & Feed	$1,347	$322	$211	$0	$0	$1,880	$161	$0	$408	$2,449	$5
2.3	Dry Coal Injection System	$44,321	$514	$4,116	$0	$0	$48,952	$4,216	$0	$10,634	$63,802	$138
2.4	Misc.Coal Prep & Feed	$816	$594	$1,780	$0	$0	$3,190	$293	$0	$697	$4,180	$9
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	$3,171	$2,604	$0	$0	$5,775	$535	$0	$1,262	$7,572	$16
	SUBTOTAL 2.	**$77,809**	**$6,484**	**$13,276**	**$0**	**$0**	**$97,568**	**$8,464**	**$0**	**$21,207**	**$127,239**	**$276**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,720	$4,671	$2,466	$0	$0	$9,856	$913	$0	$2,154	$12,923	$28
3.2	Water Makeup & Pretreating	$447	$47	$250	$0	$0	$744	$71	$0	$244	$1,059	$2
3.3	Other Feedwater Subsystems	$1,488	$503	$453	$0	$0	$2,443	$220	$0	$533	$3,196	$7
3.4	Service Water Systems	$256	$527	$1,829	$0	$0	$2,612	$255	$0	$860	$3,727	$8
3.5	Other Boiler Plant Systems	$1,374	$532	$1,319	$0	$0	$3,225	$306	$0	$706	$4,237	$9
3.6	FO Supply Sys & Nat Gas	$291	$550	$513	$0	$0	$1,354	$130	$0	$297	$1,781	$4
3.7	Waste Treatment Equipment	$625	$0	$381	$0	$0	$1,007	$98	$0	$331	$1,436	$3
3.8	Misc. Power Plant Equipment	$1,016	$136	$522	$0	$0	$1,674	$162	$0	$551	$2,387	$5
	SUBTOTAL 3.	**$8,217**	**$6,965**	**$7,732**	**$0**	**$0**	**$22,915**	**$2,154**	**$0**	**$5,676**	**$30,746**	**$67**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (TRIG)	$125,998	$0	$53,847	$0	$0	$179,845	$16,058	$41,465	$36,371	$273,739	$594
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$128,018	$0	w/equip.	$0	$0	$128,018	$12,409	$0	$14,043	$154,470	$335
4.4	LT Heat Recovery & FG Saturation	$9,189	$0	$3,493	$0	$0	$12,683	$1,238	$0	$2,784	$16,705	$36
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	Flare Stack System	$0	$1,017	$414	$0	$0	$1,431	$137	$0	$314	$1,881	$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	$9,275	$5,292	$0	$0	$14,568	$1,334	$0	$3,975	$19,877	$43
	SUBTOTAL 4.	**$263,206**	**$10,292**	**$63,047**	**$0**	**$0**	**$336,544**	**$31,175**	**$41,465**	**$57,487**	**$466,672**	**$1,013**

Exhibit 3-81 Case S2B Total Plant Cost Summary Details (Continued)

Client: USDOE/NETL **Report Date:** 2009-Oct-15

Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S2B - TRIG IGCC w/ CO2

Plant Size: 460.9 MW,net **Estimate Type:** Conceptual **Cost Base (June)** 2007 ($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	$62,625	$0	$53,138	$0	$0	$115,763	$11,196	$23,153	$30,022	$180,134	$391
5A.2	Elemental Sulfur Plant	$5,058	$1,008	$6,526	$0	$0	$12,592	$1,223	$0	$2,763	$16,578	$36
5A.3	Mercury Removal	$1,167	$0	$888	$0	$0	$2,054	$198	$103	$471	$2,827	$6
5A.4	Shift Reactors	$6,301	$0	$2,536	$0	$0	$8,837	$847	$0	$1,937	$11,621	$25
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,684	$283	$160	$0	$0	$2,127	$202	$0	$466	$2,795	$6
5A.6	Fuel Gas Piping	$0	$686	$480	$0	$0	$1,166	$108	$0	$255	$1,529	$3
5A.9	HGCU Foundations	$0	$695	$448	$0	$0	$1,142	$105	$0	$374	$1,622	$4
	SUBTOTAL 5A.	**$76,834**	**$2,672**	**$64,176**	**$0**	**$0**	**$143,682**	**$13,879**	**$23,255**	**$36,288**	**$217,105**	**$471**
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$16,750	$0	$9,707	$0	$0	$26,457	$2,547	$0	$5,801	$34,805	$76
	SUBTOTAL 5B.	**$16,750**	**$0**	**$9,707**	**$0**	**$0**	**$26,457**	**$2,547**	**$0**	**$5,801**	**$34,805**	**$76**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	$98,610	$9,348	$9,861	$11,782	$129,600	$281
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$92,027**	**$806**	**$7,475**	**$0**	**$0**	**$100,308**	**$9,507**	**$9,861**	**$12,339**	**$132,015**	**$286**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,608	$0	$4,494	$0	$0	$36,103	$3,433	$0	$3,954	$43,489	$94
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,758	$1,254	$0	$0	$3,012	$264	$0	$655	$3,932	$9
7.4	Stack	$3,430	$0	$1,288	$0	$0	$4,718	$452	$0	$517	$5,687	$12
7.9	HRSG,Duct & Stack Foundations	$0	$687	$660	$0	$0	$1,347	$125	$0	$442	$1,914	$4
	SUBTOTAL 7.	**$35,038**	**$2,445**	**$7,697**	**$0**	**$0**	**$45,181**	**$4,274**	**$0**	**$5,568**	**$55,023**	**$119**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,780	$0	$3,777	$0	$0	$26,557	$2,548	$0	$2,911	$32,016	$69
8.2	Turbine Plant Auxiliaries	$157	$0	$359	$0	$0	$515	$50	$0	$57	$622	$1
8.3a	Condenser & Auxiliaries	$2,301	$0	$735	$0	$0	$3,036	$290	$0	$333	$3,659	$8
8.3b	Air Cooled Condenser	$21,086	$0	$4,227	$0	$0	$25,314	$2,531	$0	$5,569	$33,414	$73
8.4	Steam Piping	$4,802	$0	$3,378	$0	$0	$8,181	$703	$0	$2,221	$11,104	$24
8.9	TG Foundations	$0	$776	$1,312	$0	$0	$2,088	$198	$0	$686	$2,972	$6
	SUBTOTAL 8.	**$51,126**	**$776**	**$13,789**	**$0**	**$0**	**$65,691**	**$6,321**	**$0**	**$11,776**	**$83,788**	**$182**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,007	$0	$729	$0	$0	$4,736	$451	$0	$778	$5,964	$13
9.2	Circulating Water Pumps	$1,035	$0	$58	$0	$0	$1,093	$92	$0	$178	$1,363	$3
9.3	Circ.Water System Auxiliaries	$94	$0	$13	$0	$0	$108	$10	$0	$18	$136	$0
9.4	Circ.Water Piping	$0	$3,930	$1,019	$0	$0	$4,949	$447	$0	$1,079	$6,475	$14
9.5	Make-up Water System	$260	$0	$372	$0	$0	$632	$61	$0	$139	$832	$2
9.6	Component Cooling Water Sys	$464	$555	$395	$0	$0	$1,414	$132	$0	$309	$1,855	$4
9.9	Circ.Water System Foundations	$0	$1,447	$2,460	$0	$0	$3,907	$370	$0	$1,283	$5,561	$12
	SUBTOTAL 9.	**$5,860**	**$5,932**	**$5,047**	**$0**	**$0**	**$16,839**	**$1,564**	**$0**	**$3,784**	**$22,187**	**$48**

Exhibit 3-81 Case S2B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL							Report Date:	2009-Oct-15		
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S2B - TRIG IGCC w/ CO2										
	Plant Size:	460.9	MW,net	Estimate Type:		Conceptual		Cost Base (June)		2007	($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$17,590	$0	$8,674	$0	$0	$26,264	$2,524	$0	$2,879	$31,667	$69
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$587	$0	$638	$0	$0	$1,225	$119	$0	$202	$1,545	$3
10.7	Ash Transport & Feed Equipment	$787	$0	$190	$0	$0	$977	$91	$0	$160	$1,228	$3
10.8	Misc. Ash Handling Equipment	$1,215	$1,489	$445	$0	$0	$3,149	$300	$0	$517	$3,966	$9
10.9	Ash/Spent Sorbent Foundation	$0	$52	$65	$0	$0	$117	$11	$0	$38	$166	$0
	SUBTOTAL 10.	**$20,179**	**$1,541**	**$10,013**	**$0**	**$0**	**$31,732**	**$3,044**	**$0**	**$3,796**	**$38,573**	**$84**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$859	$0	$850	$0	$0	$1,709	$163	$0	$187	$2,060	$4
11.2	Station Service Equipment	$4,297	$0	$387	$0	$0	$4,684	$432	$0	$512	$5,628	$12
11.3	Switchgear & Motor Control	$7,944	$0	$1,445	$0	$0	$9,388	$871	$0	$1,539	$11,798	$26
11.4	Conduit & Cable Tray	$0	$3,690	$12,174	$0	$0	$15,864	$1,534	$0	$4,350	$21,748	$47
11.5	Wire & Cable	$0	$7,051	$4,633	$0	$0	$11,683	$849	$0	$3,133	$15,665	$34
11.6	Protective Equipment	$0	$624	$2,269	$0	$0	$2,893	$283	$0	$476	$3,652	$8
11.7	Standby Equipment	$216	$0	$211	$0	$0	$426	$41	$0	$70	$537	$1
11.8	Main Power Transformers	$15,639	$0	$128	$0	$0	$15,767	$1,192	$0	$2,544	$19,503	$42
11.9	Electrical Foundations	$0	$139	$365	$0	$0	$504	$48	$0	$166	$718	$2
	SUBTOTAL 11.	**$28,954**	**$11,504**	**$22,461**	**$0**	**$0**	**$62,920**	**$5,413**	**$0**	**$12,976**	**$81,309**	**$176**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,059	$0	$707	$0	$0	$1,767	$167	$88	$303	$2,326	$5
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	$243	$0	$156	$0	$0	$400	$38	$20	$91	$549	$1
12.7	Computer & Accessories	$5,652	$0	$181	$0	$0	$5,832	$535	$292	$666	$7,325	$16
12.8	Instrument Wiring & Tubing	$0	$1,974	$4,036	$0	$0	$6,010	$510	$301	$1,705	$8,526	$19
12.9	Other I & C Equipment	$3,778	$0	$1,834	$0	$0	$5,612	$528	$281	$963	$7,384	$16
	SUBTOTAL 12.	**$10,732**	**$1,974**	**$6,915**	**$0**	**$0**	**$19,621**	**$1,778**	**$981**	**$3,729**	**$26,110**	**$57**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$101	$2,159	$0	$0	$2,260	$224	$0	$745	$3,230	$7
13.2	Site Improvements	$0	$1,797	$2,388	$0	$0	$4,185	$413	$0	$1,379	$5,977	$13
13.3	Site Facilities	$3,220	$0	$3,398	$0	$0	$6,618	$652	$0	$2,181	$9,451	$21
	SUBTOTAL 13.	**$3,220**	**$1,898**	**$7,945**	**$0**	**$0**	**$13,063**	**$1,290**	**$0**	**$4,306**	**$18,659**	**$40**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$1,984	$2,826	$0	$0	$4,810	$443	$0	$788	$6,040	$13
14.3	Administration Building	$0	$835	$606	$0	$0	$1,441	$128	$0	$235	$1,804	$4
14.4	Circulation Water Pumphouse	$0	$157	$83	$0	$0	$240	$21	$0	$39	$300	$1
14.5	Water Treatment Buildings	$0	$374	$365	$0	$0	$739	$67	$0	$121	$926	$2
14.6	Machine Shop	$0	$427	$292	$0	$0	$720	$64	$0	$118	$901	$2
14.7	Warehouse	$0	$690	$445	$0	$0	$1,135	$101	$0	$185	$1,421	$3
14.8	Other Buildings & Structures	$0	$413	$322	$0	$0	$735	$66	$0	$160	$961	$2
14.9	Waste Treating Building & Str.	$0	$924	$1,765	$0	$0	$2,689	$251	$0	$588	$3,528	$8
	SUBTOTAL 14.	**$0**	**$6,068**	**$6,854**	**$0**	**$0**	**$12,922**	**$1,176**	**$0**	**$2,324**	**$16,423**	**$36**
	TOTAL COST	**$705,833**	**$62,309**	**$258,448**	**$0**	**$0**	**$1,026,590**	**$95,414**	**$75,563**	**$193,851**	**$1,391,417**	**$3,019**

Exhibit 3-82 Case S2B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$11,155	$24
1 Month Variable O&M	$2,962	$6
25% of 1 Months Fuel Cost at 100% CF	$802	$2
2% of TPC	$27,828	$60
Total	**$42,748**	**$93**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,787	$15
0.5% of TPC (spare parts)	$6,957	$15
Total	**$13,745**	**$30**
Initial Cost for Catalyst and Chemicals	**$6,042**	**$13**
Land	**$900**	**$2**
Other Owner's Costs	**$208,713**	**$453**
Financing Costs	**$37,568**	**$82**
Total Owner's Costs	**$309,715**	**$672**
Total Overnight Cost (TOC)	**$1,701,132**	**$3,691**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$1,939,291**	**$4,208**

Exhibit 3-83 Case S2B Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (June):	2007
Case S2B - TRIG IGCC w/ CO2					Heat Rate-net (Btu/kWh):	10740
					MWe-net:	461
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$6,313,507	$13.700
Maintenance Labor Cost					$11,535,125	$25.030
Administrative & Support Labor					$4,462,158	$9.682
Property Taxes and Insurance					$27,828,342	$60.385
TOTAL FIXED OPERATING COSTS					**$50,139,132**	**$108.797**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$23,182,469**	**$0.00718**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	2,152	1.08	**$0**	**$679,733**	**$0.00021**
Chemicals						
MU & WT Chem. (lb)	0	12,821	0.17	$0	$647,944	$0.00020
Carbon (Mercury Removal) (lb)	89,518	123	1.05	$94,009	$37,604	$0.00001
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	5,053	3.46	498.83	$2,520,820	$504,164	$0.00016
Selexol Solution (gal)	255,792	81	13.40	$3,427,162	$318,336	$0.00010
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.	0.76	131.27	$0	$29,076	$0.00001
Subtotal Chemicals				**$6,041,991**	**$1,537,124**	**$0.00048**
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	123	0.42	$0	$14,934	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	637	16.23	$0	$3,019,289	$0.00093
Subtotal Waste Disposal				**$0**	**$3,034,224**	**$0.00094**
By-products & Emissions						
Sulfur (tons)	0	50	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$6,041,991**	**$28,433,550**	**$0.00880**
Fuel (ton)	0	6,935	15.22	**$0**	**$30,815,893**	**$0.00954**

3.4 SIEMENS FUEL GASIFIER IGCC CASES

This section contains an evaluation of plant designs for Cases S3A, S3B, L3A, and L3B, which are based on the SFG. The non-capture (A) and CO_2 capture (B) cases are very similar in terms of process, equipment, scope and arrangement, except that CO_2 capture cases includes SGS reactors, CO_2 absorption/regeneration and compression/transport systems.

Section 3.4.4 covers the results for the S3A and L3A non-capture case using PRB and Lignite coal and Section 3.4.8 covers the S3B and L3B CO_2-capture cases. The sections are organized analogously as follows:

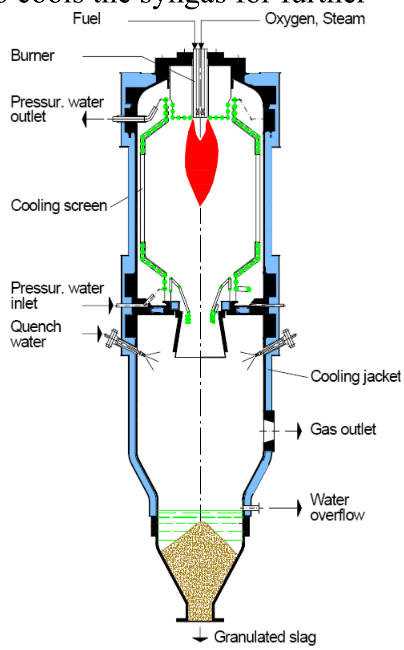
- Process and System Description provides an overview of the specific technology's operation.
- BFD and stream table display results for major processes and streams.
- Performance Results provides the main modeling results, including the performance summary, environmental performance, carbon balance, sulfur balance, water balance, mass and energy balance diagrams, and mass and energy balance tables.
- Equipment List provides an itemized list of major equipment with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs.

Process and System Description, Performance Results, Equipment List and Cost Estimates are repeated for the CO_2 capture cases in Section 3.4.8. If the information is identical to that presented for the non-capture cases, a reference is made to the earlier section rather than repeating the information.

3.4.1 Gasifier Background

Development and Current Status – The SFG process for IGCC applications is based on the Noell process, also known under the name GSP, developed by Deutsches Brennstoffinstitut Freiberg in 1975 for the gasification of German domestic brown coal and other solid fuels. The Noell Group acquired the technology in 1991 and did further development to gasify waste materials and liquid residues. The gasifier was marketed under the Future Energy GmbH company and was sold to Siemens in 2006. The first gasifier of this type was a 200 megawatt thermal (MWth) thermal unit built at Schwarze Pumpe, Germany in 1984, firing high sodium lignite. It was converted to process natural gas and waste liquids in 1990. Other installations include a 5 MWth test plant in Freiberg, Germany where alternative feed testing is ongoing and a 175 MWth autothermal oil conversion plant in the Czech Republic, commissioned in 2008. Current gasifier projects include the Shanxi Lanhua Coal 1,000 MWth coal to ammonia plant, which is in its engineering phase, and the Shenhua Ningxia Coal Based Polypropylene Project with capacity of 2,500 MWth of coal to polypropylene production, due to enter commercial operation in mid 2011. Siemens SFG-500 Gasifiers are also planned for the Secure Energy, Coal to SNG project in IL slated to be commissioned in 2013.

In this study, three parallel Siemens dry feed, pressurized, down flow, entrained, slagging gasifiers are used to power two advanced F-class turbines. The Siemens gasifiers have a 'cooling screen' (heat exchanger tubes) on the inside surface of the gasifier, which eliminates the need for refractory inside the gasifier. This cooling screen also raises a small amount of LP steam that is used inside the gasification island to heat the O_2 before entering the gasifier. A full quench in the bottom of the gasifier helps remove the slag and also cools the syngas for further downstream cleanup and heat recovery.



Gasifier Capacity – At the outset of this study, the largest commercial offering from Siemens was a nominal 500 MW thermal input gasifier. The largest current commercial offering is a nominal 1,200 MW thermal input gasifier. Based on vendor input and assuming a 500 MW thermal gasifier, less than 3 gasifiers are required to run the plant at full capacity except the lignite CCS case, which requires 3.2 gasifiers due to the low quality coal and high auxiliary requirements. For consistency and comparability, all the cases were costed as three gasifiers, while accounting for the differences in gas flow.

Distinguishing Characteristics – The Siemens gasifier is a dry feed, entrained flow, slagging, single stage, down-flow gasifier producing syngas at high pressures and temperatures. The gasifier uses a cooling screen design to control the reactor vessel wall temperature. The gasifier temperature is controlled above the slag fluid temperature to assure the creation of a protective slag layer on the inside of the cooling screen while LP steam is generated in the cooling screen. This approach helps minimize the risk of slag attack that occurs with refractory lining and helps improves the lifetime and maintenance, as well as start-up and shutdown times. The more complex dry feeding system helps achieve high conversion rates, lower oxygen consumption and higher efficiencies compared to slurry fed systems.

The gasifier unit also contains a built in quench section below the reaction section where both the hot raw syngas and liquid slag are discharged and the raw gas is cooled and saturated by injection of water. Molten slag is cooled and granulated in a water bath at the bottom of the quench vessel. This mode of operation helps improve the reliability of the gasifier by simplifying the raw gas quench and slag removal steps, at the expense of adding moisture to the syngas. The high temperature in the gasifier ensures that no tars or other hydrocarbon liquids are formed, and the quench section helps reduce the syngas exit temperature. This built in quench can be a competitive alternative to high temperature syngas cooling, especially for CO_2 capture and chemical synthesis applications where H_2 and CO_2 is preferable to CO production, as it uses the sensible heat of the syngas to directly raise steam for the WGS reaction, avoiding extracting steam from the steam cycle and the cost of the necessary heat exchangers.

Important Coal Characteristics – The Siemens gasifier is generally able to fire most types of coal, petcoke, or mixed feeds. The gasifier temperature can be controlled to use a wide range of feeds, which Siemens can characterize at their test facility, in order to develop specific operating parameters for each fuel and ash type.

3.4.2 Key System Assumptions

System assumptions for Cases S3A and L3A and S3B and L3B, SFG IGCC using PRB and lignite coal with and without CO_2 capture, are compiled in Exhibit 3-84.

Exhibit 3-84 Case S3A/L3A and S3B/L3B Plant Study Configuration Matrix

Case	S3A / L3A	S3B / L3B
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.758 / 0.720	0.767 / 0.719
Carbon Conversion, %	99.5	99.5
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	4,824 (130) / 4,437 (119)	4,834 (130) / 4,651 (125)
Nominal 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)	36 (1.4)	36 (1.4)
Combustion Turbine	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)
Gasifier Technology	Siemens (SFG)	Siemens (SFG)
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Subbituminous / Lignite	Subbituminous / Lignite
Coal Feed Moisture Content, %	6 / 12	6 / 12
COS Hydrolysis	Yes	Yes (Part of WGS)
Water Gas Shift	No	Yes
H_2S Separation	Sulfinol-M	Selexol (1st Stage)
Sulfur Removal, %	99.8	99.7
CO_2 Separation	None	Selexol (2nd Stage)
CO_2 Removal, %	N/A	90
Sulfur Recovery	Claus Plant with Tail Gas Treatment / Elemental Sulfur	Claus Plant with Tail Gas Treatment / Elemental Sulfur
Particulate Control	Cyclone, Scrubber, and AGR Absorber	Cyclone, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB) and N_2 Dilution	MNQC (LNB) and N_2 Dilution

Balance of Plant – All Cases

The balance of plant assumptions are common to all cases and are presented in Exhibit 3-85.

Exhibit 3-85 Balance of Plant Assumptions

Cooling water 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 CT Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and 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 m^3/d (1,500 GPD)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

3.4.3 Sparing Philosophy

The sparing philosophy 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 ASUs (2 x 50%).
- Two trains of coal drying and dry feed systems (2 x 50%).
- Three trains of gasification, including gasifier, SGC, cyclone, and barrier filter (3 x 33%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Sulfinol-M acid gas removal in non-capture cases and two trains of two-stage Selexol in CO_2 capture cases (2 x 50%).
- One train of Claus-based sulfur recovery (1 x 100%).
- Two CT/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.4.4 SFG IGCC Non-Capture Case (S3A and L3A) Process Description

In this section the overall SFG process for Case S3A and L3A is described. The process does not change with fuel type so a single description is provided. The system description follows the BFD in Exhibit 3-86 and stream numbers reference the same exhibit. The tables in Exhibit 3-87 and Exhibit 3-88 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 SFG 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 PRB coal used in this study contains 25.77 percent total moisture on an as-received basis and the NDL contains 36.08 percent moisture. It was assumed that the PRB coal must be dried to 6 percent moisture and the lignite to 12 percent to allow for smooth flow through the dry feed system.

The raw coal is crushed in the coal mill then delivered to a surge hopper with an approximate 2-hour capacity, which in turn delivers the coal to the coal pre-heater. The WTA coal drying process includes a water-heated, horizontal, rotary-kiln coal pre-heater, a fluidized bed coal dryer and a water-cooled, horizontal, rotary-kiln coal cooler. The moisture driven from the coal in the fluid bed dryer passes through a baghouse for particulate removal and then is split into two streams. The smaller of the two streams is compressed and used as the fluidizing medium in the coal dryer. The bulk of the removed moisture is compressed and the high temperature vapor passes through internal coils in the dryer to provide the heat to drive off the coal moisture and then exits the dryer as liquid water. The warm water is used in the coal pre-heater before being used as cooling tower makeup water. The vapor compressor consumes the vast majority of the WTA process auxiliary load.

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.

Gasifier

There are three Siemens dry feed, pressurized, down-flow, entrained, slagging gasifiers, operating at 4.24 MPa (615 psia) and processing a total of 5,782 tonne/day (6,373 tpd) of as-received coal in the PRB case and 8,098 tonne/day (8,927 tpd) in the lignite case. Coal reacts with oxygen in a reducing environment to produce principally hydrogen and carbon monoxide with little CO_2 formed. The hot raw syngas and the liquid slag flow down into the quench chamber of the gasifier and the raw gas is cooled and saturated by injecting water. The slag is cooled and granulated in a water bath at the bottom of the quench vessel.

Syngas Scrubber/Particulate Removal

A raw gas venturi scrubber system thoroughly mixes the raw syngas with water to ensure wetting of fine ash and soot particles. Cyclones are used to separate the water and particulates from the raw gas. Syngas scrubbers are employed and use gas condensate from the downstream gas cooling processes. The fine particulates are removed in a partial condenser, which continues cooling the gas, downstream of the scrubber unit. The particulates act as condensation cores and are caught by the condensed droplets in the partial condenser and are recycled to the gasifier quench chamber.

Sour Water Stripper

The sour water stripper removes ammonia, sulfur, and other impurities from the waste stream of the scrubber. The sour gas stripper consists of a sour drum that accumulates sour water from various plant sources. 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 SRU. Remaining water is sent to wastewater treatment.

COS Hydrolysis, Mercury Removal and AGR

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 AGR process; however, because COS is not readily removed, it is first catalytically converted to H_2S in a COS hydrolysis unit.

The cooled raw gas is fed to the COS hydrolysis reactor where the COS in the sour gas is hydrolyzed with steam, over a catalyst bed, into H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the AGR process, 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 then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.8).

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 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 the Siemens non-CO_2 capture applications.

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 about 15 percent of the CO_2 along with the H_2S and COS. The acid gas is fed to the SRU. The residual CO_2 passes through the SRU, the hydrogenation reactor and is recycled to the gasifier. 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 SRU is a Claus bypass type SRU utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting 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 tail gas recycle results in an overall sulfur recovery exceeding 99 percent, producing 42 tonne/day (46 tpd) of sulfur in the PRB case and 51 tonne/day (56 tpd) in the lignite case.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. Feed for each case consists of acid gas from both the acid gas cleanup unit and a vent stream from the sour water stripper in the gasifier section.

In the furnace waste heat boiler 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 LP steam header.

Power Block

Clean syngas exiting the Sulfinol absorber is reheated, diluted with nitrogen from the ASU, and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and also a portion of the air requirement for the ASU. The exhaust gas exits the CT around 566°C (1,050°F) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) 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 nominal 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit

The ASU is designed to produce approximately 3,468 tonne/day (3,823 tpd) in the PRB case and 3,979 tonne/day (4,386 tpd) in the lignite case of 95 mole percent O_2 for use in the gasifier and SRU. The plant is designed with two production trains. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as dilution in the CT combustor or as a coal transport fluid. Air extraction is taken from the CT compressor to reduce the size of the main air compressor.

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14, and 3.1.15.

Exhibit 3-86 Case S3A and L3A Process Flow Diagram

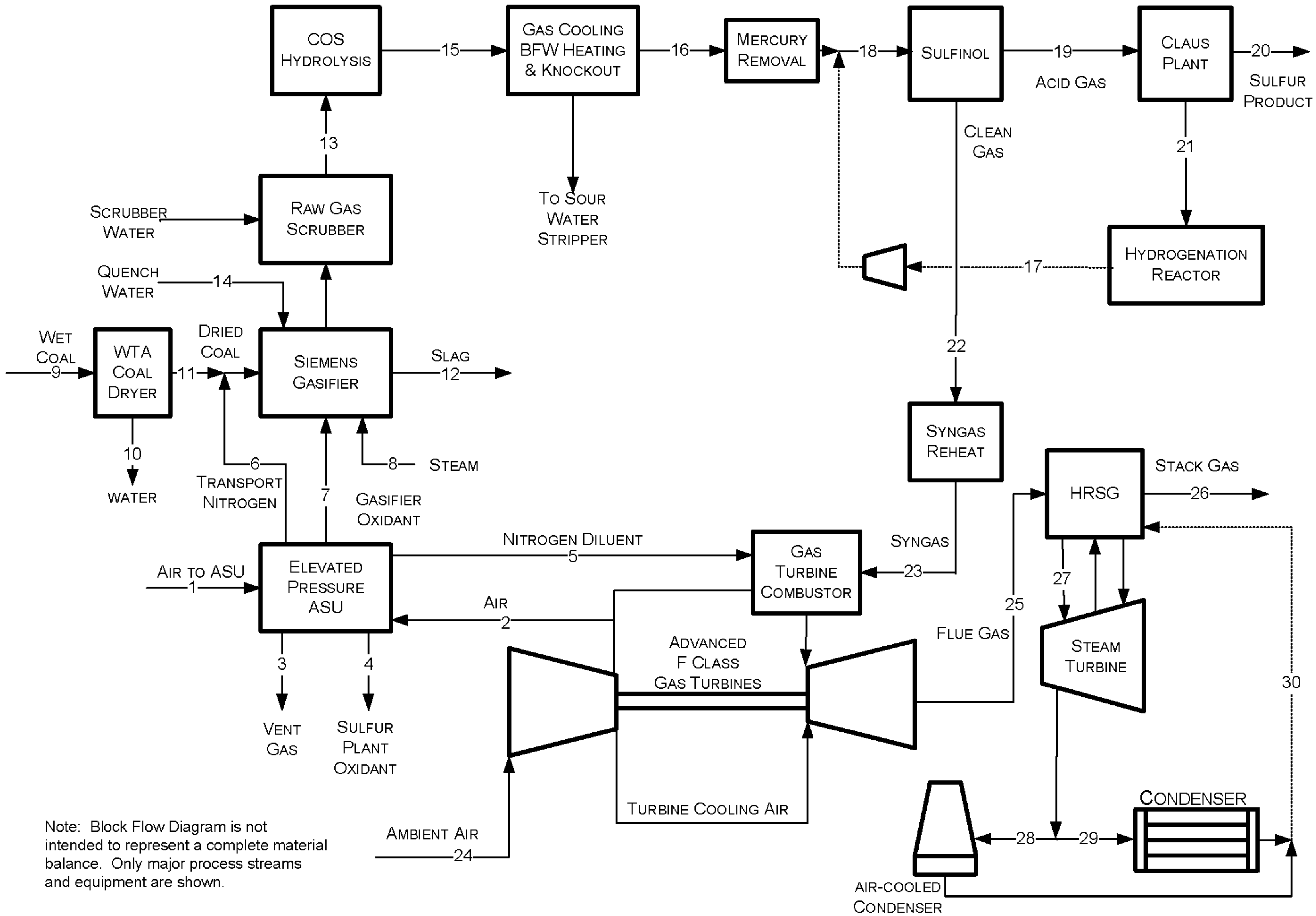


Exhibit 3-87 Case S3A Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0093	0.0291	0.0318	0.0023	0.0023	0.0360	0.0000	0.0000	0.0000	0.0000	0.0000	0.0046	0.0000	0.0046
CH_4	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	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2649	0.0000	0.2649
CO_2	0.0003	0.0003	0.0102	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0230	0.0000	0.0231
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
H_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	0.1332	0.0000	0.1332
H_2O	0.0064	0.0064	0.1937	0.0000	0.0002	0.0002	0.0000	1.0000	0.0000	1.0000	0.0000	0.0000	0.5443	0.9998	0.5442
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0014	0.0000	0.0016
N_2	0.7759	0.7759	0.5163	0.0178	0.9920	0.9920	0.0140	0.0000	0.0000	0.0000	0.0000	0.0000	0.0278	0.0000	0.0278
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0002	0.0007
O_2	0.2081	0.2081	0.2507	0.9504	0.0054	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	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	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	18,872	2,907	699	35	14,895	1,695	4,449	1,162	0	2,813	0	0	34,856	17,564	34,856
V-L Flowrate (kg/hr)	545,309	83,991	19,275	1,134	417,964	47,561	143,382	20,927	0	50,668	0	0	680,934	316,426	680,934
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	240,911	0	190,243	20,328	0	0	0
Temperature (°C)	6	411	21	32	196	125	32	343	6	33	71	260	214	175	214
Pressure (MPa, abs)	0.09	1.43	0.11	0.86	2.65	5.62	0.86	5.10	0.09	0.55	0.09	4.17	4.10	8.27	4.03
Enthalpy (kJ/kg)[A]	15.26	434.33	40.10	26.67	202.63	123.73	26.59	3,062.93	---	140.13	---	---	1,567.59	699.71	1,567.49
Density (kg/m^3)	1.1	7.2	1.6	11.0	18.9	47.0	11.0	20.1	---	985.3	---	---	20.9	833.2	20.5
V-L Molecular Weight	28.895	28.895	27.587	32.181	28.061	28.061	32.229	18.015	---	18.015	---	---	19.536	18.015	19.536
V-L Flowrate (lb_{mol}/hr)	41,606	6,408	1,540	78	32,838	3,737	9,808	2,561	0	6,201	0	0	76,844	38,722	76,844
V-L Flowrate (lb/hr)	1,202,201	185,168	42,494	2,500	921,453	104,854	316,103	46,136	0	111,704	0	0	1,501,202	697,601	1,501,202
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	531,119	0	419,414	44,815	0	0	0
Temperature (°F)	42	771	70	90	385	257	90	650	42	92	160	500	418	347	417
Pressure (psia)	13.0	207.6	16.4	125.0	385.0	815.0	125.0	740.0	13.0	80.1	12.7	604.7	594.7	1,200.0	584.7
Enthalpy (Btu/lb)[A]	6.6	186.7	17.2	11.5	87.1	53.2	11.4	1,316.8	---	60.2	---	---	673.9	300.8	673.9
Density (lb/ft^3)	0.070	0.452	0.097	0.687	1.183	2.937	0.688	1.257	---	61.510	---	---	1.304	52.017	1.282

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-87 Case S3A Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0101	0.0057	0.0101	0.0006	0.0000	0.0041	0.0102	0.0102	0.0093	0.0091	0.0091	0.0000	0.0000	0.0000	0.0000
CH_4	0.0001	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.5812	0.0026	0.5715	0.0213	0.0000	0.0457	0.5814	0.5814	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0506	0.5462	0.0592	0.5013	0.0000	0.3467	0.0512	0.0512	0.0003	0.0814	0.0814	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0002	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.2922	0.0996	0.2890	0.0118	0.0000	0.0274	0.2940	0.2940	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0015	0.0324	0.0016	0.0089	0.0000	0.3519	0.0014	0.0014	0.0064	0.0431	0.0431	1.0000	1.0000	1.0000	1.0000
H_2S	0.0034	0.0916	0.0049	0.2762	0.0000	0.0654	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0609	0.2217	0.0637	0.1799	0.0000	0.1585	0.0616	0.0616	0.7759	0.7540	0.7540	0.0000	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2081	0.1125	0.1125	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	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	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	15,882	278	16,153	286	0	389	15,793	15,793	102,359	123,228	123,228	21,819	18,972	18,972	39,649
V-L Flowrate (kg/hr)	339,066	9,598	348,526	10,670	0	11,596	336,292	336,292	2,957,681	3,627,946	3,627,946	393,078	341,794	341,794	714,297
Solids Flowrate (kg/hr)	0	0	0	0	1,748	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	35	49	35	51	181	138	51	196	6	587	134	559	32	32	33
Pressure (MPa, abs)	3.93	0.32	3.86	0.4	0.370	0.370	3.597	3.563	0.090	0.093	0.090	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	42.64	88.47	41.65	55.0	---	689.453	66.652	275.179	15.260	698.571	202.573	3,496.917	2,248.547	2,248.547	140.297
Density (kg/m^3)	32.7	4.2	32.6	5.8	---	3.3	28.3	19.2	1.1	0.4	0.8	35.2	0.04	0.04	995.0
V-L Molecular Weight	21.349	34.468	21.577	37	---	29.783	21.293	21.293	28.895	29.441	29.441	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	35,014	614	35,610	630	0	858	34,818	34,818	225,664	271,670	271,670	48,103	41,827	41,827	87,412
V-L Flowrate (lb/hr)	747,513	21,161	768,368	23,524	0	25,566	741,397	741,397	6,520,570	7,998,253	7,998,253	866,588	753,527	753,527	1,574,754
Solids Flowrate (lb/hr)	0	0	0	0	3,855	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	95	120	94	124	358	280	124	385	42	1,088	272	1,038	90	90	92
Pressure (psia)	569.7	46.5	559.7	60.0	53.6	53.6	521.7	516.7	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	18.3	38.0	17.9	23.7	---	296.4	28.7	118.3	6.6	300.3	87.1	1,503.4	966.7	966.7	60.3
Density (lb/ft^3)	2.042	0.260	2.032	0.363	---	0.203	1.767	1.199	0.070	0.024	0.049	2.200	0.002	0.002	62.116

Exhibit 3-88 Case L3A Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0093	0.0293	0.0318	0.0023	0.0023	0.0360	0.0000	0.0000	0.0000	0.0000	0.0000	0.0046	0.0000	0.0046
CH_4	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	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2484	0.0000	0.2484
CO_2	0.0003	0.0003	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0268	0.0000	0.0269
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000
H_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	0.1176	0.0000	0.1176
H_2O	0.0062	0.0062	0.1878	0.0000	0.0002	0.0002	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.5677	1.0000	0.5675
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0015	0.0000	0.0016
N_2	0.7761	0.7761	0.5200	0.0178	0.9920	0.9920	0.0140	0.0000	0.0000	0.0000	0.0000	0.0000	0.0328	0.0000	0.0328
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0005
O_2	0.2082	0.2082	0.2525	0.9504	0.0054	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	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	21,582	3,397	796	44	16,673	2,358	5,100	0	0	5,125	0	0	40,317	20,979	40,317
V-L Flowrate (kg/hr)	623,675	98,158	22,008	1,406	467,870	66,177	164,371	0	0	92,335	0	0	797,136	377,958	797,136
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	337,436	0	245,101	33,948	0	0	0
Temperature (°C)	4	408	21	32	196	125	32	---	4	32	71	260	217	175	216
Pressure (MPa, abs)	0.10	1.52	0.11	0.86	2.65	5.62	0.86	---	0.10	0.34	0.09	4.17	4.10	8.27	4.03
Enthalpy (kJ/kg)^A	13.75	431.19	40.37	26.67	202.62	123.72	26.59	---	---	135.07	---	---	1,604.74	700.03	1,604.63
Density (kg/m^3)	1.2	7.7	1.5	11.0	18.9	47.0	11.0	---	---	986.5	---	---	21.1	833.3	20.8
V-L Molecular Weight	28.898	28.898	27.657	32.181	28.061	28.061	32.229	---	---	18.015	---	---	19.771	18.016	19.771
V-L Flowrate (lb_{mol}/hr)	47,581	7,489	1,754	96	36,759	5,199	11,244	0	0	11,299	0	0	88,885	46,252	88,885
V-L Flowrate (lb/hr)	1,374,968	216,401	48,519	3,100	1,031,478	145,896	362,377	0	0	203,563	0	0	1,757,383	833,254	1,757,383
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	743,918	0	540,355	74,843	0	0	0
Temperature (°F)	40	767	70	90	385	257	90	---	40	90	160	500	422	347	421
Pressure (psia)	13.8	220.4	16.4	125.0	385.0	815.0	125.0	---	13.8	50.0	13.5	604.7	594.7	1,200.0	584.7
Enthalpy (Btu/lb)^A	5.9	185.4	17.4	11.5	87.1	53.2	11.4	---	---	58.1	---	---	689.9	301.0	689.9
Density (lb/ft^3)	0.074	0.482	0.097	0.687	1.183	2.937	0.688	---	---	61.584	---	---	1.320	52.024	1.298
	A - Reference conditions are 32.02 F & 0.089 PSIA														

Exhibit 3-88 Case L3A Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0106	0.0062	0.0105	0.0005	0.0000	0.0041	0.0107	0.0107	0.0093	0.0091	0.0091	0.0000	0.0000	0.0000	0.0000
CH_4	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	0.0000
CO	0.5744	0.0014	0.5645	0.0193	0.0000	0.0365	0.5753	0.5753	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0621	0.6432	0.0725	0.5621	0.0000	0.3896	0.0628	0.0628	0.0003	0.0852	0.0852	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.2718	0.0587	0.2681	0.0100	0.0000	0.0179	0.2732	0.2732	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0015	0.0324	0.0016	0.0080	0.0000	0.3813	0.0014	0.0014	0.0062	0.0415	0.0415	1.0000	1.0000	1.0000	1.0000
H_2S	0.0037	0.0095	0.0038	0.1960	0.0000	0.0012	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0758	0.2486	0.0790	0.2041	0.0000	0.1644	0.0765	0.0765	0.7761	0.7544	0.7544	0.0000	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2082	0.1098	0.1098	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	17,434	317	17,741	343	0	479	17,326	17,326	106,961	130,213	130,213	23,023	21,431	21,431	43,503
V-L Flowrate (kg/hr)	384,801	11,581	396,212	12,995	0	14,462	381,626	381,626	3,090,914	3,842,252	3,842,252	414,769	386,093	386,093	783,714
Solids Flowrate (kg/hr)	0	0	0	0	2,111	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	35	49	35	51	174	138	51	196	4	588	132	560	32	32	33
Pressure (MPa, abs)	3.89	0.32	3.82	0.4	0.370	0.370	3.597	3.563	0.095	0.099	0.095	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	40.72	83.74	39.48	53.4	---	724.869	63.973	266.790	13.748	697.002	197.901	3,500.312	2,248.933	2,248.933	139.912
Density (kg/m^3)	33.6	4.4	33.5	5.9	---	3.3	29.3	19.9	1.2	0.4	0.8	35.2	0.04	0.04	995.0
V-L Molecular Weight	22.072	36.583	22.333	38	---	30.205	22.027	22.027	28.898	29.508	29.508	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	38,435	698	39,113	757	0	1,056	38,197	38,197	235,808	287,070	287,070	50,757	47,248	47,248	95,907
V-L Flowrate (lb/hr)	848,340	25,533	873,497	28,650	0	31,884	841,341	841,341	6,814,298	8,470,716	8,470,716	914,408	851,189	851,189	1,727,793
Solids Flowrate (lb/hr)	0	0	0	0	4,654	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	95	120	94	124	345	280	124	385	40	1,091	269	1,041	90	90	92
Pressure (psia)	564.7	46.5	554.7	60.0	53.6	53.6	521.7	516.7	13.8	14.3	13.8	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	17.5	36.0	17.0	23.0	---	311.6	27.5	114.7	5.9	299.7	85.1	1,504.9	966.9	966.9	60.2
Density (lb/ft^3)	2.097	0.276	2.090	0.368	---	0.206	1.831	1.240	0.074	0.025	0.052	2.195	0.002	0.002	62.118

3.4.5 Case S3A and L3A Performance Results

The non-capture SFG IGCC plant using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 505 MWe at a net plant efficiency of 37.9 percent (HHV basis). The same plant configuration using lignite coal at the NDL site (elevation 1,900 ft) produces a net output of 543 MWe at a net plant efficiency of 37.6 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 3-89, which includes auxiliary power requirements. The ASU accounts for approximately 74 percent of the total auxiliary load, distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The coal handling and drying account for approximately 10 percent of the auxiliary load. The cooling water system, including the CWPs and cooling tower fan, and the air-cooled condenser account for about 6 percent of the auxiliary load. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-89 Case S3A and L3A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	S3A	L3A
Gas Turbine Power	415,100	446,500
Steam Turbine Power	207,100	232,300
TOTAL POWER, kWe	**622,200**	**678,800**
AUXILIARY LOAD SUMMARY, kWe		
Coal Handling	490	590
Coal Milling	2,480	3,470
Slag Handling	530	880
WTA Coal Dryer Compressor	8,490	11,860
WTA Coal Dryer Auxiliaries	560	780
Air Separation Unit Auxiliaries	1,000	1,000
Air Separation Unit Main Air Compressor	48,560	54,120
Oxygen Compressor	7,850	9,000
Nitrogen Compressors	29,220	33,820
Boiler Feedwater Pumps	2,490	2,710
Condensate Pump	230	260
Circulating Water Pump	2,320	2,480
Ground Water Pumps	200	200
Cooling Tower Fans	1,510	1,520
Air Cooled Condenser Fans	3,240	3,450
Quench / Scrubber Pumps	640	1,490
Acid Gas Removal	380	420
Gas Turbine Auxiliaries	1,000	1,000
Steam Turbine Auxiliaries	100	100
Claus Plant/TGTU Auxiliaries	250	250
Claus Plant TG Recycle Compressor	730	850
Miscellaneous Balance of Plant[1]	3,000	3,000
Transformer Losses	2,210	2,430
TOTAL AUXILIARIES, kWe	**117,480**	**135,680**
NET POWER, kWe	**504,720**	**543,120**
Net Plant Efficiency, % (HHV)	37.9%	37.6%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,508 (9,012)	9,562 (9,063)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	1,445 (1,370)	1,635 (1,550)
CONSUMABLES		
As-Received Coal Feed, kg/hr (lb/hr)	240,911 (531,119)	337,436 (743,918)
Thermal Input, kWt	1,333,034	1,442,644
Raw Water Withdrawal, m^3/min (gpm)	8.6 (2,259)	8.3 (2,190)
Raw Water Consumption, m^3/min (gpm)	6.5 (1,711)	6.1 (1,601)

[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 PM were presented in Section 2.3. A summary of the plant air emissions for the non-capture cases is presented in Exhibit 3-90.

Exhibit 3-90 Cases S3A and L3A Air Emissions

	kg/GJ (lb/10^6 Btu)		Tonne/year (ton/year) 80% capacity factor		kg/MWh (lb/MWh)	
	S3A	L3A	S3A	L3A	S3A	L3A
SO_2	0.002 (0.004)	0.001 (0.002)	57 (63)	34 (37)	0.013 (0.029)	0.007 (0.016)
NO_X	0.026 (0.061)	0.026 (0.061)	878 (968)	960 (1,058)	0.201 (0.444)	0.202 (0.445)
Particulates	0.003 (0.0071)	0.003 (0.0071)	103 (113)	111 (122)	0.024 (0.052)	0.023 (0.051)
Hg	1.51E-7 (3.51E-7)	2.41E-7 (5.60E-7)	0.005 (0.006)	0.009 (0.010)	1.16E-6 (2.57E-6)	1.84E-6 (4.06E-6)
CO_2 gross	91.9 (213.8)	94.0 (218.6)	3,091,870 (3,408,203)	3,420,559 (3,770,521)	709 (1,563)	719 (1,585)
CO_2 net					874 (1,927)	899 (1,981)

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 5 ppmv in both cases. This results in a concentration in the flue gas of less than 1 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 and recycled upstream of the AGR to capture most of the remaining sulfur. Because the environmental target was set based on higher sulfur bituminous coal, the resulting SO_2 emissions with lower sulfur western coals are substantially less than the environmental target.

NOx emissions are limited to 15 ppmvd (as NO_2 @ 15 percent O_2) by the use of low NOx burners and nitrogen dilution of the fuel gas. 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 NOx levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a venturi scrubber and cyclone in addition to 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 two cases is shown in Exhibit 3-91. 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 and as CO_2 in the stack gas and ASU vent gas. Carbon that is not accounted for is shown as convergence tolerance.

Exhibit 3-91 Case S3A and L3A Carbon Balance

Carbon In, kg/hr (lb/hr)			Carbon Out, kg/hr (lb/hr)		
	S3A	L3A		S3A	L3A
Coal	120,620 (265,921)	133,468 (294,247)	**Slag**	603 (1,330)	667 (1,471)
Air (CO_2)	477 (1,053)	506 (1,116)	**Stack Gas**	120,408 (265,455)	133,209 (293,675)
			ASU Vent	86 (189)	98 (217)
Total	121,097 (266,974)	133,975 (295,363)	**Total**	121,097 (266,974)	133,975 (295,363)

Exhibit 3-92 shows the sulfur balance for the non-capture case. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-92 Cases S3A and L3A Sulfur Balance

Sulfur In, kg/hr (lb/hr)			Sulfur Out, kg/hr (lb/hr)		
	S3A	L3A		S3A	L3A
Coal	1,753 (3,864)	2,114 (4,660)	**Elemental Sulfur**	1,748 (3,855)	2,112 (4,655)
			Stack Gas	4 (9)	2 (5)
Total	1,753 (3,864)	2,114 (4,660)	**Total**	1,753 (3,864)	2,114 (4,660)

Exhibit 3-93 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 coal moisture from the drying process and syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is discharged from the process to a permitted outfall. The difference between the withdrawal and discharge is the consumption.

Exhibit 3-93 Case S3A and L3A Water Balance

Water Use	Water Demand m^3/min (gpm)		Internal Recycle m^3/min (gpm)		Raw Water Withdrawal m^3/min (gpm)		Process Water Discharge m^3/min (gpm)		Raw Water Consumption m^3/min (gpm)	
	S3A	L3A	S3A	L3A	S3A	L3A	S3A	L3A	S3A	L3A
Slag Handling	**0.44 (116)**	**0.74 (194)**	**0.44 (116)**	**0.74 (194)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**
Quench / Scrubber	**5.28 (1395)**	**6.31 (1667)**	**4.72 (1248)**	**5.49 (1451)**	**0.56 (147)**	**0.82 (216)**	**0 (0)**	**0 (0)**	**0.56 (147)**	**0.82 (216)**
SWS Blowdown	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0.05 (14)**	**0.06 (16)**	**-0.05 (-14)**	**-0.06 (-16)**
Condenser Makeup	**0.51 (135)**	**0.19 (51)**	**0 (0)**	**0 (0)**	**0.51 (135)**	**0.19 (51)**	**0 (0)**	**0 (0)**	**0.51 (135)**	**0.19 (51)**
Gasifier Steam	0.35 (92)				0.35 (92)					
BFW Makeup	0.16 (43)	0.19 (51)			0.16 (43)	0.19 (51)				
Cooling Tower	**9.01 (2,380)**	**9.64 (2,546)**	**1.53 (403)**	**2.36 (622)**	**7.49 (1,977)**	**7.28 (1,923)**	**2.03 (535)**	**2.17 (573)**	**5.46 (1442)**	**5.11 (1,351)**
Water from Coal Drying			0.85 (223)	1.54 (407)	-0.85 (-223)	-1.54 (-407)				
BFW Blowdown			0.16 (43)	0.19 (51)	-0.16 (-43)	-0.19 (-51)				
SWS Blowdown			0.52 (136)	0.62 (165)	-0.52 (-136)	-0.62 (-165)				
Total	**15.2 (4,027)**	**16.9 (4,458)**	**6.7 (1,767)**	**8.6 (2,267)**	**8.6 (2,259)**	**8.3 (2,190)**	**2.1 (549)**	**2.2 (589)**	**6.5 (1,711)**	**6.1 (1,601)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-94 and Exhibit 3-95:

- Coal gasification and ASU
- Syngas cleanup
- Combined cycle power generation

An overall plant energy balance is provided in tabular form in Exhibit 3-96 for the two cases. The power out is the combined CT and steam turbine power after generator losses.

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Exhibit 3-94 Case S3A Heat and Mass Balance

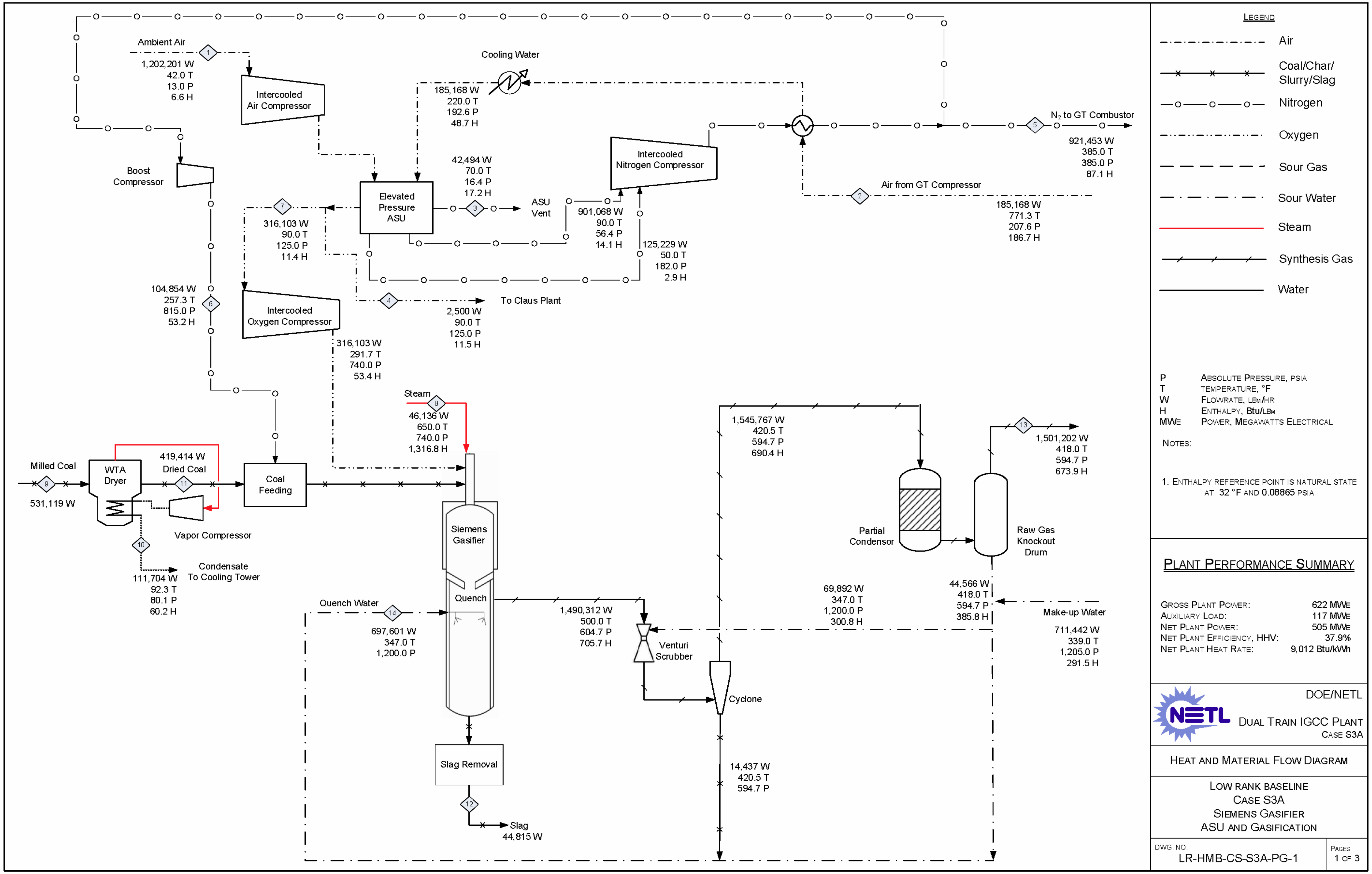


Exhibit 3-94 Case S3A Heat and Mass Balance (Continued)

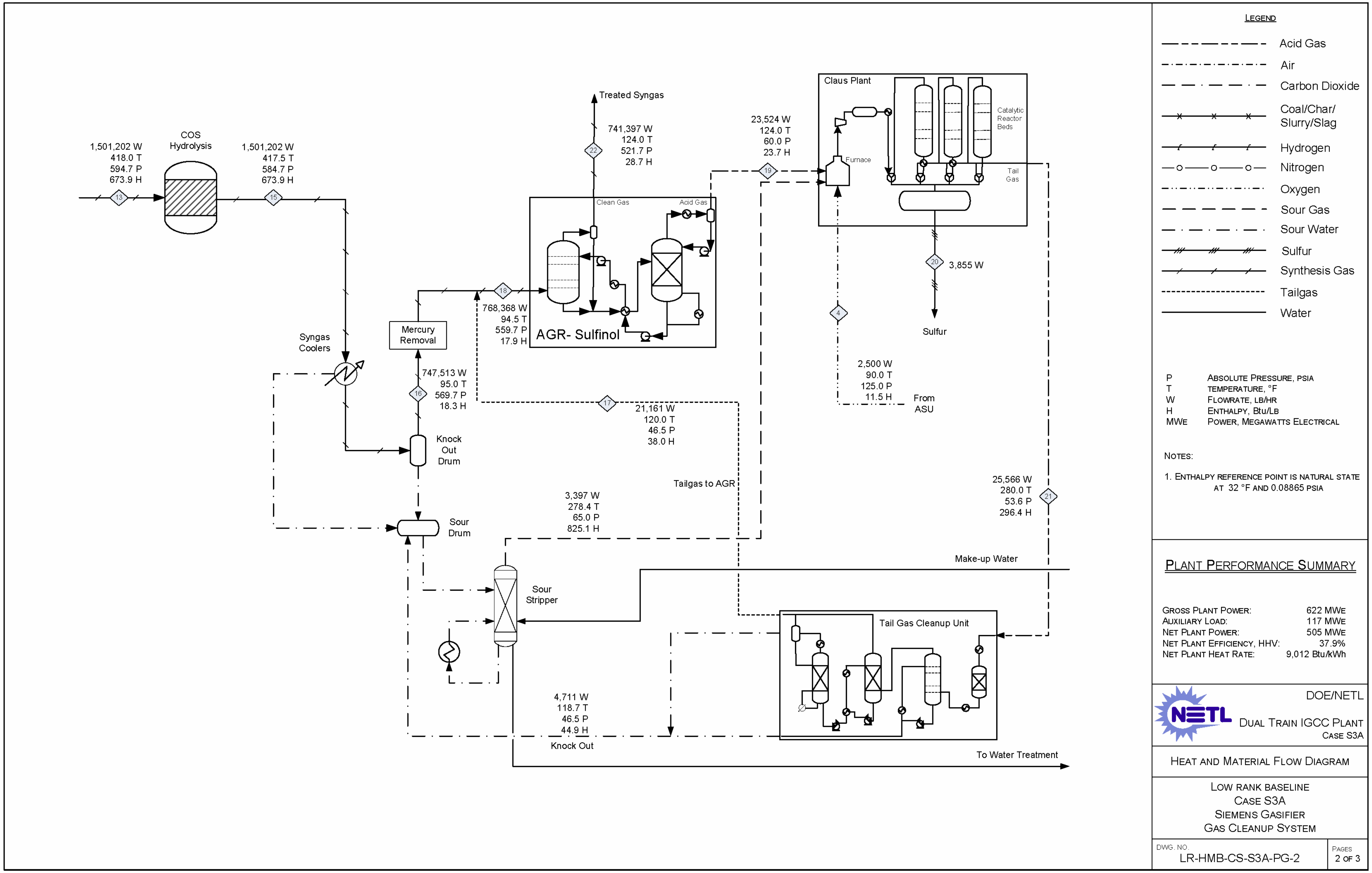


Exhibit 3-94 Case S3A Heat and Mass Balance (Continued)

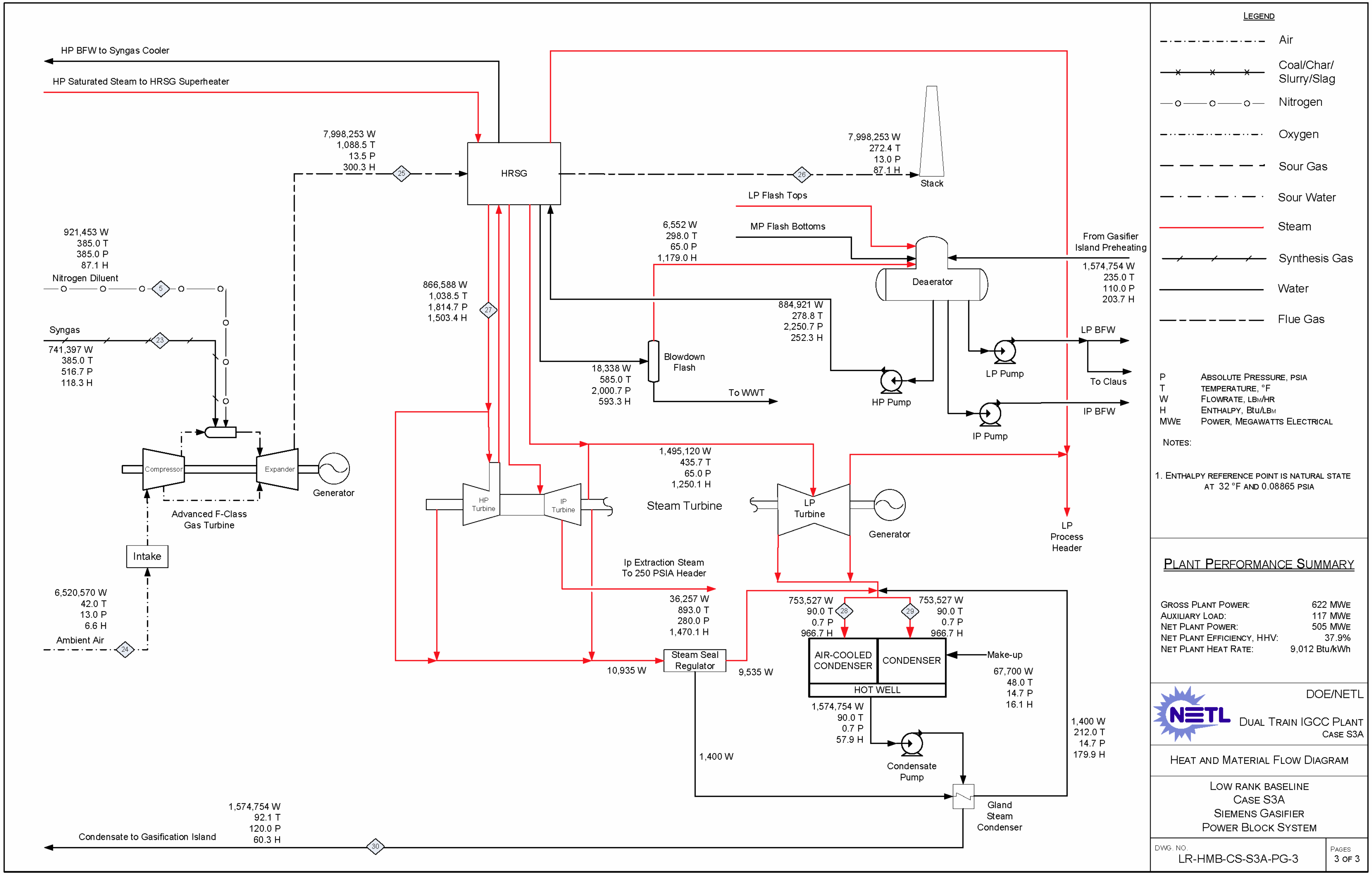


Exhibit 3-95 Case L3A Heat and Mass Balance

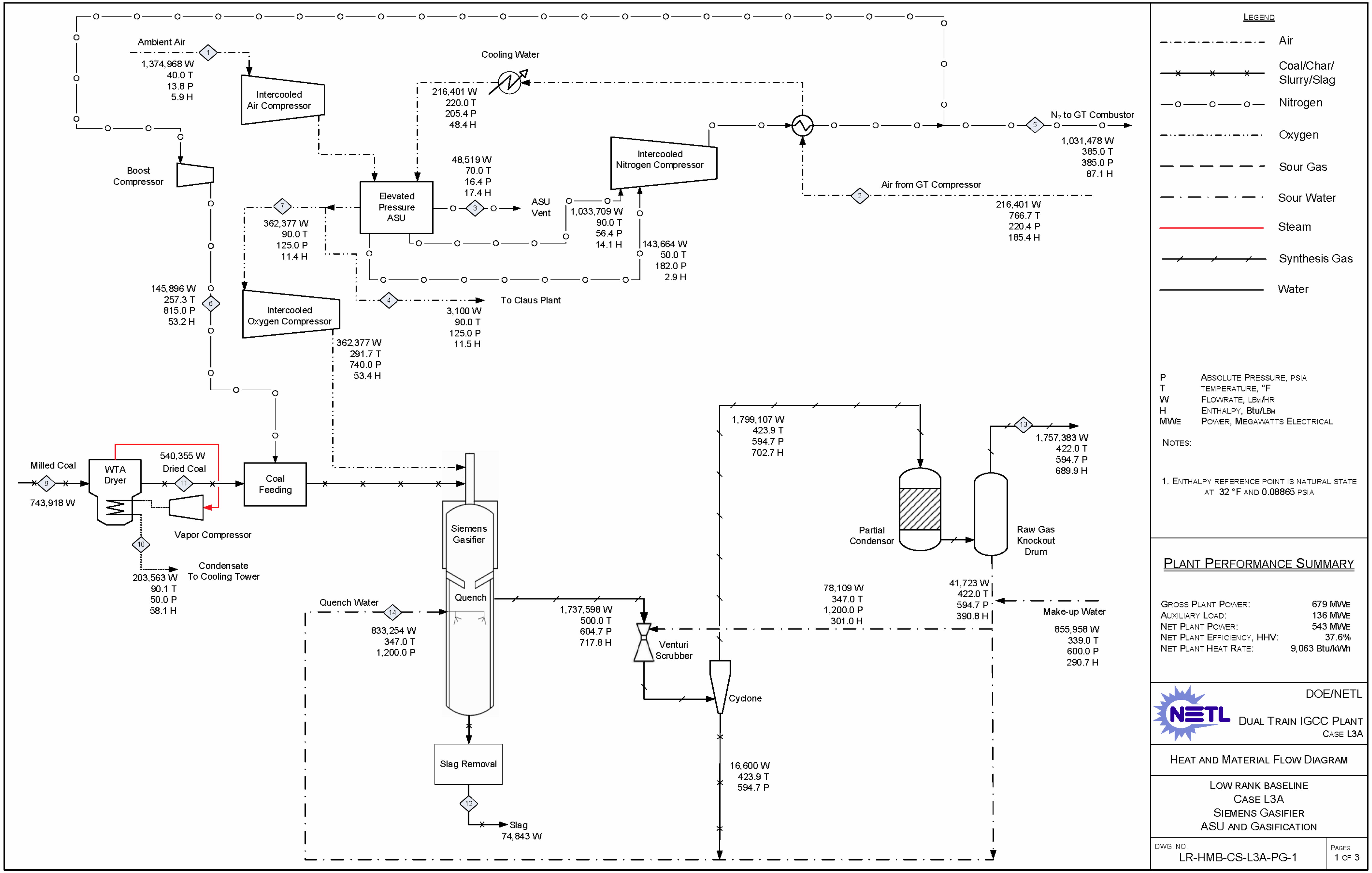


Exhibit 3-95 Case L3A Heat and Mass Balance (Continued)

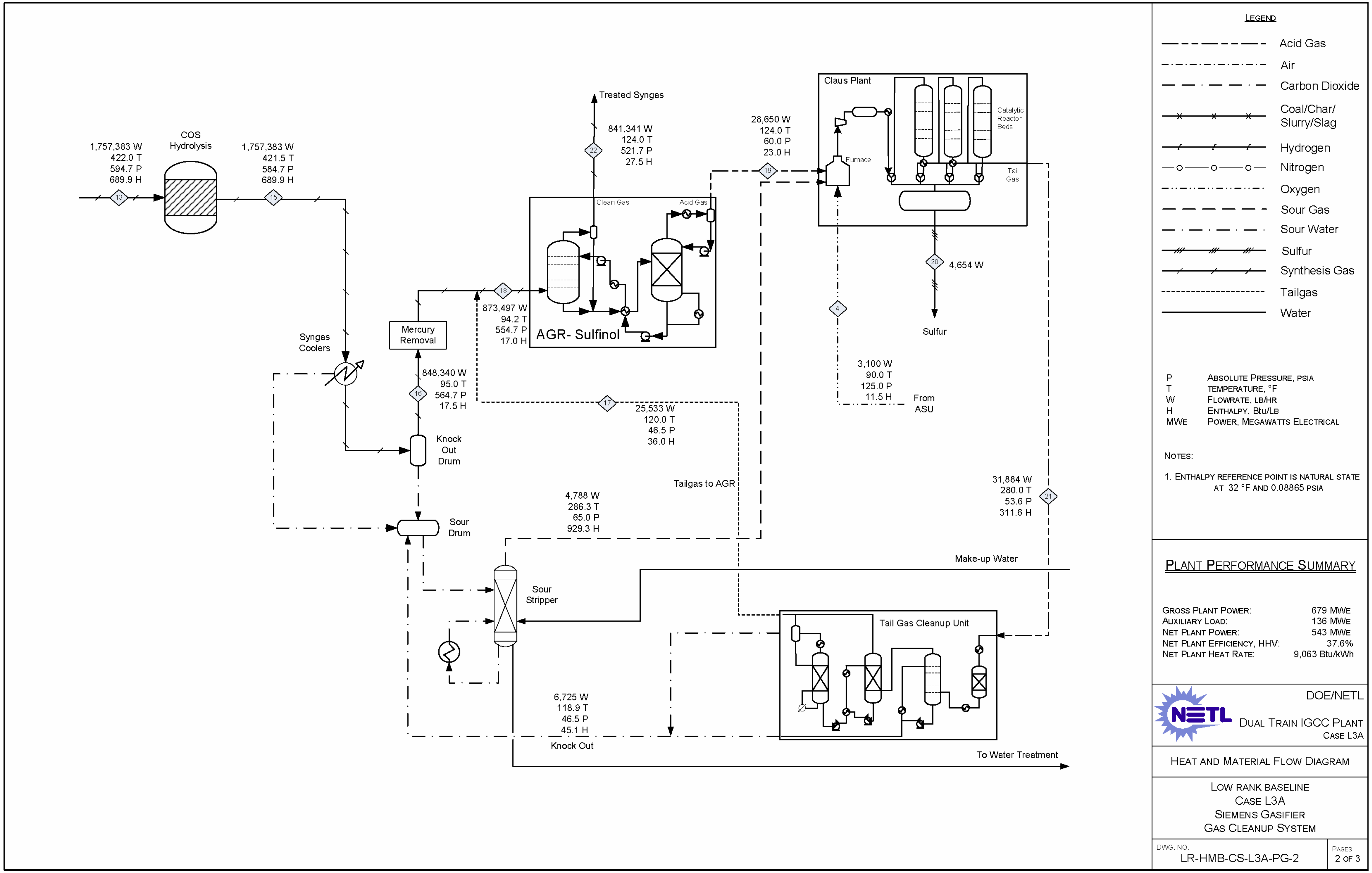


Exhibit 3-95 Case L3A Heat and Mass Balance (Continued)

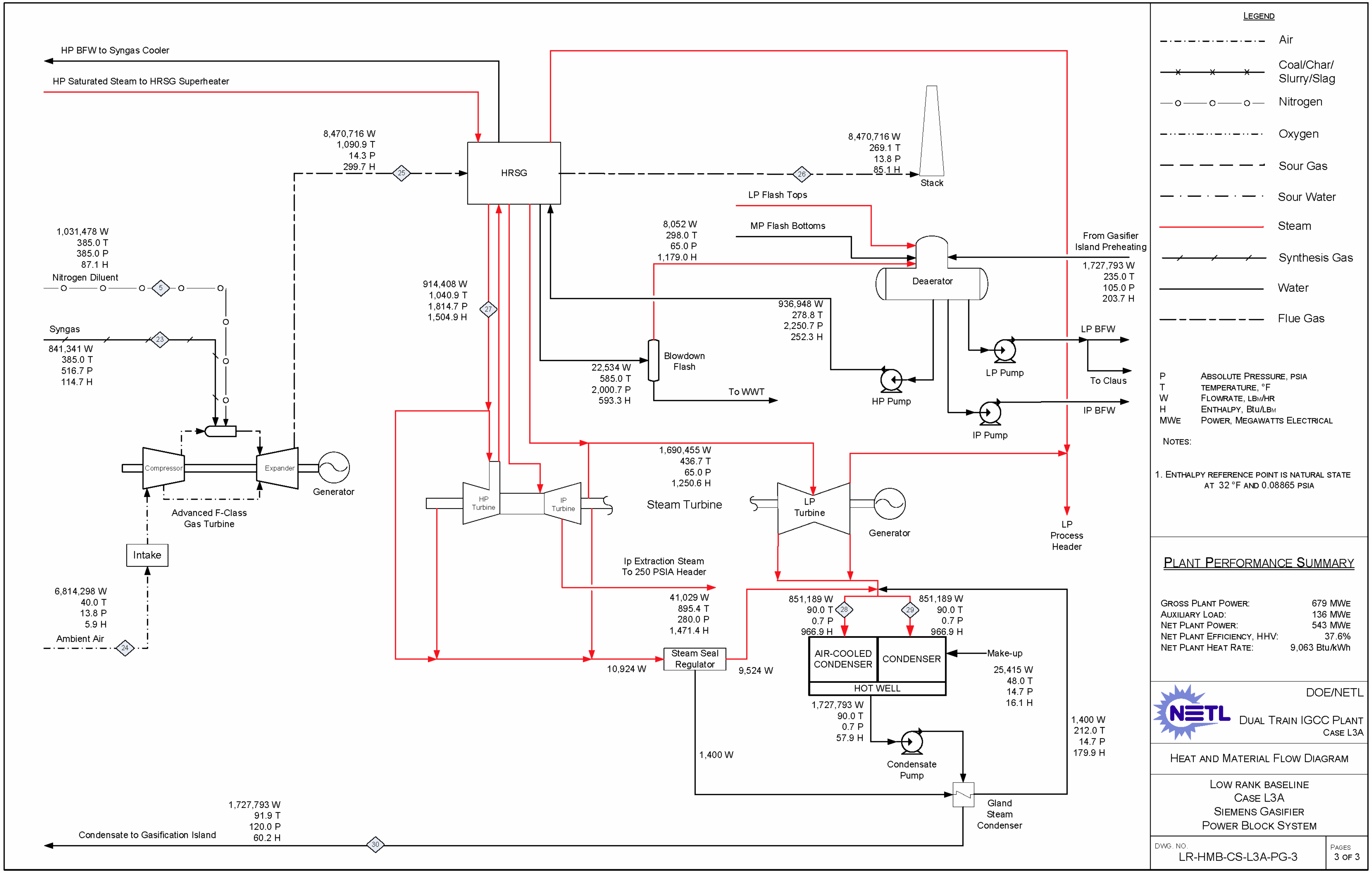


Exhibit 3-96 Cases S3A and L3A Energy Balance

	HHV		Sensible + Latent		Power		Total	
	S3A	L3A	S3A	L3A	S3A	L3A	S3A	L3A
Heat In GJ/hr (MMBtu/hr)								
Coal	4,799 (4,549)	5,194 (4,923)	2.5 (2.3)	3.0 (2.8)	0 (0)	0 (0)	4,801 (4,551)	5,197 (4,925)
ASU Air	0 (0)	0 (0)	8.3 (7.9)	8.6 (8.1)	0 (0)	0 (0)	8 (8)	9 (8)
GT Air	0 (0)	0 (0)	45.1 (42.8)	42.5 (40.3)	0 (0)	0 (0)	45 (43)	42 (40)
Raw Water Makeup	0 (0)	0 (0)	11.9 (11.3)	9.2 (8.7)	0 (0)	0 (0)	12 (11)	9 (9)
Auxiliary Power	0 (0)	0 (0)	0 (0)	0 (0)	423 (401)	488 (463)	423 (401)	488 (463)
Totals	**4,799 (4,549)**	**5,194 (4,923)**	**67.8 (64.3)**	**63.3 (60.0)**	**423 (401)**	**488 (463)**	**5,290 (5,014)**	**5,745 (5,445)**
Heat Out GJ/hr (MMBtu/hr)								
ASU Intercoolers	0 (0)	0 (0)	178 (169)	199 (189)	0 (0)	0 (0)	178 (169)	199 (189)
ASU Vent	0 (0)	0 (0)	0.8 (0.7)	0.9 (0.8)	0 (0)	0 (0)	1 (1)	1 (1)
Slag	20 (19)	22 (21)	4.4 (4.2)	7.4 (7.0)	0 (0)	0 (0)	24 (23)	29 (28)
Sulfur	16 (15)	20 (19)	0.2 (0.2)	0.2 (0.2)	0 (0)	0 (0)	16 (16)	20 (19)
Cooling Tower Blowdown	0 (0)	0 (0)	11.3 (10.7)	11.7 (11.1)	0 (0)	0 (0)	11 (11)	12 (11)
HRSG Flue Gas	0 (0)	0 (0)	735 (697)	760 (721)	0 (0)	0 (0)	735 (697)	760 (721)
Condenser	0 (0)	0 (0)	1,442 (1,367)	1,631 (1,546)	0 (0)	0 (0)	1,443 (1,368)	1,631 (1,546)
Auxiliary Cooling Load	0 (0)	0 (0)	197 (187)	158 (150)	0 (0)	0 (0)	197 (187)	158 (150)
Electrical Generator Loss	0 (0)	0 (0)	0 (0)	0 (0)	34 (32)	37 (35)	34 (32)	37 (35)
Process Losses	0 (0)	0 (0)	411 (390)	454 (430)			*411 (390)*	*454 (430)*
Power	0 (0)	0 (0)	0 (0)	0 (0)	2,240 (2,123)	2,444 (2,316)	2,240 (2,123)	2,444 (2,316)
Totals	**36 (34)**	**41 (39)**	**2,980 (2,824)**	**3,223 (3,055)**	**2,274 (2,155)**	**2,481 (2,351)**	**5,290 (5,014)**	**5,745 (5,445)**

3.4.6 Case S3A and L3A Equipment Lists

Major equipment items for the SFG 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	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	73 tonne (80 ton)	2	1
9	Feeder	Vibratory	200 tonne/hr (220 tph)	281 tonne/hr (310 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	399 tonne/hr (440 tph)	553 tonne/hr (610 tph)	1	0
11	Crusher Tower	N/A	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	200 tonne (220 ton)	281 tonne (310 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	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	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	399 tonne/hr (440 tph)	553 tonne/hr (610 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	399 tonne/hr (440 tph)	553 tonne/hr (610 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	907 tonne (1,000 ton)	1,270 tonne (1,400 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	91 tonne/hr (100 tph)	127 tonne/hr (140 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	263 tonne/hr (290 tph)	372 tonne/hr (410 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	526 tonne (580 ton)	744 tonne (820 ton)	1	0
4	Weigh Feeder	Belt	136 tonne/hr (150 tph)	181 tonne/hr (200 tph)	2	0
5	Pulverizer	Rotary	136 tonne/hr (150 tph)	181 tonne/hr (200 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	263 tonne (290 ton)	372 tonne (410 ton)	2	0
7	Coal Preheater	Water Heated Horizontal Rotary Kiln	Coal feed: 263 tonne/hr (290 tph) Heat duty: 29.5 GJ/hr (28.0 MMBtu/hr)	Coal feed: 372 tonne/hr (410 tph) Heat duty: 45.8 GJ/hr (43.4 MMBtu/hr)	1	0
8	Coal Dryer	Fluidized Bed with Internal Coils	Coal feed: 136 tonne/hr (150 tph) Heat duty: 74.2 GJ/hr (70.3 MMBtu/hr) Bed diameter: 11.9 m (39 ft)	Coal feed: 181 tonne/hr (200 tph) Heat duty: 133.0 GJ/hr (126.1 MMBtu/hr) Bed diameter: 14.0 m (46 ft)	2	0
9	Steam Compressor	Reciprocating, Multi-Stage	555 m^3/min (19,610 scfm) Suction - 0.09 MPa (13 psia) Discharge - 0.72 MPa (105 psia)	1012 m^3/min (35,730 scfm) Suction - 0.10 MPa (13.8 psia) Discharge - 0.52 MPa (75 psia)	2	0
10	Dryer Exhaust Filter	Hot Baghouse	Steam - 27,851 kg/hr (61,400 lb/hr) Temperature - 107°C (225°F)	Steam - 50,802 kg/hr (112,000 lb/hr) Temperature - 107°C (225°F)	2	0

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
11	Dry Coal Cooler	Water Cooled Horizontal Rotary Kiln	209 tonne/hr (231 tph) Heat duty - 12 GJ/hr (11 MMBtu/hr)	270 tonne/hr (297 tph) Heat duty - 17 GJ/hr (16 MMBtu/hr)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	635,949 liters (168,000 gal)	749,512 liters (198,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,587 lpm @ 91 m H_2O (1,740 gpm @ 300 ft H_2O)	7,230 lpm @ 91 m H_2O (1,910 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	469,015 kg/hr (1,034,000 lb/hr)	511,652 kg/hr (1,128,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	4,240 lpm @ 27 m H_2O (1,120 gpm @ 90 ft H_2O)	4,732 lpm @ 27 m H_2O (1,250 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 3,823 lpm @ 1,890 m H_2O (1,010 gpm @ 6,200 ft H_2O)	HP water: 4,050 lpm @ 1,890 m H_2O (1,070 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,098 lpm @ 223 m H_2O (290 gpm @ 730 ft H_2O)	IP water: 2,006 lpm @ 223 m H_2O (530 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	221 GJ/hr (209 MMBtu/hr) each	211 GJ/hr (200 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	79,115 lpm @ 21 m H_2O (20,900 gpm @ 70 ft H_2O)	75,708 lpm @ 21 m H_2O (20,000 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	2,385 lpm @ 18 m H_2O (630 gpm @ 60 ft H_2O)	2,347 lpm @ 18 m H_2O (620 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,385 lpm @ 268 m H_2O (630 gpm @ 880 ft H_2O)	2,347 lpm @ 268 m H_2O (620 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	3,520 lpm @ 49 m H_2O (930 gpm @ 160 ft H_2O)	4,088 lpm @ 49 m H_2O (1,080 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,684,508 liter (445,000 gal)	1,957,058 liter (517,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	189 lpm (50 gpm)	189 lpm (50 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,087 tonne/day, 4.2 MPa (2,300 tpd, 605 psia)	2,994 tonne/day, 4.2 MPa (3,300 tpd, 605 psia)	3	0
2	Synthesis Gas Cyclone	High efficiency	247,661 kg/hr (546,000 lb/hr) Design efficiency 90%	288,938 kg/hr (637,000 lb/hr) Design efficiency 90%	3	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical up flow	247,661 kg/hr (546,000 lb/hr)	288,938 kg/hr (637,000 lb/hr)	3	0
4	Raw Gas Coolers	Shell and tube with condensate drain	224,982 kg/hr (496,000 lb/hr)	244,033 kg/hr (538,000 lb/hr)	8	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	185,973 kg/hr, 51°C, 3.6 MPa (410,000 lb/hr, 124°F, 522 psia)	211,828 kg/hr, 35°C, 3.8 MPa (467,000 lb/hr, 95°F, 555 psia)	2	0
6	Synthesis Gas Reheater	Shell and tube	185,066 kg/hr (408,000 lb/hr)	210,013 kg/hr (463,000 lb/hr)	2	0
7	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	371,946 kg/hr (820,000 lb/hr) syngas	433,634 kg/hr (956,000 lb/hr) syngas	2	0
8	ASU Main Air Compressor	Centrifugal, multi-stage	4,106 m^3/min @ 1.3 MPa (145,000 scfm @ 190 psia)	4,701 m^3/min @ 1.3 MPa (166,000 scfm @ 190 psia)	2	0
9	Cold Box	Vendor design	1,905 tonne/day (2,100 tpd) of 95% purity oxygen	2,177 tonne/day (2,400 tpd) of 95% purity oxygen	2	2

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
10	Oxygen Compressor	Centrifugal, multi-stage	963 m^3/min (34,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	1,104 m^3/min (39,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
11	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,171 m^3/min (112,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	3,625 m^3/min (128,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
12	Secondary Nitrogen Compressor	Centrifugal, single-stage	453 m^3/min (16,000 scfm) Suction - 2.7 MPa (390 psia) Discharge - 5.7 MPa (820 psia)	510 m^3/min (18,000 scfm) Suction - 2.7 MPa (390 psia) Discharge - 5.7 MPa (820 psia)	2	0
13	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	46,266 kg/hr, 411°C, 1.4 MPa (102,000 lb/hr, 771°F, 208 psia)	53,978 kg/hr, 408°C, 1.5 MPa (119,000 lb/hr, 767°F, 220 psia)	2	0
14	Transport Nitrogen Boost Compressor	Centrifugal, multi-stage	368 m^3/min (13,000 scfm) Suction - 2.7 MPa (389 psia) Discharge - 5.6 MPa (815 psia)	513 m^3/min (18,100 scfm) Suction - 2.7 MPa (389 psia) Discharge - 5.6 MPa (815 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	186,426 kg/hr (411,000 lb/hr) 35°C (95°F) 3.9 MPa (570 psia)	211,828 kg/hr (467,000 lb/hr) 35°C (95°F) 3.9 MPa (565 psia)	2	0
2	Sulfur Plant	Claus type	46 tonne/day (51 tpd)	56 tonne/day (61 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	374,667 kg/hr (826,000 lb/hr) 216°C (420°F) 4.1 MPa (590 psia)	438,624 kg/hr (967,000 lb/hr) 216°C (420°F) 4.1 MPa (590 psia)	2	0
4	Acid Gas Removal Plant	Sulfinol	191,870 kg/hr (423,000 lb/hr) 35°C (94°F) 3.9 MPa (560 psia)	217,724 kg/hr (480,000 lb/hr) 35°C (94°F) 3.8 MPa (555 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	11,596 kg/hr (25,566 lb/hr) 232°C (450°F) 0.3 MPa (48.6 psia)	14,462 kg/hr (31,884 lb/hr) 232°C (450°F) 0.3 MPa (48.6 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	9,551 kg/hr (21,056 lb/hr)	11,411 kg/hr (25,157 lb/hr)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	S3A Design Condition	L3A Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	210 MW	225 MW	2	0
2	Gas Turbine Generator	TEWAC	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	250 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.6 m (20 ft) diameter	76 m (250 ft) high x 8.6 m (20 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 216,193 kg/hr, 12.4 MPa/559°C (476,623 lb/hr, 1,800 psig/1,038°F) Reheat steam - 199,389 kg/hr, 3.1 MPa/559°C (439,577 lb/hr, 452 psig/1,038°F)	Main steam - 228,123 kg/hr, 12.4 MPa/560°C (502,924 lb/hr, 1,800 psig/1,041°F) Reheat steam - 221,125 kg/hr, 3.1 MPa/560°C (487,498 lb/hr, 452 psig/1,041°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Steam Turbine	Commercially available	218 MW 12.4 MPa/559°C/559°C (1,800 psig/ 1,038°F/1,038°F)	244 MW 12.4 MPa/560°C/560°C (1,800 psig/ 1,041°F/1,041°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	270 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	897 GJ/hr (850 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 8°C (47°F), Water temperature rise 11°C (20°F)	1	0

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
4	Air-cooled Condenser	---	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	897 GJ/hr (850 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 4°C (40°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Circulating Water Pumps	Vertical, wet pit	230,910 lpm @ 30 m (61,000 gpm @ 100 ft)	249,837 lpm @ 30 m (66,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) WB / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,298 GJ/hr (1,230 MMBtu/hr) heat duty	2°C (36°F) WB / 8°C (47°F) CWT / 19°C (67°F) HWT / 1,382 GJ/hr (1,310 MMBtu/hr) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	Slag Quench Tank	Water bath	143,846 liters (38,000 gal)	238,481 liters (63,000 gal)	3	0
2	Slag Crusher	Roll	7 tonne/hr (8 tph)	13 tonne/hr (14 tph)	3	0
3	Slag Depressurizer	Proprietary	7 tonne/hr (8 tph)	13 tonne/hr (14 tph)	3	0
4	Slag Receiving Tank	Horizontal, weir	87,064 liters (23,000 gal)	143,846 liters (38,000 gal)	3	0
5	Black Water Overflow Tank	Shop fabricated	37,854 liters (10,000 gal)	64,352 liters (17,000 gal)	3	
6	Slag Conveyor	Drag chain	7 tonne/hr (8 tph)	13 tonne/hr (14 tph)	3	0
7	Slag Separation Screen	Vibrating	7 tonne/hr (8 tph)	13 tonne/hr (14 tph)	3	0
8	Coarse Slag Conveyor	Belt/bucket	7 tonne/hr (8 tph)	13 tonne/hr (14 tph)	3	0
9	Fine Ash Settling Tank	Vertical, gravity	121,133 liters (32,000 gal)	204,412 liters (54,000 gal)	3	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	3	2
11	Grey Water Storage Tank	Field erected	37,854 liters (10,000 gal)	64,352 liters (17,000 gal)	3	0
12	Grey Water Pumps	Centrifugal	151 lpm @ 424 m H_2O (40 gpm @ 1,390 ft H_2O)	227 lpm @ 424 m H_2O (60 gpm @ 1,390 ft H_2O)	3	3
13	Slag Storage Bin	Vertical, field erected	544 tonne (600 tons)	907 tonne (1,000 tons)	3	0
14	Unloading Equipment	Telescoping chute	91 tonne/hr (100 tph)	154 tonne/hr (170 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	S3A Design Conditions	L3A Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	24 kV/345 kV, 250 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	24 kV/345 kV, 270 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 52 MVA, 3-ph, 60 Hz	345 kV/13.8 kV, 60 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 27 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	S3A Design Conditions	L3A 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 S3A and L3A Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-97 shows the total capital cost summary organized by cost account for the PRB coal case (S3A) and Exhibit 3-101 shows the same information for the NDL coal case (L3A). A more detailed breakdown of the capital costs is shown in Exhibit 3-98 for S3A and Exhibit 3-102 for L3A. Exhibit 3-99 and Exhibit 3-103 show the calculation and addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-100 shows the initial and annual O&M costs for Case S3A and Exhibit 3-104 shows the same information for Case L3A.

The estimated TOC of the SFG with no CO_2 capture using PRB coal is $3,185/kW and using lignite coal is $3,239/kW. Process contingency represents 2 percent, project contingency represents 11 percent, and owner's costs represent 18 percent of TOC in both cases. The COE is 86.8 mills/kWh in the PRB case and 87.3 mills/kWh in the lignite case.

Exhibit 3-97 Case S3A Total Plant Cost Summary

	Client:	USDOE/NETL							Report Date:	2009-Oct-09		
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S3A - Siemens 504 MW IGCC w/o CO2										
	Plant Size:	504.7	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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	$15,069	$2,800	$11,686	$0	$0	$29,555	$2,683	$0	$6,447	$38,685	$77
2	COAL & SORBENT PREP & FEED	$113,213	$9,434	$19,316	$0	$0	$141,963	$12,316	$0	$30,856	$185,135	$367
3	FEEDWATER & MISC. BOP SYSTEMS	$6,625	$5,455	$6,288	$0	$0	$18,368	$1,730	$0	$4,587	$24,684	$49
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$112,359	$0	$52,484	$0	$0	$164,843	$14,646	$24,727	$30,632	$234,848	$465
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	$147,856	$0	w/equip.	$0	$0	$147,856	$14,332	$0	$16,219	$178,406	$353
4.4-4.9	Other Gasification Equipment	$27,422	$12,190	$17,132	$0	$0	$56,744	$5,433	$0	$13,350	$75,527	$150
	SUBTOTAL 4	$287,637	$12,190	$69,616	$0	$0	$369,443	$34,410	$24,727	$60,201	$488,782	$968
5A	Gas Cleanup & Piping	$44,796	$2,573	$43,329	$0	$0	$90,698	$8,770	$79	$20,056	$119,603	$237
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	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$230
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6	$85,752	$806	$7,162	$0	$0	$93,720	$8,883	$4,601	$11,092	$118,296	$234
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,576	$0	$4,632	$0	$0	$37,208	$3,538	$0	$4,075	$44,820	$89
7.2-7.9	Ductwork and Stack	$3,459	$2,466	$3,262	$0	$0	$9,187	$852	$0	$1,635	$11,674	$23
	SUBTOTAL 7	$36,035	$2,466	$7,894	$0	$0	$46,394	$4,390	$0	$5,709	$56,494	$112
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,782	$0	$3,965	$0	$0	$27,747	$2,662	$0	$3,041	$33,450	$66
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$34,018	$811	$10,715	$0	$0	$45,544	$4,438	$0	$10,082	$60,065	$119
	SUBTOTAL 8	$57,800	$811	$14,680	$0	$0	$73,292	$7,100	$0	$13,123	$93,515	$185
9	COOLING WATER SYSTEM	$6,387	$6,453	$5,413	$0	$0	$18,252	$1,695	$0	$4,097	$24,044	$48
10	ASH/SPENT SORBENT HANDLING SYS	$20,248	$1,402	$10,041	$0	$0	$31,692	$3,041	$0	$3,763	$38,496	$76
11	ACCESSORY ELECTRIC PLANT	$25,991	$10,114	$20,028	$0	$0	$56,133	$4,830	$0	$11,520	$72,483	$144
12	INSTRUMENTATION & CONTROL	$9,586	$1,763	$6,176	$0	$0	$17,526	$1,588	$876	$3,331	$23,321	$46
13	IMPROVEMENTS TO SITE	$3,069	$1,809	$7,572	$0	$0	$12,450	$1,229	$0	$4,104	$17,782	$35
14	BUILDINGS & STRUCTURES	$0	$5,974	$6,769	$0	$0	$12,743	$1,160	$0	$2,286	$16,188	$32
	TOTAL COST	$712,207	$64,051	$235,970	$0	$0	$1,012,228	$93,824	$30,283	$181,172	$1,317,507	$2,610

Exhibit 3-98 Case S3A Total Plant Cost Details

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S3A - Siemens 504 MW IGCC w/o CO2										
	Plant Size:	504.7	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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	$3,957	$0	$1,934	$0	$0	$5,891	$528	$0	$1,284	$7,702	$15
1.2	Coal Stackout & Reclaim	$5,114	$0	$1,240	$0	$0	$6,353	$557	$0	$1,382	$8,292	$16
1.3	Coal Conveyors & Yd Crush	$4,754	$0	$1,227	$0	$0	$5,981	$525	$0	$1,301	$7,807	$15
1.4	Other Coal Handling	$1,244	$0	$284	$0	$0	$1,528	$134	$0	$332	$1,994	$4
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	$2,800	$7,002	$0	$0	$9,802	$939	$0	$2,148	$12,890	$26
	SUBTOTAL 1.	**$15,069**	**$2,800**	**$11,686**	**$0**	**$0**	**$29,555**	**$2,683**	**$0**	**$6,447**	**$38,685**	**$77**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$45,578	$2,738	$6,641	$0	$0	$54,958	$4,742	$0	$11,940	$71,640	$142
2.2	Prepared Coal Storage & Feed	$1,959	$469	$307	$0	$0	$2,736	$234	$0	$594	$3,564	$7
2.3	Dry Coal Injection System	$64,488	$748	$5,989	$0	$0	$71,226	$6,135	$0	$15,472	$92,833	$184
2.4	Misc.Coal Prep & Feed	$1,187	$864	$2,590	$0	$0	$4,641	$427	$0	$1,014	$6,081	$12
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	$4,614	$3,788	$0	$0	$8,403	$778	$0	$1,836	$11,017	$22
	SUBTOTAL 2.	**$113,213**	**$9,434**	**$19,316**	**$0**	**$0**	**$141,963**	**$12,316**	**$0**	**$30,856**	**$185,135**	**$367**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,038	$3,501	$1,848	$0	$0	$7,387	$684	$0	$1,614	$9,686	$19
3.2	Water Makeup & Pretreating	$367	$38	$205	$0	$0	$610	$58	$0	$200	$869	$2
3.3	Other Feedwater Subsystems	$1,115	$377	$339	$0	$0	$1,831	$165	$0	$399	$2,395	$5
3.4	Service Water Systems	$210	$432	$1,500	$0	$0	$2,142	$209	$0	$705	$3,056	$6
3.5	Other Boiler Plant Systems	$1,126	$436	$1,082	$0	$0	$2,644	$251	$0	$579	$3,474	$7
3.6	FO Supply Sys & Nat Gas	$286	$541	$504	$0	$0	$1,332	$128	$0	$292	$1,752	$3
3.7	Waste Treatment Equipment	$513	$0	$313	$0	$0	$825	$80	$0	$272	$1,177	$2
3.8	Misc. Power Plant Equipment	$969	$130	$497	$0	$0	$1,596	$154	$0	$525	$2,275	$5
	SUBTOTAL 3.	**$6,625**	**$5,455**	**$6,288**	**$0**	**$0**	**$18,368**	**$1,730**	**$0**	**$4,587**	**$24,684**	**$49**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Siemen	$112,359	$0	$52,484	$0	$0	$164,843	$14,646	$24,727	$30,632	$234,848	$465
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$147,856	$0	w/equip.	$0	$0	$147,856	$14,332	$0	$16,219	$178,406	$353
4.4	LT Heat Recovery & FG Saturation	$27,422	$0	$10,425	$0	$0	$37,847	$3,694	$0	$8,308	$49,849	$99
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	Flare Stack System	$0	$1,519	$618	$0	$0	$2,137	$205	$0	$468	$2,810	$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	$10,671	$6,089	$0	$0	$16,761	$1,534	$0	$4,574	$22,869	$45
	SUBTOTAL 4.	**$287,637**	**$12,190**	**$69,616**	**$0**	**$0**	**$369,443**	**$34,410**	**$24,727**	**$60,201**	**$488,782**	**$968**

Exhibit 3-98 Case S3A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S3A - Siemens 504 MW IGCC w/o CO2										
	Plant Size:	504.7	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	Sulfinol System	$34,319	$0	$29,120	$0	$0	$63,439	$6,135	$0	$13,915	$83,489	$165
5A.2	Elemental Sulfur Plant	$4,779	$952	$6,166	$0	$0	$11,897	$1,156	$0	$2,611	$15,663	$31
5A.3	Mercury Removal	$896	$0	$682	$0	$0	$1,577	$152	$79	$362	$2,170	$4
5A.4	COS Hydrolysis	$4,802	$0	$6,271	$0	$0	$11,074	$1,077	$0	$2,430	$14,581	$29
5A.5	Particulate Removal	$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	$805	$564	$0	$0	$1,369	$127	$0	$299	$1,796	$4
5A.9	HGCU Foundations	$0	$816	$526	$0	$0	$1,341	$123	$0	$439	$1,904	$4
	SUBTOTAL 5A.	**$44,796**	**$2,573**	**$43,329**	**$0**	**$0**	**$90,698**	**$8,770**	**$79**	**$20,056**	**$119,603**	**$237**
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	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$230
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$234**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,576	$0	$4,632	$0	$0	$37,208	$3,538	$0	$4,075	$44,820	$89
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,773	$1,297	$0	$0	$3,070	$270	$0	$668	$4,008	$8
7.4	Stack	$3,459	$0	$1,299	$0	$0	$4,758	$456	$0	$521	$5,736	$11
7.9	HRSG,Duct & Stack Foundations	$0	$693	$666	$0	$0	$1,359	$126	$0	$445	$1,930	$4
	SUBTOTAL 7.	**$36,035**	**$2,466**	**$7,894**	**$0**	**$0**	**$46,394**	**$4,390**	**$0**	**$5,709**	**$56,494**	**$112**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,782	$0	$3,965	$0	$0	$27,747	$2,662	$0	$3,041	$33,450	$66
8.2	Turbine Plant Auxiliaries	$164	$0	$375	$0	$0	$539	$53	$0	$59	$650	$1
8.3a	Condenser & Auxiliaries	$2,973	$0	$950	$0	$0	$3,923	$375	$0	$430	$4,728	$9
8.3b	Air Cooled Condenser	$27,249	$0	$5,463	$0	$0	$32,711	$3,271	$0	$7,197	$43,179	$86
8.4	Steam Piping	$3,633	$0	$2,556	$0	$0	$6,188	$532	$0	$1,680	$8,400	$17
8.9	TG Foundations	$0	$811	$1,372	$0	$0	$2,183	$207	$0	$717	$3,107	$6
	SUBTOTAL 8.	**$57,800**	**$811**	**$14,680**	**$0**	**$0**	**$73,292**	**$7,100**	**$0**	**$13,123**	**$93,515**	**$185**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,417	$0	$803	$0	$0	$5,221	$497	$0	$858	$6,575	$13
9.2	Circulating Water Pumps	$1,142	$0	$67	$0	$0	$1,209	$102	$0	$197	$1,508	$3
9.3	Circ.Water System Auxiliaries	$102	$0	$15	$0	$0	$117	$11	$0	$19	$147	$0
9.4	Circ.Water Piping	$0	$4,276	$1,109	$0	$0	$5,384	$487	$0	$1,174	$7,045	$14
9.5	Make-up Water System	$220	$0	$315	$0	$0	$535	$51	$0	$117	$703	$1
9.6	Component Cooling Water Sys	$505	$604	$430	$0	$0	$1,538	$144	$0	$336	$2,019	$4
9.9	Circ.Water System Foundations	$0	$1,573	$2,675	$0	$0	$4,248	$403	$0	$1,395	$6,046	$12
	SUBTOTAL 9.	**$6,387**	**$6,453**	**$5,413**	**$0**	**$0**	**$18,252**	**$1,695**	**$0**	**$4,097**	**$24,044**	**$48**

Exhibit 3-98 Case S3A Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 2009-Oct-09
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S3A - Siemens 504 MW IGCC w/o CO2
Plant Size: 504.7 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$17,892	$0	$8,824	$0	$0	$26,716	$2,567	$0	$2,928	$32,211	$64
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$534	$0	$581	$0	$0	$1,115	$108	$0	$183	$1,406	$3
10.7	Ash Transport & Feed Equipment	$716	$0	$173	$0	$0	$889	$83	$0	$146	$1,118	$2
10.8	Misc. Ash Handling Equipment	$1,106	$1,355	$405	$0	$0	$2,866	$273	$0	$471	$3,610	$7
10.9	Ash/Spent Sorbent Foundation	$0	$47	$59	$0	$0	$107	$10	$0	$35	$151	$0
	SUBTOTAL 10.	**$20,248**	**$1,402**	**$10,041**	**$0**	**$0**	**$31,692**	**$3,041**	**$0**	**$3,763**	**$38,496**	**$76**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$860	$0	$851	$0	$0	$1,711	$163	$0	$187	$2,062	$4
11.2	Station Service Equipment	$3,746	$0	$338	$0	$0	$4,083	$376	$0	$446	$4,906	$10
11.3	Switchgear & Motor Control	$6,925	$0	$1,259	$0	$0	$8,184	$759	$0	$1,341	$10,285	$20
11.4	Conduit & Cable Tray	$0	$3,217	$10,612	$0	$0	$13,829	$1,338	$0	$3,792	$18,958	$38
11.5	Wire & Cable	$0	$6,146	$4,038	$0	$0	$10,185	$740	$0	$2,731	$13,656	$27
11.6	Protective Equipment	$0	$611	$2,225	$0	$0	$2,837	$277	$0	$467	$3,581	$7
11.7	Standby Equipment	$216	$0	$211	$0	$0	$427	$41	$0	$70	$537	$1
11.8	Main Power Transformers	$14,245	$0	$128	$0	$0	$14,373	$1,087	$0	$2,319	$17,779	$35
11.9	Electrical Foundations	$0	$139	$365	$0	$0	$505	$48	$0	$166	$719	$1
	SUBTOTAL 11.	**$25,991**	**$10,114**	**$20,028**	**$0**	**$0**	**$56,133**	**$4,830**	**$0**	**$11,520**	**$72,483**	**$144**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$946	$0	$632	$0	$0	$1,578	$149	$79	$271	$2,077	$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	$217	$0	$139	$0	$0	$357	$34	$18	$82	$490	$1
12.7	Computer & Accessories	$5,048	$0	$162	$0	$0	$5,210	$478	$260	$595	$6,543	$13
12.8	Instrument Wiring & Tubing	$0	$1,763	$3,605	$0	$0	$5,368	$455	$268	$1,523	$7,615	$15
12.9	Other I & C Equipment	$3,374	$0	$1,639	$0	$0	$5,013	$472	$251	$860	$6,595	$13
	SUBTOTAL 12.	**$9,586**	**$1,763**	**$6,176**	**$0**	**$0**	**$17,526**	**$1,588**	**$876**	**$3,331**	**$23,321**	**$46**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$96	$2,058	$0	$0	$2,154	$214	$0	$710	$3,079	$6
13.2	Site Improvements	$0	$1,713	$2,276	$0	$0	$3,988	$394	$0	$1,315	$5,696	$11
13.3	Site Facilities	$3,069	$0	$3,238	$0	$0	$6,307	$622	$0	$2,079	$9,008	$18
	SUBTOTAL 13.	**$3,069**	**$1,809**	**$7,572**	**$0**	**$0**	**$12,450**	**$1,229**	**$0**	**$4,104**	**$17,782**	**$35**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,057	$2,931	$0	$0	$4,988	$459	$0	$817	$6,264	$12
14.3	Administration Building	$0	$819	$594	$0	$0	$1,413	$126	$0	$231	$1,769	$4
14.4	Circulation Water Pumphouse	$0	$157	$83	$0	$0	$240	$21	$0	$39	$300	$1
14.5	Water Treatment Buildings	$0	$307	$299	$0	$0	$606	$55	$0	$99	$759	$2
14.6	Machine Shop	$0	$419	$287	$0	$0	$706	$63	$0	$115	$884	$2
14.7	Warehouse	$0	$677	$437	$0	$0	$1,113	$99	$0	$182	$1,394	$3
14.8	Other Buildings & Structures	$0	$394	$307	$0	$0	$700	$63	$0	$153	$916	$2
14.9	Waste Treating Building & Str.	$0	$880	$1,682	$0	$0	$2,562	$239	$0	$560	$3,362	$7
	SUBTOTAL 14.	**$0**	**$5,974**	**$6,769**	**$0**	**$0**	**$12,743**	**$1,160**	**$0**	**$2,286**	**$16,188**	**$32**
	TOTAL COST	**$712,207**	**$64,051**	**$235,970**	**$0**	**$0**	**$1,012,228**	**$93,824**	**$30,283**	**$181,172**	**$1,317,507**	**$2,610**

Exhibit 3-99 Case S3A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$11,711	$23
1 Month Variable O&M	$3,023	$6
25% of 1 Months Fuel Cost at 100% CF	$737	$1
2% of TPC	$26,350	$52
Total	**$41,821**	**$83**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,095	$12
0.5% of TPC (spare parts)	$6,588	$13
Total	**$12,682**	**$25**
Initial Cost for Catalyst and Chemicals	**$1,498**	**$3**
Land	**$900**	**$2**
Other Owner's Costs	**$197,626**	**$392**
Financing Costs	**$35,573**	**$70**
Total Owner's Costs	**$290,100**	**$575**
Total Overnight Cost (TOC)	**$1,607,607**	**$3,185**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$1,832,672**	**$3,631**

Exhibit 3-100 Case S3A Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case S3A - Siemens 504 MW IGCC w/o CO2					Heat Rate-net (Btu/kWh):	9,011
					MWe-net:	505
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	34.65	$/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					$5,918,913	$11.727
Maintenance Labor Cost					$12,818,175	$25.397
Administrative & Support Labor					$4,684,272	$9.281
Property Taxes and Insurance					$26,350,141	$52.208
TOTAL FIXED OPERATING COSTS					**$49,771,501**	**$98.614**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$25,115,707**	**$0.00710**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	1,627	1.08	**$0**	**$513,950**	**$0.00015**
Chemicals						
MU & WT Chem.(lbs)	0	9,694	0.17	$0	$489,914	$0.00014
Carbon (Mercury Removal) (lb)	61,010	84	1.05	$64,071	$25,628	$0.00001
COS Catalyst (m3)	523	0.36	2,397.36	$1,253,811	$250,762	$0.00007
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0	$0.00000
Sulfinol Solution (gal)	17,905	12	10.05	$179,922	$35,705	$0.00001
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.	0.70	131.27	$0	$26,903	$0.00001
Subtotal Chemicals				**$1,497,803**	**$828,913**	**$0.00023**
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	84	0.42	$0	$10,178	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	538	16.23	$0	$2,547,879	$0.00072
Subtotal Waste Disposal				**$0**	**$2,558,058**	**$0.00072**
By-products & Emissions						
Sulfur (tons)	0	46	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,497,803**	**$29,016,628**	**$0.00820**
Fuel (ton)	0	6,373	15.22	**$0**	**$28,319,073**	**$0.00801**

Exhibit 3-101 Case L3A Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
TOTAL PLANT COST SUMMARY												
	Case:	Case L3A - Siemens 543 MW IGCC w/o CO2										
	Plant Size:	543.1	MW,net	Estimate Type:	Conceptual			Cost Base (Jun)		2007	($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	$18,570	$3,451	$14,401	$0	$0	**$36,421**	$3,306	$0	$7,945	**$47,672**	$88
2	COAL & SORBENT PREP & FEED	$138,652	$11,733	$23,866	$0	$0	**$174,250**	$15,119	$0	$37,874	**$227,242**	$418
3	FEEDWATER & MISC. BOP SYSTEMS	$6,771	$5,627	$6,359	$0	$0	**$18,757**	$1,766	$0	$4,673	**$25,196**	$46
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Siemen	$112,359	$0	$52,484	$0	$0	**$164,843**	$14,646	$24,727	$30,632	**$234,848**	$432
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$163,595	$0	w/equip.	$0	$0	**$163,595**	$15,857	$0	$17,945	**$197,397**	$363
4.4-4.9	Other Gasification Equipment	$30,620	$14,004	$19,354	$0	$0	**$63,977**	$6,123	$0	$15,075	**$85,175**	$157
	SUBTOTAL 4	**$306,574**	**$14,004**	**$71,838**	**$0**	**$0**	**$392,415**	**$36,626**	**$24,727**	**$63,653**	**$517,421**	**$953**
5A	GAS CLEANUP & PIPING	$49,303	$2,824	$47,777	$0	$0	**$99,904**	$9,661	$85	$22,087	**$131,737**	$243
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	**$92,021**	$8,724	$4,601	$10,535	**$115,881**	$213
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$4
	SUBTOTAL 6	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$218**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,059	$0	$4,843	$0	$0	**$38,902**	$3,699	$0	$4,260	**$46,861**	$86
7.2-7.9	SCR System, Ductwork and Stack	$3,437	$2,450	$3,241	$0	$0	**$9,128**	$847	$0	$1,624	**$11,599**	$21
	SUBTOTAL 7	**$37,496**	**$2,450**	**$8,084**	**$0**	**$0**	**$48,031**	**$4,545**	**$0**	**$5,885**	**$58,461**	**$108**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,733	$0	$4,347	$0	$0	**$30,080**	$2,886	$0	$3,297	**$36,263**	$67
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$36,939	$882	$11,553	$0	$0	**$49,374**	$4,815	$0	$10,913	**$65,102**	$120
	SUBTOTAL 8	**$62,673**	**$882**	**$15,899**	**$0**	**$0**	**$79,454**	**$7,701**	**$0**	**$14,210**	**$101,365**	**$187**
9	COOLING WATER SYSTEM	$6,676	$6,750	$5,627	$0	$0	**$19,053**	$1,769	$0	$4,272	**$25,094**	$46
10	ASH/SPENT SORBENT HANDLING SYS	$27,975	$1,864	$13,870	$0	$0	**$43,710**	$4,194	$0	$5,176	**$53,079**	$98
11	ACCESSORY ELECTRIC PLANT	$27,937	$10,833	$21,400	$0	$0	**$60,169**	$5,175	$0	$12,351	**$77,695**	$143
12	INSTRUMENTATION & CONTROL	$9,866	$1,815	$6,357	$0	$0	**$18,037**	$1,635	$902	$3,428	**$24,001**	$44
13	IMPROVEMENTS TO SITE	$3,198	$1,885	$7,892	$0	$0	**$12,975**	$1,281	$0	$4,277	**$18,533**	$34
14	BUILDINGS & STRUCTURES	$0	$6,155	$7,032	$0	$0	**$13,187**	$1,201	$0	$2,364	**$16,752**	$31
	TOTAL COST	**$781,441**	**$71,079**	**$257,562**	**$0**	**$0**	**$1,110,083**	**$102,860**	**$30,314**	**$199,286**	**$1,442,543**	**$2,656**

Exhibit 3-102 Case L3A Total Plant Cost Details

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case L3A - Siemens 543 MW IGCC w/o CO2										
	Plant Size:	543.1	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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											
1.1	Coal Receive & Unload	$4,877	$0	$2,383	$0	$0	$7,260	$650	$0	$1,582	$9,492	$17
1.2	Coal Stackout & Reclaim	$6,302	$0	$1,528	$0	$0	$7,829	$686	$0	$1,703	$10,218	$19
1.3	Coal Conveyors & Yd Crush	$5,859	$0	$1,512	$0	$0	$7,370	$647	$0	$1,603	$9,621	$18
1.4	Other Coal Handling	$1,533	$0	$350	$0	$0	$1,883	$165	$0	$409	$2,457	$5
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	$3,451	$8,629	$0	$0	$12,079	$1,158	$0	$2,647	$15,885	$29
	SUBTOTAL 1.	**$18,570**	**$3,451**	**$14,401**	**$0**	**$0**	**$36,421**	**$3,306**	**$0**	**$7,945**	**$47,672**	**$88**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$56,930	$3,420	$8,295	$0	$0	$68,645	$5,924	$0	$14,914	$89,482	$165
2.2	Prepared Coal Storage & Feed	$2,366	$566	$371	$0	$0	$3,303	$282	$0	$717	$4,303	$8
2.3	Dry Coal Injection System	$77,873	$904	$7,232	$0	$0	$86,009	$7,408	$0	$18,683	$112,100	$206
2.4	Misc.Coal Prep & Feed	$1,483	$1,079	$3,235	$0	$0	$5,797	$533	$0	$1,266	$7,596	$14
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	$5,764	$4,732	$0	$0	$10,496	$972	$0	$2,294	$13,761	$25
	SUBTOTAL 2.	**$138,652**	**$11,733**	**$23,866**	**$0**	**$0**	**$174,250**	**$15,119**	**$0**	**$37,874**	**$227,242**	**$418**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,125	$3,648	$1,926	$0	$0	$7,699	$713	$0	$1,682	$10,095	$19
3.2	Water Makeup & Pretreating	$359	$37	$200	$0	$0	$597	$57	$0	$196	$849	$2
3.3	Other Feedwater Subsystems	$1,162	$393	$353	$0	$0	$1,909	$172	$0	$416	$2,496	$5
3.4	Service Water Systems	$205	$423	$1,467	$0	$0	$2,095	$204	$0	$690	$2,989	$6
3.5	Other Boiler Plant Systems	$1,101	$427	$1,058	$0	$0	$2,586	$245	$0	$566	$3,397	$6
3.6	FO Supply Sys & Nat Gas	$298	$563	$525	$0	$0	$1,385	$133	$0	$304	$1,823	$3
3.7	Waste Treatment Equipment	$501	$0	$306	$0	$0	$807	$79	$0	$266	$1,151	$2
3.8	Misc. Power Plant Equipment	$1,020	$137	$524	$0	$0	$1,680	$162	$0	$553	$2,395	$4
	SUBTOTAL 3.	**$6,771**	**$5,627**	**$6,359**	**$0**	**$0**	**$18,757**	**$1,766**	**$0**	**$4,673**	**$25,196**	**$46**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Siemen	$112,359	$0	$52,484	$0	$0	$164,843	$14,646	$24,727	$30,632	$234,848	$432
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$163,595	$0	w/equip.	$0	$0	$163,595	$15,857	$0	$17,945	$197,397	$363
4.4	LT Heat Recovery & FG Saturation	$30,620	$0	$11,640	$0	$0	$42,260	$4,124	$0	$9,277	$55,661	$102
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	Flare Stack System	$0	$1,693	$689	$0	$0	$2,382	$228	$0	$522	$3,133	$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	$12,310	$7,024	$0	$0	$19,335	$1,770	$0	$5,276	$26,381	$49
	SUBTOTAL 4.	**$306,574**	**$14,004**	**$71,838**	**$0**	**$0**	**$392,415**	**$36,626**	**$24,727**	**$63,653**	**$517,421**	**$953**

Exhibit 3-102 Case L3A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
TOTAL PLANT COST SUMMARY												
	Case:	Case L3A - Siemens 543 MW IGCC w/o CO2										
	Plant Size:	543.1	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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 System	$37,542	$0	$31,855	$0	$0	$69,397	$6,711	$0	$15,222	$91,330	$168
5A.2	Elemental Sulfur Plant	$5,422	$1,081	$6,995	$0	$0	$13,498	$1,311	$0	$2,962	$17,771	$33
5A.3	Mercury Removal	$961	$0	$731	$0	$0	$1,692	$163	$85	$388	$2,328	$4
5A.4	COS Hydrolysis	$5,378	$0	$7,023	$0	$0	$12,401	$1,206	$0	$2,721	$16,329	$30
5A.5	Particulate Removal	$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	$866	$607	$0	$0	$1,473	$137	$0	$322	$1,931	$4
5A.9	HGCU Foundations	$0	$877	$566	$0	$0	$1,443	$133	$0	$473	$2,048	$4
	SUBTOTAL 5A.	**$49,303**	**$2,824**	**$47,777**	**$0**	**$0**	**$99,904**	**$9,661**	**$85**	**$22,087**	**$131,737**	**$243**
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	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$213
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$4
	SUBTOTAL 6.	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$218**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$34,059	$0	$4,843	$0	$0	$38,902	$3,699	$0	$4,260	$46,861	$86
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,762	$1,289	$0	$0	$3,051	$268	$0	$664	$3,982	$7
7.4	Stack	$3,437	$0	$1,291	$0	$0	$4,728	$453	$0	$518	$5,699	$10
7.9	HRSG,Duct & Stack Foundations	$0	$689	$661	$0	$0	$1,350	$126	$0	$443	$1,918	$4
	SUBTOTAL 7.	**$37,496**	**$2,450**	**$8,084**	**$0**	**$0**	**$48,031**	**$4,545**	**$0**	**$5,885**	**$58,461**	**$108**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$25,733	$0	$4,347	$0	$0	$30,080	$2,886	$0	$3,297	$36,263	$67
8.2	Turbine Plant Auxiliaries	$178	$0	$408	$0	$0	$586	$57	$0	$64	$707	$1
8.3a	Condenser & Auxiliaries	$3,246	$0	$1,037	$0	$0	$4,282	$410	$0	$469	$5,161	$10
8.3b	Air Cooled Condenser	$29,744	$0	$5,963	$0	$0	$35,707	$3,571	$0	$7,855	$47,133	$87
8.4	Steam Piping	$3,772	$0	$2,653	$0	$0	$6,425	$552	$0	$1,744	$8,722	$16
8.9	TG Foundations	$0	$882	$1,491	$0	$0	$2,374	$225	$0	$780	$3,378	$6
	SUBTOTAL 8.	**$62,673**	**$882**	**$15,899**	**$0**	**$0**	**$79,454**	**$7,701**	**$0**	**$14,210**	**$101,365**	**$187**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,616	$0	$840	$0	$0	$5,456	$520	$0	$896	$6,872	$13
9.2	Circulating Water Pumps	$1,207	$0	$73	$0	$0	$1,280	$108	$0	$208	$1,595	$3
9.3	Circ.Water System Auxiliaries	$107	$0	$15	$0	$0	$123	$12	$0	$20	$155	$0
9.4	Circ.Water Piping	$0	$4,483	$1,162	$0	$0	$5,645	$510	$0	$1,231	$7,386	$14
9.5	Make-up Water System	$216	$0	$309	$0	$0	$525	$50	$0	$115	$690	$1
9.6	Component Cooling Water Sys	$529	$633	$450	$0	$0	$1,613	$151	$0	$353	$2,116	$4
9.9	Circ.Water System Foundations	$0	$1,634	$2,778	$0	$0	$4,412	$418	$0	$1,449	$6,279	$12
	SUBTOTAL 9.	**$6,676**	**$6,750**	**$5,627**	**$0**	**$0**	**$19,053**	**$1,769**	**$0**	**$4,272**	**$25,094**	**$46**

Exhibit 3-102 Case L3A Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 2009-Oct-09

Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L3A - Siemens 543 MW IGCC w/o CO2

Plant Size: 543.1 MW,net **Estimate Type:** Conceptual **Cost Base (Jun)** 2007 ($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$24,843	$0	$12,251	$0	$0	$37,095	$3,564	$0	$4,066	$44,725	$82
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$710	$0	$772	$0	$0	$1,482	$144	$0	$244	$1,870	$3
10.7	Ash Transport & Feed Equipment	$952	$0	$230	$0	$0	$1,182	$110	$0	$194	$1,486	$3
10.8	Misc. Ash Handling Equipment	$1,470	$1,802	$538	$0	$0	$3,810	$363	$0	$626	$4,798	$9
10.9	Ash/Spent Sorbent Foundation	$0	$63	$79	$0	$0	$142	$13	$0	$46	$201	$0
	SUBTOTAL 10.	**$27,975**	**$1,864**	**$13,870**	**$0**	**$0**	**$43,710**	**$4,194**	**$0**	**$5,176**	**$53,079**	**$98**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$905	$0	$895	$0	$0	$1,800	$172	$0	$197	$2,169	$4
11.2	Station Service Equipment	$4,018	$0	$362	$0	$0	$4,380	$404	$0	$478	$5,262	$10
11.3	Switchgear & Motor Control	$7,428	$0	$1,351	$0	$0	$8,779	$814	$0	$1,439	$11,032	$20
11.4	Conduit & Cable Tray	$0	$3,451	$11,383	$0	$0	$14,834	$1,435	$0	$4,067	$20,336	$37
11.5	Wire & Cable	$0	$6,593	$4,332	$0	$0	$10,925	$794	$0	$2,930	$14,648	$27
11.6	Protective Equipment	$0	$641	$2,332	$0	$0	$2,973	$290	$0	$490	$3,753	$7
11.7	Standby Equipment	$225	$0	$220	$0	$0	$445	$42	$0	$73	$560	$1
11.8	Main Power Transformers	$15,361	$0	$136	$0	$0	$15,497	$1,172	$0	$2,500	$19,170	$35
11.9	Electrical Foundations	$0	$148	$388	$0	$0	$537	$51	$0	$176	$764	$1
	SUBTOTAL 11.	**$27,937**	**$10,833**	**$21,400**	**$0**	**$0**	**$60,169**	**$5,175**	**$0**	**$12,351**	**$77,695**	**$143**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$974	$0	$650	$0	$0	$1,624	$154	$81	$279	$2,138	$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	$224	$0	$144	$0	$0	$367	$35	$18	$84	$505	$1
12.7	Computer & Accessories	$5,195	$0	$166	$0	$0	$5,361	$492	$268	$612	$6,734	$12
12.8	Instrument Wiring & Tubing	$0	$1,815	$3,710	$0	$0	$5,525	$469	$276	$1,567	$7,837	$14
12.9	Other I & C Equipment	$3,473	$0	$1,686	$0	$0	$5,159	$485	$258	$885	$6,788	$12
	SUBTOTAL 12.	**$9,866**	**$1,815**	**$6,357**	**$0**	**$0**	**$18,037**	**$1,635**	**$902**	**$3,428**	**$24,001**	**$44**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$100	$2,145	$0	$0	$2,245	$223	$0	$740	$3,209	$6
13.2	Site Improvements	$0	$1,785	$2,372	$0	$0	$4,157	$410	$0	$1,370	$5,937	$11
13.3	Site Facilities	$3,198	$0	$3,375	$0	$0	$6,573	$648	$0	$2,166	$9,388	$17
	SUBTOTAL 13.	**$3,198**	**$1,885**	**$7,892**	**$0**	**$0**	**$12,975**	**$1,281**	**$0**	**$4,277**	**$18,533**	**$34**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,204	$3,140	$0	$0	$5,344	$492	$0	$875	$6,711	$12
14.3	Administration Building	$0	$819	$594	$0	$0	$1,413	$126	$0	$231	$1,769	$3
14.4	Circulation Water Pumphouse	$0	$161	$85	$0	$0	$247	$22	$0	$40	$309	$1
14.5	Water Treatment Buildings	$0	$300	$292	$0	$0	$592	$54	$0	$97	$743	$1
14.6	Machine Shop	$0	$419	$287	$0	$0	$706	$63	$0	$115	$884	$2
14.7	Warehouse	$0	$677	$437	$0	$0	$1,113	$99	$0	$182	$1,394	$3
14.8	Other Buildings & Structures	$0	$405	$316	$0	$0	$721	$64	$0	$157	$942	$2
14.9	Waste Treating Building & Str.	$0	$906	$1,731	$0	$0	$2,637	$246	$0	$577	$3,460	$6
	SUBTOTAL 14.	**$0**	**$6,155**	**$7,032**	**$0**	**$0**	**$13,187**	**$1,201**	**$0**	**$2,364**	**$16,752**	**$31**
	TOTAL COST	$781,441	$71,079	$257,562	$0	$0	$1,110,083	$102,860	$30,314	$199,286	$1,442,543	$2,656

Exhibit 3-103 Case L3A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$12,238	$23
1 Month Variable O&M	$3,335	$6
25% of 1 Months Fuel Cost at 100% CF	$741	$1
2% of TPC	$28,851	$53
Total	**$45,164**	**$83**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,129	$11
0.5% of TPC (spare parts)	$7,213	$13
Total	**$13,342**	**$25**
Initial Cost for Catalyst and Chemicals	**$1,737**	**$3**
Land	**$900**	**$2**
Other Owner's Costs	**$216,381**	**$398**
Financing Costs	**$38,949**	**$72**
Total Owner's Costs	**$316,473**	**$583**
Total Overnight Cost (TOC)	**$1,759,016**	**$3,239**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$2,005,278**	**$3,692**

Exhibit 3-104 Case L3A Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES						
					Cost Base (Jun):	2007
Case L3A - Siemens 543 MW IGCC w/o CO2					Heat Rate-net (Btu/kWh):	9,063
					MWe-net:	543
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$5,918,913	$10.898
Maintenance Labor Cost					$13,661,375	$25.154
Administrative & Support Labor					$4,895,072	$9.013
Property Taxes and Insurance					$28,850,854	$53.121
TOTAL FIXED OPERATING COSTS					**$53,326,213**	**$98.185**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$26,380,507**	**$0.00693**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	1,577	1.08	**$0**	**$498,031**	**$0.00013**
Chemicals						
MU & WT Chem.(lbs)	0	9,394	0.17	$0	$474,740	$0.00012
Carbon (Mercury Removal) (lb)	67,428	92	1.05	$70,811	$28,325	$0.00001
COS Catalyst (m3)	605	0.41	2,397.36	$1,450,277	$290,055	$0.00008
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0	$0.00000
Sulfinol Solution (gal)	21,466	15	10.05	$215,705	$42,794	$0.00001
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.	0.83	131.27	$0	$31,975	$0.00001
Subtotal Chemicals				**$1,736,794**	**$867,889**	**$0.00023**
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	92	0.42	$0	$11,249	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	898	16.23	$0	$4,255,027	$0.00112
Subtotal Waste Disposal				**$0**	**$4,266,277**	**$0.00112**
By-products & Emissions						
Sulfur (tons)	0	56	0.00	$0	$0	$0.00000
Subtotal-By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,736,794**	**$32,012,704**	**$0.00841**
Fuel (ton)	0	8,927	10.92	**$0**	**$28,463,735**	**$0.00748**

3.4.8 SFG IGCC CO_2 Capture Cases (S3B and L3B) Process Description

Cases S3B and L3B are configured to produce electric power with CO_2 capture. The plant configurations are similar to Cases S3A and L3A with the major differences being the addition of WGS, the use of a two-stage Selexol AGR plant instead of Sulfinol and subsequent compression of the captured CO_2 stream. The gross power output is constrained by the capacity of the two CTs, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Cases S3A and L3A.

The process description for Cases S3B and L3B is similar to Cases S3A and L3A with several notable exceptions to accommodate CO_2 capture. A BFD for the CO_2 capture cases is shown in Exhibit 3-105 and stream tables are shown in Exhibit 3-106 and Exhibit 3-107. Instead of repeating the entire process description, only differences from the non-capture cases are reported here.

Coal Preparation and Feed Systems

No differences from non-capture cases.

Gasification

The gasification process is the same as the non-capture cases except the coal feed (as-received) to the gasifiers is 6,312 tonne/day (6,958 tpd) for the PRB case and 8,727 tonne/day (9,620 tpd) for the lignite case.

Raw Gas Cooling/Particulate Removal

No differences from non-capture cases.

Sour Water Stripper

No differences from non-capture cases.

Sour Gas Shift

The SGS process was described in Section 3.1.6. The water concentration in the syngas is controlled by varying the exit temperature of the water scrubber upstream of the shift reactors. The hot syngas exiting the first stage of SGS is used to superheat steam. One more stage of SGS (for a total of two) results in approximately 97 percent overall conversion of CO to CO_2. The warm syngas from the second stage of SGS is cooled to preheat the syngas prior to the first stage of SGS. The SGS catalyst 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 AGR

Mercury removal is the same as in the non-capture cases.

The AGR process in the CO_2 capture cases 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, a CO_2-rich stream and an acid gas feed to the Claus plant. The acid gas contains about 17 percent H_2S and 65 percent CO_2 with the balance primarily H_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 two pressure levels. The LP stream is compressed from 0.12 MPa (17 psia) to 1.0 MPa (150 psia) and then combined with the HP stream. The combined stream is further compressed to a SC condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dew point of -40ºC (-40°F) using a thermal swing adsorptive dryer. The raw CO_2 stream from the Selexol process contains over 99 percent CO_2. The dehydrated CO_2 is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.6.

Claus Unit

The Claus plant is the same as the non-capture cases except 46 tonne/day (51 tpd) of sulfur are produced in the PRB case and 55 tonne/day (60 tpd) in the lignite case.

Power Block

Clean syngas from the AGR plant is reheated to 196°C (385°F) using HP BFW, diluted with nitrogen, and then enters the CT burner. The exhaust gas exits the CT at a nominal 566°C (1,050°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) 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 nominal 12.4 MPa/538°C/538°C (1,800 psig/1,000°F/1,000°F) steam cycle. There is no air integration between the CT and the ASU in either capture case.

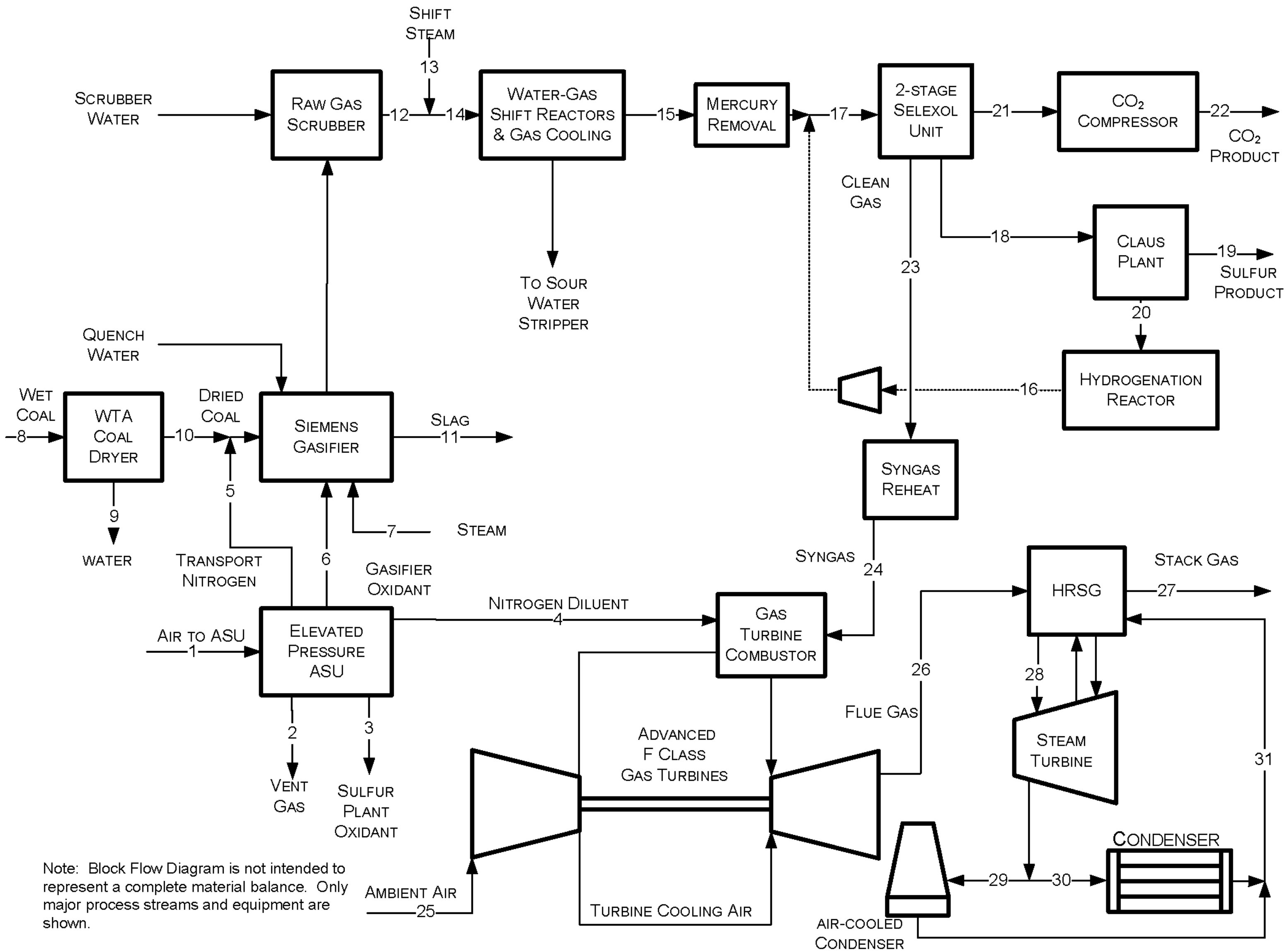
ASU

The same elevated pressure ASU is used as in non-capture cases except the output is 3,837 tonne/day (4,229 tpd) of 95 mol% oxygen to the gasifier and Claus plant for the PRB case and 4,286 tonne/day (4,725 tpd) for the lignite case

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14, and 3.1.15.

Exhibit 3-105 Case S3B and L3B Process Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 3-106 Case S3B Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0254	0.0318	0.0023	0.0023	0.0360	0.0000	0.0000	0.0000	0.0000	0.0000	0.0051	0.0000	0.0051	0.0064
CH_4	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	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2832	0.0000	0.2832	0.0101
CO_2	0.0003	0.0088	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0257	0.0000	0.0257	0.3809
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1456	0.0000	0.1456	0.5325
H_2O	0.0064	0.1664	0.0000	0.0002	0.0002	0.0000	1.0000	0.0000	1.0000	0.0000	0.0000	0.4854	1.0000	0.4854	0.0016
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0015	0.0000	0.0015	0.0021
N_2	0.7759	0.5832	0.0178	0.9920	0.9920	0.0140	0.0000	0.0000	0.0000	0.0000	0.0000	0.0524	0.0000	0.0524	0.0663
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0000	0.0008	0.0000
O_2	0.2081	0.2162	0.9504	0.0054	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	24,095	900	47	16,376	1,850	4,914	1,268	0	3,070	0	0	35,328	0	35,328	27,923
V-L Flowrate (kg/hr)	696,213	24,890	1,497	459,533	51,920	158,373	22,845	0	55,312	0	0	701,295	0	701,295	567,855
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	262,991	0	207,679	22,191	0	0	0	0
Temperature (°C)	6	20	32	196	197	32	343	6	33	71	260	208	288	232	35
Pressure (MPa, abs)	0.09	0.11	0.86	2.65	5.62	0.86	5.10	0.09	0.55	0.09	4.17	4.07	4.14	4.00	3.60
Enthalpy (kJ/kg)A	15.26	39.05	26.67	202.64	201.76	26.59	3,062.93	---	139.92	---	---	1,401.25	2,955.16	1,444.76	43.22
Density (kg/m^3)	1.1	1.5	11.0	18.9	39.6	11.0	20.1	---	985.3	---	---	21.1	18.2	19.6	29.2
V-L Molecular Weight	28.895	27.654	32.181	28.061	28.061	32.229	18.015	---	18.015	---	---	19.851	18.015	19.851	20.336
V-L Flowrate (lb_{mol}/hr)	53,119	1,984	103	36,104	4,079	10,833	2,796	0	6,769	0	0	77,885	0	77,885	61,561
V-L Flowrate (lb/hr)	1,534,887	54,874	3,300	1,013,098	114,463	349,152	50,364	0	121,942	0	0	1,546,091	0	1,546,091	1,251,906
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	579,796	0	457,854	48,923	0	0	0	0
Temperature (°F)	42	68	90	385	387	90	650	42	92	160	500	407	550	450	95
Pressure (psia)	13.0	16.4	125.0	384.0	815.0	125.0	740.0	13.0	80.0	12.7	604.7	589.7	600.0	579.7	522.6
Enthalpy (Btu/lb)A	6.6	16.8	11.5	87.1	86.7	11.4	1,316.8	---	60.2	---	---	602.4	1,270.5	621.1	18.6
Density (lb/ft^3)	0.070	0.094	0.687	1.180	2.475	0.688	1.257	---	61.513	---	---	1.318	1.135	1.223	1.823
	A - Reference conditions are 32.02 F & 0.089 PSIA														

Exhibit 3-106 Case S3B Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
V-L Mole Fraction																
Ar	0.0067	0.0064	0.0022	0.0000	0.0056	0.0002	0.0002	0.0100	0.0100	0.0093	0.0090	0.0090	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0060	0.0101	0.0038	0.0000	0.0760	0.0003	0.0003	0.0156	0.0156	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.6603	0.3853	0.6540	0.0000	0.4865	0.9916	0.9945	0.0460	0.0460	0.0003	0.0089	0.0089	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0001	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.1409	0.5283	0.1270	0.0000	0.0574	0.0047	0.0047	0.8248	0.8248	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.1381	0.0016	0.0394	0.0000	0.3338	0.0030	0.0000	0.0001	0.0001	0.0064	0.1204	0.1204	1.0000	1.0000	1.0000	1.0000
H_2S	0.0052	0.0022	0.1632	0.0000	0.0011	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0429	0.0661	0.0104	0.0000	0.0362	0.0003	0.0003	0.1034	0.1034	0.7759	0.7553	0.7553	0.0000	0.0000	0.0000	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	0.0000	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	0.2081	0.1064	0.1064	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0031	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	374	28,247	375	0	443	9,895	9,865	17,977	17,747	100,352	127,019	127,019	17,949	17,444	17,444	36,575
V-L Flowrate (kg/hr)	12,597	579,530	13,417	0	13,813	432,659	432,123	133,455	131,748	2,899,687	3,490,969	3,490,969	323,355	314,255	314,255	658,912
Solids Flowrate (kg/hr)	0	0	0	1,908	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	49	35	48	175	232	16	72	31	216	6	561	132	533	32	32	33
Pressure (MPa, abs)	0.07	3.53	0.16	0.1	0.085	0.931	15.270	3.238	3.203	0.090	0.093	0.090	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	235.23	42.11	95.90	---	755.306	6.442	-94.805	118.187	862.962	15.260	829.552	340.436	3,430.204	2,255.058	2,255.058	140.571
Density (kg/m^3)	0.9	29.0	2.2	---	0.6	18.0	460.0	9.4	5.8	1.1	0.4	0.7	36.8	0.04	0.04	995.0
V-L Molecular Weight	33.644	20.517	35.800	---	31.159	43.725	43.803	7.424	7.424	28.895	27.484	27.484	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	825	62,273	826	0	977	21,815	21,749	39,632	39,126	221,239	280,028	280,028	39,571	38,457	38,457	80,634
V-L Flowrate (lb/hr)	27,771	1,277,645	29,579	0	30,452	953,849	952,667	294,217	290,454	6,392,716	7,696,268	7,696,268	712,876	692,813	692,813	1,452,653
Solids Flowrate (lb/hr)	0	0	0	4,206	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	120	94	119	347	450	60	162	87	420	42	1,042	270	992	90	90	92
Pressure (psia)	10.6	512.6	23.7	17.3	12.3	135.0	2,214.7	469.6	464.6	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	101.1	18.1	41.2	---	324.7	2.8	-40.8	50.8	371.0	6.6	356.6	146.4	1,474.7	969.5	969.5	60.4
Density (lb/ft^3)	0.058	1.808	0.137	---	0.039	1.123	28.720	0.587	0.361	0.070	0.023	0.046	2.297	0.002	0.002	62.115

Exhibit 3-107 Case L3B Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0170	0.0318	0.0023	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0054	0.0000	0.0054	0.0068
CH_4	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	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2889	0.0000	0.2889	0.0103
CO_2	0.0003	0.0055	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0304	0.0000	0.0304	0.3960
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0002	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1415	0.0000	0.1415	0.5371
H_2O	0.0062	0.1013	0.0000	0.0002	0.0002	0.0000	1.0000	0.0000	1.0000	0.0000	0.0000	0.4950	1.0000	0.4950	0.0016
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0000	0.0017	0.0024
N_2	0.7761	0.7372	0.0178	0.9920	0.9920	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0360	0.0000	0.0360	0.0457
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0010	0.0000	0.0010	0.0000
O_2	0.2082	0.1389	0.9504	0.0054	0.0054	0.9504	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	26,909	1,591	56	17,415	2,353	5,493	0	0	5,523	0	0	37,348	0	37,348	29,362
V-L Flowrate (kg/hr)	777,605	44,312	1,814	488,676	66,031	176,772	0	0	99,501	0	0	744,717	0	744,717	600,885
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	363,623	0	264,122	36,583	0	0	0	0
Temperature (°C)	4	18	32	196	197	32	343	4	32	71	260	209	288	226	35
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	5.62	0.86	5.10	0.10	0.34	0.09	4.17	4.10	4.14	4.03	3.60
Enthalpy (kJ/kg)[A]	13.75	36.85	26.67	202.62	201.75	26.67	3,062.93	---	134.94	---	---	1,418.72	2,955.16	1,448.03	42.49
Density (kg/m^3)	1.2	1.4	11.0	18.9	39.6	11.0	20.1	---	986.5	---	---	21.4	18.2	20.2	29.4
V-L Molecular Weight	28.898	27.846	32.181	28.061	28.061	32.181	18.015	---	18.015	---	---	19.940	18.015	19.940	20.465
V-L Flowrate (lb_{mol}/hr)	59,324	3,508	124	38,393	5,188	12,110	0	0	12,176	0	0	82,338	0	82,338	64,732
V-L Flowrate (lb/hr)	1,714,325	97,692	4,000	1,077,346	145,573	389,715	0	0	219,362	0	0	1,641,820	0	1,641,820	1,324,726
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	801,651	0	582,290	80,651	0	0	0	0
Temperature (°F)	40	64	90	385	387	90	650	40	90	160	500	409	550	438	95
Pressure (psia)	13.8	16.4	125.0	384.0	815.0	125.0	740.0	13.8	50.0	13.5	604.7	594.7	600.0	584.7	522.6
Enthalpy (Btu/lb)[A]	5.9	15.8	11.5	87.1	86.7	11.5	1,316.8	---	58.0	---	---	609.9	1,270.5	622.5	18.3
Density (lb/ft^3)	0.074	0.089	0.687	1.180	2.475	0.687	1.257	---	61.586	---	---	1.335	1.135	1.261	1.837

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-107 Case L3B Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
V-L Mole Fraction																
Ar	0.0073	0.0068	0.0022	0.0000	0.0056	0.0002	0.0002	0.0108	0.0108	0.0093	0.0091	0.0091	0.0000	0.0000	0.0000	0.0000
CH_4	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	0.0000	0.0000
CO	0.0043	0.0103	0.0037	0.0000	0.0683	0.0003	0.0003	0.0162	0.0162	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.6625	0.4004	0.6492	0.0000	0.4464	0.9920	0.9948	0.0489	0.0489	0.0003	0.0091	0.0091	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0001	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.1371	0.5326	0.1223	0.0000	0.0549	0.0045	0.0045	0.8506	0.8506	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.1381	0.0016	0.0371	0.0000	0.3856	0.0029	0.0000	0.0001	0.0001	0.0062	0.1201	0.1201	1.0000	1.0000	1.0000	1.0000
H_2S	0.0077	0.0025	0.1784	0.0000	0.0010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0429	0.0458	0.0069	0.0000	0.0332	0.0002	0.0002	0.0733	0.0733	0.7761	0.7544	0.7544	0.0000	0.0000	0.0000	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	0.0000	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	0.2082	0.1073	0.1073	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0047	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	404	29,711	413	0	523	10,810	10,779	18,237	18,237	106,961	134,708	134,708	18,759	18,905	18,905	38,261
V-L Flowrate (kg/hr)	13,661	613,551	14,837	0	15,765	472,792	472,236	124,209	124,209	3,090,914	3,703,790	3,703,790	337,956	340,584	340,584	689,276
Solids Flowrate (kg/hr)	0	0	0	2,272	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	49	35	48	175	232	16	72	31	216	4	560	133	532	32	32	33
Pressure (MPa, abs)	0.07	3.53	0.16	0.1	0.085	0.931	15.270	3.238	3.234	0.095	0.099	0.095	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	234.19	41.51	92.67	---	857.472	6.283	-95.297	129.249	941.449	13.748	827.741	340.637	3,427.815	2,254.480	2,254.480	140.362
Density (kg/m^3)	0.9	29.2	2.2	---	0.6	18.0	461.3	8.6	5.4	1.2	0.4	0.8	36.9	0.04	0.04	995.0
V-L Molecular Weight	33.799	20.651	35.961	---	30.119	43.737	43.811	6.811	6.811	28.898	27.495	27.495	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	891	65,502	910	0	1,154	23,832	23,764	40,206	40,206	235,808	296,981	296,981	41,357	41,679	41,679	84,350
V-L Flowrate (lb/hr)	30,116	1,352,649	32,709	0	34,756	1,042,328	1,041,102	273,833	273,833	6,814,298	8,165,460	8,165,460	745,066	750,859	750,859	1,519,593
Solids Flowrate (lb/hr)	0	0	0	5,008	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	120	94	119	347	450	60	162	87	420	40	1,040	271	990	90	90	92
Pressure (psia)	10.6	512.6	23.7	17.3	12.3	135.0	2,214.7	469.6	469.0	13.8	14.3	13.8	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	100.7	17.8	39.8	---	368.6	2.7	-41.0	55.6	404.8	5.9	355.9	146.4	1,473.7	969.3	969.3	60.3
Density (lb/ft^3)	0.058	1.822	0.138	---	0.038	1.123	28.800	0.538	0.335	0.074	0.024	0.048	2.301	0.002	0.002	62.116

3.4.9 Case S3B and L3B Performance Results

The Case S3B and L3B modeling assumptions were presented previously in Exhibit 3-84.

The SFG IGCC plant with CO_2 capture and using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 445 MWe at a net plant efficiency of 30.6 percent (HHV basis). The same plant configuration using lignite coal at the North Dakota site (elevation 1,900 ft) produces a net output of 467 MWe at a net plant efficiency of 30.0 percent (HHV basis).

Overall performance for the plants is summarized in Exhibit 3-108, which includes auxiliary power requirements The ASU accounts for approximately 56 percent of the total auxiliary load in both cases, distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The coal drying process accounts for approximately 7 percent of the auxiliary load. CO_2 compression accounts for about 17 percent and the AGR process accounts for about 10 percent of the auxiliary load. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-108 Case S3B and L3B Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	S3B	L3B
Gas Turbine Power	430,900	456,600
Steam Turbine Power	203,800	220,300
TOTAL POWER, kWe	**634,700**	**676,900**
AUXILIARY LOAD SUMMARY, kWe		
Coal Handling	510	620
Coal Milling	2,700	3,740
Slag Handling	580	950
WTA Coal Dryer Compressor	9,270	12,780
WTA Coal Dryer Auxiliaries	600	840
Air Separation Unit Auxiliaries	1,000	1,000
Air Separation Unit Main Air Compressor	62,000	67,470
Oxygen Compressor	8,670	9,680
Nitrogen Compressors	34,640	37,800
CO_2 Compressor	31,220	34,730
Boiler Feedwater Pumps	2,330	2,440
Condensate Pump	220	230
Quench Water Pump	10	10
Circulating Water Pump	3,090	3,380
Ground Water Pumps	360	380
Cooling Tower Fans	2,020	2,070
Air Cooled Condenser Fans	2,990	3,050
Scrubber Pumps	750	740
Acid Gas Removal	18,190	19,910
Gas Turbine Auxiliaries	1,000	1,000
Steam Turbine Auxiliaries	100	100
Claus Plant/TGTU Auxiliaries	250	250
Claus Plant TG Recycle Compressor	1,460	1,580
Miscellaneous Balance of Plant[1]	3,000	3,000
Transformer Losses	2,450	2,640
TOTAL AUXILIARIES, kWe	**189,410**	**210,390**
NET POWER, kWe	**445,290**	**466,510**
Net Plant Efficiency, % (HHV)	30.6%	30.0%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,765 (11,151)	11,997 (11,371)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	1,329 (1,260)	1,445 (1,370)
CONSUMABLES		
As-Received Coal Feed, kg/hr (lb/hr)	262,991 (579,796)	363,623 (801,651)
Thermal Input, kWt	1,455,207	1,554,603
Raw Water Withdrawal, m^3/min (gpm)	15.2 (4,025)	15.8 (4,165)
Raw Water Consumption, m^3/min (gpm)	12.5 (3,304)	12.8 (3,379)

[1] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, CO_2, and PM were presented in Section 2.3. A summary of the plant air emissions for the CO_2 capture cases is presented in Exhibit 3-109.

Exhibit 3-109 Case S3B and L3B Air Emissions

	kg/GJ (lb/10^6 Btu)		Tonne/year (ton/year) 80% capacity factor		kg/MWh (lb/MWh)	
	S3B	**L3B**	**S3B**	**L3B**	**S3B**	**L3B**
SO_2	0.000 (0.001)	0.000 (0.001)	14 (15)	16 (18)	0.003 (0.007)	0.003 (0.008)
NO_X	0.022 (0.051)	0.021 (0.050)	802 (884)	841 (927)	0.180 (0.397)	0.177 (0.391)
Particulates	0.003 (0.0071)	0.003 (0.0071)	112 (124)	120 (132)	0.025 (0.056)	0.025 (0.056)
Hg	1.51E-7 (3.51E-7)	2.41E-7 (5.60E-7)	0.006 (0.006)	0.009 (0.010)	1.25E-6 (2.75E-6)	1.99E-6 (4.39E-6)
CO_2 gross	9.5 (22.0)	9.6 (22.4)	347,578 (383,140)	377,494 (416,116)	78 (172)	80 (175)
CO_2 net					111 (246)	115 (255)

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. Just as in the non-capture cases, the SO_2 emission are significantly less than the environmental targets of Section 2.3. The clean syngas exiting the AGR process has a sulfur concentration of approximately 2 ppmv. This results in a concentration in the flue gas of less than 0.3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The tail gas is hydrogenated and recycled upstream of the AGR.

NOx emissions are limited to 15 ppmvd (as NO_2 @ 15 percent O_2) by the use of low NOx burners and nitrogen dilution of the fuel gas. 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 NOx 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.

Slightly greater than 92 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 3-110. 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, CO_2 in the stack gas and ASU vent gas, and the captured CO_2 product. 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
90 percent (both cases S3B and L3B)

Exhibit 3-110 Cases S3B and L3B Carbon Balance

Carbon In, kg/hr (lb/hr)			Carbon Out, kg/hr (lb/hr)		
	S3B	L3B		S3B	L3B
Coal	131,675 (290,293)	143,826 (317,083)	**Slag**	658 (1,451)	719 (1,585)
Air (CO_2)	490 (1,081)	527 (1,163)	**Stack Gas**	13,536 (29,842)	14,701 (32,410)
			ASU Vent	95 (209)	106 (234)
			CO_2 Product	117,876 (259,871)	128,827 (284,016)
Total	**132,165 (291,374)**	**144,354 (318,245)**	**Total**	**132,165 (291,374)**	**144,354 (318,245)**

Exhibit 3-111 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, sulfur emitted in the stack gas and sulfur that is co-sequestered with the CO_2 product. Sulfur in the slag is considered negligible.

Exhibit 3-111 Cases S3B and L3B Sulfur Balance

Sulfur In, kg/hr (lb/hr)			Sulfur Out, kg/hr (lb/hr)		
	S3B	L3B		S3B	L3B
Coal	1,913 (4,218)	2,278 (5,022)	**Elemental Sulfur**	1,908 (4,206)	2,272 (5,008)
			Stack Gas	1 (2)	1 (3)
			CO_2 Product	4 (9)	5 (11)
Total	**1,913 (4,218)**	**2,278 (5,022)**	**Total**	**1,913 (4,218)**	**2,278 (5,022)**

Exhibit 3-112 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 from the coal drying process and as syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is discharged from the process to a permitted outfall. The difference between the withdrawal and discharge is the consumption.

Exhibit 3-112 Cases S3B and L3B Water Balance

Water Use	Water Demand m^3/min (gpm)		Internal Recycle m^3/min (gpm)		Raw Water Withdrawal m^3/min (gpm)		Process Water Discharge m^3/min (gpm)		Raw Water Consumption m^3/min (gpm)	
	S3B	**L3B**	**S3B**	**L3B**	**S3B**	**L3B**	**S3B**	**L3B**	**S3B**	**L3B**
Slag Handling	**0.48 (127)**	**0.79 (210)**	**0.5 (127)**	**0.8 (210)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**
Quench/Wash	**5.56 (1469)**	**5.98 (1580)**	**1.6 (426)**	**1.5 (386)**	**3.95 (1043)**	**4.52 (1194)**	**0 (0)**	**0 (0)**	**3.95 (1043)**	**4.52 (1194)**
SWS Blowdown	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0 (0)**	**0.02 (6)**	**0.02 (6)**	**-0.02 (-6)**	**-0.02 (-6)**
Condenser Makeup	**0.51 (134)**	**0.14 (36)**	**0 (0)**	**0 (0)**	**0.51 (134)**	**0.14 (36)**	**0 (0)**	**0 (0)**	**0.51 (134)**	**0.14 (36)**
Shift Steam	0.38 (101)				0.38 (101)					
BFW Makeup	0.13 (33)	0.14 (36)			0.13 (33)	0.14 (36)				
Cooling Tower	**12.04 (3,180)**	**13.13 (3,469)**	**1.3 (333)**	**2.0 (534)**	**10.78 (2,848)**	**11.11 (2,935)**	**2.71 (715)**	**2.95 (780)**	**8.07 (2,132)**	**8.16 (2,155)**
Water from Coal Drying			0.9 (244)	1.7 (439)	-0.92 (-244)	-1.66 (-439)				
BFW Blowdown			0.1 (33)	0.1 (36)	-0.13 (-33)	-0.14 (-36)				
SWS Blowdown			0.2 (55)	0.2 (60)	-0.21 (-55)	-0.23 (-60)				
Total	**18.6 (4,911)**	**20.0 (5,294)**	**3.4 (886)**	**4.3 (1,130)**	**15.2 (4,025)**	**15.8 (4,165)**	**2.7 (721)**	**3.0 (786)**	**12.5 (3,304)**	**12.8 (3,379)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-113 and Exhibit 3-114:

- Coal gasification and ASU
- Syngas cleanup
- Combined cycle power generation

An overall plant energy balance is provided in tabular form in Exhibit 3-115 for the two cases. The power out is the combined CT and steam turbine power after generator losses.

Exhibit 3-113 Case S3B Heat and Mass Balance

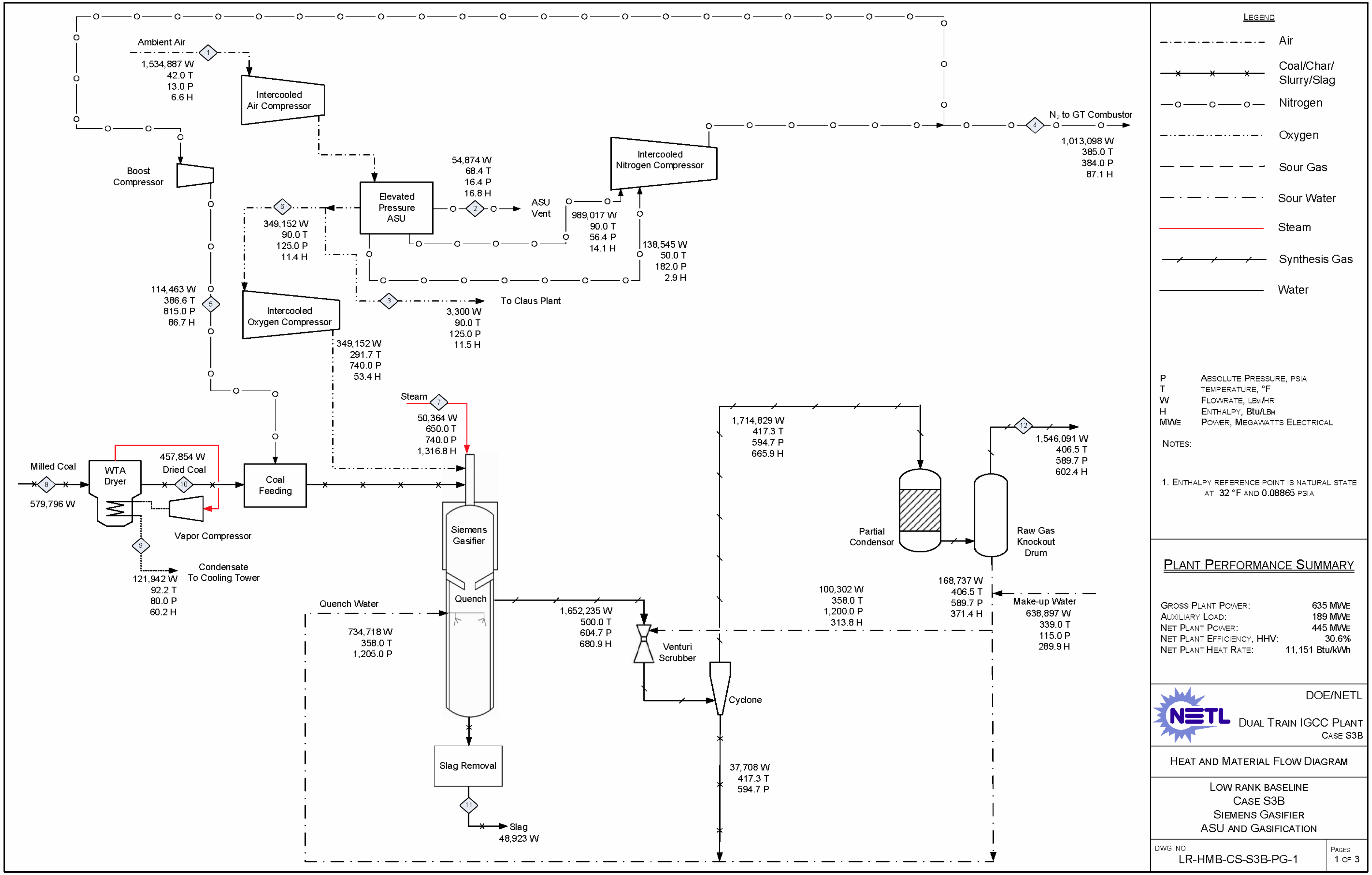


Exhibit 3-113 Case S3B Heat and Mass Balance (Continued)

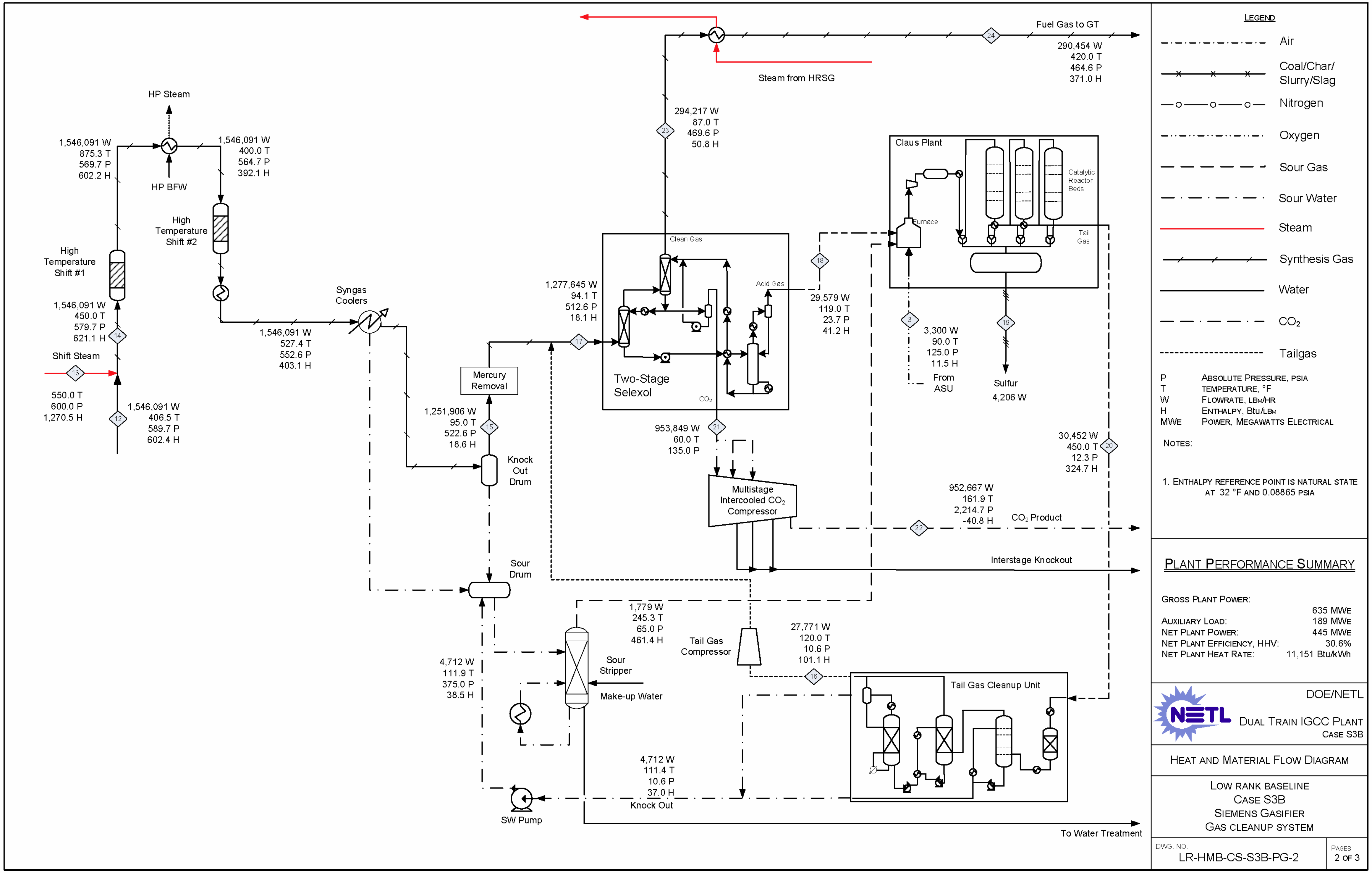


Exhibit 3-113 Case S3B Heat and Mass Balance (Continued)

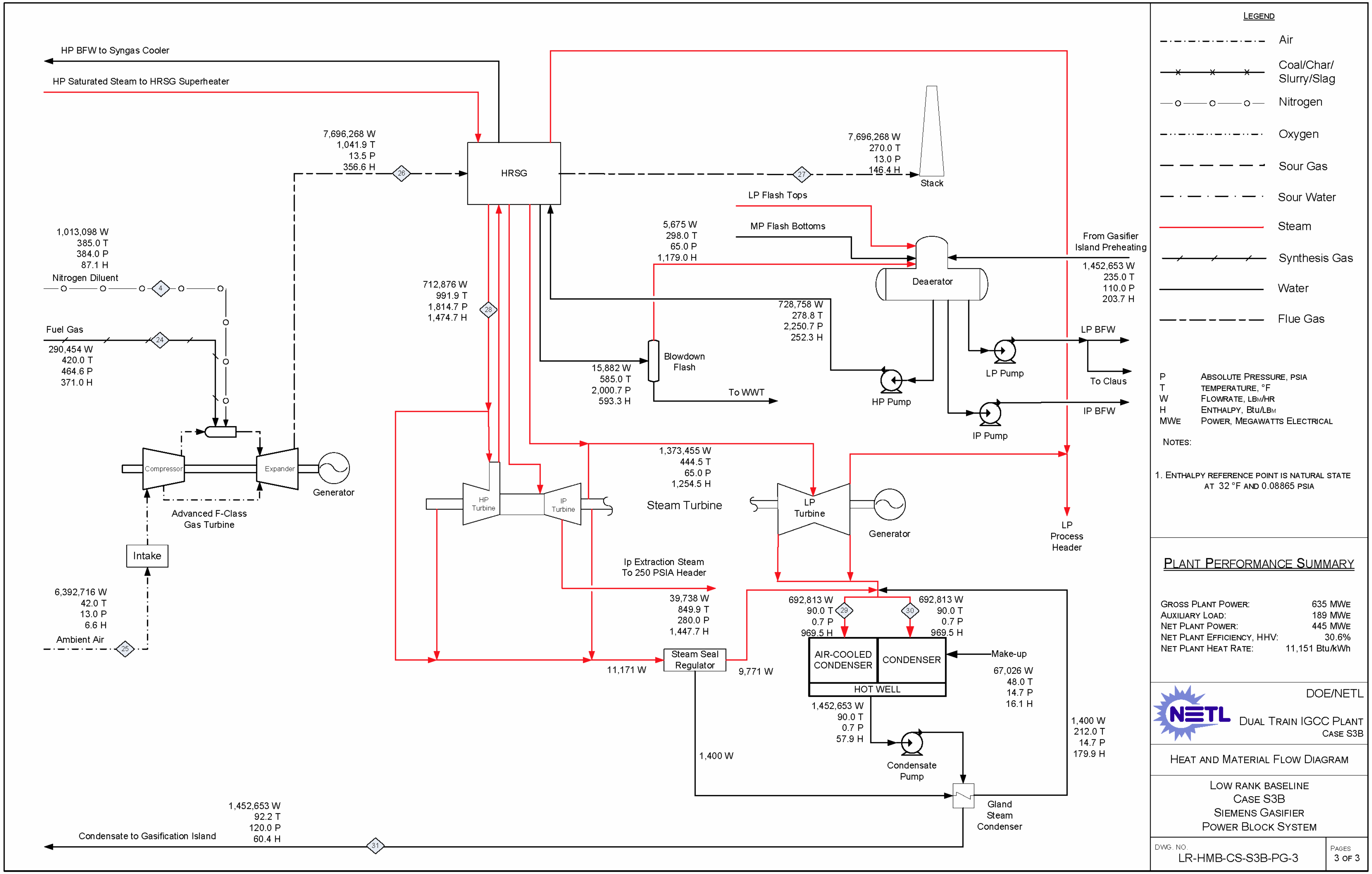


Exhibit 3-114 Case L3B Heat and Mass Balance

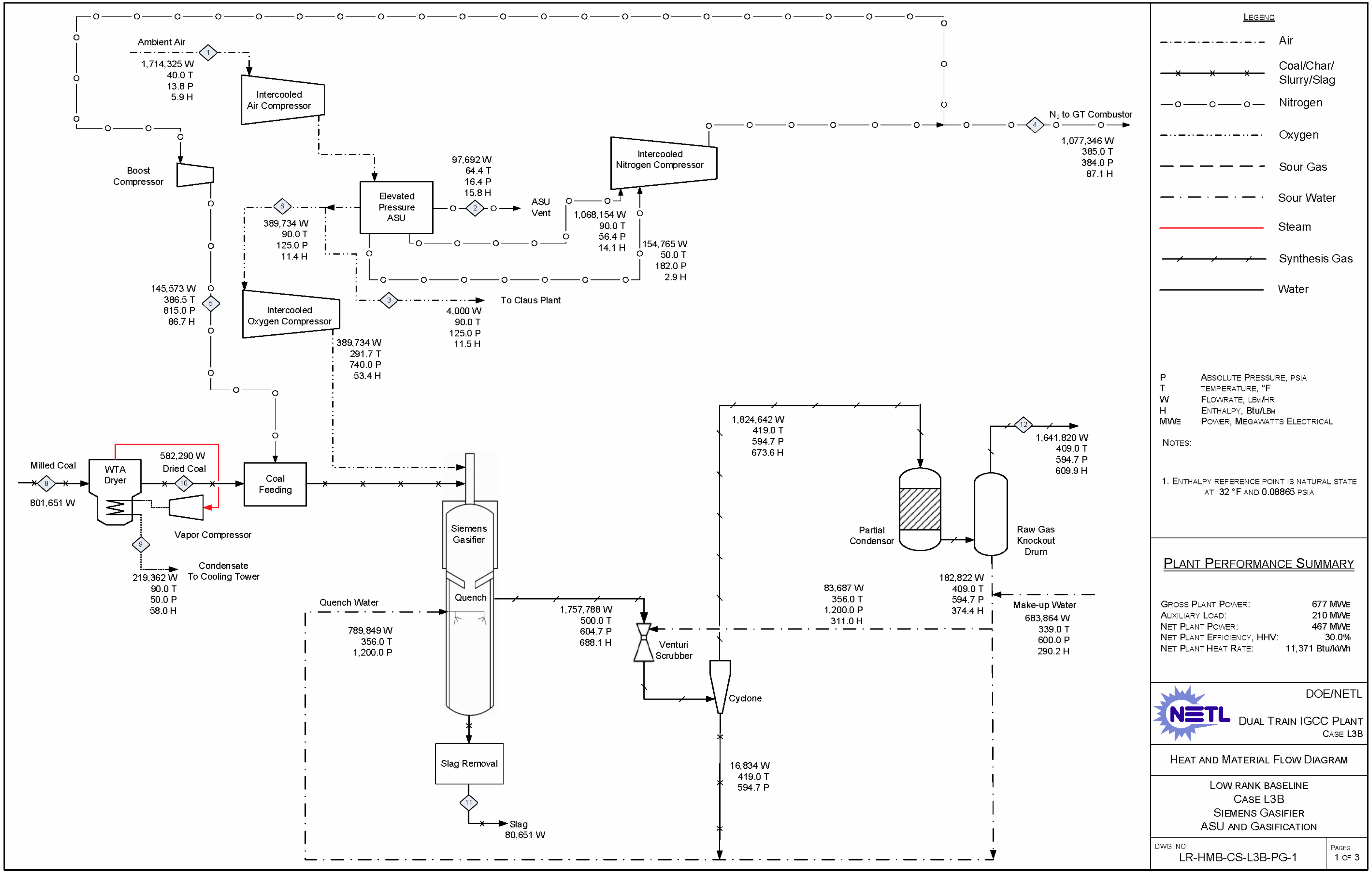


Exhibit 3-114 Case L3B Heat and Mass Balance (Continued)

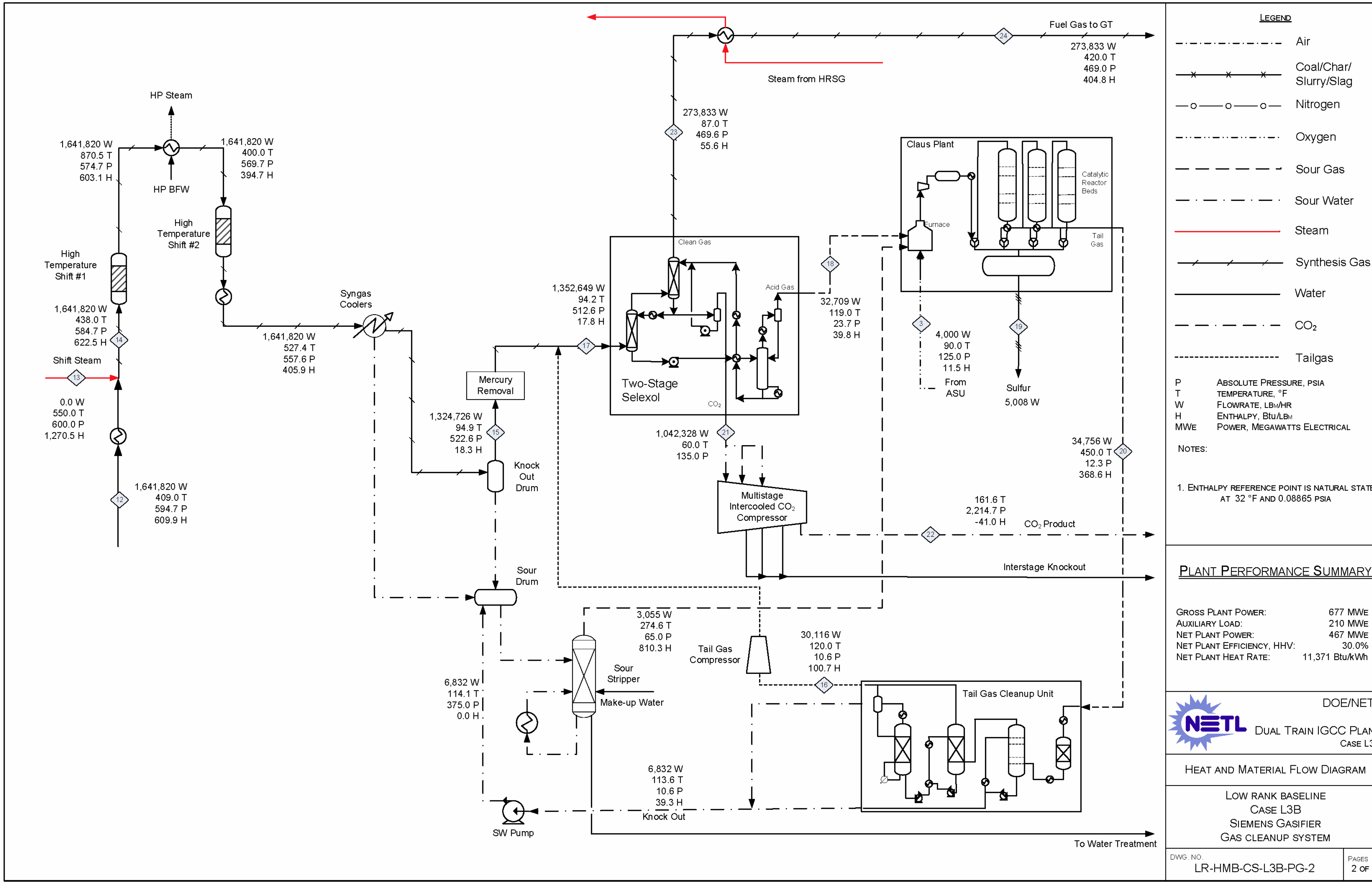


Exhibit 3-114 Case L3B Heat and Mass Balance (Continued)

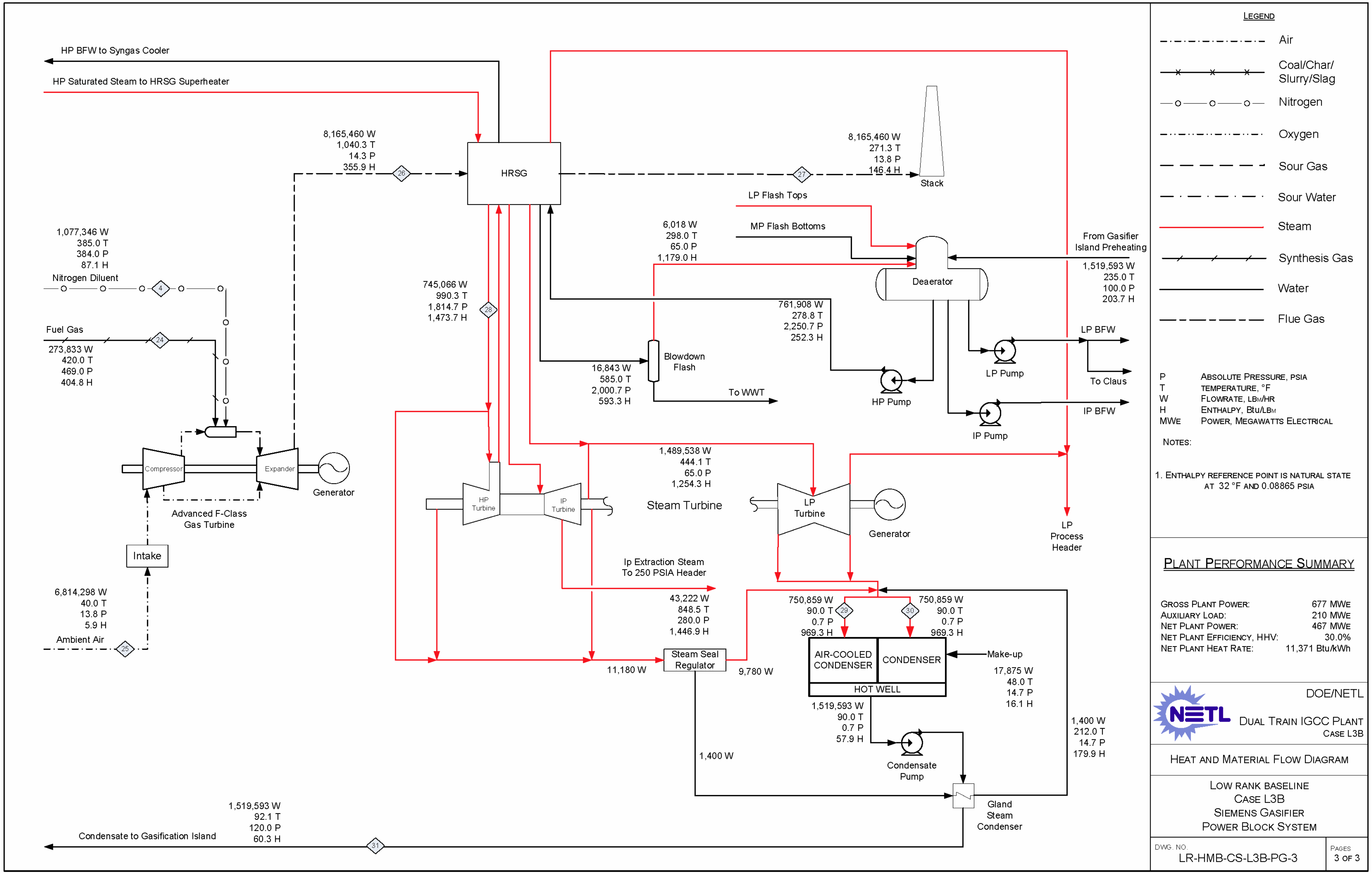


Exhibit 3-115 Cases S3B and L3B Energy Balance

	HHV		Sensible + Latent		Power		Total	
	S3B	**L3B**	**S3B**	**L3B**	**S3B**	**L3B**	**S3B**	**L3B**
Heat In GJ/hr (MMBtu/hr)								
Coal	5,239 (4,965)	5,597 (5,305)	2.7 (2.6)	3.2 (3.1)	0 (0)	0 (0)	5,241 (4,968)	5,600 (5,308)
ASU Air	0 (0)	0 (0)	10.6 (10.1)	10.7 (10.1)	0 (0)	0 (0)	11 (10)	11 (10)
GT Air	0 (0)	0 (0)	44.2 (41.9)	42.5 (40.3)	0 (0)	0 (0)	44 (42)	42 (40)
Raw Water Makeup	0 (0)	0 (0)	21.2 (20.1)	17.5 (16.6)	0 (0)	0 (0)	21 (20)	18 (17)
Auxiliary Power	0 (0)	0 (0)	0 (0)	0 (0)	682 (646)	757 (718)	682 (646)	757 (718)
Totals	**5,239 (4,965)**	**5,597 (5,305)**	**78.8 (74.6)**	**74.0 (70.1)**	**682 (646)**	**757 (718)**	**5,999 (5,686)**	**6,428 (6,093)**
Heat Out GJ/hr (MMBtu/hr)								
ASU Intercoolers	0 (0)	0 (0)	215 (204)	232 (220)	0 (0)	0 (0)	215 (204)	232 (220)
ASU Vent	0 (0)	0 (0)	1.0 (0.9)	1.6 (1.5)	0 (0)	0 (0)	1 (1)	2 (2)
Slag	22 (20)	24 (22)	4.8 (4.6)	7.9 (7.5)	0 (0)	0 (0)	26 (25)	32 (30)
Sulfur	18 (17)	21 (20)	0.2 (0.2)	0.3 (0.2)	0 (0)	0 (0)	18 (17)	21 (20)
CO_2	0 (0)	0 (0)	-41.0 (-38.8)	-45.0 (-42.7)	0 (0)	0 (0)	-41 (-39)	-45 (-43)
CO_2 Comp Intercoolers	0 (0)	0 (0)	151.4 (143.5)	167.8 (159.0)	0 (0)	0 (0)	151 (144)	168 (159)
Cooling Tower Blowdown	0 (0)	0 (0)	15.1 (14.3)	16.0 (15.2)	0 (0)	0 (0)	15 (14)	16 (15)
HRSG Flue Gas	0 (0)	0 (0)	1,188 (1,126)	1,262 (1,196)	0 (0)	0 (0)	1,188 (1,126)	1,262 (1,196)
Condenser	0 (0)	0 (0)	1,330 (1,260)	1,443 (1,368)	0 (0)	0 (0)	1,330 (1,260)	1,443 (1,368)
Auxiliary Cooling Loads	0 (0)	0 (0)	348 (329)	385 (365)	0 (0)	0 (0)	348 (329)	385 (365)
Generator Loss	0 (0)	0 (0)	0 (0)	0 (0)	35 (33)	37 (35)	35 (33)	37 (35)
Process Losses	0 (0)	0 (0)	428 (406)	439 (416)	0 (0)	0 (0)	428 (406)	439 (416)
Power	0 (0)	0 (0)	0 (0)	0 (0)	2,285 (2,166)	2,437 (2,310)	2,285 (2,166)	2,437 (2,310)
Totals	**39 (37)**	**45 (42)**	**3,640 (3,450)**	**3,909 (3,705)**	**2,320 (2,199)**	**2,474 (2,345)**	**5,999 (5,686)**	**6,428 (6,093)**

3.4.10 Case S3B and L3B Equipment List

Major equipment items for the SFG 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	S3B Design Conditions	L3B Design Condition	Operating Qty	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	73 tonne (80 ton)	2	1
9	Feeder	Vibratory	218 tonne/hr (240 tph)	299 tonne/hr (330 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	435 tonne/hr (480 tph)	599 tonne/hr (660 tph)	1	0
11	Crusher Tower	N/A	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	218 tonne (240 ton)	299 tonne (330 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	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	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	435 tonne/hr (480 tph)	599 tonne/hr (660 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	N/A	1	0

Equipment No.	Description	Type	S3B Design Conditions	L3B Design Condition	Operating Qty	Spares
17	Conveyor No. 5	Belt w/ tripper	435 tonne/hr (480 tph)	599 tonne/hr (660 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	998 tonne (1,100 ton)	1,361 tonne (1,500 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	100 tonne/hr (110 tph)	136 tonne/hr (150 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	290 tonne/hr (320 tph)	399 tonne/hr (440 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	581 tonne (640 ton)	798 tonne (880 ton)	1	0
4	Weigh Feeder	Belt	145 tonne/hr (160 tph)	200 tonne/hr (220 tph)	2	0
5	Pulverizer	Rotary	145 tonne/hr (160 tph)	200 tonne/hr (220 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	290 tonne (320 ton)	399 tonne (440 ton)	2	0
7	Coal Preheater	Water Heated Horizontal Rotary Kiln	Coal feed: 290 tonne/hr (320 tph) Heat duty: 32.2 GJ/hr (30.5 MMBtu/hr)	Coal feed: 399 tonne/hr (440 tph) Heat duty: 49.4 GJ/hr (46.8 MMBtu/hr)	1	0

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
8	Coal Dryer	Fluidized Bed with Internal Coils	Coal feed: 145 tonne/hr (160 tph) Heat duty: 81.0 GJ/hr (76.7 MMBtu/hr) Bed diameter: 12.5 m (41 ft)	Coal feed: 200 tonne/hr (220 tph) Heat duty: 143.3 GJ/hr (135.8 MMBtu/hr) Bed diameter: 14.6 m (48 ft)	2	0
9	Steam Compressor	Reciprocating, Multi-Stage	606 m^3/min (21,400 scfm) Suction - 0.09 MPa (13 psia) Discharge - 0.72 MPa (105 psia)	1,090 m^3/min (38,500 scfm) Suction - 0.10 MPa (13.8 psia) Discharge - 0.52 MPa (75 psia)	2	0
10	Dryer Exhaust Filter	Hot Baghouse	Steam - 30,436 kg/hr (67,100 lb/hr) Temperature - 107°C (225°F)	Steam - 54,703 kg/hr (120,600 lb/hr) Temperature - 107°C (225°F)	2	0
11	Dry Coal Cooler	Water Cooled Horizontal Rotary Kiln	228 tonne/hr (252 tph) Heat duty - 13 GJ/hr (13 MMBtu/hr)	291 tonne/hr (320 tph) Heat duty - 18 GJ/hr (17 MMBtu/hr)	1	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	488,318 liters (129,000 gal)	526,172 liters (139,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,095 lpm @ 91 m H_2O (1,610 gpm @ 300 ft H_2O)	6,359 lpm @ 91 m H_2O (1,680 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	441,345 kg/hr (973,000 lb/hr)	466,747 kg/hr (1,029,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	2,801 lpm @ 27 m H_2O (740 gpm @ 90 ft H_2O)	3,066 lpm @ 27 m H_2O (810 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 3,142 lpm @ 1,890 m H_2O (830 gpm @ 6,200 ft H_2O)	HP water: 3,293 lpm @ 1,890 m H_2O (870 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,136 lpm @ 223 m H_2O (300 gpm @ 730 ft H_2O)	IP water: 1,249 lpm @ 223 m H_2O (330 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	407 GJ/hr (386 MMBtu/hr) each	446 GJ/hr (422 MMBtu/hr) each	2	0

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	146,117 lpm @ 21 m H_2O (38,600 gpm @ 70 ft H_2O)	159,744 lpm @ 21 m H_2O (42,200 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	4,240 lpm @ 18 m H_2O (1,120 gpm @ 60 ft H_2O)	4,391 lpm @ 18 m H_2O (1,160 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,839 lpm @ 268 m H_2O (750 gpm @ 880 ft H_2O)	2,915 lpm @ 268 m H_2O (770 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	3,710 lpm @ 49 m H_2O (980 gpm @ 160 ft H_2O)	3,899 lpm @ 49 m H_2O (1,030 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,775,358 liter (469,000 gal)	1,866,208 liter (493,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	151 lpm (40 gpm)	151 lpm (40 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,359 tonne/day, 4.2 MPa (2,600 tpd, 605 psia)	3,175 tonne/day, 4.2 MPa (3,500 tpd, 605 psia)	3	0
2	Synthesis Gas Cyclone	High efficiency	285,310 kg/hr (629,000 lb/hr) Design efficiency 90%	303,453 kg/hr (669,000 lb/hr) Design efficiency 90%	3	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical up flow	274,877 kg/hr (606,000 lb/hr)	292,567 kg/hr (645,000 lb/hr)	3	0
4	Raw Gas Coolers	Shell and tube with condensate drain	385,554 kg/hr (850,000 lb/hr)	409,594 kg/hr (903,000 lb/hr)	8	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	312,525 kg/hr, 35°C, 3.6 MPa (689,000 lb/hr, 95°F, 528 psia)	330,669 kg/hr, 35°C, 3.6 MPa (729,000 lb/hr, 95°F, 528 psia)	2	0
6	Synthesis Gas Reheater	Shell and tube	73,482 kg/hr (162,000 lb/hr)	68,492 kg/hr (151,000 lb/hr)	2	0
7	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	412,315 kg/hr (909,000 lb/hr) syngas	438,624 kg/hr (967,000 lb/hr) syngas	2	0
8	ASU Main Air Compressor	Centrifugal, multi-stage	5,239 m^3/min @ 1.3 MPa (185,000 scfm @ 190 psia)	5,833 m^3/min @ 1.3 MPa (206,000 scfm @ 190 psia)	2	0
9	Cold Box	Vendor design	2,087 tonne/day (2,300 tpd) of 95% purity oxygen	2,359 tonne/day (2,600 tpd) of 95% purity oxygen	2	0

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
10	Oxygen Compressor	Centrifugal, multi-stage	1,076 m^3/min (38,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	1,189 m^3/min (42,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
11	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,483 m^3/min (123,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	3,738 m^3/min (132,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
12	Secondary Nitrogen Compressor	Centrifugal, single-stage	481 m^3/min (17,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.7 MPa (820 psia)	538 m^3/min (19,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.7 MPa (820 psia)	2	0
13	Transport Nitrogen Boost Compressor	Centrifugal, single-stage	402 m^3/min (14,200 scfm) Suction - 2.6 MPa (384 psia) Discharge - 5.6 MPa (815 psia)	510 m^3/min (18,000 scfm) Suction - 2.6 MPa (384 psia) Discharge - 5.6 MPa (815 psia)	2	0
14	Syngas Dilution Nitrogen Boost Compressor	Centrifugal, single-stage	1,535 m^3/min (54,200 scfm) Suction - 2.6 MPa (384 psia) Discharge - 3.2 MPa (469 psia)	1,668 m^3/min (58,900 scfm) Suction - 2.6 MPa (384 psia) Discharge - 3.2 MPa (469 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	312,525 kg/hr (689,000 lb/hr) 35°C (95°F) 3.6 MPa (523 psia)	330,669 kg/hr (729,000 lb/hr) 35°C (95°F) 3.6 MPa (523 psia)	2	0
2	Sulfur Plant	Claus type	50 tonne/day (56 tpd)	60 tonne/day (66 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	385,554 kg/hr (850,000 lb/hr) 232°C (450°F) 4.0 MPa (580 psia)	409,594 kg/hr (903,000 lb/hr) 227°C (440°F) 4.0 MPa (580 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and tube	Exchanger 1: 189 GJ/hr (179 MMBtu/hr)	Exchanger 1: 199 GJ/hr (188 MMBtu/hr)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	318,875 kg/hr (703,000 lb/hr) 35°C (94°F) 3.5 MPa (513 psia)	337,473 kg/hr (744,000 lb/hr) 35°C (94°F) 3.5 MPa (513 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	15,194 kg/hr (33,497 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	17,341 kg/hr (38,231 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	12,854 kg/hr (28,339 lb/hr)	13,945 kg/hr (30,743 lb/hr)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	CO_2 Compressor	Integrally geared, multi-stage centrifugal	1,070 m^3/min @ 15.3 MPa (37,800 scfm @ 2,215 psia)	1,169 m^3/min @ 15.3 MPa (41,300 scfm @ 2,215 psia)	4	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	215 MW	230 MW	2	0
2	Gas Turbine Generator	TEWAC	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.7 m (20 ft) diameter	76 m (250 ft) high x 8.7 m (20 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 177,845 kg/hr, 12.4 MPa/533°C (392,082 lb/hr, 1,800 psig/992°F) Reheat steam - 251,394 kg/hr, 3.1 MPa/533°C (554,230 lb/hr, 452 psig/992°F)	Main steam - 185,876 kg/hr, 12.4 MPa/532°C (409,786 lb/hr, 1,800 psig/990°F) Reheat steam - 273,486 kg/hr, 3.1 MPa/532°C (602,934 lb/hr, 452 psig/990°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Steam Turbine	Commercially available	214 MW 12.4 MPa/533°C/533°C (1,800 psig/ 992°F/992°F)	232 MW 12.4 MPa/532°C/532°C (1,800 psig/ 990°F/990°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	728 GJ/hr (690 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 8°C (47°F), Water temperature rise 11°C (20°F)	1	0
4	Air-cooled Condenser	---	728 GJ/hr (690 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	791 GJ/hr (750 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 4°C (40°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Circulating Water Pumps	Vertical, wet pit	310,404 lpm @ 30 m (82,000 gpm @ 100 ft)	336,902 lpm @ 30 m (89,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) WB / 9°C (48°F) CWT / 20°C (68°F) HWT / 1730 GJ/hr (1640 MMBtu/hr) heat duty	2°C (36°F) WB / 8°C (47°F) CWT / 19°C (67°F) HWT / 1889 GJ/hr (1790 MMBtu/hr) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	Slag Quench Tank	Water bath	155,202 liters (41,000 gal)	257,408 liters (68,000 gal)	3	0
2	Slag Crusher	Roll	8 tonne/hr (9 tph)	14 tonne/hr (15 tph)	3	0
3	Slag Depressurizer	Proprietary	8 tonne/hr (9 tph)	14 tonne/hr (15 tph)	3	0
4	Slag Receiving Tank	Horizontal, weir	94,635 liters (25,000 gal)	155,202 liters (41,000 gal)	3	0
5	Black Water Overflow Tank	Shop fabricated	41,640 liters (11,000 gal)	68,137 liters (18,000 gal)	3	
6	Slag Conveyor	Drag chain	8 tonne/hr (9 tph)	14 tonne/hr (15 tph)	3	0
7	Slag Separation Screen	Vibrating	8 tonne/hr (9 tph)	14 tonne/hr (15 tph)	3	0
8	Coarse Slag Conveyor	Belt/bucket	8 tonne/hr (9 tph)	14 tonne/hr (15 tph)	3	0
9	Fine Ash Settling Tank	Vertical, gravity	132,489 liters (35,000 gal)	219,554 liters (58,000 gal)	3	0

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	76 lpm @ 14 m H_2O (20 gpm @ 46 ft H_2O)	3	3
11	Grey Water Storage Tank	Field erected	41,640 liters (11,000 gal)	68,137 liters (18,000 gal)	3	0
12	Grey Water Pumps	Centrifugal	151 lpm @ 424 m H_2O (40 gpm @ 1,390 ft H_2O)	265 lpm @ 424 m H_2O (70 gpm @ 1,390 ft H_2O)	3	3
13	Slag Storage Bin	Vertical, field erected	544 tonne (600 tons)	998 tonne (1,100 tons)	3	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	172 tonne/hr (190 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	S3B Design Condition	L3B Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 81 MVA, 3-ph, 60 Hz	345 kV/13.8 kV, 90 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 46 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 50 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

Equipment No.	Description	Type	S3B Design Condition	L3B 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 S3B and L3B Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-116 shows the TPC summary organized by cost account for the PRB coal case (S3B) and Exhibit 3-120 shows the same information for the NDL coal case (L3B). A more detailed breakdown of the capital costs is shown in Exhibit 3-117 for S3B and Exhibit 3-121 for L3B. Exhibit 3-118 and Exhibit 3-122 show the calculation and addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-119 shows the initial and annual O&M costs for Case S3B and Exhibit 3-123 shows the same information for Case L3B.

The estimated TOC of the SFG with CO_2 capture using PRB coal is $4,318/kW and using lignite coal is $4,430/kW. Process contingency represents 3 percent, project contingency represents 12 percent, and owner's costs represent 18 percent of TOC in both cases. The COE is 121.7 mills/kWh in the PRB case and 123.7 mills/kWh in the lignite case.

Exhibit 3-116 Case S3B Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S3B - Siemens 445 MW IGCC w/ CO2										
	Plant Size:	445.3	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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	$15,911	$2,957	$12,339	$0	$0	$31,206	$2,833	$0	$6,808	$40,846	$92
2	COAL & SORBENT PREP & FEED	$119,959	$9,996	$20,467	$0	$0	$150,422	$13,050	$0	$32,694	$196,166	$441
3	FEEDWATER & MISC. BOP SYSTEMS	$7,393	$5,413	$7,602	$0	$0	$20,407	$1,931	$0	$5,245	$27,583	$62
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Siemen	$112,359	$0	$52,484	$0	$0	$164,843	$14,646	$24,727	$30,632	$234,848	$527
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$184,152	$0	w/equip.	$0	$0	$184,152	$17,850	$0	$20,200	$222,202	$499
4.4-4.9	Other Gasification Equipment	$27,994	$12,820	$17,683	$0	$0	$58,497	$5,599	$0	$13,775	$77,871	$175
	SUBTOTAL 4	$324,505	$12,820	$70,168	$0	$0	$407,493	$38,095	$24,727	$64,608	$534,921	$1,201
5A	GAS CLEANUP & PIPING	$84,233	$2,870	$71,635	$0	$0	$158,738	$15,335	$26,220	$40,227	$240,519	$540
5B	CO2 COMPRESSION	$18,605	$0	$10,561	$0	$0	$29,166	$2,807	$0	$6,395	$38,368	$86
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	$98,610	$9,348	$9,861	$11,782	$129,600	$291
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6	$92,027	$806	$7,475	$0	$0	$100,308	$9,507	$9,861	$12,339	$132,015	$296
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,401	$0	$4,465	$0	$0	$35,866	$3,410	$0	$3,928	$43,204	$97
7.2-7.9	SCR System, Ductwork and Stack	$3,524	$2,513	$3,324	$0	$0	$9,361	$868	$0	$1,666	$11,895	$27
	SUBTOTAL 7	$34,925	$2,513	$7,789	$0	$0	$45,227	$4,278	$0	$5,593	$55,098	$124
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,475	$0	$3,915	$0	$0	$27,390	$2,628	$0	$3,002	$33,019	$74
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$31,839	$802	$10,004	$0	$0	$42,645	$4,160	$0	$9,426	$56,231	$126
	SUBTOTAL 8	$55,314	$802	$13,919	$0	$0	$70,035	$6,788	$0	$12,428	$89,251	$200
9	COOLING WATER SYSTEM	$7,844	$7,697	$6,551	$0	$0	$22,092	$2,052	$0	$4,943	$29,087	$65
10	ASH/SPENT SORBENT HANDLING SYS	$21,399	$1,472	$10,612	$0	$0	$33,483	$3,213	$0	$3,974	$40,669	$91
11	ACCESSORY ELECTRIC PLANT	$30,719	$12,337	$23,901	$0	$0	$66,958	$5,760	$0	$13,849	$86,566	$194
12	INSTRUMENTATION & CONTROL	$10,750	$1,978	$6,926	$0	$0	$19,653	$1,781	$983	$3,735	$26,152	$59
13	IMPROVEMENTS TO SITE	$3,253	$1,917	$8,026	$0	$0	$13,196	$1,303	$0	$4,350	$18,849	$42
14	BUILDINGS & STRUCTURES	$0	$6,276	$7,071	$0	$0	$13,347	$1,214	$0	$2,395	$16,957	$38
	TOTAL COST	$826,836	$69,854	$285,041	$0	$0	$1,181,731	$109,945	$61,790	$219,583	$1,573,049	$3,533

Exhibit 3-117 Case S3B Total Plant Cost Summary Details

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
TOTAL PLANT COST SUMMARY												
	Case:	Case S3B - Siemens 445 MW IGCC w/ CO2										
	Plant Size:	445.3	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)		2007	($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											
1.1	Coal Receive & Unload	$4,178	$0	$2,042	$0	$0	$6,220	$557	$0	$1,355	$8,133	$18
1.2	Coal Stackout & Reclaim	$5,399	$0	$1,309	$0	$0	$6,708	$588	$0	$1,459	$8,755	$20
1.3	Coal Conveyors & Yd Crush	$5,020	$0	$1,295	$0	$0	$6,315	$554	$0	$1,374	$8,243	$19
1.4	Other Coal Handling	$1,313	$0	$300	$0	$0	$1,613	$141	$0	$351	$2,105	$5
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	$2,957	$7,393	$0	$0	$10,350	$992	$0	$2,268	$13,610	$31
	SUBTOTAL 1.	**$15,911**	**$2,957**	**$12,339**	**$0**	**$0**	**$31,206**	**$2,833**	**$0**	**$6,808**	**$40,846**	**$92**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$48,294	$2,901	$7,037	$0	$0	$58,232	$5,025	$0	$12,651	$75,909	$170
2.2	Prepared Coal Storage & Feed	$2,076	$497	$326	$0	$0	$2,899	$248	$0	$629	$3,776	$8
2.3	Dry Coal Injection System	$68,331	$793	$6,346	$0	$0	$75,470	$6,500	$0	$16,394	$98,364	$221
2.4	Misc.Coal Prep & Feed	$1,258	$915	$2,745	$0	$0	$4,918	$452	$0	$1,074	$6,444	$14
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	$4,889	$4,014	$0	$0	$8,903	$825	$0	$1,946	$11,674	$26
	SUBTOTAL 2.	**$119,959**	**$9,996**	**$20,467**	**$0**	**$0**	**$150,422**	**$13,050**	**$0**	**$32,694**	**$196,166**	**$441**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$1,771	$3,041	$1,605	$0	$0	$6,417	$594	$0	$1,402	$8,413	$19
3.2	Water Makeup & Pretreating	$553	$58	$309	$0	$0	$919	$88	$0	$302	$1,309	$3
3.3	Other Feedwater Subsystems	$969	$327	$295	$0	$0	$1,591	$143	$0	$347	$2,080	$5
3.4	Service Water Systems	$316	$651	$2,260	$0	$0	$3,227	$315	$0	$1,062	$4,604	$10
3.5	Other Boiler Plant Systems	$1,697	$657	$1,629	$0	$0	$3,984	$378	$0	$872	$5,234	$12
3.6	FO Supply Sys & Nat Gas	$286	$541	$504	$0	$0	$1,332	$128	$0	$292	$1,752	$4
3.7	Waste Treatment Equipment	$772	$0	$471	$0	$0	$1,243	$121	$0	$409	$1,774	$4
3.8	Misc. Power Plant Equipment	$1,029	$138	$529	$0	$0	$1,696	$164	$0	$558	$2,417	$5
	SUBTOTAL 3.	**$7,393**	**$5,413**	**$7,602**	**$0**	**$0**	**$20,407**	**$1,931**	**$0**	**$5,245**	**$27,583**	**$62**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Siemen	$112,359	$0	$52,484	$0	$0	$164,843	$14,646	$24,727	$30,632	$234,848	$527
4.2	Syngas Cooling	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$184,152	$0	w/equip.	$0	$0	$184,152	$17,850	$0	$20,200	$222,202	$499
4.4	LT Heat Recovery & FG Saturation	$27,994	$0	$10,642	$0	$0	$38,636	$3,771	$0	$8,481	$50,887	$114
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	Flare Stack System	$0	$1,670	$680	$0	$0	$2,350	$225	$0	$515	$3,090	$7
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	$11,150	$6,362	$0	$0	$17,512	$1,603	$0	$4,779	$23,894	$54
	SUBTOTAL 4.	**$324,505**	**$12,820**	**$70,168**	**$0**	**$0**	**$407,493**	**$38,095**	**$24,727**	**$64,608**	**$534,921**	**$1,201**

Exhibit 3-117 Case S3B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S3B - Siemens 445 MW IGCC w/ CO2										
	Plant Size:	445.3	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$70,593	$0	$59,900	$0	$0	$130,492	$12,620	$26,098	$33,842	$203,053	$456
5A.2	Elemental Sulfur Plant	$5,067	$1,010	$6,537	$0	$0	$12,614	$1,225	$0	$2,768	$16,607	$37
5A.3	Mercury Removal	$1,384	$0	$1,054	$0	$0	$2,438	$235	$122	$559	$3,354	$8
5A.4	Shift Reactors	$7,189	$0	$2,894	$0	$0	$10,082	$967	$0	$2,210	$13,259	$30
5A.5	Particulate Removal	$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	$924	$647	$0	$0	$1,572	$146	$0	$344	$2,061	$5
5A.9	HGCU Foundations	$0	$936	$604	$0	$0	$1,540	$141	$0	$504	$2,185	$5
	SUBTOTAL 5A.	$84,233	$2,870	$71,635	$0	$0	$158,738	$15,335	$26,220	$40,227	$240,519	$540
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	w/5A.1	$0	w/5A.1	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$18,605	$0	$10,561	$0	$0	$29,166	$2,807	$0	$6,395	$38,368	$86
	SUBTOTAL 5B.	$18,605	$0	$10,561	$0	$0	$29,166	$2,807	$0	$6,395	$38,368	$86
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	$98,610	$9,348	$9,861	$11,782	$129,600	$291
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	$92,027	$806	$7,475	$0	$0	$100,308	$9,507	$9,861	$12,339	$132,015	$296
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,401	$0	$4,465	$0	$0	$35,866	$3,410	$0	$3,928	$43,204	$97
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,807	$1,322	$0	$0	$3,128	$275	$0	$681	$4,083	$9
7.4	Stack	$3,524	$0	$1,324	$0	$0	$4,848	$464	$0	$531	$5,844	$13
7.9	HRSG,Duct & Stack Foundations	$0	$706	$678	$0	$0	$1,384	$129	$0	$454	$1,967	$4
	SUBTOTAL 7.	$34,925	$2,513	$7,789	$0	$0	$45,227	$4,278	$0	$5,593	$55,098	$124
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,475	$0	$3,915	$0	$0	$27,390	$2,628	$0	$3,002	$33,019	$74
8.2	Turbine Plant Auxiliaries	$162	$0	$371	$0	$0	$532	$52	$0	$58	$643	$1
8.3a	Condenser & Auxiliaries	$2,805	$0	$896	$0	$0	$3,701	$354	$0	$405	$4,460	$10
8.3b	Air Cooled Condenser	$25,704	$0	$5,153	$0	$0	$30,857	$3,086	$0	$6,788	$40,731	$91
8.4	Steam Piping	$3,169	$0	$2,229	$0	$0	$5,398	$464	$0	$1,465	$7,327	$16
8.9	TG Foundations	$0	$802	$1,356	$0	$0	$2,157	$205	$0	$709	$3,071	$7
	SUBTOTAL 8.	$55,314	$802	$13,919	$0	$0	$70,035	$6,788	$0	$12,428	$89,251	$200
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,403	$0	$983	$0	$0	$6,386	$608	$0	$1,049	$8,043	$18
9.2	Circulating Water Pumps	$1,405	$0	$90	$0	$0	$1,495	$126	$0	$243	$1,864	$4
9.3	Circ.Water System Auxiliaries	$122	$0	$17	$0	$0	$140	$13	$0	$23	$176	$0
9.4	Circ.Water Piping	$0	$5,107	$1,324	$0	$0	$6,430	$581	$0	$1,402	$8,414	$19
9.5	Make-up Water System	$311	$0	$445	$0	$0	$756	$73	$0	$166	$994	$2
9.6	Component Cooling Water Sys	$603	$721	$513	$0	$0	$1,837	$172	$0	$402	$2,411	$5
9.9	Circ.Water System Foundations	$0	$1,870	$3,179	$0	$0	$5,049	$479	$0	$1,658	$7,185	$16
	SUBTOTAL 9.	$7,844	$7,697	$6,551	$0	$0	$22,092	$2,052	$0	$4,943	$29,087	$65

Exhibit 3-117 Case S3B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S3B - Siemens 445 MW IGCC w/ CO2										
	Plant Size:	445.3	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$18,925	$0	$9,333	$0	$0	$28,258	$2,715	$0	$3,097	$34,071	$77
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$561	$0	$610	$0	$0	$1,170	$114	$0	$193	$1,477	$3
10.7	Ash Transport & Feed Equipment	$752	$0	$181	$0	$0	$933	$87	$0	$153	$1,173	$3
10.8	Misc. Ash Handling Equipment	$1,161	$1,423	$425	$0	$0	$3,009	$286	$0	$494	$3,790	$9
10.9	Ash/Spent Sorbent Foundation	$0	$50	$62	$0	$0	$112	$11	$0	$37	$159	$0
	SUBTOTAL 10.	**$21,399**	**$1,472**	**$10,612**	**$0**	**$0**	**$33,483**	**$3,213**	**$0**	**$3,974**	**$40,669**	**$91**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$870	$0	$861	$0	$0	$1,731	$165	$0	$190	$2,086	$5
11.2	Station Service Equipment	$4,634	$0	$418	$0	$0	$5,052	$466	$0	$552	$6,069	$14
11.3	Switchgear & Motor Control	$8,568	$0	$1,558	$0	$0	$10,126	$939	$0	$1,660	$12,725	$29
11.4	Conduit & Cable Tray	$0	$3,980	$13,130	$0	$0	$17,110	$1,655	$0	$4,691	$23,456	$53
11.5	Wire & Cable	$0	$7,604	$4,996	$0	$0	$12,601	$915	$0	$3,379	$16,895	$38
11.6	Protective Equipment	$0	$611	$2,225	$0	$0	$2,837	$277	$0	$467	$3,581	$8
11.7	Standby Equipment	$218	$0	$213	$0	$0	$431	$41	$0	$71	$543	$1
11.8	Main Power Transformers	$16,429	$0	$130	$0	$0	$16,559	$1,252	$0	$2,672	$20,483	$46
11.9	Electrical Foundations	$0	$141	$371	$0	$0	$512	$49	$0	$168	$729	$2
	SUBTOTAL 11.	**$30,719**	**$12,337**	**$23,901**	**$0**	**$0**	**$66,958**	**$5,760**	**$0**	**$13,849**	**$86,566**	**$194**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,061	$0	$709	$0	$0	$1,770	$168	$88	$304	$2,330	$5
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	$244	$0	$156	$0	$0	$400	$38	$20	$92	$550	$1
12.7	Computer & Accessories	$5,661	$0	$181	$0	$0	$5,842	$536	$292	$667	$7,337	$16
12.8	Instrument Wiring & Tubing	$0	$1,978	$4,043	$0	$0	$6,020	$511	$301	$1,708	$8,540	$19
12.9	Other I & C Equipment	$3,784	$0	$1,837	$0	$0	$5,621	$529	$281	$965	$7,396	$17
	SUBTOTAL 12.	**$10,750**	**$1,978**	**$6,926**	**$0**	**$0**	**$19,653**	**$1,781**	**$983**	**$3,735**	**$26,152**	**$59**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$102	$2,181	$0	$0	$2,283	$227	$0	$753	$3,263	$7
13.2	Site Improvements	$0	$1,815	$2,412	$0	$0	$4,227	$417	$0	$1,393	$6,038	$14
13.3	Site Facilities	$3,253	$0	$3,432	$0	$0	$6,685	$659	$0	$2,203	$9,548	$21
	SUBTOTAL 13.	**$3,253**	**$1,917**	**$8,026**	**$0**	**$0**	**$13,196**	**$1,303**	**$0**	**$4,350**	**$18,849**	**$42**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,038	$2,903	$0	$0	$4,940	$455	$0	$809	$6,204	$14
14.3	Administration Building	$0	$859	$623	$0	$0	$1,482	$132	$0	$242	$1,856	$4
14.4	Circulation Water Pumphouse	$0	$158	$84	$0	$0	$241	$21	$0	$39	$302	$1
14.5	Water Treatment Buildings	$0	$462	$451	$0	$0	$912	$82	$0	$149	$1,144	$3
14.6	Machine Shop	$0	$440	$301	$0	$0	$740	$66	$0	$121	$927	$2
14.7	Warehouse	$0	$710	$458	$0	$0	$1,168	$103	$0	$191	$1,462	$3
14.8	Other Buildings & Structures	$0	$416	$324	$0	$0	$740	$66	$0	$161	$968	$2
14.9	Waste Treating Building & Str.	$0	$930	$1,778	$0	$0	$2,708	$253	$0	$592	$3,553	$8
	SUBTOTAL 14.	**$0**	**$6,276**	**$7,071**	**$0**	**$0**	**$13,347**	**$1,214**	**$0**	**$2,395**	**$16,957**	**$38**
	TOTAL COST	**$826,836**	**$69,854**	**$285,041**	**$0**	**$0**	**$1,181,731**	**$109,945**	**$61,790**	**$219,583**	**$1,573,049**	**$3,533**

Exhibit 3-118 Case S3B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$12,933	$29
1 Month Variable O&M	$3,445	$8
25% of 1 Months Fuel Cost at 100% CF	$805	$2
2% of TPC	$31,461	$71
Total	**$48,644**	**$109**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,932	$16
0.5% of TPC (spare parts)	$7,865	$18
Total	**$14,797**	**$33**
Initial Cost for Catalyst and Chemicals	**$6,922**	**$16**
Land	**$900**	**$2**
Other Owner's Costs	**$235,957**	**$530**
Financing Costs	**$42,472**	**$95**
Total Owner's Costs	**$349,692**	**$785**
Total Overnight Cost (TOC)	**$1,922,741**	**$4,318**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$2,191,925**	**$4,922**

Exhibit 3-119 Case S3B Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun)	2007
Case S3B - Siemens 445 MW IGCC w/ CO2					Heat Rate-net(Btu/kWh):	11,151
					MWe-net:	445
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$6,313,507	$14.178
Maintenance Labor Cost					$14,379,765	$32.293
Administrative & Support Labor					$5,173,318	$11.618
Property Taxes and Insurance					$31,460,972	$70.653
TOTAL FIXED OPERATING COSTS					**$57,327,563**	**$128.742**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$27,449,429**	**$0.00880**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	2,898	1.08	**$0**	**$915,331**	**$0.00029**
Chemicals						
MU & WT Chem.(lbs)	0	17,265	0.17	$0	$872,524	$0.00028
Carbon (Mercury Removal) (lb)	114,477	157	1.05	$120,220	$48,088	$0.00002
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	6,049	4.14	498.83	$3,017,654	$603,531	$0.00019
Selexol Solution (gal)	282,412	90	13.40	$3,783,824	$351,466	$0.00011
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.	0.76	131.27	$0	$29,144	$0.00001
Subtotal Chemicals				**$6,921,697**	**$1,904,753**	**$0.00061**
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	157	0.42	$0	$19,098	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	587	16.23	$0	$2,781,394	$0.00089
Subtotal Waste Disposal				**$0**	**$2,800,492**	**$0.00090**
By-products & Emissions						
Sulfur (tons)	0	50	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$6,921,697**	**$33,070,006**	**$0.01060**
Fuel (ton)	0	6,958	15.22	**$0**	**$30,914,533**	**$0.00991**

Exhibit 3-120 Case L3B Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
					TOTAL PLANT COST SUMMARY							
	Case:	Case L3B - Siemens 467 MW IGCC w/ CO2										
	Plant Size:	466.5	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$19,450	$3,614	$15,084	$0	$0	**$38,148**	$3,463	$0	$8,322	**$49,933**	$107
2	COAL & SORBENT PREP & FEED	$145,819	$12,270	$24,711	$0	$0	**$182,800**	$15,856	$0	$39,731	**$238,387**	$511
3	FEEDWATER & MISC. BOP SYSTEMS	$7,616	$5,584	$7,820	$0	$0	**$21,020**	$1,989	$0	$5,401	**$28,409**	$61
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$112,359	$0	$52,484	$0	$0	**$164,843**	$14,646	$24,727	$30,632	**$234,848**	$503
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	$198,687	$0	w/equip.	$0	$0	**$198,687**	$19,259	$0	$21,795	**$239,740**	$514
4.4-4.9	Other Gasification Equipment	$29,196	$14,523	$19,100	$0	$0	**$62,820**	$6,005	$0	$14,860	**$83,686**	$179
	SUBTOTAL 4	**$340,242**	**$14,523**	**$71,585**	**$0**	**$0**	**$426,350**	**$39,910**	**$24,727**	**$67,287**	**$558,274**	**$1,197**
5A	Gas Cleanup & Piping	$87,936	$3,020	$75,000	$0	$0	**$165,956**	$16,033	$27,288	$42,026	**$251,303**	$539
5B	CO_2 REMOVAL & COMPRESSION	$19,885	$0	$11,288	$0	$0	**$31,173**	$3,000	$0	$6,835	**$41,008**	$88
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	**$98,609**	$9,348	$9,861	$11,782	**$129,599**	$278
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$5
	SUBTOTAL 6	**$92,026**	**$806**	**$7,475**	**$0**	**$0**	**$100,307**	**$9,507**	**$9,861**	**$12,339**	**$132,014**	**$283**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,635	$0	$4,640	$0	$0	**$37,275**	$3,544	$0	$4,082	**$44,901**	$96
7.2-7.9	Ductwork and Stack	$3,526	$2,514	$3,326	$0	$0	**$9,366**	$869	$0	$1,667	**$11,901**	$26
	SUBTOTAL 7	**$36,161**	**$2,514**	**$7,966**	**$0**	**$0**	**$46,641**	**$4,413**	**$0**	**$5,749**	**$56,802**	**$122**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$24,841	$0	$4,166	$0	$0	**$29,007**	$2,783	$0	$3,179	**$34,969**	$75
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$33,661	$849	$10,539	$0	$0	**$45,049**	$4,396	$0	$9,950	**$59,395**	$127
	SUBTOTAL 8	**$58,502**	**$849**	**$14,705**	**$0**	**$0**	**$74,056**	**$7,179**	**$0**	**$13,129**	**$94,364**	**$202**
9	COOLING WATER SYSTEM	$8,311	$8,092	$6,895	$0	$0	**$23,298**	$2,164	$0	$5,209	**$30,671**	$66
10	ASH/SPENT SORBENT HANDLING SYS	$29,325	$1,943	$14,539	$0	$0	**$45,807**	$4,395	$0	$5,422	**$55,625**	$119
11	ACCESSORY ELECTRIC PLANT	$32,486	$12,985	$25,133	$0	$0	**$70,604**	$6,071	$0	$14,599	**$91,274**	$196
12	INSTRUMENTATION & CONTROL	$10,955	$2,015	$7,059	$0	$0	**$20,029**	$1,815	$1,001	$3,807	**$26,653**	$57
13	IMPROVEMENTS TO SITE	$3,354	$1,977	$8,275	$0	$0	**$13,606**	$1,343	$0	$4,485	**$19,434**	$42
14	BUILDINGS & STRUCTURES	$0	$6,418	$7,268	$0	$0	**$13,685**	$1,245	$0	$2,455	**$17,385**	$37
	TOTAL COST	**$892,068**	**$76,612**	**$304,802**	**$0**	**$0**	**$1,273,481**	**$118,383**	**$62,877**	**$236,794**	**$1,691,536**	**$3,626**

Exhibit 3-121 Case L3B Total Plant Cost Summary Details

	Client:	USDOE/NETL								**Report Date:**	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case L3B - Siemens 467 MW IGCC w/ CO2										
	Plant Size:	466.5	MW,net	**Estimate Type:**		Conceptual				**Cost Base (Jun)**	2007	($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											
1.1	Coal Receive & Unload	$5,108	$0	$2,496	$0	$0	$7,604	$681	$0	$1,657	$9,942	$21
1.2	Coal Stackout & Reclaim	$6,600	$0	$1,600	$0	$0	$8,201	$719	$0	$1,784	$10,703	$23
1.3	Coal Conveyors & Yd Crush	$6,137	$0	$1,583	$0	$0	$7,720	$678	$0	$1,680	$10,077	$22
1.4	Other Coal Handling	$1,606	$0	$366	$0	$0	$1,972	$173	$0	$429	$2,573	$6
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	$3,614	$9,038	$0	$0	$12,652	$1,213	$0	$2,773	$16,638	$36
	SUBTOTAL 1.	**$19,450**	**$3,614**	**$15,084**	**$0**	**$0**	**$38,148**	**$3,463**	**$0**	**$8,322**	**$49,933**	**$107**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$59,809	$3,593	$8,715	$0	$0	$72,116	$6,223	$0	$15,668	$94,007	$202
2.2	Prepared Coal Storage & Feed	$2,833	$678	$444	$0	$0	$3,955	$338	$0	$859	$5,152	$11
2.3	Dry Coal Injection System	$81,811	$949	$7,598	$0	$0	$90,358	$7,782	$0	$19,628	$117,768	$252
2.4	Misc.Coal Prep & Feed	$1,367	$995	$2,983	$0	$0	$5,344	$491	$0	$1,167	$7,003	$15
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	$6,055	$4,971	$0	$0	$11,026	$1,021	$0	$2,409	$14,457	$31
	SUBTOTAL 2.	**$145,819**	**$12,270**	**$24,711**	**$0**	**$0**	**$182,800**	**$15,856**	**$0**	**$39,731**	**$238,387**	**$511**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$1,829	$3,141	$1,658	$0	$0	$6,627	$614	$0	$1,448	$8,689	$19
3.2	Water Makeup & Pretreating	$566	$59	$316	$0	$0	$942	$90	$0	$309	$1,341	$3
3.3	Other Feedwater Subsystems	$1,001	$338	$304	$0	$0	$1,643	$148	$0	$358	$2,149	$5
3.4	Service Water Systems	$324	$667	$2,315	$0	$0	$3,306	$323	$0	$1,089	$4,717	$10
3.5	Other Boiler Plant Systems	$1,738	$674	$1,669	$0	$0	$4,081	$387	$0	$894	$5,362	$11
3.6	FO Supply Sys & Nat Gas	$298	$563	$525	$0	$0	$1,385	$133	$0	$304	$1,823	$4
3.7	Waste Treatment Equipment	$791	$0	$483	$0	$0	$1,274	$124	$0	$419	$1,817	$4
3.8	Misc. Power Plant Equipment	$1,069	$143	$549	$0	$0	$1,761	$170	$0	$579	$2,511	$5
	SUBTOTAL 3.	**$7,616**	**$5,584**	**$7,820**	**$0**	**$0**	**$21,020**	**$1,989**	**$0**	**$5,401**	**$28,409**	**$61**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Siemen	$112,359	$0	$52,484	$0	$0	$164,843	$14,646	$24,727	$30,632	$234,848	$503
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$198,687	$0	w/equip.	$0	$0	$198,687	$19,259	$0	$21,795	$239,740	$514
4.4	LT Heat Recovery & FG Saturation	$29,196	$0	$11,099	$0	$0	$40,295	$3,933	$0	$8,846	$53,073	$114
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	Flare Stack System	$0	$1,744	$710	$0	$0	$2,454	$235	$0	$538	$3,227	$7
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	$12,779	$7,292	$0	$0	$20,071	$1,837	$0	$5,477	$27,385	$59
	SUBTOTAL 4.	**$340,242**	**$14,523**	**$71,585**	**$0**	**$0**	**$426,350**	**$39,910**	**$24,727**	**$67,287**	**$558,274**	**$1,197**

Exhibit 3-121 Case L3B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case L3B - Siemens 467 MW IGCC w/ CO2										
	Plant Size:	466.5	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$73,469	$0	$62,340	$0	$0	$135,809	$13,134	$27,162	$35,221	$211,325	$453
5A.2	Elemental Sulfur Plant	$5,695	$1,135	$7,347	$0	$0	$14,177	$1,377	$0	$3,111	$18,665	$40
5A.3	Mercury Removal	$1,435	$0	$1,092	$0	$0	$2,527	$244	$126	$579	$3,476	$7
5A.4	Shift Reactors	$7,337	$0	$2,953	$0	$0	$10,291	$987	$0	$2,255	$13,533	$29
5A.5	Particulate Removal	$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	$937	$656	$0	$0	$1,593	$148	$0	$348	$2,089	$4
5A.9	HGCU Foundations	$0	$949	$612	$0	$0	$1,560	$143	$0	$511	$2,215	$5
	SUBTOTAL 5A.	**$87,936**	**$3,020**	**$75,000**	**$0**	**$0**	**$165,956**	**$16,033**	**$27,288**	**$42,026**	**$251,303**	**$539**
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System (w/5A.1)	w/5A.1	$0	w/5A.1	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$19,885	$0	$11,288	$0	$0	$31,173	$3,000	$0	$6,835	$41,008	$88
	SUBTOTAL 5B.	**$19,885**	**$0**	**$11,288**	**$0**	**$0**	**$31,173**	**$3,000**	**$0**	**$6,835**	**$41,008**	**$88**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	$98,609	$9,348	$9,861	$11,782	$129,599	$278
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$92,026**	**$806**	**$7,475**	**$0**	**$0**	**$100,307**	**$9,507**	**$9,861**	**$12,339**	**$132,014**	**$283**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,635	$0	$4,640	$0	$0	$37,275	$3,544	$0	$4,082	$44,901	$96
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,808	$1,322	$0	$0	$3,130	$275	$0	$681	$4,086	$9
7.4	Stack	$3,526	$0	$1,325	$0	$0	$4,851	$465	$0	$532	$5,847	$13
7.9	HRSG,Duct & Stack Foundations	$0	$706	$679	$0	$0	$1,385	$129	$0	$454	$1,968	$4
	SUBTOTAL 7.	**$36,161**	**$2,514**	**$7,966**	**$0**	**$0**	**$46,641**	**$4,413**	**$0**	**$5,749**	**$56,802**	**$122**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$24,841	$0	$4,166	$0	$0	$29,007	$2,783	$0	$3,179	$34,969	$75
8.2	Turbine Plant Auxiliaries	$171	$0	$392	$0	$0	$563	$55	$0	$62	$680	$1
8.3a	Condenser & Auxiliaries	$2,973	$0	$950	$0	$0	$3,923	$375	$0	$430	$4,728	$10
8.3b	Air Cooled Condenser	$27,249	$0	$5,463	$0	$0	$32,711	$3,271	$0	$7,197	$43,179	$93
8.4	Steam Piping	$3,268	$0	$2,299	$0	$0	$5,567	$478	$0	$1,511	$7,557	$16
8.9	TG Foundations	$0	$849	$1,435	$0	$0	$2,284	$216	$0	$750	$3,250	$7
	SUBTOTAL 8.	**$58,502**	**$849**	**$14,705**	**$0**	**$0**	**$74,056**	**$7,179**	**$0**	**$13,129**	**$94,364**	**$202**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,744	$0	$1,045	$0	$0	$6,789	$646	$0	$1,115	$8,551	$18
9.2	Circulating Water Pumps	$1,488	$0	$98	$0	$0	$1,586	$134	$0	$258	$1,977	$4
9.3	Circ.Water System Auxiliaries	$129	$0	$18	$0	$0	$147	$14	$0	$24	$185	$0
9.4	Circ.Water Piping	$0	$5,364	$1,391	$0	$0	$6,754	$610	$0	$1,473	$8,838	$19
9.5	Make-up Water System	$318	$0	$454	$0	$0	$772	$74	$0	$169	$1,015	$2
9.6	Component Cooling Water Sys	$633	$757	$539	$0	$0	$1,929	$181	$0	$422	$2,532	$5
9.9	Circ.Water System Foundations	$0	$1,971	$3,350	$0	$0	$5,321	$504	$0	$1,748	$7,573	$16
	SUBTOTAL 9.	**$8,311**	**$8,092**	**$6,895**	**$0**	**$0**	**$23,298**	**$2,164**	**$0**	**$5,209**	**$30,671**	**$66**

Exhibit 3-121 Case L3B Total Plant Cost Summary Details (Continued)

Client: USDOE/NETL   **Report Date:** 2009-Oct-09
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L3B - Siemens 467 MW IGCC w/ CO2
Plant Size: 466.5 MW,net   **Estimate Type:** Conceptual   **Cost Base (Jun)** 2007   ($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$26,061	$0	$12,852	$0	$0	$38,912	$3,739	$0	$4,265	$46,916	$101
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$740	$0	$805	$0	$0	$1,545	$150	$0	$254	$1,949	$4
10.7	Ash Transport & Feed Equipment	$992	$0	$239	$0	$0	$1,232	$115	$0	$202	$1,548	$3
10.8	Misc. Ash Handling Equipment	$1,532	$1,878	$561	$0	$0	$3,971	$378	$0	$652	$5,001	$11
10.9	Ash/Spent Sorbent Foundation	$0	$65	$82	$0	$0	$148	$14	$0	$48	$210	$0
	SUBTOTAL 10.	**$29,325**	**$1,943**	**$14,539**	**$0**	**$0**	**$45,807**	**$4,395**	**$0**	**$5,422**	**$55,625**	**$119**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$904	$0	$894	$0	$0	$1,797	$172	$0	$197	$2,166	$5
11.2	Station Service Equipment	$4,879	$0	$440	$0	$0	$5,319	$490	$0	$581	$6,390	$14
11.3	Switchgear & Motor Control	$9,020	$0	$1,640	$0	$0	$10,661	$989	$0	$1,747	$13,397	$29
11.4	Conduit & Cable Tray	$0	$4,190	$13,823	$0	$0	$18,014	$1,742	$0	$4,939	$24,695	$53
11.5	Wire & Cable	$0	$8,006	$5,260	$0	$0	$13,267	$964	$0	$3,558	$17,788	$38
11.6	Protective Equipment	$0	$641	$2,332	$0	$0	$2,973	$290	$0	$490	$3,753	$8
11.7	Standby Equipment	$225	$0	$219	$0	$0	$444	$42	$0	$73	$559	$1
11.8	Main Power Transformers	$17,458	$0	$136	$0	$0	$17,594	$1,330	$0	$2,839	$21,763	$47
11.9	Electrical Foundations	$0	$148	$388	$0	$0	$535	$51	$0	$176	$763	$2
	SUBTOTAL 11.	**$32,486**	**$12,985**	**$25,133**	**$0**	**$0**	**$70,604**	**$6,071**	**$0**	**$14,599**	**$91,274**	**$196**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,081	$0	$722	$0	$0	$1,804	$171	$90	$310	$2,374	$5
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	$249	$0	$159	$0	$0	$408	$39	$20	$93	$560	$1
12.7	Computer & Accessories	$5,769	$0	$185	$0	$0	$5,954	$546	$298	$680	$7,478	$16
12.8	Instrument Wiring & Tubing	$0	$2,015	$4,120	$0	$0	$6,135	$520	$307	$1,741	$8,703	$19
12.9	Other I & C Equipment	$3,856	$0	$1,873	$0	$0	$5,729	$539	$286	$983	$7,538	$16
	SUBTOTAL 12.	**$10,955**	**$2,015**	**$7,059**	**$0**	**$0**	**$20,029**	**$1,815**	**$1,001**	**$3,807**	**$26,653**	**$57**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$105	$2,249	$0	$0	$2,354	$234	$0	$776	$3,364	$7
13.2	Site Improvements	$0	$1,872	$2,487	$0	$0	$4,359	$430	$0	$1,437	$6,225	$13
13.3	Site Facilities	$3,354	$0	$3,539	$0	$0	$6,893	$680	$0	$2,272	$9,844	$21
	SUBTOTAL 13.	**$3,354**	**$1,977**	**$8,275**	**$0**	**$0**	**$13,606**	**$1,343**	**$0**	**$4,485**	**$19,434**	**$42**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,135	$3,042	$0	$0	$5,177	$476	$0	$848	$6,501	$14
14.3	Administration Building	$0	$859	$623	$0	$0	$1,482	$132	$0	$242	$1,856	$4
14.4	Circulation Water Pumphouse	$0	$161	$85	$0	$0	$247	$22	$0	$40	$308	$1
14.5	Water Treatment Buildings	$0	$473	$462	$0	$0	$935	$84	$0	$153	$1,172	$3
14.6	Machine Shop	$0	$440	$301	$0	$0	$740	$66	$0	$121	$927	$2
14.7	Warehouse	$0	$710	$458	$0	$0	$1,168	$103	$0	$191	$1,462	$3
14.8	Other Buildings & Structures	$0	$425	$331	$0	$0	$756	$68	$0	$165	$988	$2
14.9	Waste Treating Building & Str.	$0	$950	$1,816	$0	$0	$2,766	$258	$0	$605	$3,629	$8
	SUBTOTAL 14.	**$0**	**$6,418**	**$7,268**	**$0**	**$0**	**$13,685**	**$1,245**	**$0**	**$2,455**	**$17,385**	**$37**
	TOTAL COST	**$892,068**	**$76,612**	**$304,802**	**$0**	**$0**	**$1,273,481**	**$118,383**	**$62,877**	**$236,794**	**$1,691,536**	**$3,626**

Exhibit 3-122 Case L3B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$13,411	$29
1 Month Variable O&M	$3,766	$8
25% of 1 Months Fuel Cost at 100% CF	$799	$2
2% of TPC	$33,831	$73
Total	**$51,807**	**$111**
Inventory Capital		
60 day supply of consumables at 100% CF	$6,910	$15
0.5% of TPC (spare parts)	$8,458	$18
Total	**$15,368**	**$33**
Initial Cost for Catalyst and Chemicals	**$7,452**	**$16**
Land	**$900**	**$2**
Other Owner's Costs	**$253,730**	**$544**
Financing Costs	**$45,671**	**$98**
Total Owner's Costs	**$374,928**	**$804**
Total Overnight Cost (TOC)	**$2,066,464**	**$4,430**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$2,355,769**	**$5,050**

Exhibit 3-123 Case L3B Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case L3B - Siemens 467 MW IGCC w/ CO2					Heat Rate-net (Btu/kWh):	11,371
					MWe-net:	467
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$6,313,507	$13.533
Maintenance Labor Cost					$15,143,762	$32.462
Administrative & Support Labor					$5,364,317	$11.499
Property Taxes and Insurance					$33,830,718	$72.519
TOTAL FIXED OPERATING COSTS					**$60,652,304**	**$130.013**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$28,595,428**	**$0.00875**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	2,999	1.08	**$0**	**$947,169**	**$0.00029**
Chemicals						
MU & WT Chem. (lb)	0	17,866	0.17	$0	$902,873	$0.00028
Carbon (Mercury Removal) (lb)	120,179	165	1.05	$126,208	$50,483	$0.00002
COS Catalyst (lb)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	6,395	4.38	498.83	$3,190,190	$638,038	$0.00020
Selexol Solution (gal)	308,653	98	13.40	$4,135,407	$384,552	$0.00012
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.	0.89	131.27	$0	$34,196	$0.00001
Subtotal Chemicals				**$7,451,805**	**$2,010,143**	**$0.00061**
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	165	0.42	$0	$20,050	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	968	16.23	$0	$4,585,247	$0.00140
Subtotal Waste Disposal				**$0**	**$4,605,296**	**$0.00141**
By-products & Emissions						
Sulfur (tons)	0	60	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$7,451,805**	**$36,158,036**	**$0.01106**
Fuel (ton)	0	9,620	10.92	**$0**	**$30,672,715**	**$0.00938**

3.5 COP E-GAS™ IGCC CASES

This section contains an evaluation of plant designs for Cases S4A and S4B, which are based on the E-Gas™ gasifier, developed by CoP. The non-capture (A) and CO_2 capture (B) cases are very similar in terms of process, equipment, scope and arrangement, except that CO_2 capture cases includes SGS reactors, CO_2 absorption/regeneration and compression/transport systems.

Section 3.5.4 covers the results for the S4A non-capture case using PRB coal and Section 3.5.8 covers the S4B CO_2-capture case using PRB coal. The sections are organized analogously as follows:

- Process and System Description provides an overview of the specific technology's operation.
- BFD and stream table display results for major processes and streams
- Performance Results provides the main modeling results, 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 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs.

Process and System Description, Performance Results, Equipment List and Cost Estimates are repeated for Case S4B in Section 3.5.8. If the information is identical to that presented for the non-capture cases, a reference is made to the earlier section rather than repeating the information.

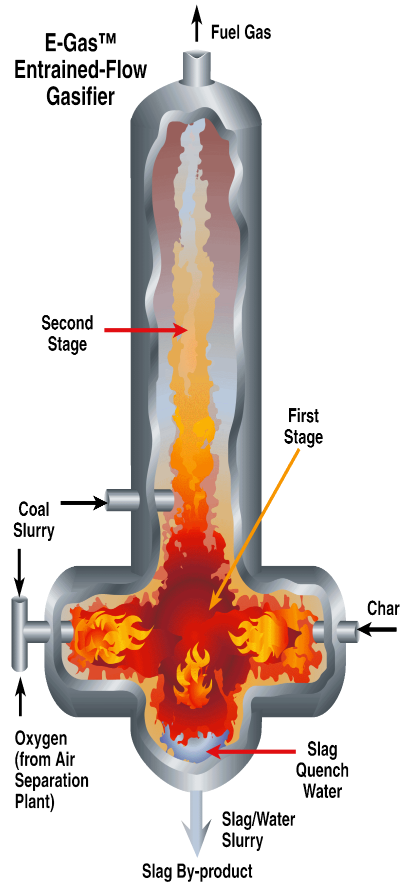
3.5.1 Gasifier Background

Development and Current Status – The CoP E-Gas™ technology was first developed by Dow Chemical (the former principal stockholder of Destec Energy, which was bought by Global Energy, Inc., the gasifier business that was later purchased by CoP) who is a major producer of chemicals. They began coal gasification development work in 1976 with bench-scale (2 kg/hr [4 lb/hr]) 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 utilizing a Westinghouse D-Class CT.. 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 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/hr (5 million scf/hr) with an energy content of about 1,370 MMkJ/hr (1,300 MMBtu/hr) (HHV). The daily coal-handling capacity of the gasifier at Wabash River is about 1,680 tonnes (1,850 tons) (MAF basis) for high-sulfur bituminous coal. The dry gas production rate is about 189,720 Nm^3/hr (6.7 million scf/hr) with an energy content of about 1,950 MMkJ/hr (1,850 MMBtu/hr) (HHV). This size matches the CT, which is a GE 7FA.

Gasifier sizing for this study was limited, per CoP recommendation, to 130 percent of the Wabash gasifier, as the maximum scale-up for a demonstrated commercial design resulting in a maximum gasifier throughput of around 4,000 tpd of as-received coal, depending on the feedstock, resulting in 2 gasifier trains for both cases.

Distinguishing Characteristics - The CoP E-Gas™ gasifier is a slurry feed, entrained flow, slagging, two-stage gasifier producing syngas at high pressures and high temperatures, which is quenched using a coal slurry, offering additional operational flexibility and the ability to tune the gasifier for different applications. Slurry feed of the coal eliminates the need to dry the coal and simplifies the feed system for the coal. The gasifier portion of the reactor is refractory lined, requiring periodic maintenance. The fire-tube SGC used by E-Gas™ has a lower capital cost than a water-tube design.

Relative 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 although the syngas exits the gasifier at lower temperatures compared to dry feed gasifiers due to the slurry quench. The upper stage slurry quench helps to increase the calorific value of the resulting syngas and the gasifier CGE, which results in a quenched syngas that is higher in methane (CH_4) content than other dry feed gasifiers. Special gasifier tuning by the vendor can adjust the composition of the syngas to achieve the desired end application, be it power or chemicals production, optimized towards high efficiency or low methane for carbon removal. Although high efficiency is generally desired, the associated high methane content will require a tradeoff in order to capture 90 percent of the overall carbon since the AGR process does not capture the carbon from the methane in the syngas.

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.

An 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. 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.

3.5.2 Key System Assumptions

System assumptions for Cases S4A and S4B CoP E-Gas™ IGCC using PRB coal, with and without CO_2 capture, are compiled in Exhibit 3-124.

Exhibit 3-124 Case S4A and S4B Plant Study Configuration Matrix

Case	S4A	S4B
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.907	0.917
Carbon Conversion, %	99.1	99.1
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	6,027 (162)	5,878 (158)
Nominal Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1,800/1,050/1,050)	12.4/538/538 (1,800/1,000/1,000)
Condenser Pressure, mm Hg (in Hg)	36 (1.4)	36 (1.4)
Combustion Turbine	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)
Gasifier Technology	CoP E-Gas™	CoP E-Gas™
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Subbituminous	Subbituminous
Coal Slurry Solids Content, %	50	49
COS Hydrolysis	Yes	Yes (Part of WGS)
Water Gas Shift	No	Yes
H_2S Separation	MDEA	Selexol (1st Stage)
Sulfur Removal, %	99.9	99.8
CO_2 Separation	None	Selexol (2nd Stage)
CO_2 Removal, %	N/A	90
Sulfur Recovery	Claus Plant with Tail Gas Treatment / Elemental Sulfur	Claus Plant with Tail Gas Treatment / Elemental Sulfur
Particulate Control	Cyclone, Candle Filter, and AGR Absorber	Cyclone, Candle Filter, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB) and N_2 Dilution	MNQC (LNB) and N_2 Dilution

Balance of Plant – All Cases

The balance of plant assumptions are common to all cases and are presented in Exhibit 3-125.

Exhibit 3-125 Balance of Plant Assumptions

Cooling water 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 CT Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and 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 GPD)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

3.5.3 Sparing Philosophy

The sparing philosophy for Cases S4A and S4B 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 ASUs (2 x 50%).
- Two trains of coal drying and dry feed systems (2 x 50%).
- Two trains of gasification, including gasifier, SGC, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of MDEA acid gas removal in non-capture cases and two trains of two-stage Selexol in CO_2 capture cases (2 x 50%).
- One train of Claus-based sulfur recovery (1 x 100%).
- Two CT/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

3.5.4 CoP E-Gas™ IGCC Non-Capture Case (S4A) Process Description

In this section the overall CoP E-Gas™ gasification process for Case S4A is described. The system description follows the BFD in Exhibit 3-126. The tables in Exhibit 3-127 provide process data for the numbered streams in the BFD for the PRB case (S4A).

Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and generally described in Section 3.1.1. For the CoP E-Gas™ slurry fed gasifier, 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 trammel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The coal is prepared into a slurry with approximately 50 percent solids and is injected in both the oxidizing and reducing portions of the E-Gas™ gasifier, referred to as the full slurry quench, tuned by CoP to achieve high CGE.

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).

Gasifier

The CoP E-Gas™ gasifier is a two-stage, entrained-flow, slurry-fed gasifier. The coal is fed to the gasifier as in the full slurry quench configuration, maximizing CGE. The slurry feed and quench configuration removes the need for coal drying and also causes lower syngas exit temperatures compared to dry feed gasifiers. Oxygen injection is scaled from the coal feed resulting in a gasifier exit temperature of around 1,900^{o}F. Roughly 20 percent of the cleaned syngas is recycled to the gasifier to moderate the temperature and aid in transport. The predicted raw gas composition and gasifier performance is based on published data and was refined with specific vendor quotes by adjusting the gasification reaction's equilibrium approach temperatures.

The two parallel CoP E-Gas™ gasifiers operate at 4.2 MPa (615 psia) and process a total of 7,144 tonne/day (7,875 tpd) of as-received PRB. The oxygen is used to gasify a portion of the slurry in the horizontal cylinder portion with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at high 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 coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1,038°C (1,900°F).

Raw Gas Cooling/Particulate Removal

High-temperature heat recovery in each gasifier train is performed by raw gas coolers in three sections, a superheater, an evaporator, and an economizer, which lower the raw gas temperature from 1,038°C (1,900°F) to 337°C (638°F). After passing through the raw gas coolers, 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 using recycled syngas. 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 exits the gasifier in liquid form. The slag is solidified in a quench tank for disposal.

Sour Water Stripper

Water condensed during the cooling of the raw gas, along with all other sour water from the plant are sent to the sour water stripper, which removes NH_3, SO_2, and other impurities from the waste stream. The sour gas stripper consists of a sour drum that accumulates sour water that 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 SRU. Remaining water is sent to wastewater treatment.

COS Hydrolysis, Mercury Removal and AGR

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 AGR process; however, because COS is not readily removed, it is first catalytically converted to H_2S in a COS hydrolysis unit.

The cooled raw gas is fed to the COS hydrolysis reactor where the COS in the sour gas is hydrolyzed with steam, over a catalyst bed, into H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the AGR process, 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 then passes through a carbon bed to remove 95 percent of the Hg.

Cool, particulate-free synthesis gas enters the MDEA absorber unit at approximately 3.7 MPa (535 psia) and 35°C (95°F). This AGR system was chosen to mimic the current Wabash CoP E-Gas™ IGCC installation, as a proven commercial offering. In the absorber, H_2S is preferentially removed from the fuel gas stream by contact with MDEA. The stripper acid gas stream, consisting of 7 percent H_2S and 91 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

The SRU is a Claus bypass type SRU utilizing oxygen instead of air. The Claus plant produces molten sulfur by converting 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 tail gas recycle results in an overall sulfur recovery exceeding 99 percent, producing 52 tonne/day (57 tpd) of sulfur.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. Feed for each case consists of acid gas from both the acid gas cleanup unit and a vent stream from the sour water stripper in the gasifier section.

In the furnace waste heat boiler 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 LP steam header.

Power Block

Clean syngas exiting the MDEA absorber is reheated, diluted with nitrogen from the ASU, and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and a portion of the air requirements for the ASU. The exhaust gas exits the CT at 586°C (1,087°F) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) and is discharged through the plant stack. The steam generated in the HRSG is used to power a steam turbine using a nominal 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

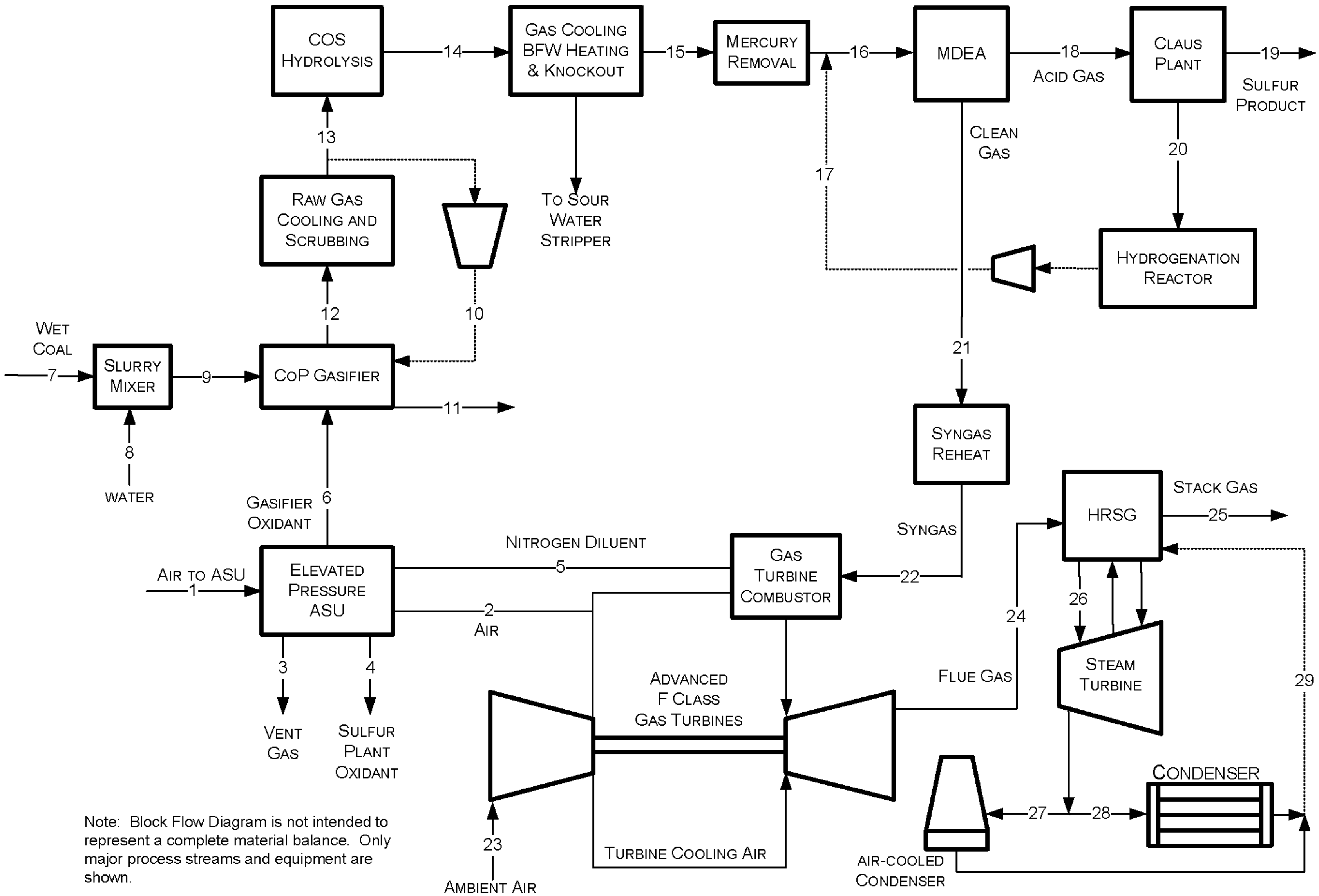
Air Separation Unit

The ASU is designed to produce approximately 5,212 tonne/day (5,746 tpd) of 95 mole percent O_2 for use in the gasifier and SRU. The plant is designed with two production trains. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as dilution in the CT combustor or as a coal transport fluid. Air extraction is taken from the CT compressor to reduce the size of the main air compressor.

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14, and 3.1.15.

Exhibit 3-126 Case S4A Process Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 3-127 Case S4A Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0093	0.0094	0.0052	0.0319	0.0021	0.0360	0.0000	0.0000	0.0000	0.0114	0.0000	0.0082	0.0080	0.0080
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0161	0.0000	0.0116	0.0113	0.0113
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3235	0.0000	0.2329	0.2264	0.2264
CO_2	0.0003	0.0003	0.0010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2450	0.0000	0.1765	0.1717	0.1717
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2625	0.3080	0.0000	0.2217	0.2156	0.2156
H_2O	0.0064	0.0104	0.0211	0.0000	0.0002	0.0000	0.0000	0.9973	0.6778	0.0833	0.0000	0.3381	0.3563	0.3562
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0031	0.0000	0.0022	0.0022	0.0022
N_2	0.7759	0.7722	0.9429	0.0178	0.9927	0.0140	0.0000	0.0000	0.0040	0.0048	0.0000	0.0035	0.0034	0.0034
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0027	0.0012	0.0048	0.0000	0.0053	0.0051	0.0051
O_2	0.2081	0.2077	0.0297	0.9503	0.0049	0.9500	0.0000	0.0000	0.0544	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	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	26,378	6,059	10,801	97	14,950	6,641	0	8,671	19,040	1,582	0	31,402	30,031	30,031
V-L Flowrate (kg/hr)	762,198	174,817	302,410	3,137	419,453	214,047	0	156,182	278,273	36,401	0	678,578	645,989	645,989
Solids Flowrate (kg/hr)	0	0	0	0	0	0	297,660	0	175,569	0	25,712	0	0	0
Temperature (°C)	6	411	15	32	93	32	6	171	149	174	1,038	1,023	232	232
Pressure (MPa, abs)	0.09	1.43	0.11	0.86	2.65	0.86	0.09	5.10	5.10	5.52	4.24	4.24	4.07	4.00
Enthalpy (kJ/kg)[A]	15.26	441.49	33.48	26.67	92.33	26.59	---	674.86	---	394.70	---	2,466.99	1,081.69	1,081.63
Density (kg/m^3)	1.1	7.2	1.3	11.0	24.4	11.0	---	836.6	---	34.2	---	8.4	21.3	21.0
V-L Molecular Weight	28.895	28.854	27.999	32.181	28.056	32.229	---	18.013	---	23.005	---	21.610	21.511	21.511
V-L Flowrate (lb_{mol}/hr)	58,154	13,357	23,812	215	32,960	14,642	0	19,116	41,975	3,488	0	69,229	66,208	66,208
V-L Flowrate (lb/hr)	1,680,359	385,406	666,700	6,915	924,735	471,894	0	344,323	613,487	80,251	0	1,496,009	1,424,161	1,424,161
Solids Flowrate (lb/hr)	0	0	0	0	0	0	656,228	0	387,064	0	56,686	0	0	0
Temperature (°F)	42	771	58	90	199	90	42	340	300	345	1,900	1,873	450	450
Pressure (psia)	13.0	207.6	16.4	125.0	384.0	125.0	13.0	740.0	740.0	800.0	614.7	614.7	589.7	579.7
Enthalpy (Btu/lb)[A]	6.6	189.8	14.4	11.5	39.7	11.4	---	290.1	---	169.7	---	1,060.6	465.0	465.0
Density (lb/ft^3)	0.070	0.451	0.083	0.687	1.522	0.688	---	52.227	---	2.133	---	0.527	1.331	1.309

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-127 Case S4A Stream Table (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction															
Ar	0.0124	0.0120	0.0037	0.0002	0.0000	0.0031	0.0126	0.0126	0.0093	0.0094	0.0094	0.0000	0.0000	0.0000	0.0000
CH_4	0.0176	0.0167	0.0000	0.0005	0.0000	0.0002	0.0175	0.0175	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.3541	0.3357	0.0057	0.0045	0.0000	0.0494	0.3529	0.3529	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.2686	0.2993	0.8515	0.9102	0.0000	0.6630	0.2676	0.2676	0.0003	0.1008	0.1008	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.3371	0.3229	0.0670	0.0047	0.0000	0.0118	0.3394	0.3394	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0014	0.0015	0.0019	0.0029	0.0000	0.2142	0.0014	0.0014	0.0064	0.0642	0.0642	1.0000	1.0000	1.0000	1.0000
H_2S	0.0035	0.0034	0.0013	0.0682	0.0000	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0053	0.0086	0.0689	0.0088	0.0000	0.0573	0.0086	0.0086	0.7759	0.7238	0.7238	0.0000	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2081	0.1018	0.1018	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	19,206	20,274	1,068	1,000	0	1,285	19,274	19,274	100,835	122,337	122,337	40,099	22,058	22,058	44,671
V-L Flowrate (kg/hr)	451,111	493,753	42,642	42,828	0	46,542	450,925	450,925	2,913,623	3,609,183	3,609,183	722,401	397,375	397,375	804,761
Solids Flowrate (kg/hr)	0	0	0	0	2,163	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	35	33	38	51	174	232	51	196	6	594	131	566	32	32	33
Pressure (MPa, abs)	3.82	3.76	5.51	0.4	0.370	0.335	3.597	3.563	0.090	0.093	0.090	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	34.80	30.60	-13.86	43.7	---	508.895	58.933	268.577	15.260	745.200	233.099	3,513.669	2,304.786	2,304.786	139.823
Density (kg/m^3)	35.8	36.8	109.0	6.7	---	2.9	31.6	21.2	1.1	0.4	0.8	34.9	0.04	0.04	995.0
V-L Molecular Weight	23.489	24.355	39.927	43	---	36.231	23.396	23.396	28.895	29.502	29.502	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	42,341	44,696	2,354	2,204	0	2,832	42,491	42,491	222,302	269,707	269,707	88,404	48,629	48,629	98,483
V-L Flowrate (lb/hr)	994,530	1,088,539	94,008	94,420	0	102,608	994,119	994,119	6,423,439	7,956,887	7,956,887	1,592,622	876,061	876,061	1,774,195
Solids Flowrate (lb/hr)	0	0	0	0	4,769	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	95	92	100	124	345	450	124	385	42	1,100	268	1,050	90	90	92
Pressure (psia)	554.7	544.7	799.5	60.0	53.6	48.6	521.7	516.7	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	15.0	13.2	-6.0	18.8	---	218.8	25.3	115.5	6.6	320.4	100.2	1,510.6	990.9	990.9	60.1
Density (lb/ft^3)	2.234	2.298	6.807	0	---	0.181	1.975	1.324	0.070	0.024	0.051	2.176	0.002	0.002	62.119

3.5.5 Case S4A Performance Results

The non-capture CoP E-Gas™ IGCC plant using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 605 MWe at a net plant efficiency of 36.7 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 3-128, which includes auxiliary power requirements. The ASU accounts for approximately 78 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 CWPs and cooling tower fan, and the air-cooled condenser account for about 7 percent of the auxiliary load, and the BFW pumps account for an additional 3 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-128 Case S4A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	S4A
Gas Turbine Power	416,400
Steam Turbine Power	321,900
TOTAL POWER, kWe	**738,300**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	550
Coal Milling	3,060
Sour Water Recycle Slurry Pump	290
Slag Handling	1,330
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	67,880
Oxygen Compressor	11,160
Nitrogen Compressors	23,850
Boiler Feedwater Pumps	4,370
Condensate Pump	260
Syngas Recycle Compressor	610
Circulating Water Pump	2,870
Ground Water Pumps	270
Cooling Tower Fans	1,870
Air Cooled Condenser Fans	3,880
Scrubber Pumps	10
Acid Gas Removal	1,320
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	2,520
Miscellaneous Balance of Plant[1]	3,000
Transformer Losses	2,010
TOTAL AUXILIARIES, kWe	**133,460**
NET POWER, kWe	**604,840**
Net Plant Efficiency, % (HHV)	36.7%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,803 (9,292)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	1,720 (1,630)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	297,660 (656,228)
Thermal Input, kWt	1,647,041
Raw Water Withdrawal, m^3/min (gpm)	11.4 (3,023)
Raw Water Consumption, m^3/min (gpm)	8.86 (2,341)

[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 PM were presented in Section 2.3. A summary of the plant air emissions for Case S4A is presented in Exhibit 3-129.

Exhibit 3-129 Cases S4A Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	29 (32)	0.006 (0.012)
NO_X	0.022 (0.052)	934 (1,030)	0.180 (0.398)
Particulates	0.003 (0.0071)	127 (140)	0.025 (0.054)
Hg	1.51E-7 (3.51E-7)	0.006 (0.007)	1.21E-6 (2.67E-6)
CO_2 gross	91.5 (212.8)	3,802,037 (4,191,028)	735 (1,620)
CO_2 net			897 (1,977)

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the MDEA AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 5 ppmv. This results in a concentration in the flue gas of less than 1 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 and recycled to the AGR to capture most of the remaining sulfur. Because the environmental target was set based on higher sulfur bituminous coal, the resulting SO_2 emissions with lower sulfur western coals are substantially less than the environmental target.

NOx emissions are limited to 15 ppmvd (as NO_2 @ 15 percent O_2) by the use of low NOx burners and nitrogen dilution of the fuel gas. 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 NOx 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 two cases is shown in Exhibit 3-130. 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 ash and as CO_2 in the stack gas and ASU vent gas.

Exhibit 3-130 Case S4A Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	149,033 (328,561)	**Slag**	1,341 (2,957)
Air (CO_2)	501 (1,105)	**Stack Gas**	148,065 (326,427)
		ASU Vent	128 (282)
Total	149,534 (329,666)	**Total**	149,534 (329,666)

Exhibit 3-131 shows the sulfur balance for the non capture case. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the ash is considered to be negligible.

Exhibit 3-131 Case S4A Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	2,165 (4,774)	**Elemental Sulfur**	2,163 (4,769)
		Stack Gas	2 (5)
Total	2,165 (4,774)	**Total**	2,165 (4,774)

Exhibit 3-132 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 coal moisture from the drying process and syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is discharged from the process to a permitted outfall. The difference between the withdrawal and discharge is the consumption.

Exhibit 3-132 Case S4A Water Balance

Water Use	Water Demand m^3/min (gpm)	Internal Recycle m^3/min (gpm)	Raw Water Withdrawal m^3/min (gpm),	Process Water Discharge m^3/min (gpm),	Raw Water Consumption m^3/min (gpm),
	S4A	S4A	S4A	S4A	S4A
Slag Handling	**0.56 (147)**	**0.56 (147)**	**0 (0)**	**0 (0)**	**0 (0)**
Slurry Water	**2.61 (689)**	**2.30 (609)**	**0.30 (80)**	**0.00 (0)**	**0.30 (80)**
SWS Blowdown	**0 (0)**	**0 (0)**	**0 (0)**	**0.08 (21)**	**-0.08 (-21)**
Condenser Makeup	**0.17 (44)**	**0 (0)**	**0.17 (44)**	**0 (0)**	**0.17 (44)**
BFW Makeup	0.17 (44)		0.17 (44)		
Cooling Tower Makeup	**11.14 (2,943)**	**0.17 (44)**	**10.97 (2,899)**	**2.51 (662)**	**8.47 (2,237)**
BFW Blowdown		0.17 (44)	-0.17 (-44)		
Total	**14.5 (3,823)**	**3.03 (800)**	**11.4 (3,023)**	**2.58 (683)**	**8.86 (2,341)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-133:

- Coal gasification and ASU
- Syngas cleanup
- Power block

An overall plant energy balance is provided in tabular form in Exhibit 3-134 based on 0°C (32°F) reference conditions. The power out is the combined CT and steam turbine power after generator losses.

Exhibit 3-133 Case S4A Heat and Mass Balance

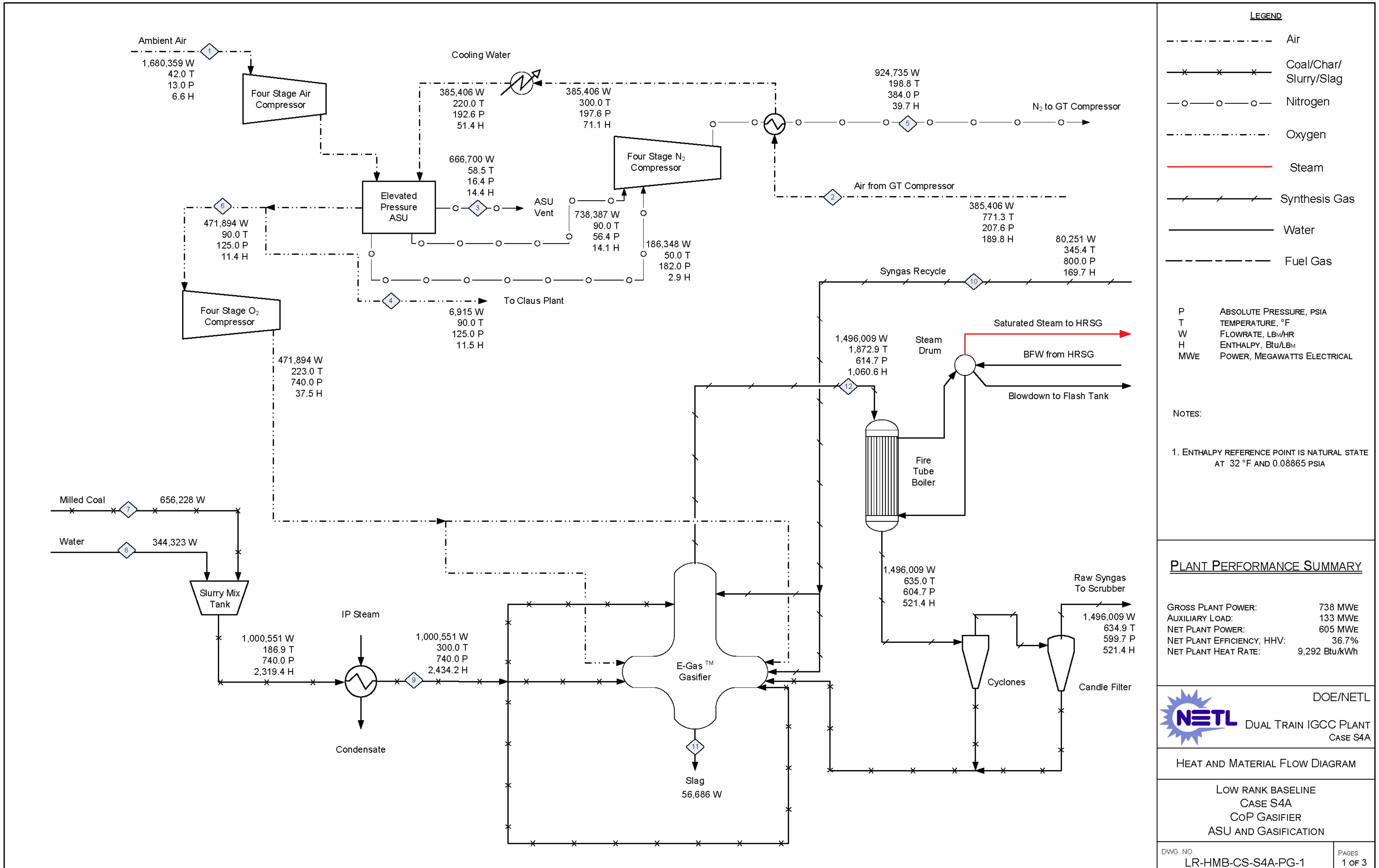


Exhibit 3-133 Case S4A Heat and Mass Balance (Continued)

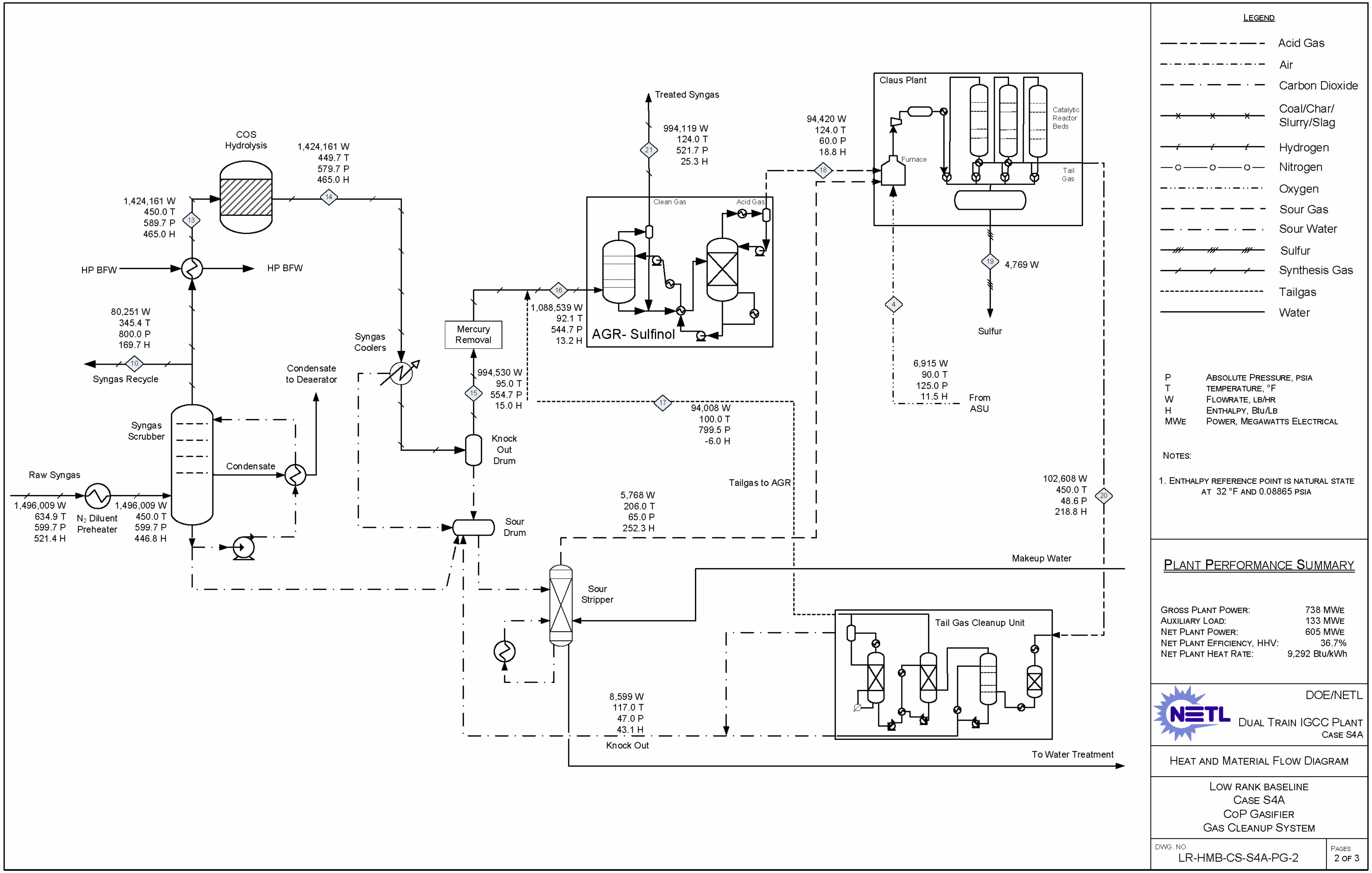


Exhibit 3-133 Case S4A Heat and Mass Balance (Continued)

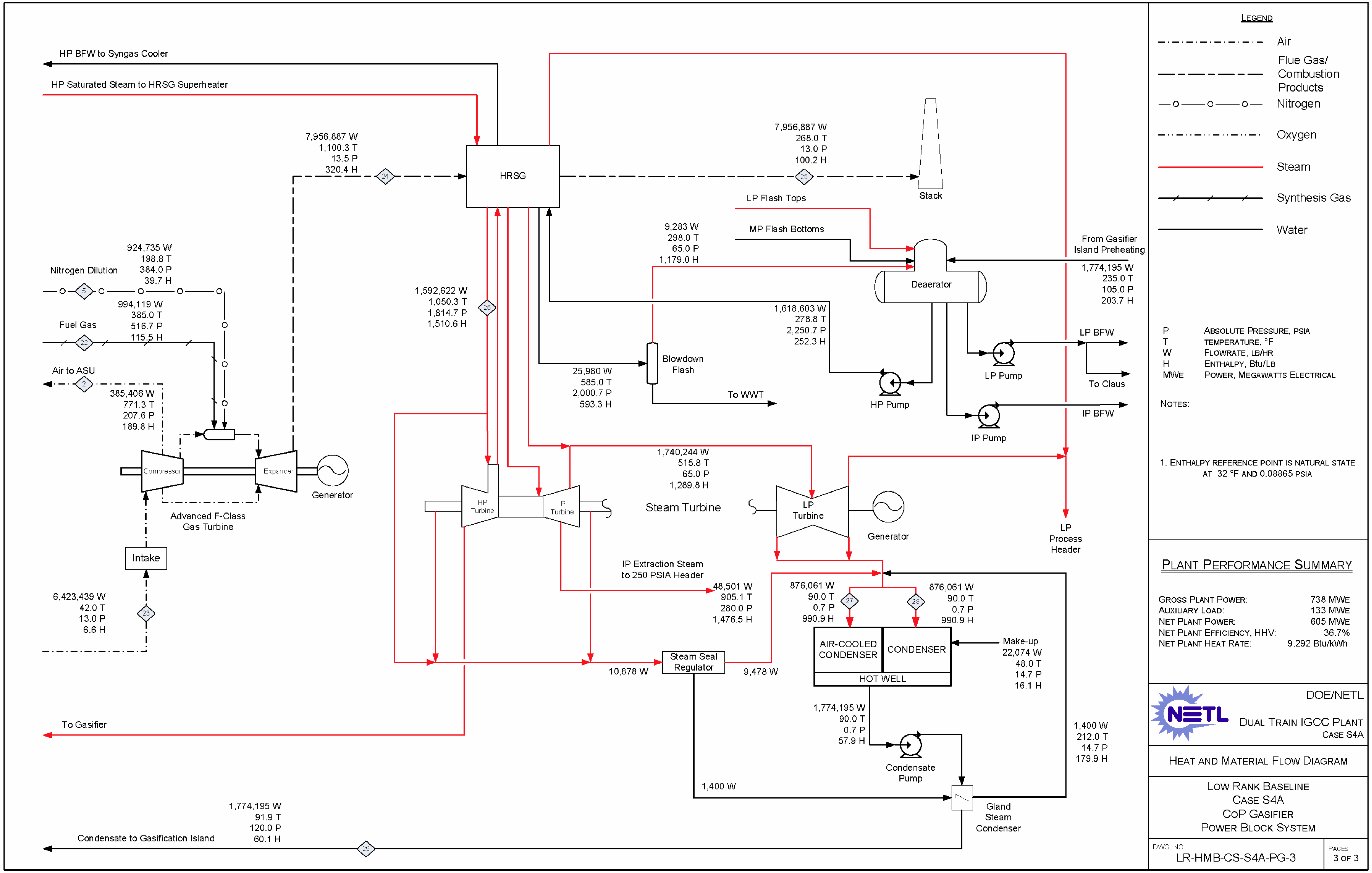


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Exhibit 3-134 Case S4A Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,929 (5,620)	3.0 (2.9)	0 (0)	5,932 (5,623)
ASU Air	0 (0)	11.6 (11.0)	0 (0)	12 (11)
GT Air	0 (0)	44.5 (42.1)	0 (0)	44 (42)
Raw Water Makeup	0 (0)	15.9 (15.1)	0 (0)	16 (15)
Auxiliary Power	0 (0)	0 (0)	480 (455)	480 (455)
Totals	**5,929 (5,620)**	**75.1 (71.1)**	**480 (455)**	**6,485 (6,146)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Intercoolers	0 (0)	273 (259)	0 (0)	273 (259)
ASU Vent	0 (0)	10.1 (9.6)	0 (0)	10 (10)
Slag	44 (42)	28.6 (27.1)	0 (0)	73 (69)
Sulfur	20 (19)	0.2 (0.2)	0 (0)	20 (19)
Cooling Tower Blowdown	0 (0)	14.0 (13.2)	0 (0)	14 (13)
HRSG Flue Gas	0 (0)	841 (797)	0 (0)	841 (797)
Condenser	0 (0)	1,724 (1,634)	0 (0)	1,724 (1,634)
Auxiliary Cooling Load	0 (0)	108 (102)	0 (0)	108 (102)
Generator Loss	0 (0)	0 (0)	40 (38)	40 (38)
Process Losses	0 (0)	724 (686)	0 (0)	724 (686)
Power	0 (0)	0 (0)	2,658 (2,519)	2,658 (2,519)
Totals	**64 (61)**	**3,722 (3,528)**	**2,698 (2,558)**	**6,485 (6,146)**

3.5.6 Case S4A Equipment Lists

Major equipment items for the COP™ gasifier with no CO_2 capture using PRB coal 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 3.5.7. 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/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (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/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	64 tonne (70 ton)	2	1
9	Feeder	Vibratory	245 tonne/hr (270 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	490 tonne/hr (540 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	490 tonne/hr (540 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	490 tonne/hr (540 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,089 tonne (1,200 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	109 tonne/hr (120 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	327 tonne/hr (360 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	653 tonne (720 ton)	1	0
4	Weigh Feeder	Belt	163 tonne/hr (180 tph)	2	0
5	Rod Mill	Rotary	163 tonne/hr (180 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	515,729 liters (136,240 gal)	2	0
7	Slurry Water Pumps	Centrifugal	2,877 lpm (760 gpm)	1	0
8	Rod Mill Discharge Tank with Agitator	Field erected	254 tonne/hr (280 tph)	2	0
9	Slurry Recycle Pumps	Centrifugal	469,773 liters (124,100 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,785 lpm (1000 gpm)	2	0
11	Slurry Storage Tank with Agitator	Field erected	2,818,640 liters (744,600 gal)	1	0
12	Slurry Recycle Pumps	Centrifugal	7,949 lpm (2,100 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,785 lpm (1,000 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	647,305 liters (171,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,419 lpm @ 91 m H_2O (1,960 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	549,754 kg/hr (1,212,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	2,309 lpm @ 27 m H_2O (610 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 7,003 lpm @ 1,890 m H_2O (1,850 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 114 lpm @ 223 m H_2O (30 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	224 GJ/hr (212 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	80,251 lpm @ 21 m H_2O (21,200 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
			(1,000 gpm @ 350 ft H_2O)		
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	2,801 lpm @ 18 m H_2O (740 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,801 lpm @ 268 m H_2O (740 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	1,173 lpm @ 49 m H_2O (310 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	556,456 liter (147,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	189 lpm (50 gpm)	2	0
19	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 two-stage, slurry-feed entrained bed	3,901 tonne/day, 4.2 MPa (4,300 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	373,307 kg/hr (823,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	373,307 kg/hr (823,000 lb/hr) 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 up flow	373,307 kg/hr (823,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	355,163 kg/hr (783,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	248,569 kg/hr, 38°C, 3.9 MPa (548,000 lb/hr, 100°F, 565 psia)	2	0
8	Synthesis Gas Reheater	Shell and tube	248,115 kg/hr (547,000 lb/hr)	2	0
9	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	373,307 kg/hr (823,000 lb/hr) syngas	2	0
10	ASU Main Air Compressor	Centrifugal, multi-stage	5,720 m^3/min @ 1.3 MPa (202,000 scfm @ 190 psia)	2	0
11	Cold Box	Vendor design	2,812 tonne/day (3,100 tpd) of 95% purity oxygen	2	0
12	Oxygen Compressor	Centrifugal, multi-stage	1,444 m^3/min (51,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
13	Primary Nitrogen Compressor	Centrifugal, multi-stage	2,605 m^3/min (92,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
14	Secondary Nitrogen Compressor	Centrifugal, single-stage	651 m^3/min (23,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
15	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	96,162 kg/hr, 411°C, 1.4 MPa (212,000 lb/hr, 771°F, 208 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	248,115 kg/hr (547,000 lb/hr) 35°C (95°F) 3.8 MPa (555 psia)	2	0
2	Sulfur Plant	Claus type	57 tonne/day (63 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	355,163 kg/hr (783,000 lb/hr) 232°C (450°F) 4.1 MPa (590 psia)	2	0
4	Acid Gas Removal Plant	Sulfinol	271,702 kg/hr (599,000 lb/hr) 33°C (92°F) 3.8 MPa (545 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	46,542 kg/hr (102,608 lb/hr) 232°C (450°F) 0.3 MPa (48.6 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	42,658 kg/hr (94,044 lb/hr)	1	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	210 MW	2	0
2	Gas Turbine Generator	TEWAC	230 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 8.4 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 397,321 kg/hr, 12.4 MPa/566°C (875,942 lb/hr, 1,800 psig/1,050°F) Reheat steam - 390,352 kg/hr, 3.1 MPa/566°C (860,579 lb/hr, 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	339 MW 12.4 MPa/566°C/566°C (1,800 psig/ 1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	380 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	50% steam flow @ design steam conditions	1	0
4	Air-cooled Condenser	---	950 GJ/hr (900 MMBtu/hr), Inlet water temperature 09°C (48°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	287,691 lpm @ 30 m (76,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) WB / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,604 GJ/hr (1,520 MMBtu/hr) 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	268,764 liters (71,000 gal)	2	0
2	Slag Crusher	Roll	15 tonne/hr (16 tph)	2	0
3	Slag Depressurizer	Proprietary	15 tonne/hr (16 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	162,773 liters (43,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	71,923 liters (19,000 gal)	2	0
6	Slag Conveyor	Drag chain	15 tonne/hr (16 tph)	2	0
7	Slag Separation Screen	Vibrating	15 tonne/hr (16 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	15 tonne/hr (16 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	230,910 liters (61,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	76 lpm @ 14 m H_2O (20 gpm @ 46 ft H_2O)	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 H_2O (70 gpm @ 1,420 ft H_2O)	2	2
13	Slag Storage Bin	Vertical, field erected	998 tonne (1,100 tons)	2	0
14	Unloading Equipment	Telescoping chute	118 tonne/hr (130 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 380 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 57 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 32 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	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

3.5.7 Case S4A Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-135 shows the TPC summary organized by cost account for the Case S4A. A more detailed breakdown of the capital costs is shown in Exhibit 3-136. Exhibit 3-137 shows the calculation and addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-138 shows the initial and annual O&M costs for Case S4A.

The estimated TOC of the CoP E-Gas™ IGCC plant with no CO_2 capture using PRB coal is $2,771/kW. Process contingency represents 2 percent, project contingency represents 11 percent, and owner's costs represent 18 percent of TOC. The COE is 78.7 mills/kWh.

Exhibit 3-135 Case S4A Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S4A - ConocoPhillips IGCC w/o CO2										
	Plant Size:	604.8	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$17,180	$3,193	$13,323	$0	$0	**$33,696**	$3,059	$0	$7,351	**$44,106**	$73
2	COAL & SORBENT PREP & FEED	$29,627	$5,415	$17,900	$0	$0	**$52,942**	$4,753	$0	$11,539	**$69,233**	$114
3	FEEDWATER & MISC. BOP SYSTEMS	$9,132	$8,032	$8,390	$0	$0	**$25,554**	$2,398	$0	$6,265	**$34,218**	$57
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$141,056	$0	$76,694	$0	$0	**$217,750**	$19,592	$30,569	$40,951	**$308,862**	$511
4.2	Syngas Cooling	w/4.1	w/4.1	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$170,773	$0	w/equip.	$0	$0	**$170,773**	$16,553	$0	$18,733	**$206,059**	$341
4.4-4.9	Other Gasification Equipment	$21,702	$12,064	$14,900	$0	$0	**$48,667**	$4,645	$0	$11,574	**$64,886**	$107
	SUBTOTAL 4	**$333,532**	**$12,064**	**$91,594**	**$0**	**$0**	**$437,191**	**$40,790**	**$30,569**	**$71,257**	**$579,807**	**$959**
5A	GAS CLEANUP & PIPING	$53,335	$2,999	$49,299	$0	$0	**$105,634**	$10,211	$91	$23,330	**$139,266**	$230
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	**$92,022**	$8,724	$4,601	$10,535	**$115,882**	$192
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$4
	SUBTOTAL 6	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$196**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,203	$0	$4,721	$0	$0	**$37,924**	$3,606	$0	$4,153	**$45,683**	$76
7.2-7.9	Open, Ductwork and Stack	$3,336	$2,378	$3,115	$0	$0	**$8,829**	$819	$0	$1,570	**$11,217**	$19
	SUBTOTAL 7	**$36,539**	**$2,378**	**$7,836**	**$0**	**$0**	**$46,753**	**$4,424**	**$0**	**$5,723**	**$56,900**	**$94**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$32,394	$0	$5,646	$0	$0	**$38,040**	$3,650	$0	$4,169	**$45,859**	$76
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$40,553	$1,120	$13,767	$0	$0	**$55,441**	$5,370	$0	$12,451	**$73,262**	$121
	SUBTOTAL 8	**$72,947**	**$1,120**	**$19,413**	**$0**	**$0**	**$93,480**	**$9,020**	**$0**	**$16,620**	**$119,121**	**$197**
9	COOLING WATER SYSTEM	$7,368	$7,303	$6,231	$0	$0	**$20,903**	$1,942	$0	$4,678	**$27,522**	$46
10	ASH/SPENT SORBENT HANDLING SYS	$21,024	$1,598	$10,432	$0	$0	**$33,053**	$3,171	$0	$3,953	**$40,177**	$66
11	ACCESSORY ELECTRIC PLANT	$28,690	$10,887	$21,639	$0	$0	**$61,216**	$5,261	$0	$12,523	**$78,999**	$131
12	INSTRUMENTATION & CONTROL	$10,114	$1,861	$6,517	$0	$0	**$18,492**	$1,676	$925	$3,514	**$24,607**	$41
13	IMPROVEMENTS TO SITE	$3,329	$1,962	$8,214	$0	$0	**$13,505**	$1,333	$0	$4,452	**$19,290**	$32
14	BUILDINGS & STRUCTURES	$0	$6,804	$7,884	$0	$0	**$14,688**	$1,338	$0	$2,615	**$18,641**	$31
	TOTAL COST	**$708,571**	**$66,423**	**$275,834**	**$0**	**$0**	**$1,050,827**	**$98,259**	**$36,187**	**$184,912**	**$1,370,185**	**$2,265**

Exhibit 3-136 Case S4A Total Plant Cost Details

	Client:	USDOE/NETL								**Report Date:**	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S4A - ConocoPhillips IGCC w/o CO2										
	Plant Size:	604.8	MW,net	**Estimate Type:**		Conceptual				**Cost Base (Jun)**	2007	($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	$4,512	$0	$2,205	$0	$0	$6,716	$602	$0	$1,464	$8,782	$15
1.2	Coal Stackout & Reclaim	$5,830	$0	$1,413	$0	$0	$7,243	$635	$0	$1,576	$9,454	$16
1.3	Coal Conveyors & Yd Crush	$5,420	$0	$1,398	$0	$0	$6,819	$599	$0	$1,484	$8,901	$15
1.4	Other Coal Handling	$1,418	$0	$324	$0	$0	$1,742	$152	$0	$379	$2,273	$4
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	$3,193	$7,983	$0	$0	$11,176	$1,071	$0	$2,449	$14,696	$24
	SUBTOTAL 1.	**$17,180**	**$3,193**	**$13,323**	**$0**	**$0**	**$33,696**	**$3,059**	**$0**	**$7,351**	**$44,106**	**$73**
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	$1,950	$467	$306	$0	$0	$2,723	$233	$0	$591	$3,546	$6
2.3	Slurry Prep & Feed	$26,604	$0	$11,832	$0	$0	$38,436	$3,432	$0	$8,374	$50,241	$83
2.4	Misc.Coal Prep & Feed	$1,072	$780	$2,340	$0	$0	$4,193	$385	$0	$916	$5,493	$9
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	$4,168	$3,422	$0	$0	$7,590	$703	$0	$1,659	$9,952	$16
	SUBTOTAL 2.	**$29,627**	**$5,415**	**$17,900**	**$0**	**$0**	**$52,942**	**$4,753**	**$0**	**$11,539**	**$69,233**	**$114**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$3,252	$5,584	$2,948	$0	$0	$11,784	$1,092	$0	$2,575	$15,451	$26
3.2	Water Makeup & Pretreating	$450	$47	$251	$0	$0	$748	$71	$0	$246	$1,065	$2
3.3	Other Feedwater Subsystems	$1,779	$601	$541	$0	$0	$2,921	$263	$0	$637	$3,821	$6
3.4	Service Water Systems	$257	$530	$1,839	$0	$0	$2,626	$256	$0	$865	$3,747	$6
3.5	Other Boiler Plant Systems	$1,381	$535	$1,326	$0	$0	$3,242	$307	$0	$710	$4,259	$7
3.6	FO Supply Sys & Nat Gas	$313	$591	$552	$0	$0	$1,456	$140	$0	$319	$1,916	$3
3.7	Waste Treatment Equipment	$629	$0	$383	$0	$0	$1,012	$99	$0	$333	$1,444	$2
3.8	Misc. Power Plant Equipment	$1,072	$143	$550	$0	$0	$1,766	$171	$0	$581	$2,517	$4
	SUBTOTAL 3.	**$9,132**	**$8,032**	**$8,390**	**$0**	**$0**	**$25,554**	**$2,398**	**$0**	**$6,265**	**$34,218**	**$57**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$141,056	$0	$76,694	$0	$0	$217,750	$19,592	$30,569	$40,951	$308,862	$511
4.2	Syngas Cooling	w/4.1	w/4.1	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$170,773	$0	w/equip.	$0	$0	$170,773	$16,553	$0	$18,733	$206,059	$341
4.4	LT Heat Recovery & FG Saturation	$21,702	$0	$8,250	$0	$0	$29,952	$2,923	$0	$6,575	$39,451	$65
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	Flare Stack System	$0	$1,428	$581	$0	$0	$2,009	$193	$0	$440	$2,642	$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	$10,636	$6,069	$0	$0	$16,705	$1,529	$0	$4,559	$22,793	$38
	SUBTOTAL 4.	**$333,532**	**$12,064**	**$91,594**	**$0**	**$0**	**$437,191**	**$40,790**	**$30,569**	**$71,257**	**$579,807**	**$959**

Exhibit 3-136 Case S4A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
TOTAL PLANT COST SUMMARY												
	Case:	Case S4A - ConocoPhillips IGCC w/o CO2										
	Plant Size:	604.8	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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	$40,356	$0	$34,243	$0	$0	$74,599	$7,215	$0	$16,363	$98,176	$162
5A.2	Elemental Sulfur Plant	$5,512	$1,098	$7,111	$0	$0	$13,721	$1,333	$0	$3,011	$18,064	$30
5A.3	Mercury Removal	$1,039	$0	$790	$0	$0	$1,829	$177	$91	$419	$2,516	$4
5A.4	COS Hydrolysis	$4,527	$0	$5,912	$0	$0	$10,440	$1,015	$0	$2,291	$13,746	$23
5A.5	Particulate Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$1,902	$320	$180	$0	$0	$2,402	$228	$0	$526	$3,156	$5
5A.7	Fuel Gas Piping	$0	$785	$550	$0	$0	$1,335	$124	$0	$292	$1,751	$3
5A.9	HGCU Foundations	$0	$795	$513	$0	$0	$1,308	$120	$0	$428	$1,857	$3
	SUBTOTAL 5A.	**$53,335**	**$2,999**	**$49,299**	**$0**	**$0**	**$105,634**	**$10,211**	**$91**	**$23,330**	**$139,266**	**$230**
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	$85,752	$0	$6,269	$0	$0	$92,022	$8,724	$4,601	$10,535	$115,882	$192
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$4
	SUBTOTAL 6.	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$196**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,203	$0	$4,721	$0	$0	$37,924	$3,606	$0	$4,153	$45,683	$76
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,710	$1,220	$0	$0	$2,930	$257	$0	$637	$3,824	$6
7.4	Stack	$3,336	$0	$1,253	$0	$0	$4,589	$440	$0	$503	$5,532	$9
7.9	HRSG,Duct & Stack Foundations	$0	$668	$642	$0	$0	$1,310	$122	$0	$430	$1,862	$3
	SUBTOTAL 7.	**$36,539**	**$2,378**	**$7,836**	**$0**	**$0**	**$46,753**	**$4,424**	**$0**	**$5,723**	**$56,900**	**$94**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$32,394	$0	$5,646	$0	$0	$38,040	$3,650	$0	$4,169	$45,859	$76
8.2	Turbine Plant Auxiliaries	$218	$0	$499	$0	$0	$716	$70	$0	$79	$865	$1
8.3a	Condenser & Auxiliaries	$3,404	$0	$1,088	$0	$0	$4,492	$430	$0	$492	$5,414	$9
8.3b	Air Cooled Condenser	$31,198	$0	$6,255	$0	$0	$37,453	$3,745	$0	$8,240	$49,438	$82
8.4	Steam Piping	$5,733	$0	$4,033	$0	$0	$9,766	$839	$0	$2,651	$13,256	$22
8.9	TG Foundations	$0	$1,120	$1,893	$0	$0	$3,013	$286	$0	$990	$4,289	$7
	SUBTOTAL 8.	**$72,947**	**$1,120**	**$19,413**	**$0**	**$0**	**$93,480**	**$9,020**	**$0**	**$16,620**	**$119,121**	**$197**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,099	$0	$993	$0	$0	$6,092	$580	$0	$1,001	$7,673	$13
9.2	Circulating Water Pumps	$1,320	$0	$82	$0	$0	$1,402	$118	$0	$228	$1,749	$3
9.3	Circ.Water System Auxiliaries	$116	$0	$17	$0	$0	$133	$13	$0	$22	$167	$0
9.4	Circ.Water Piping	$0	$4,840	$1,255	$0	$0	$6,095	$551	$0	$1,329	$7,975	$13
9.5	Make-up Water System	$261	$0	$374	$0	$0	$635	$61	$0	$139	$835	$1
9.6	Component Cooling Water Sys	$571	$683	$486	$0	$0	$1,741	$163	$0	$381	$2,285	$4
9.9	Circ.Water System Foundations	$0	$1,779	$3,025	$0	$0	$4,804	$455	$0	$1,578	$6,838	$11
	SUBTOTAL 9.	**$7,368**	**$7,303**	**$6,231**	**$0**	**$0**	**$20,903**	**$1,942**	**$0**	**$4,678**	**$27,522**	**$46**

Exhibit 3-136 Case S4A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S4A - ConocoPhillips IGCC w/o CO2										
	Plant Size:	604.8	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$18,340	$0	$9,044	$0	$0	$27,384	$2,631	$0	$3,001	$33,016	$55
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$608	$0	$662	$0	$0	$1,270	$123	$0	$209	$1,602	$3
10.7	Ash Transport & Feed Equipment	$816	$0	$197	$0	$0	$1,013	$94	$0	$166	$1,273	$2
10.8	Misc. Ash Handling Equipment	$1,260	$1,544	$461	$0	$0	$3,265	$311	$0	$536	$4,112	$7
10.9	Ash/Spent Sorbent Foundation	$0	$54	$68	$0	$0	$121	$11	$0	$40	$173	$0
	SUBTOTAL 10.	**$21,024**	**$1,598**	**$10,432**	**$0**	**$0**	**$33,053**	**$3,171**	**$0**	**$3,953**	**$40,177**	**$66**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$951	$0	$940	$0	$0	$1,891	$181	$0	$207	$2,279	$4
11.2	Station Service Equipment	$4,020	$0	$362	$0	$0	$4,383	$404	$0	$479	$5,265	$9
11.3	Switchgear & Motor Control	$7,433	$0	$1,352	$0	$0	$8,784	$815	$0	$1,440	$11,039	$18
11.4	Conduit & Cable Tray	$0	$3,453	$11,390	$0	$0	$14,843	$1,436	$0	$4,070	$20,348	$34
11.5	Wire & Cable	$0	$6,597	$4,335	$0	$0	$10,931	$794	$0	$2,931	$14,657	$24
11.6	Protective Equipment	$0	$680	$2,474	$0	$0	$3,154	$308	$0	$519	$3,981	$7
11.7	Standby Equipment	$234	$0	$229	$0	$0	$463	$44	$0	$76	$583	$1
11.8	Main Power Transformers	$16,052	$0	$145	$0	$0	$16,197	$1,225	$0	$2,613	$20,035	$33
11.9	Electrical Foundations	$0	$157	$412	$0	$0	$569	$54	$0	$187	$811	$1
	SUBTOTAL 11.	**$28,690**	**$10,887**	**$21,639**	**$0**	**$0**	**$61,216**	**$5,261**	**$0**	**$12,523**	**$78,999**	**$131**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$998	$0	$667	$0	$0	$1,665	$158	$83	$286	$2,192	$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	$229	$0	$147	$0	$0	$377	$36	$19	$86	$517	$1
12.7	Computer & Accessories	$5,326	$0	$171	$0	$0	$5,497	$505	$275	$628	$6,904	$11
12.8	Instrument Wiring & Tubing	$0	$1,861	$3,804	$0	$0	$5,664	$480	$283	$1,607	$8,035	$13
12.9	Other I & C Equipment	$3,560	$0	$1,729	$0	$0	$5,289	$498	$264	$908	$6,959	$12
	SUBTOTAL 12.	**$10,114**	**$1,861**	**$6,517**	**$0**	**$0**	**$18,492**	**$1,676**	**$925**	**$3,514**	**$24,607**	**$41**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$104	$2,232	$0	$0	$2,337	$232	$0	$771	$3,340	$6
13.2	Site Improvements	$0	$1,858	$2,469	$0	$0	$4,326	$427	$0	$1,426	$6,179	$10
13.3	Site Facilities	$3,329	$0	$3,513	$0	$0	$6,842	$675	$0	$2,255	$9,771	$16
	SUBTOTAL 13.	**$3,329**	**$1,962**	**$8,214**	**$0**	**$0**	**$13,505**	**$1,333**	**$0**	**$4,452**	**$19,290**	**$32**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,682	$3,820	$0	$0	$6,502	$598	$0	$1,065	$8,165	$13
14.3	Administration Building	$0	$842	$611	$0	$0	$1,453	$129	$0	$237	$1,819	$3
14.4	Circulation Water Pumphouse	$0	$166	$88	$0	$0	$254	$22	$0	$41	$317	$1
14.5	Water Treatment Buildings	$0	$376	$367	$0	$0	$742	$67	$0	$121	$931	$2
14.6	Machine Shop	$0	$431	$295	$0	$0	$726	$64	$0	$119	$909	$2
14.7	Warehouse	$0	$696	$449	$0	$0	$1,145	$101	$0	$187	$1,433	$2
14.8	Other Buildings & Structures	$0	$417	$324	$0	$0	$741	$66	$0	$161	$969	$2
14.9	Waste Treating Building & Str.	$0	$931	$1,780	$0	$0	$2,712	$253	$0	$593	$3,557	$6
	SUBTOTAL 14.	**$0**	**$6,804**	**$7,884**	**$0**	**$0**	**$14,688**	**$1,338**	**$0**	**$2,615**	**$18,641**	**$31**
	TOTAL COST	**$708,571**	**$66,423**	**$275,834**	**$0**	**$0**	**$1,050,827**	**$98,259**	**$36,187**	**$184,912**	**$1,370,185**	**$2,265**

Exhibit 3-137 Case S4A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$13,902	$23
1 Month Variable O&M	$3,684	$6
25% of 1 Months Fuel Cost at 100% CF	$911	$2
2% of TPC	$27,404	$45
Total	**$45,902**	**$76**
Inventory Capital		
60 day supply of consumables at 100% CF	$7,551	$12
0.5% of TPC (spare parts)	$6,851	$11
Total	**$14,402**	**$24**
Initial Cost for Catalyst and Chemicals	**$1,878**	**$3**
Land	**$900**	**$1**
Other Owner's Costs	**$205,528**	**$340**
Financing Costs	**$36,995**	**$61**
Total Owner's Costs	**$305,605**	**$505**
Total Overnight Cost (TOC)	**$1,675,790**	**$2,771**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$1,910,400**	**$3,159**

Exhibit 3-138 Case S4A Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun)	2007
Case S4A - ConocoPhillips IGCC w/o CO2					Heat Rate-net(Btu/kWh):	9,292
					MWe-net:	605
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$5,918,913	$9.786
Maintenance Labor Cost					$16,324,769	$26.990
Administrative & Support Labor					$5,560,920	$9.194
Property Taxes and Insurance					$27,403,700	$45.307
TOTAL FIXED OPERATING COSTS					**$55,208,302**	**$91.278**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$30,375,594**	**$0.00717**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	2,167.92	1.08	**$0**	**$684,736**	**$0.00016**
Chemicals						
MU & WT Chem. (lb)	0	12,916	0.17	$0	$652,713	$0.00015
Carbon (Mercury Removal) (lb)	74,181	102	1.05	$77,902	$31,161	$0.00001
COS Catalyst (m3)	451	0.31	2,397.36	$1,080,271	$216,054	$0.00005
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0	$0.00000
MDEA Solution (gal)	82,792	56	8.70	$720,105	$142,912	$0.00003
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.	0.85	131.27	$0	$32,699	$0.00001
Subtotal Chemicals				**$1,878,278**	**$1,075,539**	**$0.00025**
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	102	0.42	$0	$12,376	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	680	16.23	$0	$3,222,772	$0.00076
Subtotal Waste Disposal				**$0**	**$3,235,147**	**$0.00076**
By-products & Emissions						
Sulfur (tons)	0	57	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,878,278**	**$35,371,017**	**$0.00834**
Fuel (ton)	0	7,875	15.22	**$0**	**$34,989,859**	**$0.00825**

3.5.8 CoP E-Gas™ IGCC CO_2 Capture Cases (S4B) Process Description

Case S4B is configured to produce electric power with CO_2 capture. The plant configuration is similar to Cases S4A with the major differences being the addition of WGS, the use of a two-stage Selexol AGR plant instead of MDEA and subsequent compression of the captured CO_2 stream. The gross power output is constrained by the capacity of the two CTs, 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 S4A.

The process description for Case S4B is similar to Case S4A with several notable exceptions to accommodate CO_2 capture. A BFD for the CO_2 capture case is shown in Exhibit 3-139 and stream tables are shown in Exhibit 3-140. Instead of repeating the entire process description, only differences from Cases S4A are reported here.

Coal Preparation and Feed Systems

Same as for Case S4A except for the coal is slurried to 49 percent solids for injection into the two stages of the gasifier.

Gasification

The gasification process is similar to Case S4A except the coal feed (as-received) to the two gasifiers is 7,349 tonne/day (8,101 tpd). For cases with a design target of 90 percent overall carbon capture, the gasifier can be tuned to minimize methane concentrations, which end up in the flue gas as the gas cleanup process does not capture the carbon in the form of methane. Varying slurry concentration and different combinations of two stage slurry injection were considered based on vendor supplied gasifier performance, guaranteeing a maximum methane concentration, with the tradeoff of lower CGE. This reduction in CGE is mainly due to the increased slurry water diluent, but for carbon capture requiring WGS reaction, this slurry water replaces injected shift steam that would otherwise be extracted from the steam turbine.

Raw Gas Cooling/Particulate Removal

No differences from Case S4A.

Sour Water Stripper

No differences from Case S4A.

Sour Gas Shift

The SGS process was described in Section 3.1.6. The water concentration in the syngas is adjusted upstream of the shift reactors by the injection of shift steam, extracted from the steam cycle. The hot syngas exiting the first stage of SGS is used to superheat steam. One more stage of SGS (for a total of two) results in approximately 97 percent overall conversion of CO to CO_2. The warm syngas from the second stage of SGS is cooled to preheat the syngas prior to the first stage of SGS. The SGS catalyst 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 AGR

Mercury removal is the same as in Case S4A.

The AGR process in Case S4B 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, a CO_2-rich stream, and an acid gas feed to the Claus plant. The acid gas contains about 17 percent H_2S and 68 percent CO_2 with the balance primarily H_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 two pressure levels. The LP stream is compressed from 0.12 MPa (17 psia) to 1.0 MPa (150 psia) and then combined with the HP stream. The combined stream is further compressed to a SC condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dew point of -40ºC (-40°F) using a thermal swing adsorptive dryer. The raw CO_2 stream from the Selexol process contains over 99 percent CO_2. The dehydrated CO_2 is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.6.

Claus Unit

The Claus plant is the same as Cases S4A except 53 tonne/day (59 tpd) of sulfur are produced.

Power Block

Clean syngas from the AGR plant is reheated to 196°C (385°F). The conditioned syngas is diluted with nitrogen, and then enters the CT burner. The exhaust gas exits the CT at 561°C (1,042°F) and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) 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 nominal 12.4MPa/538°C/538°C (1,800 psig/1,000°F/1,000°F) steam cycle. There is no air integration between the CT and the ASU in the capture case.

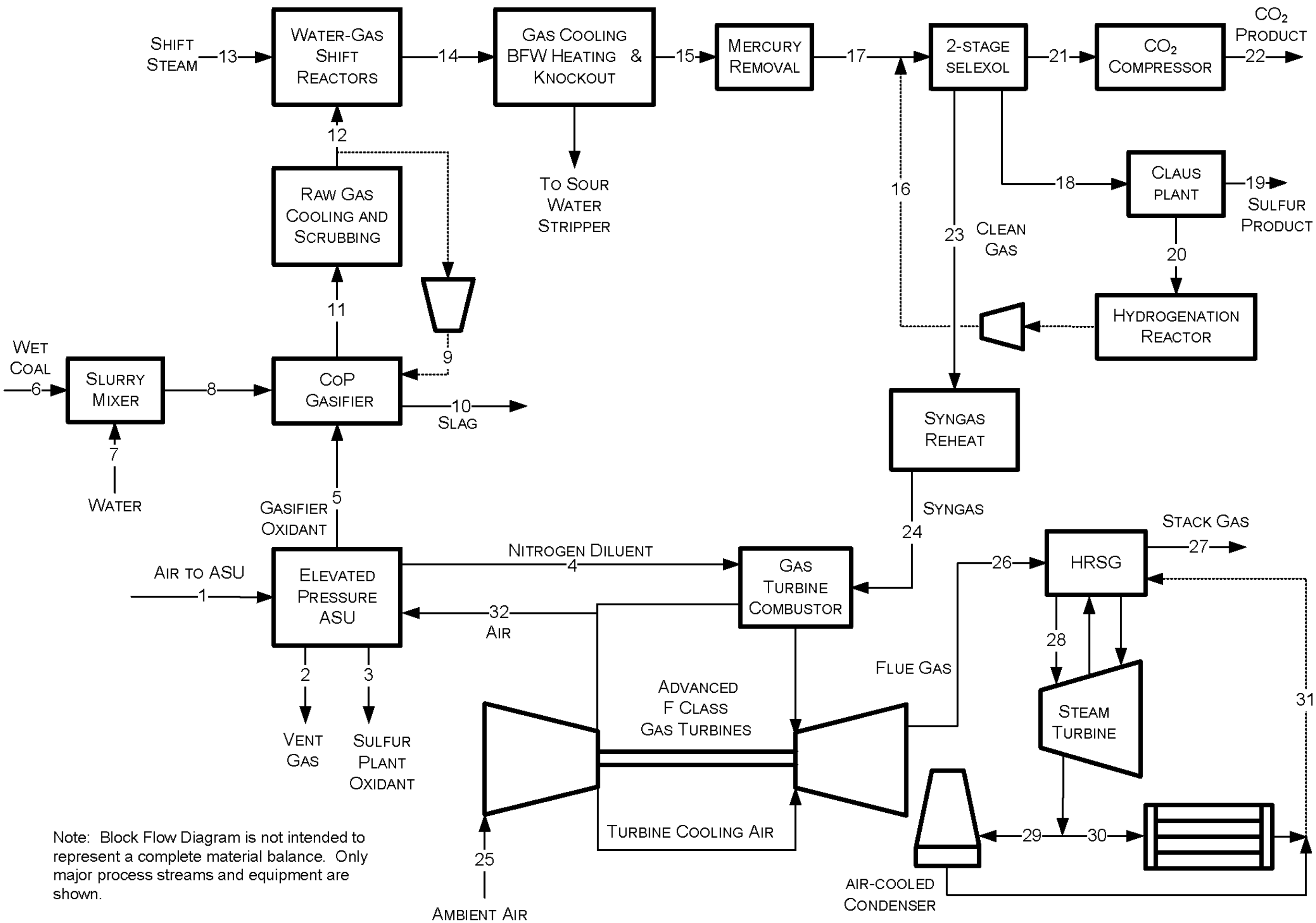
ASU

The same elevated pressure ASU is used as in Cases S4A except the output is 5,323 tonne/day (5,867 tpd) of 95 mole percent oxygen and 11,750 tonne/day (12,952 tpd) of nitrogen.

Balance of Plant

Balance of plant items were covered in Sections 3.1.12, 3.1.13, 3.1.14 and 3.1.15.

Exhibit 3-139 Case S4B Process Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 3-140 Case S4B Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0058	0.0318	0.0022	0.0360	0.0000	0.0000	0.0000	0.0077	0.0000	0.0079	0.0077	0.0000	0.0067	0.0090
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0068	0.0000	0.0069	0.0068	0.0000	0.0059	0.0079
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2356	0.0000	0.2419	0.2356	0.0000	0.0027	0.0036
CO_2	0.0003	0.0012	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1536	0.0000	0.1577	0.1536	0.0000	0.3376	0.4498
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2625	0.2137	0.0000	0.2194	0.2137	0.0000	0.3901	0.5197
H_2O	0.0064	0.0230	0.0000	0.0002	0.0000	0.0000	0.9993	0.6787	0.3744	0.0000	0.3577	0.3744	1.0000	0.2498	0.0016
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0022	0.0021	0.0000	0.0019	0.0025
N_2	0.7759	0.9350	0.0178	0.9925	0.0140	0.0000	0.0000	0.0040	0.0050	0.0000	0.0051	0.0050	0.0000	0.0044	0.0058
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0003	0.0011	0.0000	0.0011	0.0011	0.0000	0.0010	0.0000
O_2	0.2081	0.0350	0.9504	0.0051	0.9500	0.0000	0.0000	0.0544	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	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	33,471	9,121	49	17,449	6,832	0	8,919	19,585	2,404	0	33,454	31,944	4,593	36,538	27,421
V-L Flowrate (kg/hr)	967,149	255,486	1,588	489,579	220,189	0	160,664	286,258	50,937	0	711,541	676,731	82,753	759,484	595,271
Solids Flowrate (kg/hr)	0	0	0	0	0	306,201	0	180,607	0	26,450	0	0	0	0	0
Temperature (°C)	6	15	32	93	32	6	149	149	241	1,038	1,017	194	288	204	35
Pressure (MPa, abs)	0.09	0.11	0.86	2.65	0.86	0.09	5.10	5.10	5.52	4.24	4.24	4.00	4.14	3.79	3.62
Enthalpy (kJ/kg)[A]	15.26	33.66	26.67	92.32	26.59	---	571.24	---	1,140.59	---	2,517.45	1,069.76	2,956.19	859.79	38.17
Density (kg/m^3)	1.1	1.3	11.0	24.4	11.0	---	863.7	---	28.2	---	8.3	22.6	18.2	20.2	31.6
V-L Molecular Weight	28.895	28.011	32.181	28.058	32.229	---	18.015	---	21.185	---	21.270	21.185	18.015	20.786	21.709
V-L Flowrate (lb_{mol}/hr)	73,791	20,108	109	38,468	15,062	0	19,662	43,177	5,301	0	73,752	70,425	10,127	80,552	60,452
V-L Flowrate (lb/hr)	2,132,199	563,251	3,500	1,079,336	485,435	0	354,203	631,091	112,296	0	1,568,680	1,491,937	182,439	1,674,377	1,312,349
Solids Flowrate (lb/hr)	0	0	0	0	0	675,058	0	398,171	0	58,313	0	0	0	0	0
Temperature (°F)	42	59	90	199	90	42	300	300	465	1,900	1,863	382	550	400	95
Pressure (psia)	13.0	16.4	125.0	384.0	125.0	13.0	740.0	740.0	800.0	614.7	614.7	579.7	600.0	549.7	524.7
Enthalpy (Btu/lb)[A]	6.6	14.5	11.5	39.7	11.4	---	245.6	---	490.4	---	1,082.3	459.9	1,270.9	369.6	16.4
Density (lb/ft^3)	0.070	0.084	0.687	1.522	0.688	---	53.921	---	1.761	---	0.521	1.409	1.135	1.261	1.972

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-140 Case S4B Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
V-L Mole Fraction																
Ar	0.0084	0.0090	0.0027	0.0000	0.0062	0.0002	0.0002	0.0154	0.0154	0.0093	0.0096	0.0096	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0079	0.0042	0.0000	0.0014	0.0004	0.0004	0.0132	0.0132	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0071	0.0036	0.0012	0.0000	0.0784	0.0001	0.0001	0.0063	0.0063	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.7741	0.4498	0.6789	0.0000	0.4933	0.9929	0.9955	0.0603	0.0603	0.0003	0.0102	0.0102	0.0000	0.0000	0.0000	0.0000
COS	0.0000	0.0000	0.0001	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.1630	0.5197	0.1090	0.0000	0.0466	0.0039	0.0039	0.8937	0.8937	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0018	0.0016	0.0345	0.0000	0.3407	0.0025	0.0000	0.0001	0.0001	0.0064	0.1204	0.1204	1.0000	1.0000	1.0000	1.0000
H_2S	0.0043	0.0025	0.1685	0.0000	0.0010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0412	0.0058	0.0009	0.0000	0.0303	0.0000	0.0000	0.0110	0.0110	0.7759	0.7535	0.7535	0.0000	0.0000	0.0000	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	0.0000	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	0.2081	0.1062	0.1062	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0019	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	367	27,421	419	0	500	11,456	11,427	15,913	15,913	100,835	127,035	127,035	32,906	22,438	22,438	49,951
V-L Flowrate (kg/hr)	13,301	595,271	15,361	0	15,704	501,429	500,903	91,783	91,783	2,913,623	3,494,984	3,494,984	592,804	404,228	404,228	899,885
Solids Flowrate (kg/hr)	0	0	0	2,223	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	38	35	48	176	138	16	72	31	196	6	561	130	533	32	32	33
Pressure (MPa, abs)	5.51	3.5	0.163	0.119	0.119	0.931	15.270	3.238	3.203	0.090	0.093	0.090	12.512	0.005	0.005	0.827
Enthalpy (kJ/kg)[A]	-5.12	38.2	87.882	---	644.216	5.951	-96.995	153.366	1,017.404	15.260	829.125	338.189	3,430.351	2,273.814	2,273.814	139.321
Density (kg/m^3)	93.2	31.0	2.3	---	1.1	18.0	465.8	7.3	4.7	1.1	0.4	0.7	36.8	0.04	0.04	995.1
V-L Molecular Weight	36.268	22	36.699	---	31.428	43.769	43.834	5.768	5.768	28.895	27.512	27.512	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	809	60,452	923	0	1,102	25,257	25,193	35,081	35,081	222,302	280,065	280,065	72,544	49,467	49,467	110,124
V-L Flowrate (lb/hr)	29,323	1,312,349	33,865	0	34,621	1,105,461	1,104,303	202,347	202,347	6,423,439	7,705,122	7,705,122	1,306,908	891,170	891,170	1,983,906
Solids Flowrate (lb/hr)	0	0	0	4,901	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	100	95	119	349	280	60	161	87	385	42	1,042	267	992	90	90	92
Pressure (psia)	799.5	514.7	23.7	17.3	17.3	135.0	2,214.7	469.6	464.6	13.0	13.5	13.0	1,814.7	0.7	0.7	120.0
Enthalpy (Btu/lb)[A]	-2.2	16.4	37.8	---	277.0	2.6	-41.7	65.9	437.4	6.6	356.5	145.4	1,474.8	977.6	977.6	59.9
Density (lb/ft^3)	5.816	1.935	0.141	---	0.069	1.124	29.077	0.456	0.292	0.070	0.023	0.046	2.297	0.002	0.002	62.121

3.5.9 Case S4B Performance Results

The Case S4B modeling assumptions were presented previously in Exhibit 3-124.

The CoP E-Gas™ IGCC plant with CO_2 capture and using PRB coal at the Montana site (elevation 3,400 ft) produces a net output of 515 MWe at a net plant efficiency of 30.4 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 3-141, which includes auxiliary power requirements. The ASU accounts for approximately 63 percent of the total auxiliary load, distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. CO_2 compression accounts for about 18 percent, and the AGR process about 10 percent of the auxiliary load. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-141 Case S4B Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	**S4B**
Gas Turbine Power	429,000
Steam Turbine Power	298,200
TOTAL POWER, kWe	**727,200**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	560
Coal Milling	3,150
Sour Water Recycle Slurry Pump	300
Slag Handling	1,370
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	86,130
Oxygen Compressor	11,480
Nitrogen Compressors	28,300
CO_2 Compressor	36,110
Boiler Feedwater Pumps	3,910
Condensate Pump	290
Syngas Recycle Compressor	1,040
Circulating Water Pump	3,400
Ground Water Pumps	360
Cooling Tower Fans	2,210
Air Cooled Condenser Fans	3,850
Scrubber Pumps	10
Acid Gas Removal	20,580
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	1,660
Miscellaneous Balance of Plant[1]	3,000
Transformer Losses	2,070
TOTAL AUXILIARIES, kWe	**212,130**
NET POWER, kWe	**515,070**
Net Plant Efficiency, % (HHV)	30.4%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,842 (11,224)
CONDENSER COOLING DUTY GJ/hr (10^6 Btu/hr)	1,720 (1,630)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	306,201 (675,058)
Thermal Input, kWt	1,694,303
Raw Water Withdrawal, m^3/min (gpm)	15.1 (3,987)
Raw Water Consumption, m^3/min (gpm)	12.1 (3,199)

[1] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, CO_2, and PM were presented in Section 2.3. A summary of the plant air emissions for Case S4B is presented in Exhibit 3-142.

Exhibit 3-142 Case S4B Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.000 (0.001)	16 (17)	0.003 (0.007)
NO_X	0.019 (0.044)	804 (886)	0.158 (0.348)
Particulates	0.003 (0.0071)	130 (144)	0.026 (0.056)
Hg	1.51E-7 (3.51E-7)	0.006 (0.007)	1.27E-6 (2.79E-6)
CO_2 gross	9.4 (21.9)	401,650 (442,743)	79 (174)
CO_2 net			111 (245)

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. Just as in the non-capture cases, the SO_2 emission are significantly less than the environmental targets of Section 2.3. The clean syngas exiting the AGR process has a sulfur concentration of approximately 2 ppmv. This results in a concentration in the flue gas of less than 0.3 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The tail gas is hydrogenated and recycled to the gasifier.

NOx emissions are limited to 15 ppmvd (as NO_2 @ 15 percent O_2) by the use of low NOx burners and nitrogen dilution of the fuel gas. 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 NOx 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.

Slightly greater than 92 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 3-143. 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 ash, CO_2 in the stack gas and ASU vent gas, and the captured CO_2 product. 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
90.0 percent

Exhibit 3-143 Case S4B Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	153,309 (337,988)	**Slag**	1,380 (3,042)
Air (CO_2)	529 (1,166)	**Stack Gas**	15,642 (34,484)
		ASU Vent	132 (291)
		CO_2 Product	136,684 (301,337)
Total	153,838 (339,154)	**Total**	153,838 (339,154)

Exhibit 3-144 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, sulfur emitted in the stack gas, and sulfur that is co-sequestered with the CO_2 product. Sulfur in the ash is considered negligible.

Exhibit 3-144 Case S4B Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	2,227 (4,911)	**Elemental Sulfur**	2,223 (4,901)
		Stack Gas	1 (2)
		CO_2 Product	3 (8)
Total	2,227 (4,911)	**Total**	2,227 (4,911)

[1] By difference

Exhibit 3-145 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 from the coal drying process and 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 3-145 Case S4B Water Balance

Water Use	Water Demand m^3/min (gpm)	Internal Recycle m^3/min (gpm)	Raw Water Withdrawal m^3/min (gpm),	Process Water Discharge m^3/min (gpm),	Raw Water Consumption m^3/min (gpm),
	S4B	S4B	S4B	S4B	S4B
Slag Handling	0.57 (151)	0.57 (151)	0 (0)	0 (0)	0 (0)
Slurry Water	2.68 (708)	2.1 (557)	0.57 (151)	0 (0)	0.57 (151)
SWS Blowdown	0 (0)	0 (0)	0 (0)	0.01 (2)	-0.01 (-2)
Condenser Makeup	**1.53 (403)**	**0 (0)**	**1.53 (403)**	**0 (0)**	**1.53 (403)**
Shift Steam	1.38 (365)		1.38 (365)		
BFW Makeup	0.14 (38)		0.14 (38)		
Cooling Tower Makeup	**13.22 (3,492)**	**0.2 (60)**	**12.99 (3,432)**	**2.97 (785)**	**10.02 (2,647)**
BFW Blowdown		0.14 (38)	-0.14 (-38)		
SWS Blowdown		0.08 (22)	-0.08 (-22)		
Total	**18.0 (4,755)**	**2.91 (768)**	**15.1 (3,987)**	**2.98 (788)**	**12.11 (3,199)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-146:

- Coal gasification and ASU
- Syngas cleanup
- Power block

An overall plant energy balance is provided in tabular form in Exhibit 3-147 based on 0°C (32°F) reference conditions. The power out is the combined CT and steam turbine power after generator losses.

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Exhibit 3-146 Case S4B Heat and Mass Balance

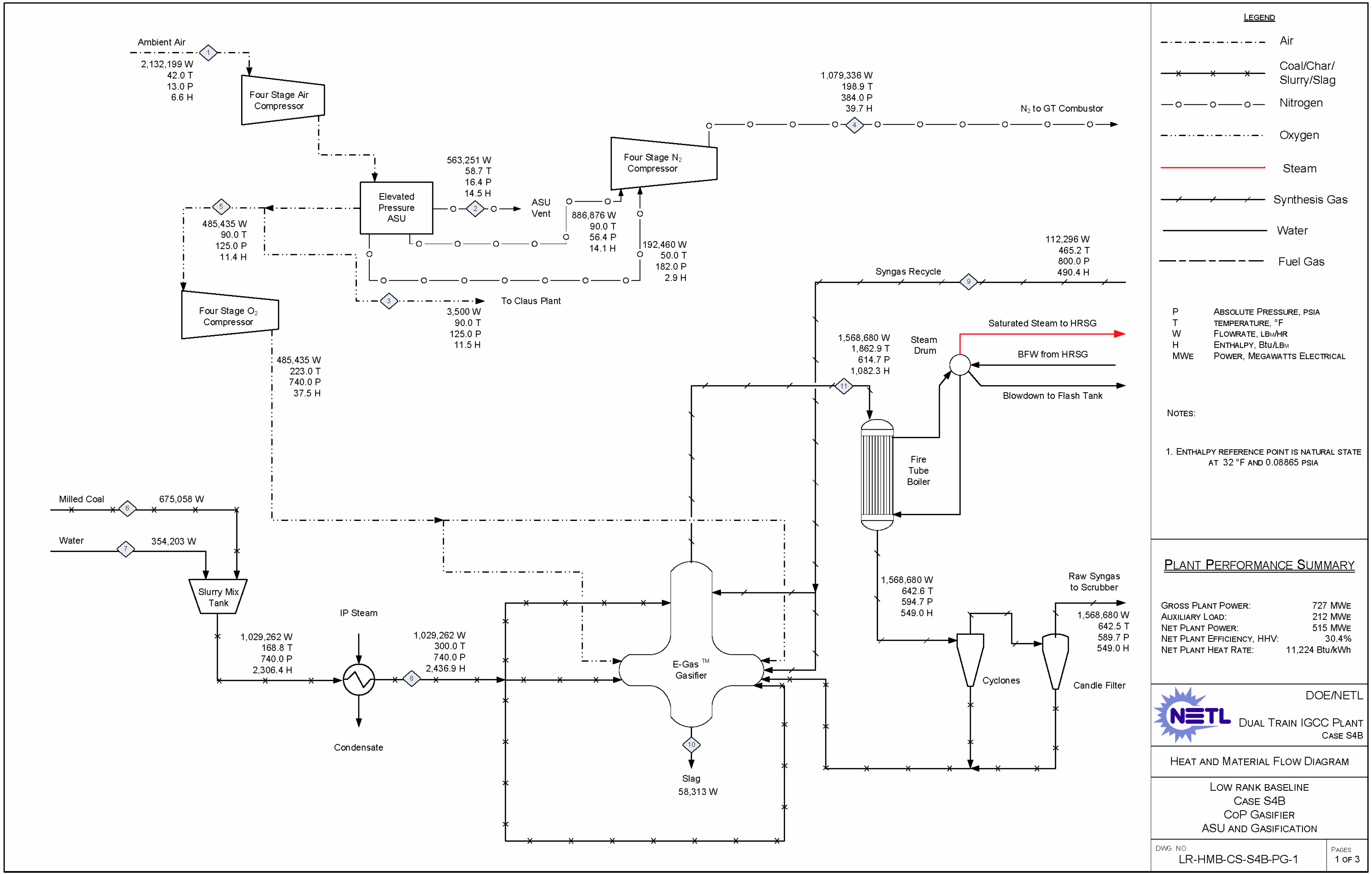

Exhibit 3-146 Case S4B Heat and Mass Balance (Continued)

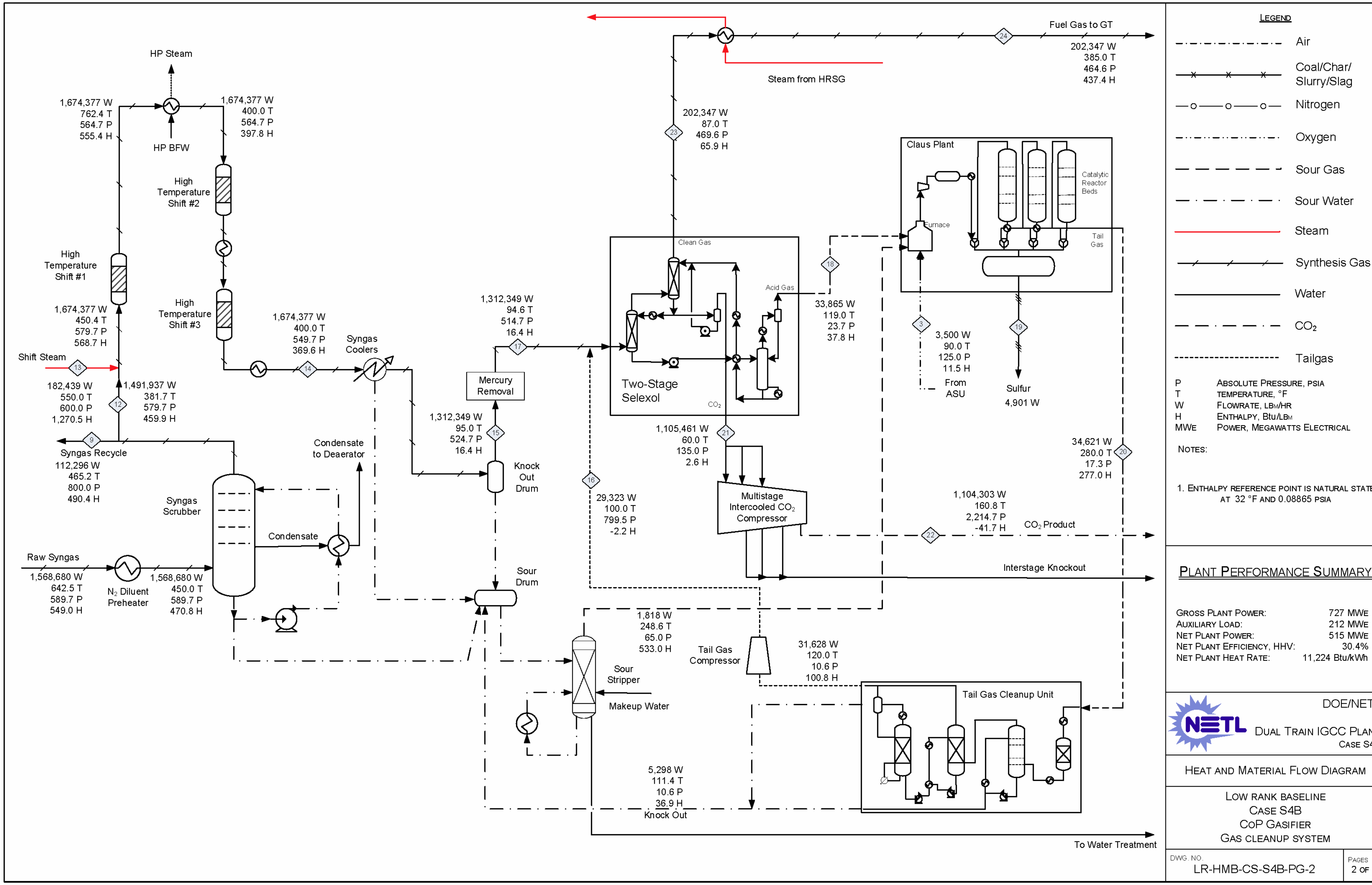

Exhibit 3-146 Case S4B Heat and Mass Balance (Continued)

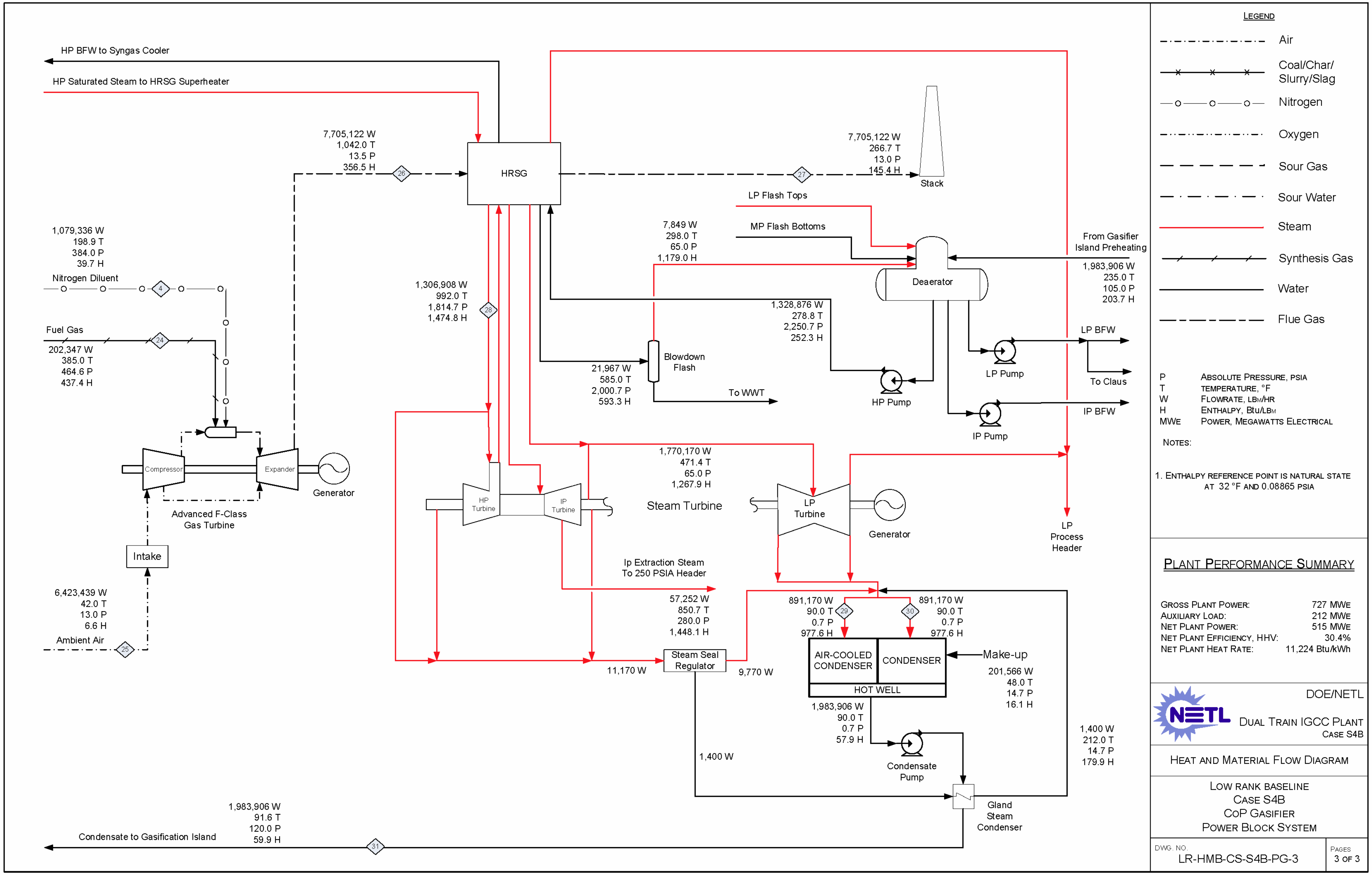

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Exhibit 3-147 Case S4B Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	6,099 (5,781)	3.1 (3.0)	0 (0)	6,103 (5,784)
ASU Air	0 (0)	14.8 (14.0)	0 (0)	15 (14)
GT Air	0 (0)	44.5 (42.1)	0 (0)	44 (42)
Raw Water Makeup	0 (0)	21.0 (19.9)	0 (0)	21 (20)
Auxiliary Power	0 (0)	0 (0)	764 (724)	764 (724)
Totals	**6,099 (5,781)**	**83.3 (79.0)**	**764 (724)**	**6,947 (6,584)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Intercoolers	0 (0)	342 (324)	0 (0)	342 (324)
ASU Vent	0 (0)	8.6 (8.2)	0 (0)	9 (8)
Slag	45 (43)	29.5 (27.9)	0 (0)	75 (71)
Sulfur	21 (20)	0.3 (0.2)	0 (0)	21 (20)
CO_2	0 (0)	-48.6 (-46.0)	0 (0)	-49 (-46)
CO_2 Comp Intercoolers	0 (0)	176.2 (167.0)	0 (0)	176 (167)
Cooling Tower Blowdown	0 (0)	16.6 (15.7)	0 (0)	17 (16)
HRSG Flue Gas	0 (0)	1,182 (1,120)	0 (0)	1,182 (1,120)
Condenser	0 (0)	1,720 (1,631)	0 (0)	1,720 (1,631)
Auxiliary Cooling	0 (0)	132 (125)	0 (0)	132 (125)
Generator Loss	0 (0)	0 (0)	40 (38)	40 (38)
Process Losses	0 (0)	663 (629)	0 (0)	663 (629)
Power	0 (0)	0 (0)	2,618 (2,481)	2,618 (2,481)
Totals	**66 (62)**	**4,223 (4,003)**	**2,658 (2,519)**	**6,947 (6,584)**

3.5.10 Case S4B Equipment List

Major equipment items for the CoP E-Gas™ 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 3.5.11. 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/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (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/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	64 tonne (70 ton)	2	1
9	Feeder	Vibratory	254 tonne/hr (280 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	508 tonne/hr (560 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	254 tonne (280 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	508 tonne/hr (560 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	508 tonne/hr (560 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,089 tonne (1,200 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Feeder	Vibratory	109 tonne/hr (120 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	336 tonne/hr (370 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	671 tonne (740 ton)	1	0
4	Weigh Feeder	Belt	172 tonne/hr (190 tph)	2	0
5	Rod Mill	Rotary	172 tonne/hr (190 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	530,530 liters (140,150 gal)	2	0
7	Slurry Water Pumps	Centrifugal	2,953 lpm (780 gpm)	1	0
8	Trommel Screen	Coarse	263 tonne/hr (290 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	483,250 liters (127,660 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	4,164 lpm (1100 gpm)	2	0
11	Slurry Storage Tank with Agitator	Field erected	2,899,649 liters (766,000 gal)	1	0
12	Slurry Recycle Pumps	Centrifugal	7,949 lpm (2,100 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	4,164 lpm (1,100 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	560,241 liters (148,000 gal)	2	0
2	Condensate Pumps	Vertical canned	8,290 lpm @ 91 m H_2O (2,190 gpm @ 300 ft H_2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	573,341 kg/hr (1,264,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	2,158 lpm @ 27 m H_2O (570 gpm @ 90 ft H_2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 5,754 lpm @ 1,890 m H_2O (1,520 gpm @ 6,200 ft H_2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 189 lpm @ 223 m H_2O (50 gpm @ 730 ft H_2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	372 GJ/hr (353 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	133,625 lpm @ 21 m H_2O (35,300 gpm @ 70 ft H_2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	3,785 lpm @ 18 m H_2O (1,000 gpm @ 60 ft H_2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,536 lpm @ 268 m H_2O (670 gpm @ 880 ft H_2O)	2	1
16	Filtered Water Pumps	Stainless steel, single suction	1,931 lpm @ 49 m H_2O (510 gpm @ 160 ft H_2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	927,426 liter (245,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	908 lpm (240 gpm)	2	0
19	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 two-stage, slurry-feed entrained bed	4,082 tonne/day, 4.2 MPa (4,500 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	391,450 kg/hr (863,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	391,450 kg/hr (863,000 lb/hr) 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 up flow	391,450 kg/hr (863,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	417,759 kg/hr (921,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	327,494 kg/hr, 35°C, 3.9 MPa (722,000 lb/hr, 95°F, 560 psia)	2	0
8	Synthesis Gas Reheater	Shell and tube	50,349 kg/hr (111,000 lb/hr)	2	0
9	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	391,450 kg/hr (863,000 lb/hr) syngas	2	0
10	ASU Main Air Compressor	Centrifugal, multi-stage	7,277 m^3/min @ 1.3 MPa (257,000 scfm @ 190 psia)	2	0
11	Cold Box	Vendor design	2,903 tonne/day (3,200 tpd) of 95% purity oxygen	2	0
12	Oxygen Compressor	Centrifugal, multi-stage	1,501 m^3/min (53,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
13	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,115 m^3/min (110,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
14	Secondary Nitrogen Compressor	Centrifugal, single-stage	680 m^3/min (24,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
15	Syngas Dilution Nitrogen Boost Compressor	Centrifugal, single-stage	1,750 m^3/min (61,800 scfm) Suction - 2.6 MPa (384 psia) Discharge - 3.2 MPa (469 psia)	2	0

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Mercury Adsorber	Sulfated carbon bed	327,494 kg/hr (722,000 lb/hr) 35°C (95°F) 3.6 MPa (525 psia)	2	0
2	Sulfur Plant	Claus type	59 tonne/day (65 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	417,759 kg/hr (921,000 lb/hr) 232°C (450°F) 4.0 MPa (580 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 133 GJ/hr (126 MMBtu/hr)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	327,494 kg/hr (722,000 lb/hr) 35°C (95°F) 3.5 MPa (515 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	17,274 kg/hr (38,083 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	14,644 kg/hr (32,284 lb/hr)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	CO_2 Compressor	Integrally geared, multi-stage centrifugal	1,240 m^3/min @ 15.3 MPa (43,800 scfm @ 2,215 psia)	4	0

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Gas Turbine	Advanced F class	215 MW	2	0
2	Gas Turbine Generator	TEWAC	240 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 8.7 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 326,042 kg/hr, 12.4 MPa/533°C (718,800 lb/hr, 1,800 psig/992°F) Reheat steam - 384,422 kg/hr, 3.1 MPa/533°C (847,506 lb/hr, 452 psig/992°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Steam Turbine	Commercially available	314 MW 12.4 MPa/533°C/533°C (1,800 psig/ 992°F/992°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	950 GJ/hr (900 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	1	0
4	Air-cooled Condenser	---	950 GJ/hr (900 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	Circulating Water Pumps	Vertical, wet pit	340,687 lpm @ 30 m (90,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) WB / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,899 GJ/hr (1,800 MMBtu/hr) 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	276,335 liters (73,000 gal)	2	0
2	Slag Crusher	Roll	15 tonne/hr (16 tph)	2	0
3	Slag Depressurizer	Proprietary	15 tonne/hr (16 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	166,558 liters (44,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	75,708 liters (20,000 gal)	2	0
6	Slag Conveyor	Drag chain	15 tonne/hr (16 tph)	2	0
7	Slag Separation Screen	Vibrating	15 tonne/hr (16 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	15 tonne/hr (16 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	238,481 liters (63,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	76 lpm @ 14 m H_2O (20 gpm @ 46 ft H_2O)	2	2
11	Grey Water Storage Tank	Field erected	75,708 liters (20,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	265 lpm @ 433 m H_2O (70 gpm @ 1,420 ft H_2O)	2	2
13	Slag Storage Bin	Vertical, field erected	1,089 tonne (1,200 tons)	2	0
14	Unloading Equipment	Telescoping chute	118 tonne/hr (130 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 340 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 70 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 94 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 14 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	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

3.5.11 Case S4B Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-148 shows the TPC summary organized by cost account with a more detailed breakdown of the capital costs shown in Exhibit 3-149. Exhibit 3-150 shows the calculation and addition of owner's costs to determine the TOC, used to calculate COE. Exhibit 3-151 shows the initial and annual O&M costs for Case S4B.

The estimated TOC of the CoP E-Gas™ IGCC plant with CO_2 capture using PRB coal is \$3,851/kW. Process contingency represents 4 percent, project contingency represents 11 percent, and owner's costs represent 18 percent of TOC. The COE is 112.3 mills/kWh.

Exhibit 3-148 Case S4B Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
				TOTAL PLANT COST SUMMARY								
	Case:	Case S4B - ConocoPhillips IGCC w/ CO2										
	Plant Size:	515.11	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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	$17,484	$3,249	$13,559	$0	$0	**$34,292**	$3,113	$0	$7,481	**$44,886**	$87
2	COAL & SORBENT PREP & FEED	$30,185	$5,517	$18,237	$0	$0	**$53,939**	$4,842	$0	$11,756	**$70,538**	$137
3	FEEDWATER & MISC. BOP SYSTEMS	$8,916	$7,230	$8,653	$0	$0	**$24,800**	$2,336	$0	$6,215	**$33,351**	$65
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$145,903	$0	$79,531	$0	$0	**$225,434**	$20,280	$31,720	$42,380	**$319,815**	$621
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$207,324	$0	w/equip.	$0	$0	**$207,324**	$20,096	$0	$22,742	**$250,162**	$486
4.4-4.9	Other Gasification Equipment	$24,306	$12,187	$15,965	$0	$0	**$52,457**	$5,014	$0	$12,419	**$69,889**	$136
	SUBTOTAL 4	**$377,533**	**$12,187**	**$95,496**	**$0**	**$0**	**$485,215**	**$45,390**	**$31,720**	**$77,541**	**$639,866**	**$1,242**
5A	GAS CLEANUP & PIPING	$90,779	$3,037	$75,014	$0	$0	**$168,830**	$16,307	$27,123	$42,594	**$254,854**	$495
5B	CO2 COMPRESSION	$20,780	$0	$12,237	$0	$0	**$33,018**	$3,179	$0	$7,239	**$43,436**	$84
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	**$98,610**	$9,348	$9,861	$11,782	**$129,600**	$252
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$5
	SUBTOTAL 6	**$92,027**	**$806**	**$7,475**	**$0**	**$0**	**$100,308**	**$9,507**	**$9,861**	**$12,339**	**$132,015**	**$256**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,545	$0	$4,485	$0	$0	**$36,031**	$3,426	$0	$3,946	**$43,402**	$84
7.2-7.9	Open, Ductwork and Stack	$3,418	$2,436	$3,191	$0	$0	**$9,045**	$839	$0	$1,608	**$11,492**	$22
	SUBTOTAL 7	**$34,963**	**$2,436**	**$7,677**	**$0**	**$0**	**$45,076**	**$4,264**	**$0**	**$5,554**	**$54,895**	**$107**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$30,702	$0	$5,308	$0	$0	**$36,010**	$3,455	$0	$3,947	**$43,412**	$84
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$39,331	$1,059	$12,929	$0	$0	**$53,319**	$5,181	$0	$11,889	**$70,389**	$137
	SUBTOTAL 8	**$70,034**	**$1,059**	**$18,237**	**$0**	**$0**	**$89,329**	**$8,637**	**$0**	**$15,835**	**$113,801**	**$221**
9	COOLING WATER SYSTEM	$8,342	$8,140	$6,985	$0	$0	**$23,467**	$2,180	$0	$5,242	**$30,889**	$60
10	ASH/SPENT SORBENT HANDLING SYS	$21,401	$1,623	$10,619	$0	$0	**$33,643**	$3,228	$0	$4,023	**$40,893**	$79
11	ACCESSORY ELECTRIC PLANT	$33,841	$13,137	$25,530	$0	$0	**$72,507**	$6,227	$0	$14,935	**$93,669**	$182
12	INSTRUMENTATION & CONTROL	$11,248	$2,069	$7,247	$0	$0	**$20,564**	$1,864	$1,028	$3,908	**$27,364**	$53
13	IMPROVEMENTS TO SITE	$3,470	$2,045	$8,562	$0	$0	**$14,077**	$1,390	$0	$4,640	**$20,107**	$39
14	BUILDINGS & STRUCTURES	$0	$6,957	$7,977	$0	$0	**$14,934**	$1,360	$0	$2,664	**$18,958**	$37
	TOTAL COST	**$821,003**	**$69,492**	**$323,505**	**$0**	**$0**	**$1,214,001**	**$113,822**	**$69,732**	**$221,967**	**$1,619,522**	**$3,144**

Exhibit 3-149 Case S4B Total Plant Cost Summary Details

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S4B - ConocoPhillips IGCC w/ CO2										
	Plant Size:	515.11	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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											
1.1	Coal Receive & Unload	$4,591	$0	$2,244	$0	$0	$6,835	$612	$0	$1,490	$8,937	$17
1.2	Coal Stackout & Reclaim	$5,933	$0	$1,438	$0	$0	$7,372	$646	$0	$1,604	$9,621	$19
1.3	Coal Conveyors & Yd Crush	$5,516	$0	$1,423	$0	$0	$6,940	$609	$0	$1,510	$9,058	$18
1.4	Other Coal Handling	$1,443	$0	$329	$0	$0	$1,773	$155	$0	$386	$2,313	$4
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	$3,249	$8,124	$0	$0	$11,373	$1,090	$0	$2,493	$14,956	$29
	SUBTOTAL 1.	**$17,484**	**$3,249**	**$13,559**	**$0**	**$0**	**$34,292**	**$3,113**	**$0**	**$7,481**	**$44,886**	**$87**
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	$1,987	$475	$312	$0	$0	$2,774	$237	$0	$602	$3,613	$7
2.3	Slurry Prep & Feed	$27,106	$0	$12,055	$0	$0	$39,161	$3,496	$0	$8,531	$51,188	$99
2.4	Misc.Coal Prep & Feed	$1,093	$795	$2,384	$0	$0	$4,272	$393	$0	$933	$5,597	$11
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	$4,247	$3,487	$0	$0	$7,733	$716	$0	$1,690	$10,140	$20
	SUBTOTAL 2.	**$30,185**	**$5,517**	**$18,237**	**$0**	**$0**	**$53,939**	**$4,842**	**$0**	**$11,756**	**$70,538**	**$137**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,699	$4,635	$2,447	$0	$0	$9,780	$906	$0	$2,137	$12,823	$25
3.2	Water Makeup & Pretreating	$548	$57	$306	$0	$0	$912	$87	$0	$300	$1,299	$3
3.3	Other Feedwater Subsystems	$1,477	$499	$449	$0	$0	$2,425	$218	$0	$529	$3,171	$6
3.4	Service Water Systems	$314	$646	$2,242	$0	$0	$3,202	$312	$0	$1,054	$4,569	$9
3.5	Other Boiler Plant Systems	$1,684	$652	$1,617	$0	$0	$3,953	$375	$0	$866	$5,194	$10
3.6	FO Supply Sys & Nat Gas	$313	$591	$552	$0	$0	$1,456	$140	$0	$319	$1,916	$4
3.7	Waste Treatment Equipment	$766	$0	$468	$0	$0	$1,234	$120	$0	$406	$1,760	$3
3.8	Misc. Power Plant Equipment	$1,115	$149	$573	$0	$0	$1,837	$177	$0	$604	$2,619	$5
	SUBTOTAL 3.	**$8,916**	**$7,230**	**$8,653**	**$0**	**$0**	**$24,800**	**$2,336**	**$0**	**$6,215**	**$33,351**	**$65**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$145,903	$0	$79,531	$0	$0	$225,434	$20,280	$31,720	$42,380	$319,815	$621
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$207,324	$0	w/equip.	$0	$0	$207,324	$20,096	$0	$22,742	$250,162	$486
4.4	LT Heat Recovery & FG Saturation	$24,306	$0	$9,240	$0	$0	$33,546	$3,274	$0	$7,364	$44,183	$86
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	$1,399	$569	$0	$0	$1,968	$189	$0	$431	$2,588	$5
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	$10,788	$6,155	$0	$0	$16,943	$1,551	$0	$4,623	$23,117	$45
	SUBTOTAL 4.	**$377,533**	**$12,187**	**$95,496**	**$0**	**$0**	**$485,215**	**$45,390**	**$31,720**	**$77,541**	**$639,866**	**$1,242**

Exhibit 3-149 Case S4B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S4B - ConocoPhillips IGCC w/ CO2										
	Plant Size:	515.11	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($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	$73,047	$0	$61,982	$0	$0	$135,029	$13,059	$27,006	$35,019	$210,112	$408
5A.2	Elemental Sulfur Plant	$5,613	$1,119	$7,241	$0	$0	$13,973	$1,357	$0	$3,066	$18,396	$36
5A.3	Mercury Removal	$1,328	$0	$1,011	$0	$0	$2,339	$226	$117	$536	$3,218	$6
5A.4	Shift Reactors	$8,762	$0	$3,527	$0	$0	$12,288	$1,178	$0	$2,693	$16,160	$31
5A.5	Particulate Removal	w/4.1	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$2,030	$342	$192	$0	$0	$2,564	$243	$0	$561	$3,368	$7
5A.7	Fuel Gas Piping	$0	$784	$549	$0	$0	$1,332	$124	$0	$291	$1,747	$3
5A.9	HGCU Foundations	$0	$794	$512	$0	$0	$1,305	$120	$0	$428	$1,853	$4
	SUBTOTAL 5A.	**$90,779**	**$3,037**	**$75,014**	**$0**	**$0**	**$168,830**	**$16,307**	**$27,123**	**$42,594**	**$254,854**	**$495**
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	w/ 5A.1	$0	w/ 5A.1	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$20,780	$0	$12,237	$0	$0	$33,018	$3,179	$0	$7,239	$43,436	$84
	SUBTOTAL 5B.	**$20,780**	**$0**	**$12,237**	**$0**	**$0**	**$33,018**	**$3,179**	**$0**	**$7,239**	**$43,436**	**$84**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	$98,610	$9,348	$9,861	$11,782	$129,600	$252
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	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$92,027**	**$806**	**$7,475**	**$0**	**$0**	**$100,308**	**$9,507**	**$9,861**	**$12,339**	**$132,015**	**$256**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$31,545	$0	$4,485	$0	$0	$36,031	$3,426	$0	$3,946	$43,402	$84
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,752	$1,250	$0	$0	$3,002	$263	$0	$653	$3,918	$8
7.4	Stack	$3,418	$0	$1,284	$0	$0	$4,701	$450	$0	$515	$5,667	$11
7.9	HRSG,Duct & Stack Foundations	$0	$685	$658	$0	$0	$1,342	$125	$0	$440	$1,907	$4
	SUBTOTAL 7.	**$34,963**	**$2,436**	**$7,677**	**$0**	**$0**	**$45,076**	**$4,264**	**$0**	**$5,554**	**$54,895**	**$107**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$30,702	$0	$5,308	$0	$0	$36,010	$3,455	$0	$3,947	$43,412	$84
8.2	Turbine Plant Auxiliaries	$213	$0	$489	$0	$0	$703	$69	$0	$77	$849	$2
8.3a	Condenser & Auxiliaries	$3,378	$0	$1,079	$0	$0	$4,457	$426	$0	$488	$5,372	$10
8.3b	Air Cooled Condenser	$30,958	$0	$6,207	$0	$0	$37,164	$3,716	$0	$8,176	$49,057	$95
8.4	Steam Piping	$4,782	$0	$3,364	$0	$0	$8,146	$700	$0	$2,211	$11,057	$21
8.9	TG Foundations	$0	$1,059	$1,790	$0	$0	$2,849	$270	$0	$936	$4,054	$8
	SUBTOTAL 8.	**$70,034**	**$1,059**	**$18,237**	**$0**	**$0**	**$89,329**	**$8,637**	**$0**	**$15,835**	**$113,801**	**$221**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,767	$0	$1,122	$0	$0	$6,889	$656	$0	$1,132	$8,677	$17
9.2	Circulating Water Pumps	$1,500	$0	$99	$0	$0	$1,599	$135	$0	$260	$1,993	$4
9.3	Circ.Water System Auxiliaries	$129	$0	$18	$0	$0	$148	$14	$0	$24	$186	$0
9.4	Circ.Water Piping	$0	$5,400	$1,400	$0	$0	$6,800	$615	$0	$1,483	$8,897	$17
9.5	Make-up Water System	$309	$0	$442	$0	$0	$751	$72	$0	$165	$988	$2
9.6	Component Cooling Water Sys	$637	$762	$542	$0	$0	$1,942	$182	$0	$425	$2,549	$5
9.9	Circ.Water System Foundations	$0	$1,977	$3,361	$0	$0	$5,339	$506	$0	$1,753	$7,598	$15
	SUBTOTAL 9.	**$8,342**	**$8,140**	**$6,985**	**$0**	**$0**	**$23,467**	**$2,180**	**$0**	**$5,242**	**$30,889**	**$60**

Exhibit 3-149 Case S4B Total Plant Cost Summary Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S4B - ConocoPhillips IGCC w/ CO2										
	Plant Size:	515.11	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($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
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$18,675	$0	$9,209	$0	$0	$27,884	$2,679	$0	$3,056	$33,620	$65
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$618	$0	$672	$0	$0	$1,290	$125	$0	$212	$1,628	$3
10.7	Ash Transport & Feed Equipment	$829	$0	$200	$0	$0	$1,029	$96	$0	$169	$1,293	$3
10.8	Misc. Ash Handling Equipment	$1,280	$1,568	$469	$0	$0	$3,317	$316	$0	$545	$4,177	$8
10.9	Ash/Spent Sorbent Foundation	$0	$55	$69	$0	$0	$123	$12	$0	$40	$175	$0
	SUBTOTAL 10.	**$21,401**	**$1,623**	**$10,619**	**$0**	**$0**	**$33,643**	**$3,228**	**$0**	**$4,023**	**$40,893**	**$79**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$942	$0	$932	$0	$0	$1,874	$179	$0	$205	$2,259	$4
11.2	Station Service Equipment	$4,921	$0	$443	$0	$0	$5,365	$495	$0	$586	$6,445	$13
11.3	Switchgear & Motor Control	$9,098	$0	$1,655	$0	$0	$10,752	$997	$0	$1,762	$13,512	$26
11.4	Conduit & Cable Tray	$0	$4,226	$13,942	$0	$0	$18,168	$1,757	$0	$4,981	$24,907	$48
11.5	Wire & Cable	$0	$8,075	$5,306	$0	$0	$13,381	$972	$0	$3,588	$17,941	$35
11.6	Protective Equipment	$0	$680	$2,474	$0	$0	$3,154	$308	$0	$519	$3,981	$8
11.7	Standby Equipment	$232	$0	$227	$0	$0	$459	$44	$0	$75	$579	$1
11.8	Main Power Transformers	$18,647	$0	$143	$0	$0	$18,790	$1,421	$0	$3,032	$23,243	$45
11.9	Electrical Foundations	$0	$155	$408	$0	$0	$563	$54	$0	$185	$802	$2
	SUBTOTAL 11.	**$33,841**	**$13,137**	**$25,530**	**$0**	**$0**	**$72,507**	**$6,227**	**$0**	**$14,935**	**$93,669**	**$182**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,110	$0	$741	$0	$0	$1,852	$175	$93	$318	$2,438	$5
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	$255	$0	$164	$0	$0	$419	$40	$21	$96	$575	$1
12.7	Computer & Accessories	$5,923	$0	$190	$0	$0	$6,113	$561	$306	$698	$7,677	$15
12.8	Instrument Wiring & Tubing	$0	$2,069	$4,230	$0	$0	$6,299	$534	$315	$1,787	$8,935	$17
12.9	Other I & C Equipment	$3,959	$0	$1,923	$0	$0	$5,882	$553	$294	$1,009	$7,739	$15
	SUBTOTAL 12.	**$11,248**	**$2,069**	**$7,247**	**$0**	**$0**	**$20,564**	**$1,864**	**$1,028**	**$3,908**	**$27,364**	**$53**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$109	$2,327	$0	$0	$2,436	$242	$0	$803	$3,481	$7
13.2	Site Improvements	$0	$1,936	$2,573	$0	$0	$4,510	$445	$0	$1,486	$6,441	$13
13.3	Site Facilities	$3,470	$0	$3,662	$0	$0	$7,132	$703	$0	$2,350	$10,185	$20
	SUBTOTAL 13.	**$3,470**	**$2,045**	**$8,562**	**$0**	**$0**	**$14,077**	**$1,390**	**$0**	**$4,640**	**$20,107**	**$39**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,560	$3,647	$0	$0	$6,208	$571	$0	$1,017	$7,796	$15
14.3	Administration Building	$0	$923	$670	$0	$0	$1,593	$142	$0	$260	$1,995	$4
14.4	Circulation Water Pumphouse	$0	$165	$87	$0	$0	$252	$22	$0	$41	$316	$1
14.5	Water Treatment Buildings	$0	$458	$447	$0	$0	$905	$82	$0	$148	$1,135	$2
14.6	Machine Shop	$0	$450	$308	$0	$0	$758	$67	$0	$124	$949	$2
14.7	Warehouse	$0	$727	$469	$0	$0	$1,196	$106	$0	$195	$1,497	$3
14.8	Other Buildings & Structures	$0	$435	$339	$0	$0	$774	$69	$0	$169	$1,012	$2
14.9	Waste Treating Building & Str.	$0	$973	$1,860	$0	$0	$2,833	$264	$0	$619	$3,716	$7
	SUBTOTAL 14.	**$0**	**$6,957**	**$7,977**	**$0**	**$0**	**$14,934**	**$1,360**	**$0**	**$2,664**	**$18,958**	**$37**
	TOTAL COST	$821,003	$69,492	$323,505	$0	$0	$1,214,001	$113,822	$69,732	$221,967	$1,619,522	$3,144

Exhibit 3-150 Case S4B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$15,260	$30
1 Month Variable O&M	$4,088	$8
25% of 1 Months Fuel Cost at 100% CF	$937	$2
2% of TPC	$32,390	$63
Total	**$52,676**	**$102**
Inventory Capital		
60 day supply of consumables at 100% CF	$7,986	$16
0.5% of TPC (spare parts)	$8,098	$16
Total	**$16,084**	**$31**
Initial Cost for Catalyst and Chemicals	**$7,532**	**$15**
Land	**$900**	**$2**
Other Owner's Costs	**$242,928**	**$472**
Financing Costs	**$43,727**	**$85**
Total Owner's Costs	**$363,846**	**$706**
Total Overnight Cost (TOC)	**$1,983,369**	**$3,851**
TASC Multiplier	1.140	
Total As-Spent Cost (TASC)	**$2,261,041**	**$4,390**

Exhibit 3-151 Case S4B Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES						
Case S4B - ConocoPhillips IGCC w/ CO2					Cost Base (Jun):	2007
					Heat Rate-net (Btu/kWh):	11,223
					MWe-net:	515
					Capacity Factor (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/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					$6,313,507	$12.257
Maintenance Labor Cost					$18,102,733	$35.143
Administrative & Support Labor					$6,104,060	$11.850
Property Taxes and Insurance					$32,390,449	$62.881
TOTAL FIXED OPERATING COSTS					**$62,910,750**	**$122.131**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$33,033,881**	**$0.00915**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	2,867	1.08	**$0**	**$905,553**	**$0.00025**
Chemicals						
MU & WT Chem. (lb)	0	17,081	0.17	$0	$863,203	$0.00024
Carbon (Mercury Removal) (lb)	116,627	160	1.05	$122,478	$48,991	$0.00001
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	6,257	4.29	498.83	$3,120,990	$624,198	$0.00017
Selexol Solution (gal)	320,048	102	13.40	$4,288,080	$397,550	$0.00011
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.	0.87	131.27	$0	$33,524	$0.00001
Subtotal Chemicals				**$7,531,548**	**$1,967,466**	**$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	160	0.42	$0	$19,457	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	700	16.23	$0	$3,315,235	$0.00092
Subtotal Waste Disposal				**$0**	**$3,334,692**	**$0.00092**
By-products & Emissions						
Sulfur (tons)	0	59	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$7,531,548**	**$39,241,592**	**$0.01087**
Fuel (ton)	0	8,101	15.22	**$0**	**$35,993,745**	**$0.00997**

3.6 IGCC CASE SUMMARY

A summary of the results of the twelve IGCC plant configurations modeled in this study is presented in Exhibit 3-152.

The normalized components of TOC and overall TASC are shown for each plant configuration in Exhibit 3-153. The TOC, which is used for COE calculations, is the TPC plus owner's costs. The following conclusions can be drawn:

- The TOC is higher for the North Dakota elevation lignite coal cases as compared to the Montana elevation PRB coal cases by approximately 9 percent.
- The TOC increase to add CO_2 capture is approximately 38 percent.

The COE results are shown in Exhibit 3-154 with the capital cost, fixed operating cost, variable operating cost, and fuel cost shown separately. In the capture cases, the CO_2 TS&M costs are also shown as a separate bar segment. The following conclusions can be drawn:

- The COEs for the Shell and Siemens systems are higher than TRIG™ and CoP for both capture and non-capture cases. Note that TRIG™ and CoP were only studied for PRB coal and TRIG™ with capture only achieved 83 percent carbon capture.
- TRIG™ is the only technology evaluated that has not been demonstrated at commercial scale. For this reason, TRIG™ COEs are subject to a greater level of uncertainty than the other technologies in the group.
- The COE is dominated by capital charges in all cases. The capital cost component of COE ranges from 61 to 66 percent for IGCC cases.
- The fuel cost component is relatively minor in all cases, ranging from 7 to 10 percent of the COE for IGCC cases.
- The CO_2 TS&M component adds approximately 5 percent to the COE.
- The COE increases by 40 to 46% percent for IGCC plants when CO_2 capture is added.
- The COE is generally lower for Montana PRB cases compared to the North Dakota lignite cases.

Exhibit 3-155 shows the COE sensitivity to fuel costs. The solid lines are the COE of non-capture cases. The dotted lines are the capture cases. As expected, all cases show a linear decrease in COE with the decrease in coal prices. As the price for PRB coal decreases from \$0.89 to \$0/MMBtu, the average COE decreases from 81 to 73 mills/kWh for the non-capture PRB cases and from 115 to 105 mills/kWh for the PRB capture cases. As the price for ND lignite coal decreases from \$0.83 to \$0/MMBtu, the average COE decreases from 85 to 78 mills/kWh for the non-capture lignite cases and from 123 to 113 mills/kWh for the lignite capture cases.

Exhibit 3-152 Estimated Performance and Cost Results for IGCC Cases

	Shell IGCC Cases				TRIG IGCC Cases		Siemens IGCC Cases				CoP IGCC Cases	
PERFORMANCE	**S1A**	**L1A**	**S1B**	**L1B**	**S2A**	**S2B**	**S3A**	**L3A**	**S3B**	**L3B**	**S4A**	**S4B**
CO_2 Capture	No	No	Yes	Yes	No	Yes	No	No	Yes	Yes	No	Yes
Gross Power Output (kW_e)	696,700	752,600	663,400	713,300	652,700	621,300	622,200	678,800	634,700	676,900	738,300	727,200
Auxiliary Power Requirement (kW_e)	124,020	135,900	191,790	213,240	107,280	160,450	117,480	135,680	189,410	210,390	133,460	212,130
Net Power Output (kW_e)	572,680	616,700	471,610	500,060	545,420	460,850	504,720	543,120	445,290	466,510	604,840	515,070
Coal Flowrate (lb/hr)	542,713	760,093	585,970	814,029	545,197	577,946	531,119	743,918	579,796	801,651	656,228	675,058
HHV Thermal Input (kW_{th})	1,362,134	1,474,011	1,470,704	1,578,608	1,368,368	1,450,564	1,333,034	1,442,644	1,455,207	1,554,603	1,647,041	1,694,303
Net Plant HHV Efficiency (%)	42.0%	41.8%	32.1%	31.7%	39.9%	31.8%	37.9%	37.6%	30.6%	30.0%	36.7%	30.4%
Net Plant HHV Heat Rate (Btu/kWh)	8,116	8,156	10,641	10,772	8,560	10,740	9,012	9,063	11,151	11,371	9,292	11,224
Raw Water Withdrawal (gpm/MW_{net})	3.1	3.0	7.2	7.8	3.7	6.5	4.5	4.0	9.0	8.9	5.4	8.4
Process Water Discharge (gpm/MW_{net})	0.8	0.8	1.4	1.6	0.8	1.0	1.1	1.1	1.6	1.7	1.1	1.5
Raw Water Consumption (gpm/MW_{net})	2.3	2.2	5.9	6.2	2.9	5.5	3.4	2.9	7.4	7.2	4.3	6.9
CO_2 Emissions (lb/MMBtu)	214	219	22	22	211	36	214	219	22	22	213	22
CO_2 Emissions (lb/MWh_{gross})	1,426	1,461	165	170	1,507	287	1,563	1,585	172	175	1,620	174
CO_2 Emissions (lb/MWh_{net})	1,735	1,783	233	242	1,803	386	1,927	1,981	246	255	1,977	245
SO_2 Emissions (lb/MMBtu)	0.0023	0.0023	0.0009	0.0010	0.0019	0.0009	0.0039	0.0021	0.0009	0.0010	0.0016	0.0009
SO_2 Emissions (lb/MWh_{gross})	0.015	0.015	0.007	0.007	0.013	0.007	0.029	0.016	0.007	0.008	0.012	0.007
NOx Emissions (lb/MMBtu)	0.062	0.063	0.050	0.049	0.059	0.049	0.061	0.061	0.051	0.050	0.052	0.044
NOx Emissions (lb/MWh_{gross})	0.412	0.418	0.381	0.371	0.422	0.390	0.444	0.445	0.397	0.391	0.398	0.348
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071
PM Emissions (lb/MWh_{gross})	0.047	0.047	0.054	0.054	0.051	0.057	0.052	0.051	0.056	0.056	0.054	0.056
Hg Emissions (lb/TBtu)	0.351	0.560	0.351	0.560	0.351	0.351	0.351	0.560	0.351	0.560	0.351	0.351
Hg Emissions (lb/MWh_{gross})	2.34E-06	3.74E-06	2.66E-06	4.23E-06	2.51E-06	2.80E-06	2.57E-06	4.06E-06	2.75E-06	4.39E-06	2.67E-06	2.79E-06
COST												
Total Plant Cost (2007$/kW)	2,506	2,539	3,480	3,584	2,236	3,019	2,610	2,656	3,533	3,626	2,265	3,144
Total Overnight Cost (2007$/kW)	3,056	3,094	4,253	4,378	2,728	3,691	3,185	3,239	4,318	4,430	2,771	3,851
Bare Erected Cost	1,914	1,941	2,610	2,692	1,692	2,228	2,006	2,044	2,654	2,730	1,737	2,357
Home Office Expenses	177	179	242	250	157	207	186	189	247	254	162	221
Project Contingency	343	349	486	502	305	421	359	367	493	508	306	431
Process Contingency	72	69	142	141	83	164	60	56	139	135	60	135
Owner's Costs	550	556	773	794	492	672	575	583	785	804	505	706
Total Overnight Cost (2007$x1,000)	1,750,189	1,908,200	2,005,883	2,189,363	1,488,063	1,701,132	1,607,607	1,759,016	1,922,741	2,066,464	1,675,790	1,983,369
Total As Spent Capital (2007$/kW)	3,484	3,527	4,849	4,991	3,110	4,208	3,631	3,692	4,922	5,050	3,159	4,390
COE (mills/kWh, 2007$)[1]	83.2	83.5	119.7	121.9	74.5	105.2	86.8	87.3	121.7	123.7	78.7	112.3
CO_2 TS&M Costs	0.0	0.0	6.0	5.7	0.0	5.9	0.0	0.0	6.3	6.2	0.0	5.8
Fuel Costs	7.2	6.7	9.5	8.9	7.6	9.5	8.0	7.5	9.9	9.4	8.3	10.0
Variable Costs	8.0	8.2	10.6	11.1	6.8	8.8	8.2	8.4	10.6	11.1	8.3	10.9
Fixed Costs	13.7	13.6	18.3	18.6	11.8	15.5	14.1	14.0	18.4	18.6	13.0	17.4
Capital Costs	54.2	54.9	75.4	77.6	48.4	65.4	56.5	57.4	76.6	78.5	49.1	68.3
LCOE (mills/kWh, 2007$)[1]	105.4	105.8	151.8	154.5	94.5	133.3	110.0	110.7	154.3	156.9	99.8	142.4

[1] CF is 80% for IGCC

Exhibit 3-153 Plant Capital Costs

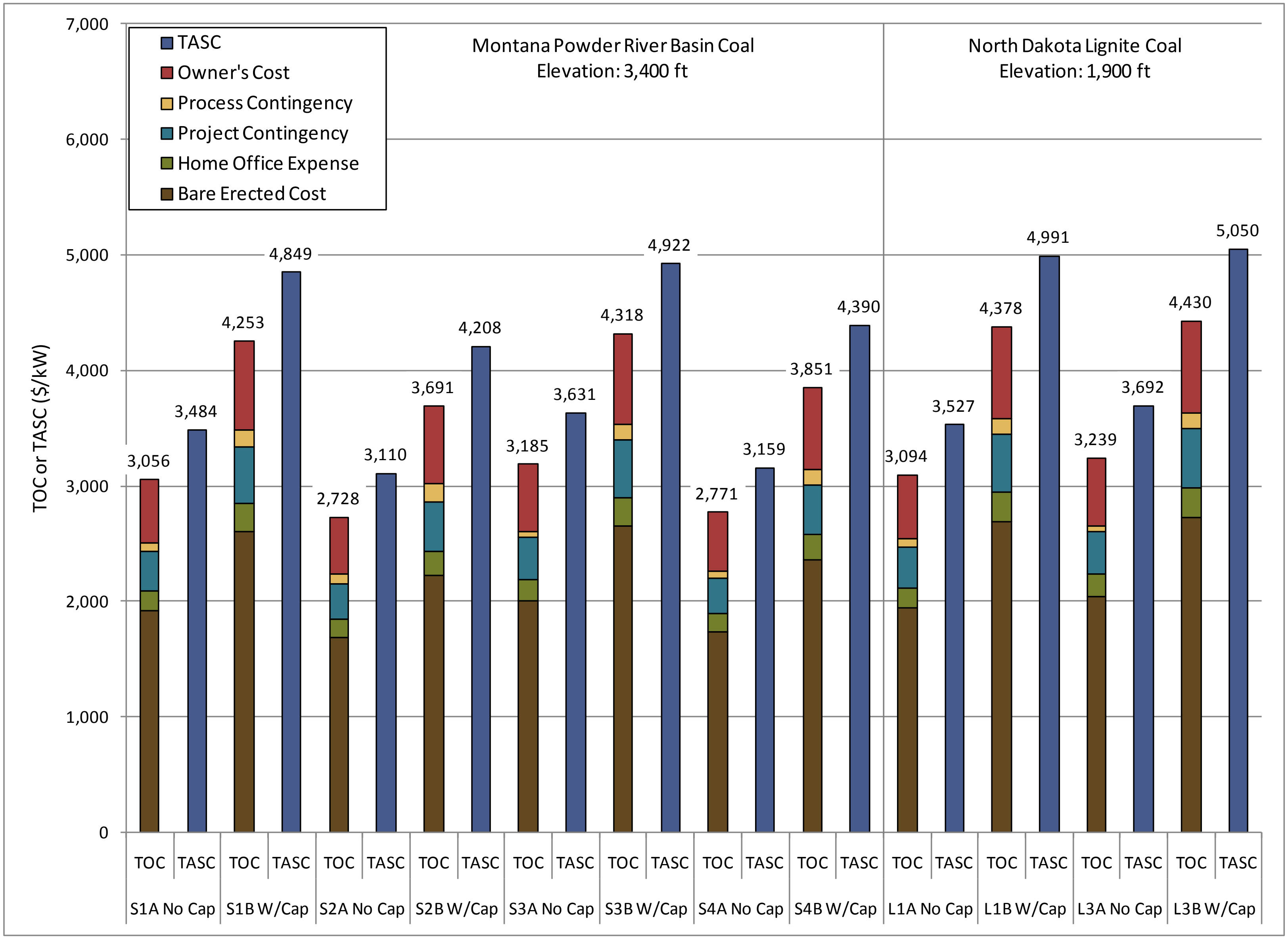


Exhibit 3-154 COE by Cost Component

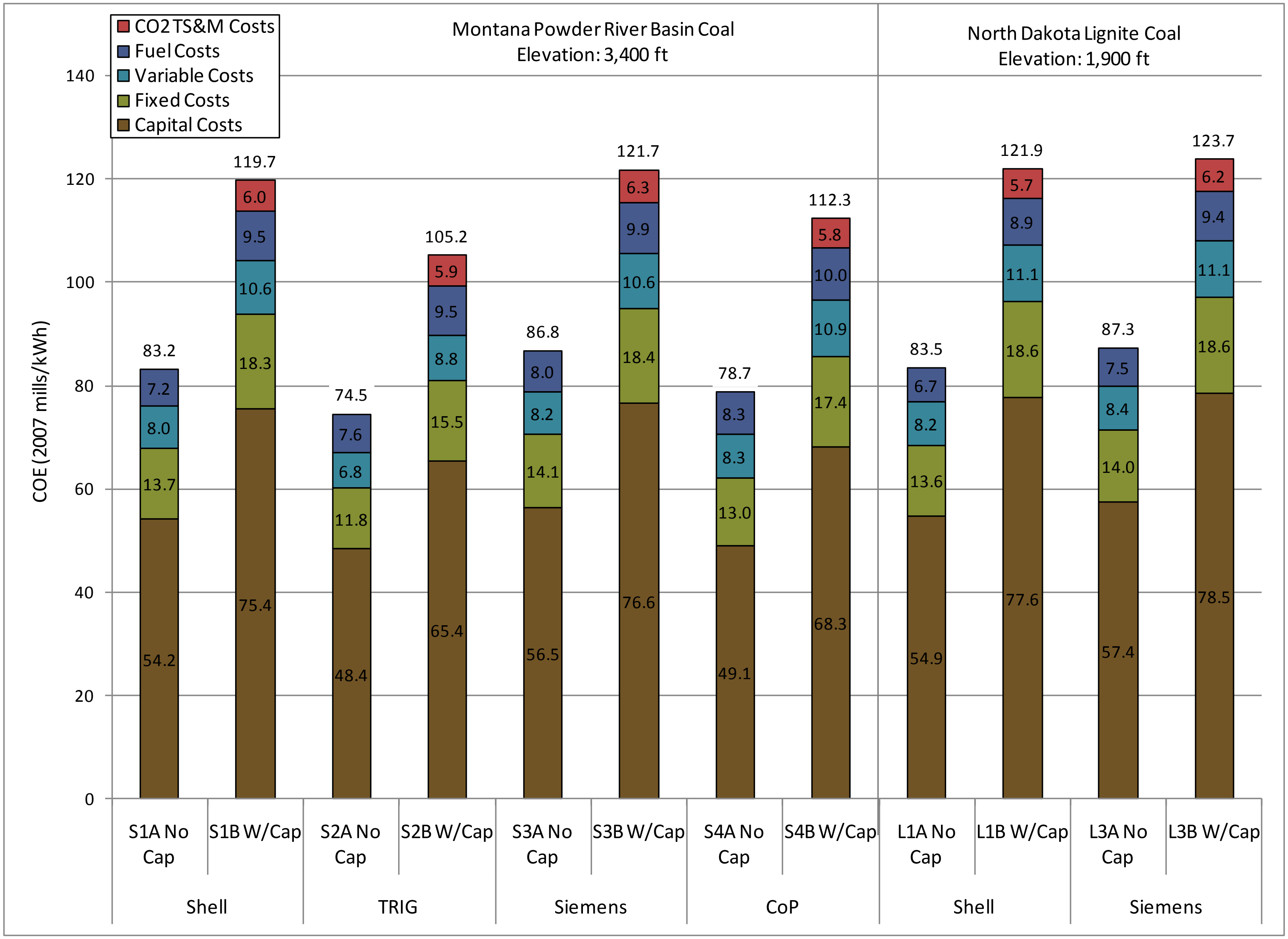
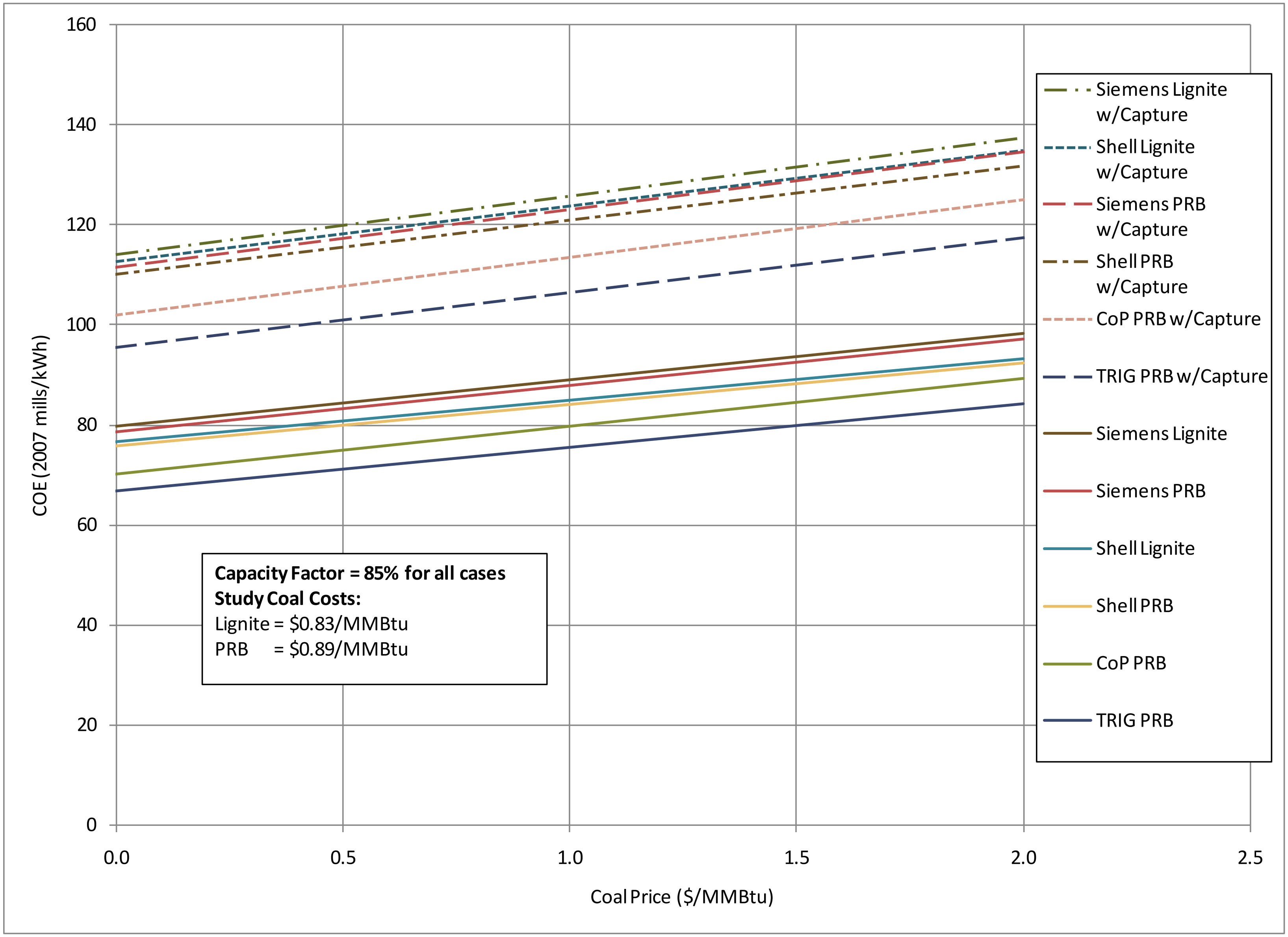


Exhibit 3-155 COE Sensitivity to Fuel Costs



The sensitivity of COE to CF is shown in Exhibit 3-156. CF is equal to availability since it was assumed that the plants are able to operate at 100 percent capacity whenever power production is needed. The solid lines are the COE of non-capture cases. The dotted lines are the capture cases. All cases show a decrease in COE with the increase in CF. As the CF increases from 80 to 100 percent, the average COE decreases from 81 to 66 mills/kWh for the non-capture PRB cases and from 115 to 94 mills/kWh for the CO_2 capture PRB cases. The average COE decreases from 85 to 70 mills/kWh for the non-capture lignite cases and from 123 to 100 mills/kWh for the lignite capture cases.

As presented in Section 2.6 the cost of CO_2 avoided was compared in two ways, relative to the analogous plant design and compared to a baseline SC PC plant utilizing the same coal. The results for the IGCC carbon capture cases are shown in Exhibit 3-157. The cost of CO_2 avoided compared to the analogous non-capture design averages $45/ton, with a range of $40/ton–$53/ton. The cost of CO_2 avoided, compared to the baseline SC PC non-capture (A) design, was determined using results available in Exhibit 2-22 and averages $70/ton, with a range of $63/ton-$77/ton. The analogous CO_2 avoided costs are lower for the Montana PRB than the North Dakota lignite cases, mainly because of the capital cost increase in the lignite fuel cases, as well as the additional cost for fuel. The cost of CO_2 avoided, compared to the baseline SC PC plant, follows the same general trend as the COE for each of the cases, after accounting for the TRIG™ case only achieving 83 percent overall carbon removal. The comparison of the analogous Shell designs is affected by the change from a water quench in the CO_2 capture case to high temperature syngas heat recovery. This increases efficiency when high water concentrations are not required for the WGS reaction, as is the case for non-capture cases and also avoids the expense of high temperature heat exchangers, thus increasing the cost of avoiding carbon for the semi-analogous Shell cases.

Water demand, internal recycles, and raw water consumption, all normalized by net output, are presented in Exhibit 3-158. The following observations can be made:

- The raw water usage is lower in the lignite coal cases because of its higher moisture content, and a significant amount of the coal moisture is recovered in the drying process for dry feed cases and used as internal recycle. Thus, while the water demand is nearly equal in the Montana PRB and North Dakota lignite cases, the water usage is significantly lower when using lignite coal.
- The use of the parallel wet/dry cooling system reduces water demand by 36-47 percent in the non-capture cases and by 24-30 percent in the CO_2 capture cases relative to using a purely wet cooling system. The water savings is less in the CO_2 capture cases because a significant amount of extraction steam is used in the shift reaction and therefore not condensed in the surface condenser.
- The water demand is significantly greater in the CO_2 capture cases because one-half of the condenser load represents a smaller percentage of the total water requirements again due primarily to the high shift steam requirement.

Exhibit 3-156 COE Sensitivity to Capacity Factor

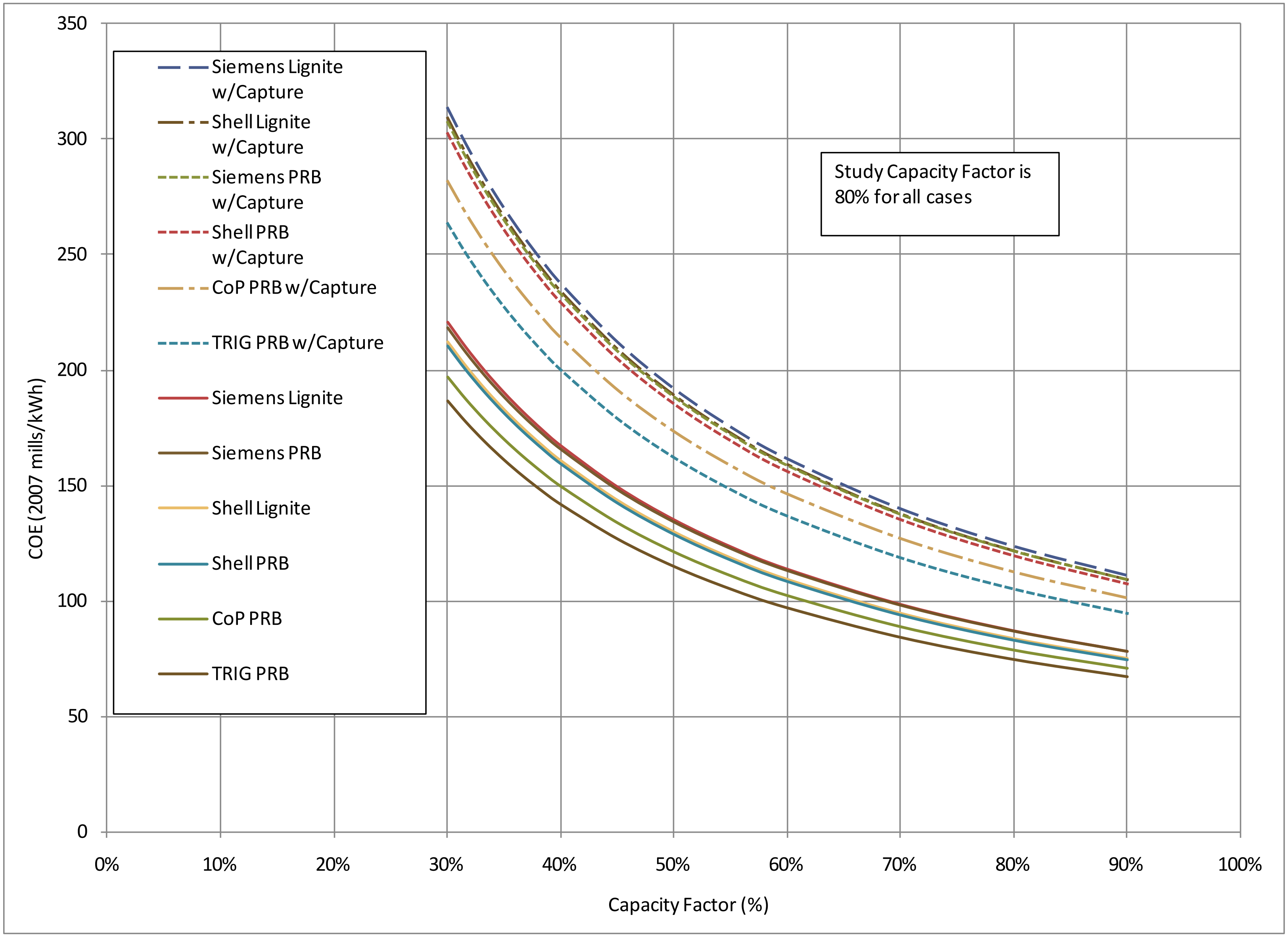


Exhibit 3-157 Cost of CO_2 Avoided in IGCC Cases

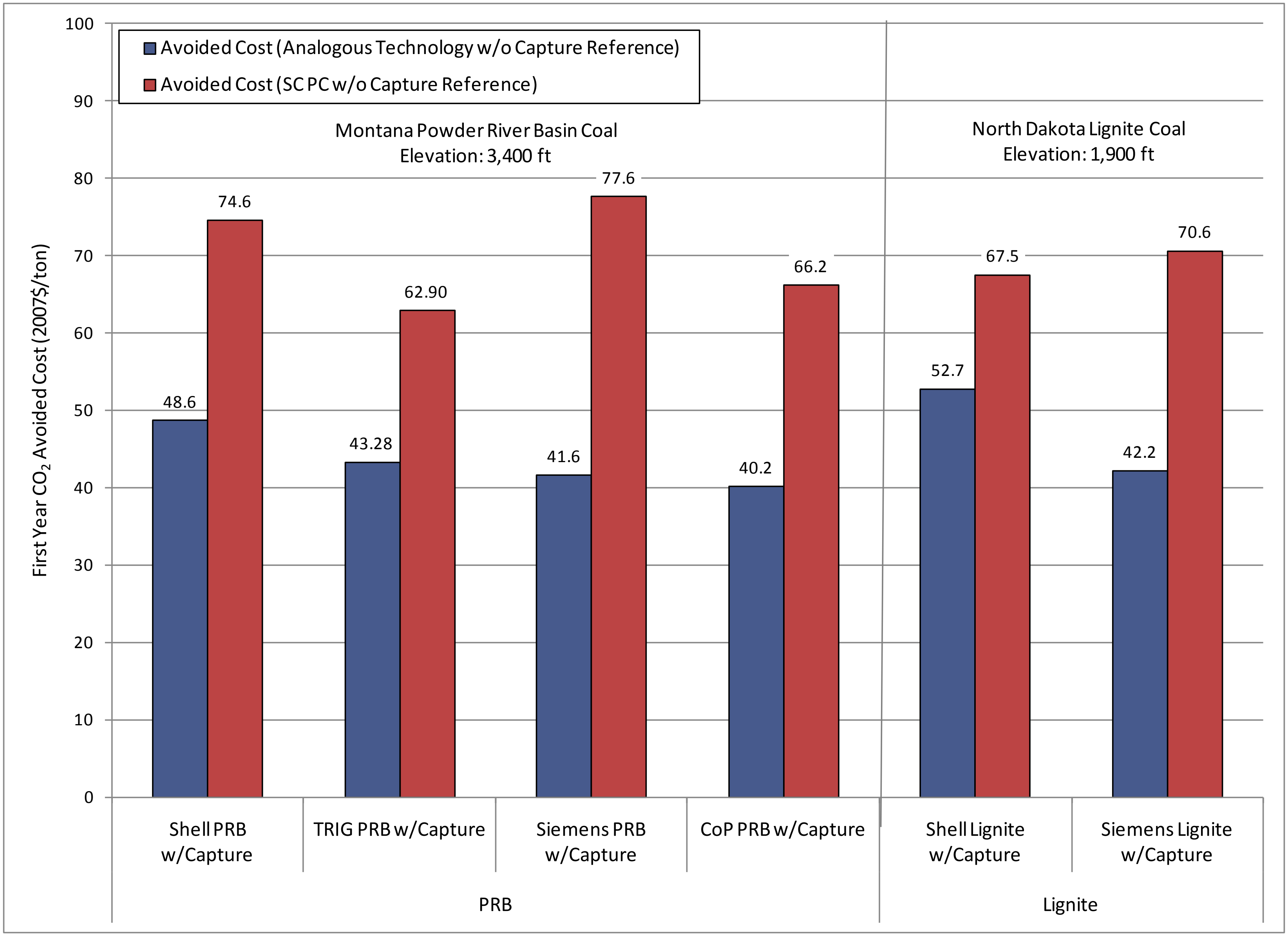
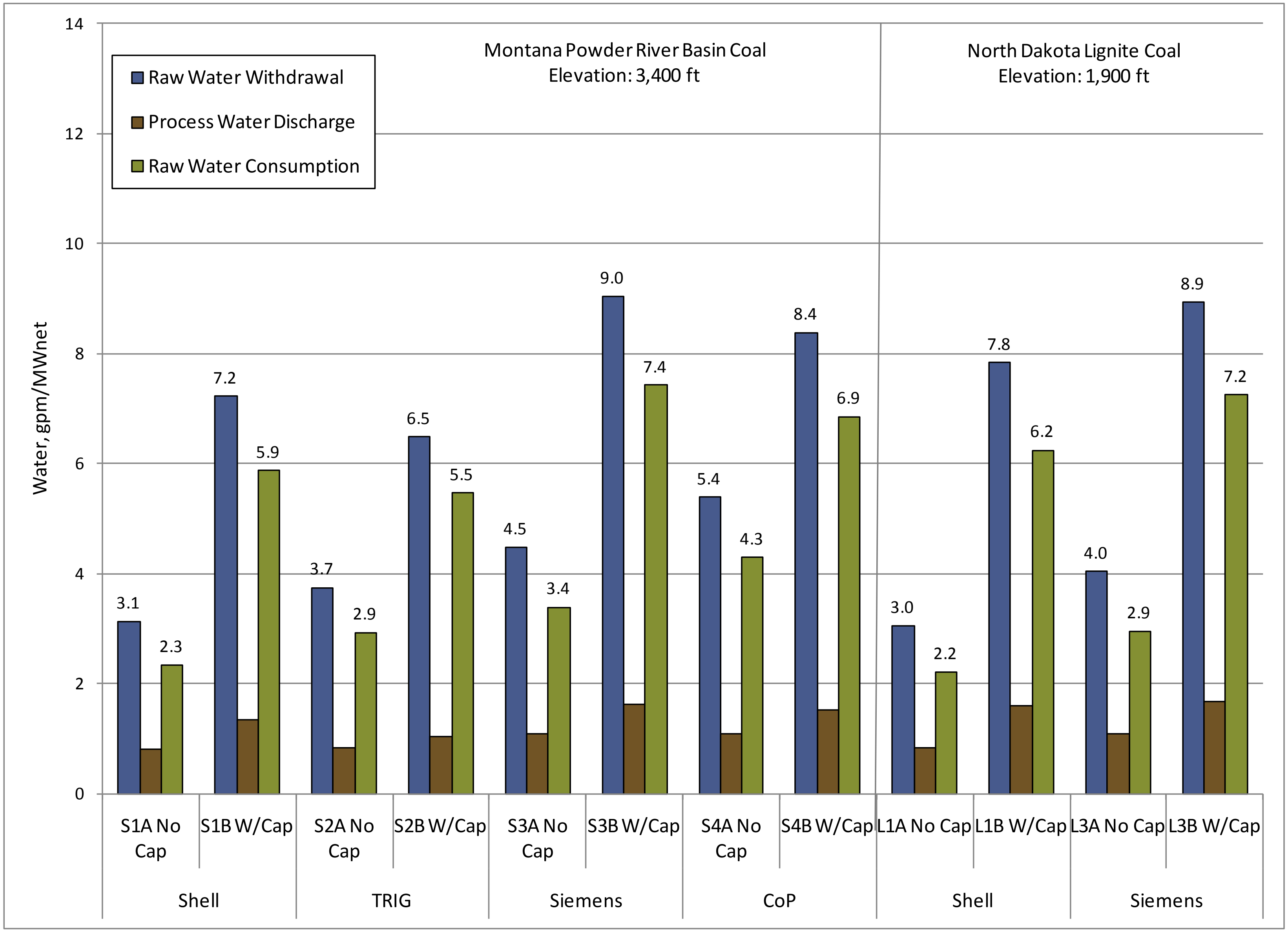


Exhibit 3-158 Normalized Water Usage in IGCC Cases



The environmental targets were described in Section 2.3. The emissions of SO_2, NOx, and PM are shown in Exhibit 3-159 and mercury emissions are shown in Exhibit 3-160. The following observations can be made:

- Emissions of SO_2 are uniformly extremely low. The same environmental target was used as in the bituminous coal cases of Volume 1 of this study, and because the coal sulfur content is significantly lower in the design coals of this study, the resulting SO_2 emissions are also significantly lower.
- Particulate emissions are the same for each case because it was a study assumption that the combination of cyclones and candle filters would exactly meet the environmental target of 0.0071 lb/MMBtu.
- NOx emissions were assumed to be 15 ppmv at 15 percent oxygen in all cases. The resulting emissions on a lb/MMBtu basis vary slightly because of the variable coal feed rates and flue gas volumes generated among cases.
- Mercury emissions are constant for each coal type and significantly below the NSPS limit of 20×10^{-6} lb/MWh for IGCC systems. The emissions shown in Exhibit 3-160 are equivalent to $3.7 - 4.4 \times 10^{-6}$ lb/MWh for the four lignite cases (which have the higher Hg concentration of the two coal types), or a minimum of 78 percent less than NSPS.

Exhibit 3-159 Emissions Profile for IGCC Cases

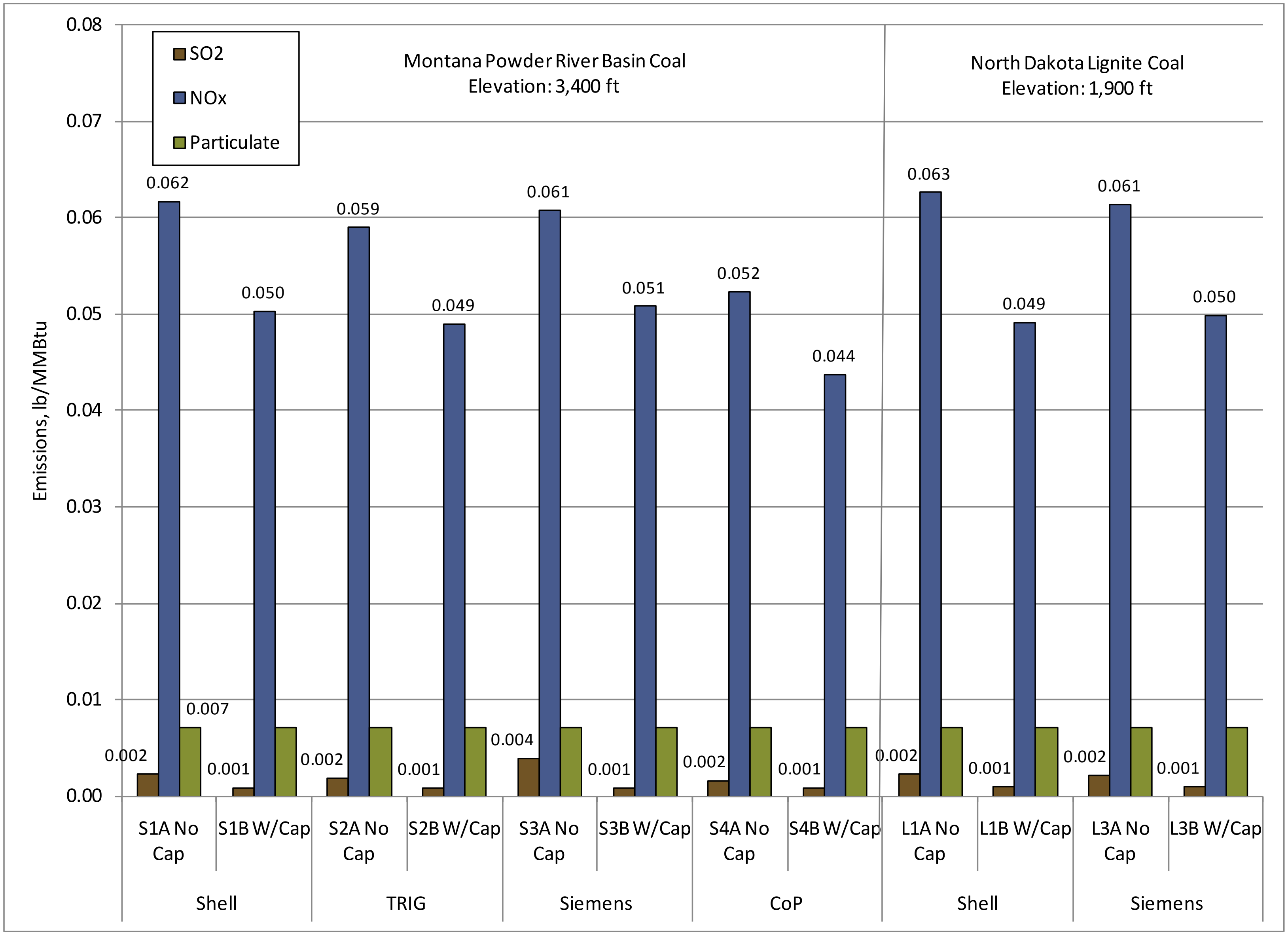
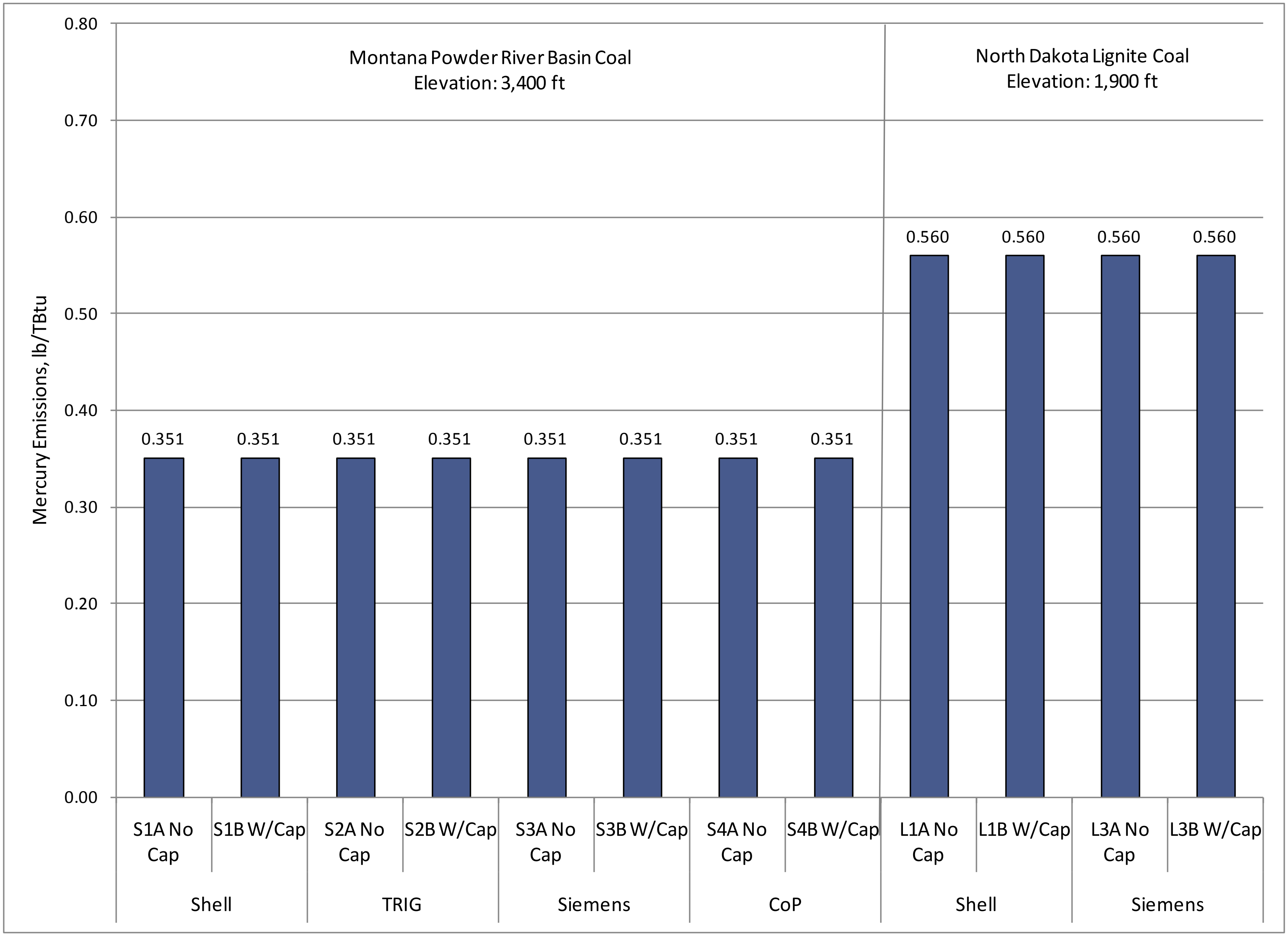


Exhibit 3-160 Mercury Emission for IGCC Cases



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