TECHNOECONOMIC AND LIFE CYCLE ANALYSIS OF BIO-ENERGY WITH CARBON CAPTURE AND STORAGE (BECCS) BASELINE

KYLE BUCHHEIT, ERIC LEWIS,
KISHORE MAHBUBANI, DERRICK CARLSON
STRATEGIC SYSTEMS ANALYSIS AND ENGINEERING

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Disclaimer

Authors

Kyle Buchheit,[1] Eric Lewis,[2] Kishore Mahbubani,[1] Derrick Carlson[1]

Reviewers

Travis Shultz,[3] Timothy Fout,[3] Mark C. Woods,[1] Alex Zoelle,[4]*
Greg Cooney,[1] Morgan Summers,[3] Timohty J. Skone, P.E.[3]

[1] KeyLogic, Mission Execution and Strategic Analysis (MESA)
[2] Deloitte, MESA
[3] National Energy Technology Laboratory (NETL)
[4] Leidos, MESA

*Corresponding contact: Travis.Shultz@netl.doe.gov, 304.285.1370

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ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering International
ABE	American Biomass Energy
abs	Absolute
acfm	Actual cubic foot per minute
ACI	Activated carbon injection
AGR	Acid gas removal
AQCS	Air quality control system
Al_2O_3	Aluminum oxide
Ar	Argon
AR	As received
AR5	Fifth Assessment Report
Aspen	Aspen Plus®
atm	Atmosphere
B&W	Black and white
BBR4	Bituminous Baseline Report Revision 4
BEC	Bare erected cost
BECCS	Bio-Energy with Carbon Capture and Storage
BFDP	Bioenergy Feedstock Development Program
BFW	Boiler feed water
BOP	Balance of plant
Btu	British thermal unit
C	Carbon
$CaCl_2$	Calcium dichloride
$CaSO_3$	Calcium sulfite
$CaSO_4$	Calcium sulfate
CCS	Carbon capture and sequestration
CDR	Carbon dioxide recovery
CF	Capacity factor
CFC	Chlorofluorocarbon
CFC-11e	Trichlorofluoromethane equivalent
CH_4	Methane
Cl^-	Chloride Ion
CL	Closed loop
cm	Centimeter
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CRP	Conservation Reserve Program
CS	Carbon steel
CWP	Circulating water pump
CWS	Circulating water system
CWT	Cold water temperature
DCS	Distributed control system
DOE	Department of Energy
DSI	Dry sorbent injection
EAF	Equivalent availability factor
ELG	Effluent Limitation Guidelines
EMF	Emission modification factor
Eng'g CM H.O. & Fee	Engineering construction management home office and fees
EPA	Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPCC	Engineering, procurement, and construction cost
ESP	Electrostatic precipitator
FD	Forced draft
FE	Fossil Energy
Fe_2O_3	Ferric oxide
FG	Flue gas
FGD	Flue gas desulfurization
FRP	Fiberglass-reinforced plastic
ft	Foot, feet
ft^3	Cubic foot
FW	Feedwater
GADS	Generating Availability Data System
gal	Gallon
GHG	Greenhouse gas
GJ	Gigajoule
gpm	Gallons per minute
GW	Gigawatt
GWP	Global warming potential
H+	Hydrogen ions
H_2	Hydrogen
H_2O	Water
HCL	Hydrochloric acid
HCO_3	Bicarbonate

Hg	Mercury
HHV	Higher heating value
hp	Horsepower
HP	High pressure
hr	hour
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
HX	Heat exchanger
Hz	Hertz
ID	Induced draft
in	Inch
IOU	Investor-owned utility
IP	Intermediate pressure
IPCC	Intergovernmental Panel on Climate Change
IPM	Integrated planning model
ISO	International Organization for Standardization
kg	Kilogram
kg_{mol}	Kilogram mole
kJ	Kilojoule
KO	Knockout
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatt electric
kWh, kWhr, kW-hr	Kilowatt-hour
kWt, kW_{th}	Kilowatt thermal
lb	Pound
lb_{mol}	Pound mole
LCA	Life cycle analysis
LCI	Life cycle inventory
LCIA	Life cycle impact assessment
LCOE	Levelized cost of electricity
LHV	Lower heating value
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
m	Meter
m^3	Cubic meter
MATS	Mercury and Air Toxics Standards
MCR	Maximum continuous rating
MESA	Mission Execution and Strategic Analysis
mg/Nm^3	Milligram per cubic meter
mi	Mile
mills	1/1000th of USD
min	Minute
MJ	Megajoule
MM$	Millions of dollars
MMacf	Million actual cubic feet
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MPa	Megapascal
MVA	Mega volt-amp
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt-hour
N/A	Not applicable/available
N_2	Nitrogen
N_2O	Nitrous oxide
NaCl	Sodium chloride
NaOH	Sodium hydroxide
N e	Nitrogen equivalent
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NH_3	Ammonia
NOx	Nitrogen oxides
NRCS	Natural Resources Conservation Service
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operating and maintenance
O_2	Oxygen
O_3e	Ozone equivalent
O-H	Overhead
OFA	Overfire air
OP/VWO	Over pressure/valves wide open
p.f.	Power factor
PA	Primary air
PAC	Powdered activated carbon
PC	Pulverized coal
ph	Phase
pH	Power of hydrogen

PM	Particulate matter
PM2.5	Particulate matter 2.5 microns or smaller
PM2.5e	Particulate matter 2.5 microns or smaller-equivalent
PMFP	Particulate matter formation potential
ppb	Parts per billion
ppm	Parts per million
ppmv	Parts per million, volume
ppmw	Parts per million, weight
ppmwd	Parts per million, weight dry
ppt	Parts per trillion
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
QGESS	Quality Guidelines for Energy System Studies
RO	Reverse osmosis
RPS	Renewable Portfolio Standard
SC	Supercritical
scfm	Standard cubic foot per minute
SCR	Selective catalytic reduction
SDE	Spray dryer evaporator
SF_6	Sulfur hexafluoride
SiO_2	Silicon dioxide
SO_2	Sulfur dioxide
SO_2e	Sulfur dioxide equivalent
SO_3	Sulfur trioxide
STG	Steam turbine generator
T&S	Transport and storage
TASC	Total as-spent cost
TBtu	Trillion British thermal units
TEG	Triethylene glycol
TRACI	Tool for Reduction and Assessment of Chemicals and Other Environmental Impacts
TOC	Total overnight cost
tonne	Metric ton (1000 kg)
TPC	Total plant cost
tph	Tons per hour
U.S.	United States
UCC	United Conveyor Corporation
USDA	United States Department of Agriculture
V	Volt
V-L	Vapor liquid portion of stream (excluding solids)
VOC	Volatile organic compound
WFGD	Wet flue gas desulfurization
WG	Water gauge
wt%	Weight percent
WTA	Wirbelschicht Trocknung Anlage (fluidized-bed drying with internal waste heat utilization)
ZLD	Zero liquid discharge
$	U.S. dollar
°C	Degrees Celsius
°F	Degrees Fahrenheit

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EXECUTIVE SUMMARY

The objective of this study is to examine the performance, environmental impact, and economics of co-firing biomass in pulverized coal (PC) power plants. The analysis is based on various plant configurations (with and without carbon dioxide [CO_2] capture) using hybrid poplar biomass at three levels of co-fire (20, 35, and 49 weight percent) with Illinois No. 6 coal. This study is an analysis of the overall performance and economics of the plant, which was used to determine the levelized cost of electricity (LCOE) and to perform a full environmental life cycle analysis (LCA) of greenfield PC plants co-firing biomass.

Bio-Energy with Carbon Capture and Storage (BECCS) is an attractive option from an environmental standpoint, as biomass regrowth removes CO_2 from the atmosphere, which offsets the emissions produced by burning the biomass. When combined with carbon capture, this produces a system that is capable of zero or even negative greenhouse gas (GHG) emissions.

Co-firing varying degrees of biomass demonstrates overall system sensitivity to biomass. Although there are several options for biomass fuels, hybrid poplar was selected as the sole biomass feed for the study for its ability to be cultivated as a short rotation crop on marginal lands and its characterization as a non-food source. No other biomass fuel sources were considered in order to maintain consistency between cases and make comparisons more meaningful. Eight power plant configurations were analyzed, as listed in Exhibit ES-1, supplemented with a performance analysis and LCA of two additional cases utilizing 100 percent biomass (see Appendix B: 100 Percent Biomass Scenario Results).

The methodology included performing steady-state process simulations of the technology using the Aspen Plus® (Aspen) modeling program. The resulting energy and mass balance data from the Aspen model were used to size major pieces of equipment. These equipment sizes formed the basis for the reference estimates used in this study. 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.

For the economic analysis, capital and operating costs were scaled from estimates that were based on vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. The baseline coal cost for this analysis is specified in the 2019 revision of the Quality Guidelines for Energy System Studies (QGESS) report "Fuel Prices for Selected Feedstocks in National Energy Technology Laboratory [NETL] Studies." [1] The levelized price for Illinois No. 6 coal delivered to the Midwest is \$2.11/GJ (\$2.23/MMBtu), on a higher heating value (HHV) basis and in 2018 United States (U.S.) dollars. Biomass costs depend on the system feed rate and range from \$8.54/GJ (\$9.01/MMBtu) to \$8.90/GJ (\$9.39/MMBtu), depending on the overall transportation cost to the site. First-year capital expenditure costs are expressed in 2018 United States (U.S.) dollars.

For the LCA, system modeling was conducted using the OpenLCA program. NETL's Coal Upstream model was used to assess the environmental impacts of coal mining and processing, while NETL's Life Cycle Inventory Unit Processes for Biomass cultivation, harvesting, storage, and residue decomposition were used to do the same for hybrid poplar production. NETL data were also used to model impacts from transportation and the production of plant consumables.

Exhibit ES-1. Study matrix

Case	Biomass Type	Plant Type	% Biomass in Feed	CO_2 Capture %	Capture Technology
B12A*	None	Greenfield Supercritical	0	0	N/A
PN1	Hybrid Poplar		20		
PN2			35		
PN3			49		
B12B*	None		0	90	State-of-the-Art Amine (Cansolv)
PA1	Hybrid Poplar		20		
PA2			35		
PA3			49		

*Case from the NETL report "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4" (the "Bituminous Baseline Report Revision 4" [BBR4]) for a 100 percent coal reference [2]

Each PC plant is designed to achieve a nominal 650 MW net plant electrical output. This output level is consistent with the base electric supply of the coal-fired plants studied in the BBR4. While biomass co-fire at these levels might be a challenge regarding the logistical supply of fuel, it allows for a consistent comparison between systems. The differences in auxiliary loads are primarily attributable to CO_2 separation and compression and variable biomass dryer load, which differs depending on the amount of biomass required.

The major results from the study are discussed below in the following order:

- Performance (efficiency and direct emissions)
- Economics (LCOE, plant cost, and CO_2 breakeven value)
- Environmental (total system impacts)

A high-level performance and cost summary for all cases is shown in Exhibit ES-2.

Exhibit ES-2. Cost and performance summary and environmental profile for all cases

PC Supercritical								
	Case B12A [A]	Case PN1	Case PN2	Case PN3	Case B12B [A]	Case PA1	Case PA2	Case PA3
PERFORMANCE								
Nominal CO_2 Capture	**0%**	**0%**	**0%**	**0%**	**90%**	**90%**	**90%**	**90%**
Net CO_2 Abatement	**0%**	**11%**	**21%**	**33%**	**90%**	**101%**	**111%**	**123%**
Capacity Factor	**85%**	**85%**	**85%**	**85%**	**85%**	**85%**	**85%**	**85%**
Gross Power Output (MWe)	685	695	704	716	770	786	801	821
Auxiliary Power Requirement (MWe)	35	45	54	66	120	136	151	171
Net Power Output (MWe)	650	650	650	650	650	650	650	650
Coal Flow Rate (lb/hr)	472,037	439,879	407,662	368,334	603,246	566,601	529,149	482,441
Biomass Flow Rate (lb/hr)	0	109,970	219,510	353,889	0	141,650	284,926	463,521
HHV Thermal Input (kW_t)	1,613,879	1,639,906	1,665,199	1,696,892	2,062,478	2,112,337	2,161,445	2,222,578
Net Plant HHV Efficiency (%)	40.3%	39.6%	39.0%	38.3%	31.5%	30.8%	30.1%	29.2%
Net Plant HHV Heat Rate (Btu/kWh)	8,473	8,607	8,742	8,909	10,834	11,090	11,349	11,668
Raw Water Withdrawal (gpm)	6,054	6,019	5,972	5,917	9,911	10,165	10,416	10,729
Process Water Discharge (gpm)	1,242	1,260	1,276	1,297	2,893	3,134	3,376	3,678
Raw Water Consumption (gpm)	4,811	4,759	4,696	4,620	7,018	7,031	7,040	7,051
CO_2 Emissions (lb/MMBtu)	202	204	206	209	20	20	21	21
CO_2 Emissions (lb/MWh-gross)	1,627	1,646	1,665	1,688	185	188	190	193
CO_2 Emissions (lb/MWh-net)	1,714	1,760	1,805	1,861	219	227	234	244
SO_2 Emissions (lb/MMBtu)	0.081	0.074	0.067	0.060	0.000	0.000	0.000	0.000
SO_2 Emissions (lb/MWh-gross)	0.648	0.595	0.543	0.482	0.000	0.000	0.000	0.000
NOx Emissions (lb/MMBtu)	0.087	0.087	0.087	0.087	0.077	0.076	0.076	0.076
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.011	0.011	0.011	0.010	0.010	0.010	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.373	0.373	0.372	0.371	0.328	0.327	0.334	0.317

	PC Supercritical							
	Case B12A [A]	Case PN1	Case PN2	Case PN3	Case B12B [A]	Case PA1	Case PA2	Case PA3
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.07E-06	2.93E-06
COST								
Total Plant Cost (2018$/kW)	2,099	2,157	2,213	2,279	3,800	3,911	4,020	4,152
Bare Erected Cost	1,548	1,628	1,672	1,723	2,677	2,795	2,877	2,973
Home Office Expenses	271	285	293	302	469	489	503	520
Project Contingency	280	295	302	311	531	552	568	586
Process Contingency	0	0	0	0	123	126	128	131
Total Overnight Cost (2018$MM)	1,678	1,768	1,820	1,881	3,023	3,160	3,256	3,372
Total Overnight Cost (2018$/kW)	2,582	2,669	2,746	2,837	4,654	4,810	4,955	5,130
Owner's Costs	484	511	533	558	854	899	935	978
Total As-Spent Cost (2018$/kW)	2,981	3,139	3,232	3,341	5,372	5,613	5,784	5,990
LCOE ($/MWh) (excluding T&S)	64.4	71.5	77.9	85.9	105.3	115.3	124.7	136.7
Capital Costs	28.3	29.8	30.7	31.7	51.0	53.3	55.0	56.9
Fixed Costs	9.5	9.9	10.1	10.4	16.1	16.8	17.2	17.7
Variable Costs	7.7	7.8	7.7	7.7	14.0	14.2	14.4	14.6
Fuel Costs	18.9	24.0	29.3	36.1	24.1	31.0	38.2	47.5
LCOE ($/MWh) (including T&S)	64.4	71.5	77.9	85.9	114.3	124.5	134.3	146.6
CO_2 T&S Costs	0.0	0.0	0.0	0.0	8.9	9.3	9.6	10.0
Breakeven CO_2 Value (ex. T&S), $/tonne	0.0	96.3	91.7	90.6	45.7	49.9	52.6	55.4
Breakeven CO_2 Emissions Penalty (incl. T&S), $/tonne	0.0	133.6	127.4	126.0	73.5	78.2	81.1	84.2

[A] Case from the BBR4 for a 100% coal reference [2]

PERFORMANCE

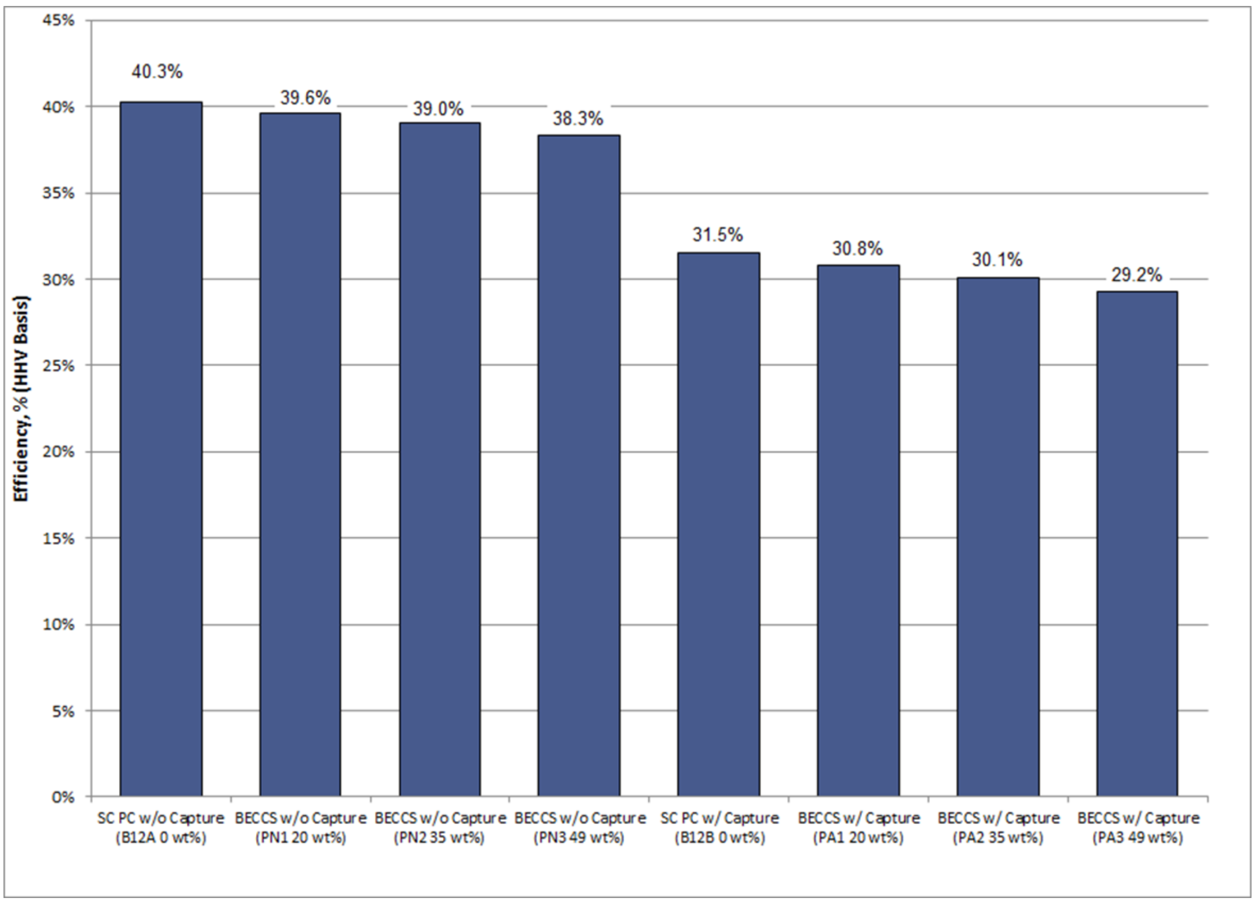
Energy Efficiency

Exhibit ES-3 illustrates the net plant efficiency as a function of the biomass percentage for non-capture and amine-based capture plants. An efficiency drop is observed due to the additional auxiliary load from the amine carbon capture process.

The primary conclusion that can be drawn concerning net plant efficiencies (HHV) is as follows:

For each technology, the addition of biomass to the feed decreases the net plant efficiency. This trend is due to a reduction in feed quality, as well as increased auxiliary requirements associated with the preparation of the biomass feed.

Exhibit ES-3. Net plant efficiency vs. feed composition



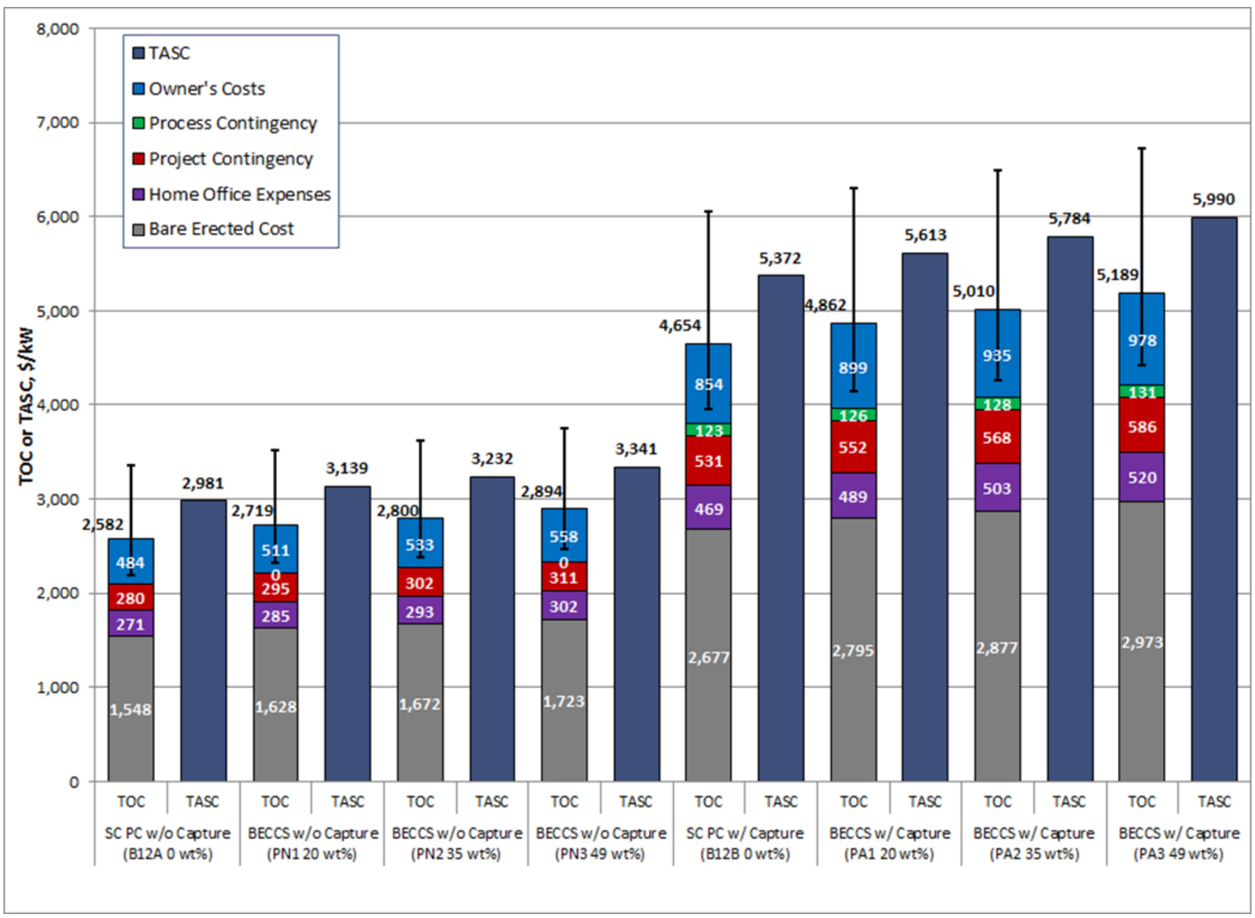
ECONOMICS

Capital and operating and maintenance (O&M) cost estimates were scaled for each plant based on previous reference estimates for non-capture and capture PC systems using Illinois No. 6 coal. Costs were scaled using process parameters and scaling exponents derived from preexisting cost data. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, and cost and performance data from design/build utility projects. Baseline costs for this analysis were determined using results from the BBR4 [2] and scaled following the 2019 revision of the QGESS "Capital Cost Scaling Methodology." [3]

Plant Costs

Additional plant costs associated with biomass co-firing increase the total overnight cost (TOC). Biomass receiving, preparation, and processing all have significant associated costs, which increase as the proportion of biomass in the plant feed rises. Additionally, the total mass flow of feed required to maintain a nominal 650 MW net plant power increases as more biomass is present in the feed. The result is a larger boiler and downstream equipment. Exhibit ES-4 shows the normalized TOC and total as-spent cost (TASC) including plant owner's costs for various biomass feed proportions. The error bars represent the potential cost range relative to the maximum and minimum capital cost uncertainty ranges (-15 percent/+30 percent).

Exhibit ES-4. TOC and TASC ($/kWnet)



Current-Dollar, Thirty-Year Levelized Cost of Electricity

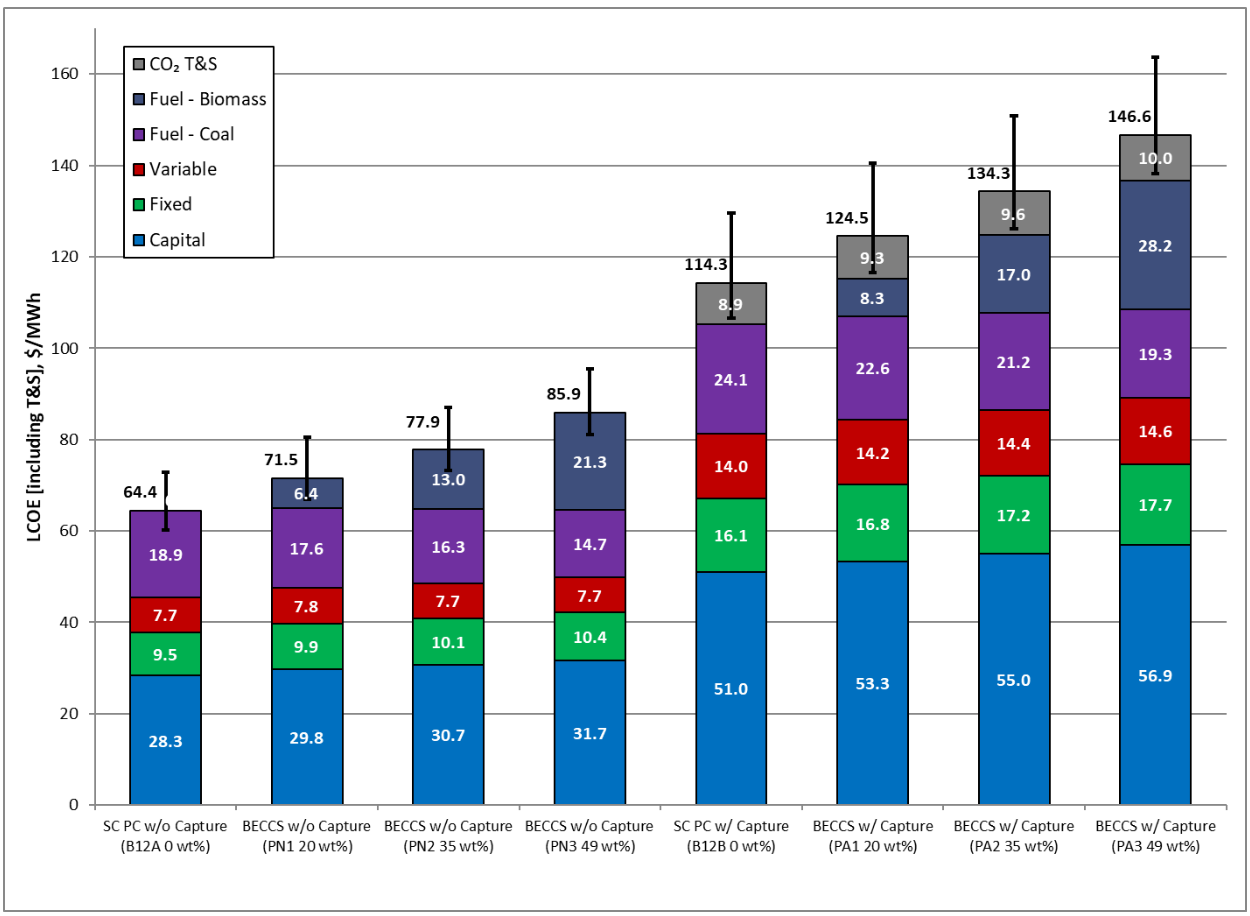
The revenue requirement figure-of-merit in this report is cost of electricity levelized over a 30-year period and expressed in \$/MWh (numerically equivalent to mills/kWh). The current-dollar, 30-year LCOE was calculated following the methodology laid out in the 2019 QGESS "Cost Estimation Methodology for NETL Assessments of Power Plant Performance." [4] CO_2 transport and storage (T&S) costs were included for capture cases. Capital and O&M costs are expressed in December 2018 dollars, coal and biomass fuel costs in 2018 dollars, and the resulting LCOE is expressed in real 2018 dollars.

The breakdown of LCOE components is shown in Exhibit ES-5. The error bars represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges (-15 percent/+30 percent). The main conclusions that can be drawn are as follows:

LCOE increases with increased hybrid poplar biomass co-firing in all cases considered primarily due to increased fuel costs.

A minor increase in capital and O&M costs is due to the reduction in plant efficiency and increased auxiliary loads from co-firing biomass.

Exhibit ES-5. LCOE

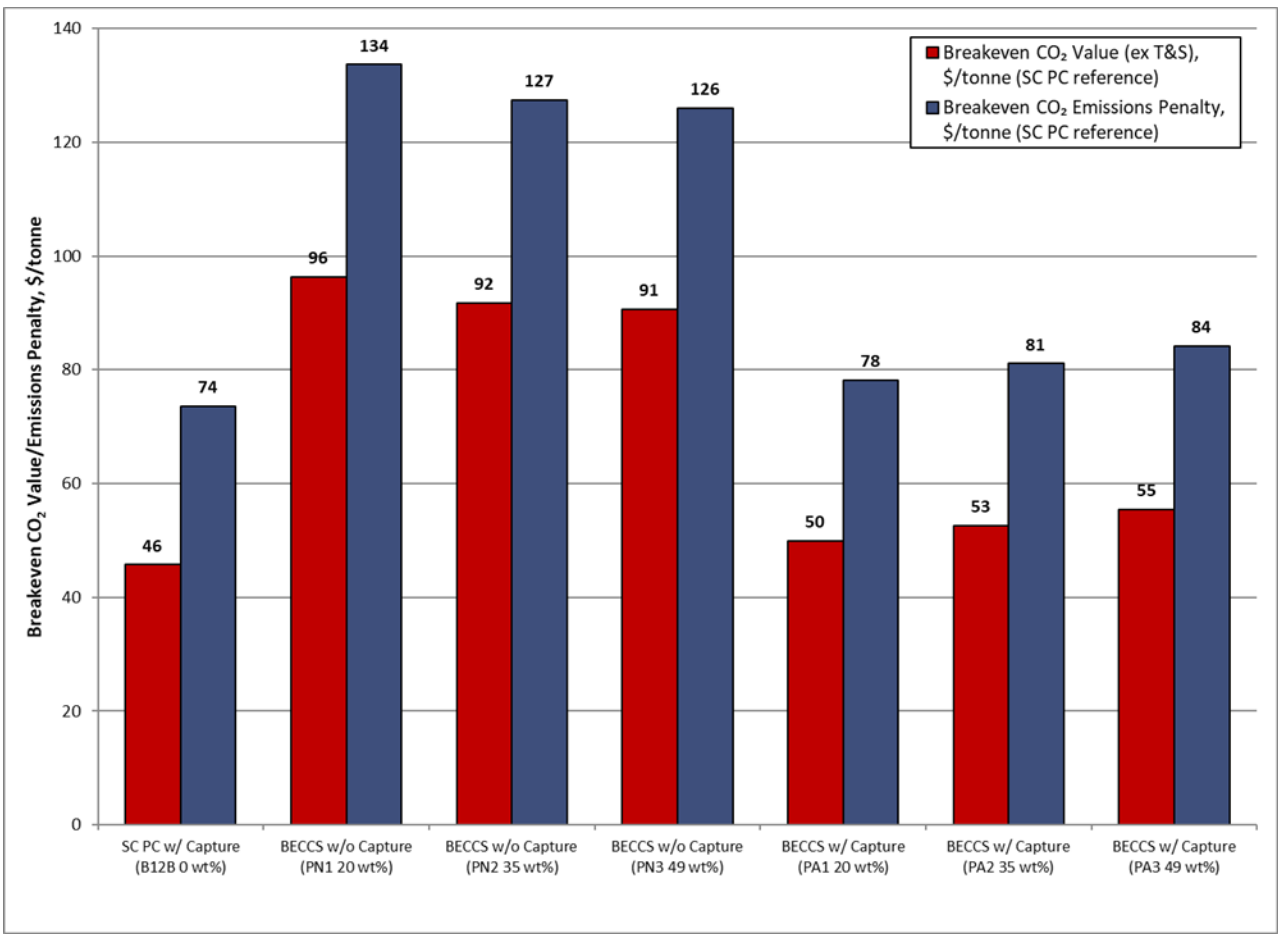


CO_2 Valuation

Co-firing biomass as a means of GHG abatement becomes economically competitive with traditional carbon capture and sequestration only after an incentive is in place to mitigate emissions. The point at which co-firing becomes an attractive option depends on the potential value of CO_2, the level of an emissions penalty, and the type of plant. Exhibit ES-6 shows the levelized breakeven CO_2 value and emissions penalty for various levels of co-firing both with and without capture. The breakeven value would either represent the amount required on the sale of the captured CO_2 in the capture cases, or a benefit received for the use of biomass as a fuel source in the non-capture cases, when compared to the economics of a supercritical (SC) PC plant without capture or co-firing. This value would need to be reached before incentivizing either CO_2 capture or biomass co-firing. The emissions penalty would be the minimum value required to encourage the use of capture technology or abatement using biomass. The major conclusion that can be taken away from this graph is as follows:

Plants that employ amine-based carbon capture at a 90 percent rate require a lower incentive or penalty to become competitive with non-capture before the benefits of co-firing biomass become realized.

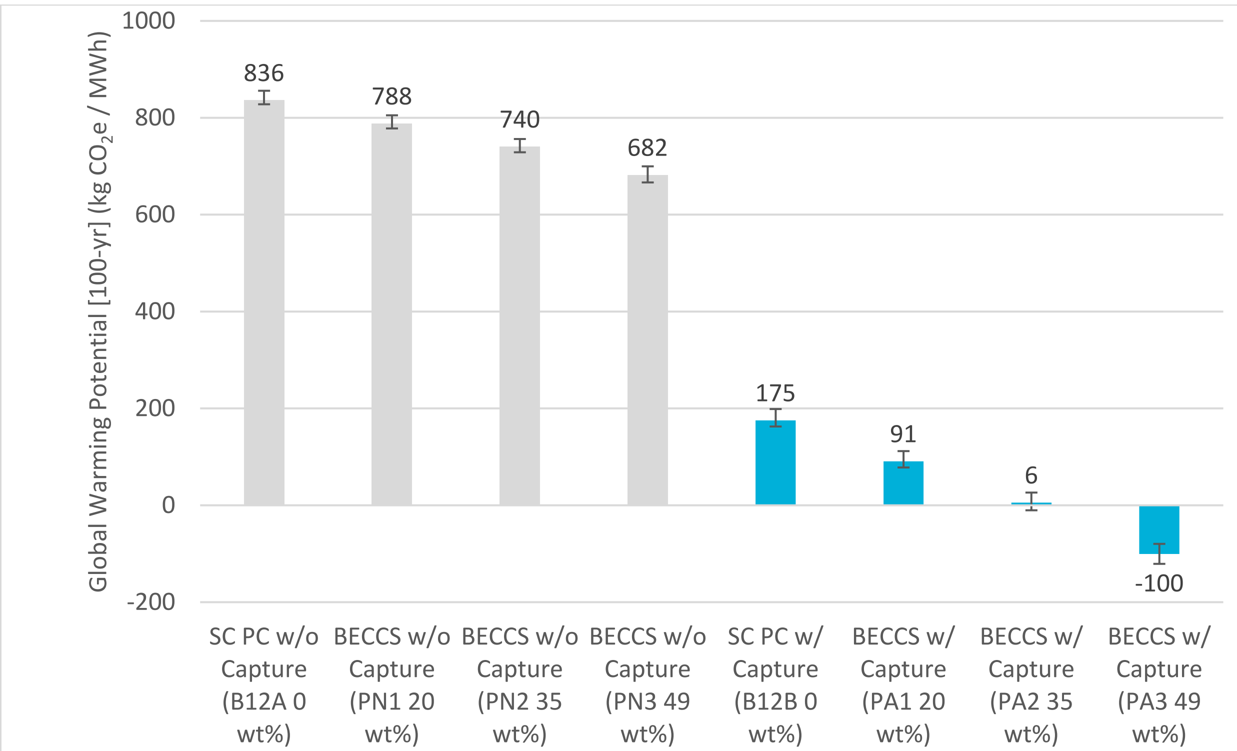
Exhibit ES-6. Breakeven CO_2 value



ENVIRONMENTAL IMPACT

As can be seen in Exhibit ES-7, increasing the co-firing rate of biomass reduces system GHG emissions in both capture and non-capture cases. For the capture cases, increased co-firing rates eventually result in negative GHG emissions, as the carbon captured by the biomass during its growth phase is sequestered in underground storage. However, increased biomass co-firing also increases impacts for all other environmental metrics analyzed, due to the impacts of biomass cultivation.

Exhibit ES-7. Global warming potential results



Note: blue bars indicate the presence of 90% CCS

GHG Breakeven Point

The BECCS system has net negative GHGs at more than 35.9 percent biomass (by mass) with 90 percent carbon capture and storage (CCS). Systems that use less biomass with 90 percent CCS case still produce net positive GHGs.

Other Environmental Impacts

Replacing coal with biomass and the addition of carbon capture systems increases non-GHG environmental burdens relative to power produced by coal. These burdens include eutrophication potential, ozone depletion potential, particulate matter formation potential, photochemical smog formation, and water consumption. Acidification results are slightly more complicated because sulfur dioxide-equivalent (SO_2e) decreases as a result of the addition of the capture system but increases with the additional fuel use for processing and drying biomass. The scenario with the lowest acidification potential modeled was a coal plant with 90 percent post-combustion carbon capture. The reduction in SO_2e due to the carbon capture system is offset in the 49 percent biomass case because additional fuel is needed to process and dry the biomass, and additional combustion is necessary due to the lower energy density of the biomass fuel.

1 INTRODUCTION

1.1 STUDY BACKGROUND

Using biomass as fuel generates power while producing lower net greenhouse gas (GHG) emissions than fossil fuels, as biomass crops absorb atmospheric carbon dioxide (CO_2) during photosynthesis, which offsets the emissions produced during the biomass combustion. However, the cultivation, harvesting, and delivery processes to provide biomass and the mining and delivery process to provide coal feedstocks to power generation facilities utilize fossil fuels and produce emissions that cannot be considered GHG-neutral over anything less than a geologic timescale. This study examines the performance, cost, and environmental impacts of co-firing varying amounts of biomass on a pulverized coal (PC) power plant.

Wood has been used as a fuel source for millennia. Though industrial use tapered off once coal became a viable fuel, environmental concerns caused woody biomass to be revisited. A study conducted at Michigan City Firing Station demonstrated that, as early as 1997, co-firing 20 percent biomass with coal was viable. [5] The National Institute for Occupational Safety and Health boiler plant study demonstrated that it is possible to co-feed coal with up to 33 percent biomass by total feed weight. [6] This study examines how a PC plant co-firing biomass while employing conventional carbon capture and sequestration (CCS) might play a role in the future of low-carbon power generation. Currently, an ongoing biomass study in Ontario, Canada, is looking at 100 percent biomass firing of a 500 MW plant—close to the 650 MW output modeled in this study.

In 2018 coal-fired power plants accounted for approximately 28 percent of the power generation in the United States (U.S.) and approximately 66 percent of the GHG emissions produced by the power generation sector. [7] Because coal-fired power generation is a significant contributor to both national energy security as well as overall GHG emissions, it is very important to develop methods for reducing the carbon footprint of coal-fired power plants to mitigate environmental concerns while continuing to reliably satisfy power demand. Effects of GHG reduction in the power industry could even be felt in the transportation industry if plug-in hybrid and fully electric vehicles, fueled by low-GHG power, continue to increase their market share.

All technologies used in the systems analyses presented here are commercially viable; however, the mode of operation or scale in some cases has yet to be demonstrated. With further demonstration, particularly in biomass feeding systems and proving sustainable CO_2 sequestration, these PC plants could be considered state-of-the art. It is important to note that while this study focuses on hybrid poplar, other types of biomass, including switchgrass, algae, and municipal wastes, will have similar, though not identical, GHG reduction advantages over coal.

1.2 Project Objectives

The objective of this study is to simulate biomass co-firing in a PC power plant and examine the performance, environmental response, and economic response under the following scenario: 0 ft of elevation (International Organization for Standardization [ISO] conditions) co-fired with Illinois No. 6 coal.

In lieu of comparing identical system configurations from case to case, system configuration and operation were both adjusted in ways considered to reflect those anticipated to be the most practical and appropriate as feed composition was varied. The specific objectives of this study are to

1. Complete a system study for each of the cases outlined in Exhibit ES-1
2. Examine the economics of each system design including the potential value of CO_2 sold or penalty applied to emissions in order to breakeven compared to non-capture
3. Examine the environmental impact of each system design including the upstream impacts of fuel production and transportation
4. Evaluate the potential for co-firing to achieve a reduction of 30 percent in levelized cost of electricity (LCOE) when compared to a PC power plant with CCS
5. Discuss the requirements for co-firing biomass in existing PC plants without carbon capture. These specifics include assessing the potential performance characteristics, performance limitations, integration issues, and costs associated with a biomass co-fire retrofit

1.3 State-of-the-Art Experience in Biomass Co-Firing

Biomass co-firing is not a new concept. In May 2004, the Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy reported that at least 182 separate boilers in the United States had co-fired biomass with fossil fuels. Much of the experience was gained in the 1970s as a result of the energy crisis, when many boiler operators were looking to lower costs. Of the 182 co-firing operations, 63 percent were at industrial facilities, 18 percent at utility-owned power plants, and the balance at municipal boilers, educational institutions, and federal facilities. [8] As of 2007, biomass fueled over 3.5 GW of domestic power production. [9] The biomass sources include bagasse (the fibers remaining after sugar juice is squeezed out of sugar cane), animal manure, fish oil, ethanol, digester gas, railroad ties, utility poles, wood, and wood chips. These opportunity fuels are used primarily at the source of their production or use, namely sugar mills, lumber mills, paper mills, and farms. Much of the power produced is consumed internally, but excess power is sent to the grid. Biomass is often considered a carbon-neutral fuel over its utilization and growth cycle. There is again increased interest in using it as an energy source to reduce carbon emissions. Recent examples abound of utilities using biomass in test burns and converting boilers to handle biomass co-fire or to accept 100 percent biomass:

- The Boardman Power Plant operated by Portland General Electric tested wood pellets to determine if firing 100 percent torrefied biomass is feasible for this 585 MW plant. [10]
- Electrabel and GDF Suez Group opened a new biomass system at the Gelderland power station in Nijmegen, Netherlands. This addition brings the site's total biomass capacity to 180 MW. The new addition requires 426,000 tonnes/year (470,000 tons/year) of wood pellets. [11]
- Ontario, Canada, mandated that no electrical power will be produced by coal by the end of 2014. Ontario Power Generation converted some of its five fossil fuel stations (totaling 8.18 GW) to wood pellets. [12]

2 General Evaluation Basis

This study is designed to assess technical and economic impacts of co-firing strategic levels of hybrid poplar and Illinois No. 6 coal in a PC plant both with and without 90 percent CO_2 capture.

For each of the plant configurations in this study, a process simulation was developed and used to generate energy and mass balances. The energy and mass balances were used as the basis for generating the capital and operating cost estimates. Ultimately, an LCOE was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

The balance of this section provides details on the site characteristics, coal and hybrid poplar characteristics and costs, environmental targets, capacity factor, raw water withdrawal and consumption, cost estimating methods, life cycle analysis (LCA) methods, and a description of each process system.

2.1 Site Characteristics

The site location considered in this study is a generic midwestern site using Illinois No. 6 with an assumed adequate local supply of hybrid poplar. Ambient conditions are shown in Exhibit 2-1 and site characteristics are shown in Exhibit 2-2. The ambient conditions are the same as ISO conditions.

Exhibit 2-1. Site ambient conditions, midwestern, Illinois No. 6 coal

Parameter	Value
Elevation, m (ft)	0 (0)
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[A]	15.6 (60)
Air composition based on published psychrometric data, mass %	
N_2	75.055
O_2	22.998
Ar	1.280
H_2O	0.616
CO_2	0.050
Total	100.00

[A]The cooling water temperature is the cooling tower cooling water exit temperature
This is set to 4.8°C (8.5°F) above ambient wet bulb conditions in ISO cases

Exhibit 2-2. General site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (PC), acres	300
Transportation	Rail or Highway
Ash (PC) Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

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 and Cost

All of the cases described in this report either exclusively fire coal or co-fire coal and hybrid poplar. The coal composition for Illinois No. 6 is shown in Exhibit 2-3. The coal properties are from the 2019 revision of the Quality Guidelines for Energy System Studies (QGESS) document "Detailed Coal Specifications." [13] The mercury (Hg) content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppmwd with standard deviation of 0.06 based on coal samples shipped by Illinois mines. [14] Hence, there is a 50 percent probability that the Hg content in the Illinois No. 6 coal would not exceed 0.09 ppmwd. The coal Hg content for this report was assumed to be 0.15 ppmwd, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all the coal Hg enters the gas phase and none leaves with the bottom ash. [15]

Exhibit 2-3. Design coal analysis [2]

Rank	Bituminous	
Seam	Illinois No. 6	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.15	0.17
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen[B]	7.02	7.91
Total	100.00	100.00

[A]The proximate analysis assumes sulfur as volatile matter
[B]By difference

Coal costs used in this report are specified according to the 2019 QGESS "Fuel Prices for Selected Feedstocks in NETL Studies." [1] The current levelized coal price is $2.11/GJ ($2.23/MMBtu) on a higher heating value (HHV) basis for Illinois No. 6 bituminous coal delivered to the Midwest and reported in 2018 dollars. Fuel costs are levelized over an assumed 30-year plant operational period with an assumed online year of 2023.

2.3 Hybrid Poplar Characteristics and Cost

Hybrid poplar grown on Conservation Reserve Program (CRP) lands is the sole biofeed used in this study. The CRP program was established by the United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS) and provides incentive for farmers to address soil, water, and related issues by converting marginal or degraded lands to vegetative cover. [16] The current use of CRP lands in proximity to the plant site is unknown; because of the great deal of uncertainty in actual land cover and resultant land use changes, for the purposes of this study, the assumption was made that hybrid poplar could be grown without land-use changes on CRP lands that support this growth.

Hybrid poplar is not a food source, so using it as a fuel does not compete with food markets. Hybrid poplar is grown in systems known as short rotation intensive culture. The system is more similar to agriculture than forestry. Success of the system depends on the soil quality and tree breed selection.

Exhibit 2-4 shows the composition of the design biofeed.

Exhibit 2-4. Hybrid poplar design analysis

Ultimate Analysis	As Received, wt%	Dry Basis, wt%
Moisture	50.00	0.00
Carbon	26.18	52.36
Hydrogen	2.80	5.60
Nitrogen	0.19	0.37
Chlorine	0.00	0.00
Sulfur	0.02	0.03
Ash	0.74	1.48
Oxygen[A]	20.08	40.16
Total	**100.0**	**100.00**
HHV, kJ/kg (Btu/lb)	9,813 (4,219)	19,627 (8,438)
LHV, kJ/kg (Btu/lb)	9,232 (3,969)	18,464 (7,938)

[A] By difference

The cost of the hybrid poplar (in 2007 dollars) was determined from a prior National Energy Technology Laboratory (NETL) study and was calculated as a function of quantity consumed as follows:

$$Hybrid\ Poplar\ (\$/dry\ ton) = 1.136x10^{-11}X^3 - 2.675^{-7}X^2 + 3.153^{-3}X + 116.2$$

Where: $X = (1 - Biomass\ Moisture\ Fraction) \times AR\ Biomass\ Feed\ [tons\ per\ day]$

The price of hybrid poplar is dependent on cultivation costs and land availability as well as the distance needed to transport it to the plant site. Demands for large biomass feed rates require large areas of cultivation and, in turn, higher cost for collection and transportation to the plant. Exhibit 2-5 shows the relationship hybrid poplar cost and transport distance have with the required production. The hybrid poplar price resulting from the equation is escalated from 2007 dollars to December 2018 dollars using the Consumer Price Index.

Exhibit 2-5. Hybrid poplar cost and transportation distance

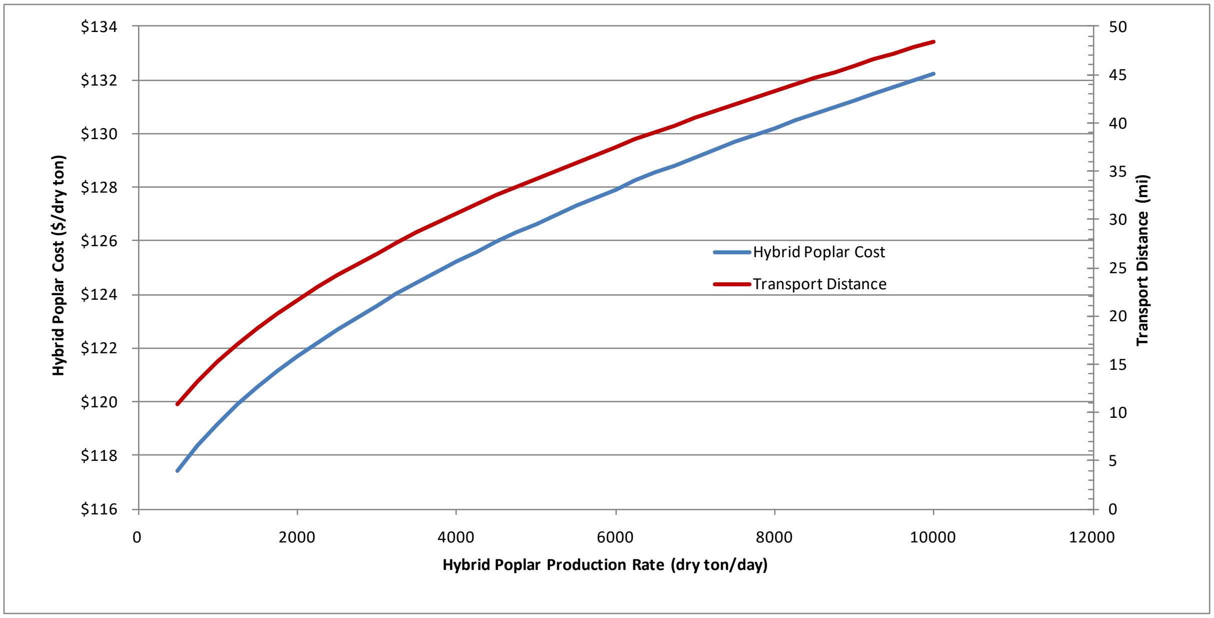


Exhibit 2-6 provides a comparison of the fuel prices in this study. Illinois No. 6 costs do not change with feed requirements and are presented as is. A range of hybrid poplar prices, from the minimum feed to the maximum feed used in this study, are presented.

Exhibit 2-6. Fuel price comparison

Coal Cost		
	$/AR ton	$/MMBtu
Illinois No. 6 Cost	51.96	2.23
Hybrid Poplar Cost		
Minimum Feed	76.01	9.01
Maximum Feed	79.21	9.39

Hybrid Poplar Selection:

Several biomass types have been successfully burned in commercial PC facilities. Hybrid poplar was chosen as the sole biomass feedstock in this study in lieu of other feeds (e.g., switchgrass) for the following reasons:

- Hybrid poplar is not a food source. Its ability to grow on marginal or depleted lands avoids competition over agricultural lands.
- Woody biomass is a robust fuel that has been relied on as an energy source for centuries.
- Hybrid poplar is a relatively fast-growing crop that has shown potential for use as a fuel easily co-fired with coal in existing plants, as well as the sole fuel source.

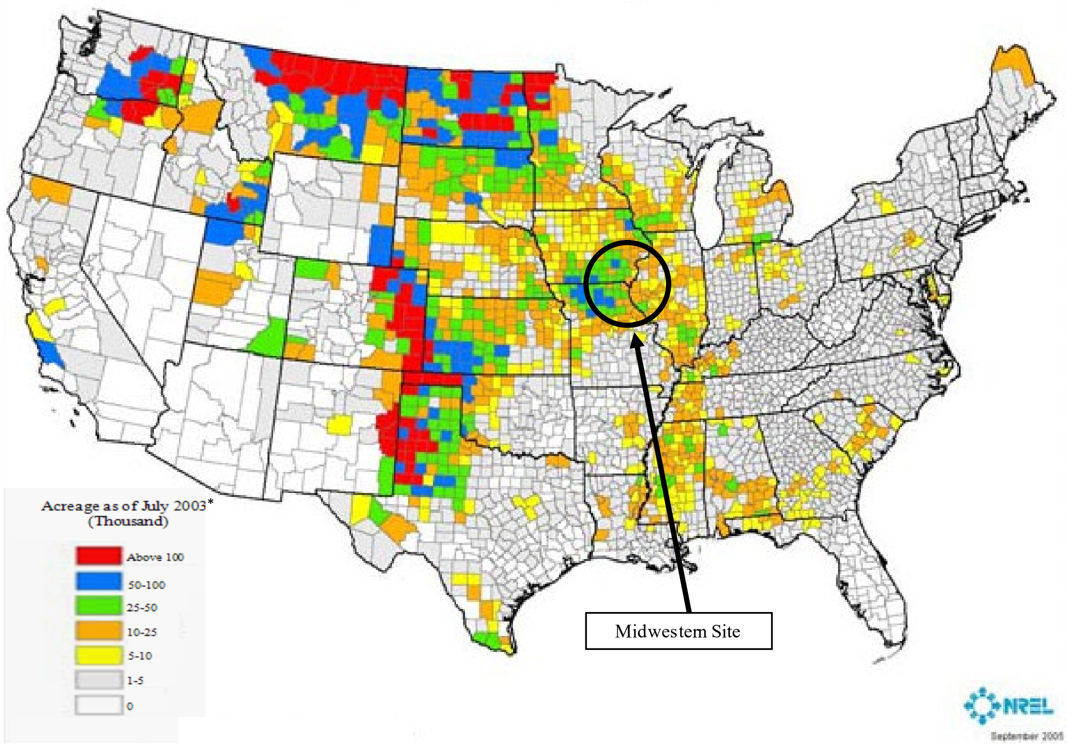
2.3.1 Hybrid Poplar Availability

Hybrid poplar is a member of the willow family—a hardwood tree that is one of the fastest growing trees in North America. As its name implies, hybrid poplars are a hybrid combination of cottonwood, aspen, and/or willow. Hybrid poplars were first produced in Britain in 1912. After World War II, many countries in Europe established farms of hybrid poplar to combat the timber shortage. Research and development coordinated by DOE's Bioenergy Feedstock Development Program (BFDP), beginning in 1979, produced hybrid strains that are resistant to drought, disease, and pests while increasing yields. Through the initial work of the BFDP and continuing work by a national consortium that involves government researchers from several agencies, universities, and the private sector, hybrid strains are more versatile, hearty, and able to live in most North American locations. However, regional availability is an important consideration for power plants planning on co-firing the crop.

The NRCS sectioned the United States into land resource regions and further into land resource areas. [17] The intention is to classify land regions of the United States and characterize the physiography, geology, biological resources, etc., of each land resource area in the region. The plant location assumed in this study is characterized as a midwestern (0 ft elevation) site. Referring to the NRCS classifications, several land resource areas concentrated in the Missouri and Illinois locale are able to support hybrid poplar growth. These most notably include the Southern Illinois and Indiana Thin Loess and Till Plain and Ozark Highland land resource areas.

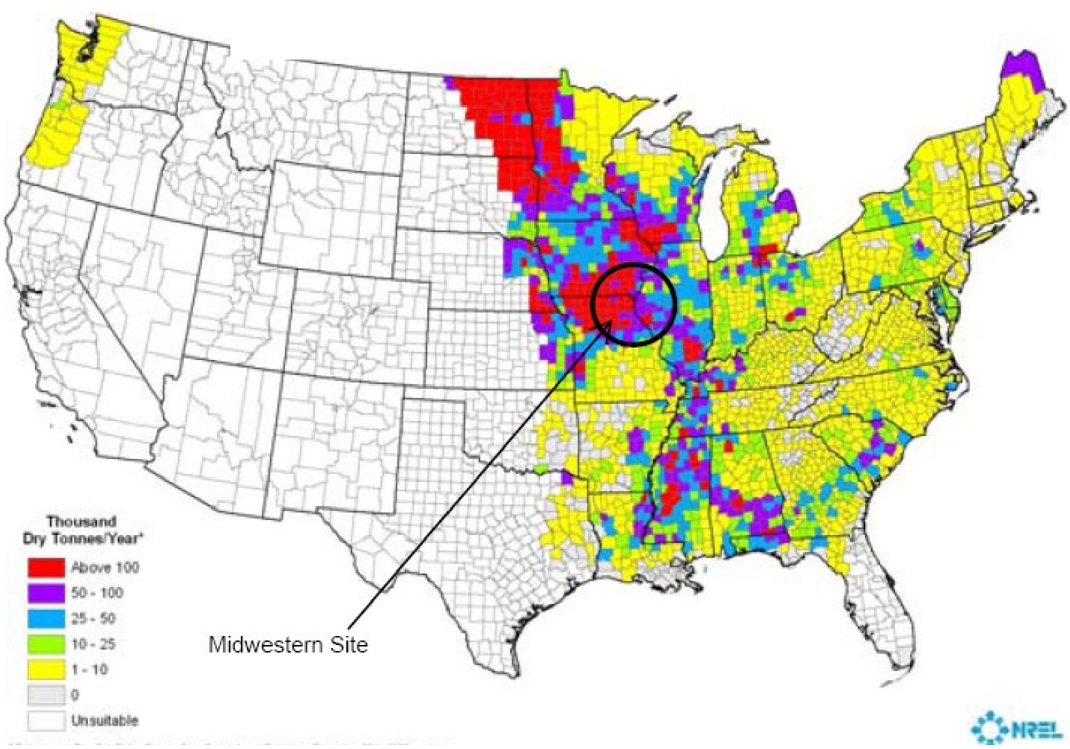
The plant is assumed to be located in regions with adequate hybrid poplar growth potential on CRP lands. A study conducted by the National Renewable Energy Laboratory (NREL) compiled data generated by the USDA's Farm Service Agency in order to create the maps shown in Exhibit 2-7 and Exhibit 2-8, which show national CRP acres and the potential for hybrid poplar production on CRP land throughout the United States, respectively. [18] From these maps, it is clear that the combination of CRP land concentration and hybrid poplar potential production is ideal for a midwestern site. This report does not assume that sufficient hybrid poplar currently exists for commercial power generation in the study site location in the aforementioned exhibits, only that there is adequate potential for cultivation thereon as supported by the NRCS land classifications and NREL CRP records.

Exhibit 2-7. CRP acres



Source: NREL [18]

Exhibit 2-8. Annual yield potential of hybrid poplar on CRP lands



Source: NREL [18]

2.3.2 Maximum Hybrid Poplar Supply

In order to supply a 49 percent biomass-fed plant utilizing an amine-based CO_2 capture unit at a net output of 650 MW, an annual feedrate of approximately 1.7 million as received (AR) tons, or 5,000 AR tonnes/day (5,600 AR ton/day), of hybrid poplar is required. This number represents the maximum hybrid poplar feed rate of all the plants in the study. Using Exhibit 2-7 and Exhibit 2-8 suggests that 0.2 to 0.5 million acres of CRP land are sufficient to supply the maximum annual feed rate.

In order to isolate the techno-economic implications of operating co-fed power plants, it was necessary to assume that the transportation and logistical barriers of supplying large amounts of biomass have been resolved. The authors acknowledge that future infrastructure development, such as converting a portion of the current coal mining and transportation system into biomass harvesting and transportation, could assist in reaching the goal. Further investigation into the total logistics of biomass delivery at this quantity is needed.

A potential requirement for large-scale biomass-fired PC plants is the integration of satellite chipping, drying, and pelletizing facilities in order to reduce the cost of transportation and streamline the biomass supply chain in situations where biomass cultivation areas are not localized, or the pelletizing process is not economical to place on-site. Satellite facilities will reduce the number of transportation vehicles (whether truck, railcar, or barge) needed to deliver fuel to the plant and increase the fuel's heating value.

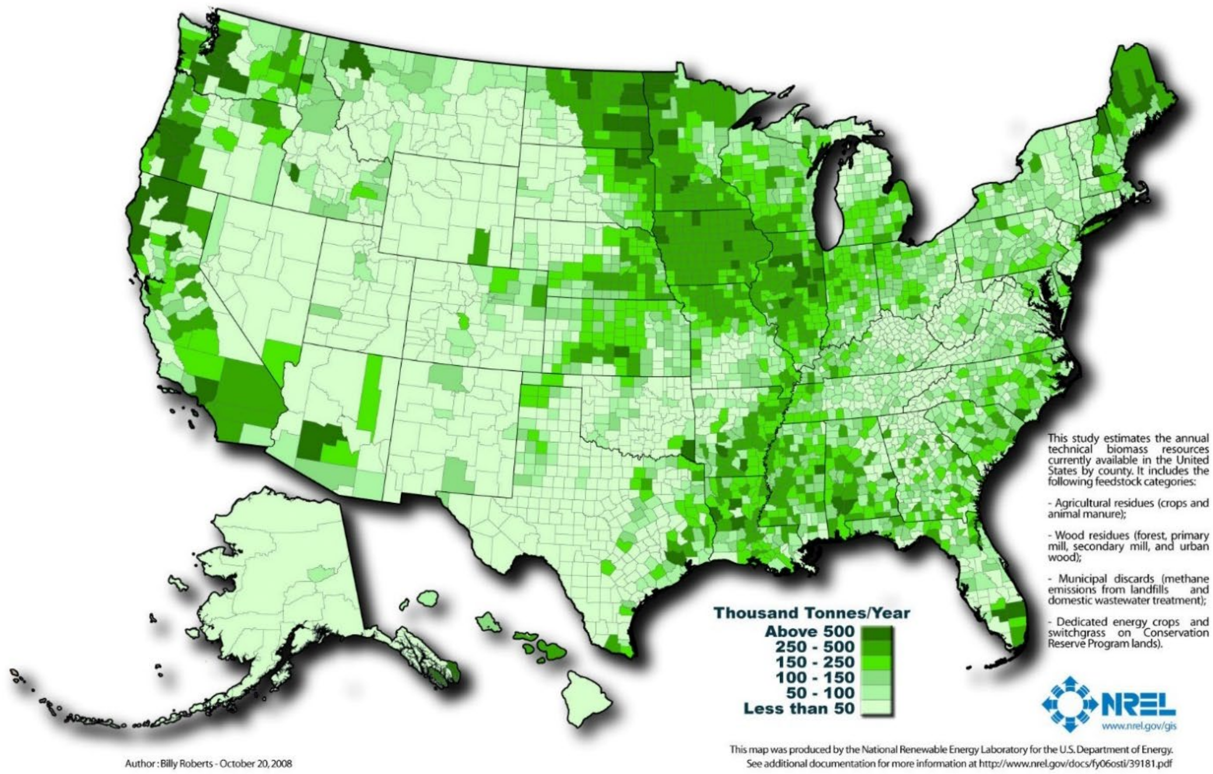
American Biomass Energy (ABE) provides a service to organize closed-loop (CL) plantations for use in biomass. In a CL operation, biomass is grown and fed to a plant specifically for biomass power rather than using biomass waste as fuel. For large-scale applications, ABE recommends torrefaction in addition to chipping and pelletization of the wood prior to shipping to the plant site.

ABE claims their plantations average 4,000 trees/acre and can harvest every two years for up to seven harvests before replanting. Though they can only produce 18 AR tonnes/year/acre (20 AR tons/year/acre), pelletizing and torrefaction increases the heating value to 23,550 kJ/kg (10,125 Btu/lb), which would reduce boiler intake by a factor of 3–4.

A CL system such as the one shown above is in full-scale planning stages in the Philippines, where a 30 MW plant will use an 80,000-hectare plantation of ipil-ipil plants as its feedstock. [19]

Nevertheless, hybrid poplar economics, due to transportation costs or competitive pricing, can present feed restrictions if used as the sole biomass feedstock. Therefore, other biofeed may be needed to supplement hybrid poplar in order to increase the availability of a plant's carbon-neutral fuel options. Feeds such as urban woody waste, forest residue, and other dedicated energy crops like switchgrass and corn stalks, offer CO_2 credit and may be more readily available in some regions. Exhibit 2-9 shows the entire U.S. resources for biomass that include the above options.

Exhibit 2-9. Total U.S. biomass resources



Source: NREL [18]

2.3.3 Maximum Hybrid Poplar Feed Rate

The maximum hybrid poplar feed rate in this study, at 50 percent moisture content, was 5,045 AR tonnes/day (5,562 AR tons/day), which represents the amount of hybrid poplar logs that must be delivered to the site. Harvesting and transporting this quantity of biomass presents significant challenges and represents a primary barrier in the successful adoption of the technology at this scale. Assuming a delivery truck capacity of 22,000 kg (48,000 lb) and year-round hybrid poplar harvestability, this feed would equate to about one full truck arriving at the plant every 6 minutes around the clock. Even with multiple truck unloading facilities, this frequency of truck transportation is logistically unobtainable. In order to support feeds of this magnitude, it is necessary to develop hybrid poplar mass transit like the coal system's current barge and train infrastructure. Storage capabilities at the plant to satisfy demand during times of minimal or no harvest must also be investigated in order to make transporting the fuel to the facility feasible.

Logistical issues of transporting and efficiently feeding large quantities of biomass to conventional PC plants are currently being examined with major focuses on pelletization. [20, 21] Processes such as these produce a dried, compacted, energy-densified biomass product that can improve fuel feeding methods as well as improve the logistics of transporting biomass to the plant.

Torrefaction: Improving Biomass Logistics
Torrefaction is a pyrolysis treatment that operates within a temperature range of 200–300°C (392–572°F). The mechanical effect of torrefaction on biomass is similar to its effect on coffee beans, giving the product a brittle structure. The main torrefaction product is a solid, which is the charred residue (or char) of the processed biomass. Following torrefaction, the biomass char is structurally sound and can be pelletized to improve grindability. Hybrid poplar specifications from various sources consistently show the volatile content to be around 80–85 percent. [20] The yield of chemical energy contained in the biomass through torrefaction is of importance because of the particularly high volatile content. One study shows that dried biomass fed to a torrefaction process at 15 percent moisture can potentially recover 90 percent of its chemical energy post torrefaction if process temperatures remain between 230 and 270°C (446 and 518°F). [70]

The largest domestic, biomass-fueled energy plants currently operating use conventional combustion-based technology and are co-located with paper mills. For example, the Mead Coated Board Plant in Alabama used over 1.16 million tons (1.05 million tonnes) of wood-derived solids and the Gaylord Container Bogalusa Plant used over 1.14 million tons (1.034 million tonnes) in 2008. [22] During their peak months, these plants consume between 3,600 and 4,300 tons (3,265 – 3,900 tonnes) per day of wood-based fuel.

Existing dedicated electricity generating plants burning biomass and not co-located with paper or sugar mills are generally limited to 50–105 MW capacity. The largest of these is Nacogdoches Power, a joint venture between Bay Corporation Holdings, Ltd. and Energy Management, Inc., is a 100 MW plant in Texas fueled entirely by wood (forest residues, whole tree chips, municipal tree waste, and mill residue). The Pittsylvania Power Plant in Virginia (80 MW), the J.C. McNeil Plant in Vermont (59.5 MW), the Kettle Falls Generating Station in Washington (50.7 MW), and the Craven County Wood Energy Plant in North Carolina (50 MW) have peak biomass feed requirements of 1,600–2,400 tpd.

2.3.4 Hybrid Poplar Harvest Timetable and Storage

Typically, hybrid poplar crops require two years before they are fully established. A 100 percent yield of the harvest potential can be realized by the second year. The growth cycle can only continue for 15 years (7 harvests) before replanting becomes necessary.

Because harvest times are limited throughout the year, hybrid poplar storage will be required on-site in large-scale applications. For the purposes of this study, it was assumed that hybrid poplar is harvested once to twice a year. It was found, during the progression of the "Coal and Biomass to Power in Integrated Gasification Combined Cycles" legacy study, that storage and collection logistics have potential to limit production. [23] Varying degrees of losses occur due to decomposition depending on the storage method. Pelletization and torrefaction would reduce this loss.

2.4 Environmental Targets

2.4.1 Air Emissions Targets

The Environmental Protection Agency (EPA) could propose new environmental regulations that might impact biomass-fired boilers. However, for the purpose of this study, the environmental approach is to evaluate each case on the same regulatory design basis. The current enacted process for establishing environmental requirements for new plants is the New Source Performance Standards (NSPS) as amended in February 2013. [24] Since all cases are located at a greenfield site, NSPS could be a starting point for design air emission rates. Other emission limits were set by the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS). [25, 24] NSPS and MATS emission requirements are summarized in Exhibit 2-10.

Exhibit 2-10. NSPS and MATS emission requirements summary

Pollutant	Emission Limit (lb/MWh-gross)
SO_2	1.00
NOx	0.70
PM (Filterable)	0.09
Hg	$3x10^{-6}$
HCl	0.010

Permitting a new plant with emission rates controlled by NSPS requirements likely will not be acceptable to EPA and/or individual states, who would probably invoke the New Source Review (NSR) permitting process. The NSR process is expected to result in allowable emission rates more stringent than NSPS. The NSR process requires installation of emission control technology meeting either Best Available Control Technology determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate 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 EPA's Green Book Non-attainment Area Map, [26] relatively few areas in the Midwestern United States are classified as "non-attainment." Therefore, for this study, the proposed plants are assumed to be in an attainment area and Lowest Achievable Emission Rate technology is not required.

Exhibit 2-11 provides the emissions limits for PC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-11. Environmental targets for PC cases [24] [25] [26]

Pollutant	PC (lb/MWh-gross)	Control Technology
SO_2	1.00	Wet limestone scrubber
NOx	0.70	Low NOx burners, overfire air and SCR
PM (Filterable)	0.09	Fabric filter
Hg	$3x10^{-6}$	Co-benefit capture, dry sorbent injection[A], activated carbon injection
HCl	0.010	SO_2 surrogate[B]

[A]Limits sulfur trioxide (SO_3) levels and their detrimental effects on activated carbon injection
[B]Sulfur dioxide (SO_2) may be utilized as a surrogate for HCl measurement if the electric utility steam generating units utilizes wet FGD [27]

It was assumed that low nitrogen oxides (NOx) burners (LNBs) and staged overfire air (OFA) would limit NOx production to 0.15 kg/GJ (0.35 lb/MMBtu) and that selective catalytic reduction (SCR) technology would be 75–79 percent efficient. By adjusting the ammonia (NH_3) flow rate and/or catalyst bed depth in the SCR, the NOx emissions limit was able to be met exactly.

The wet limestone scrubber was assumed to be 98 percent efficient, which results in SO_2 emissions below the NSPS SO_2 limit. Current technology allows wet flue gas desulfurization (FGD) removal efficiencies in excess of 99 percent, but based on NSPS requirements, such high removal efficiency is not necessary.

The fabric filter was assumed to be capable of achieving an efficiency of greater than 99.9 percent. As the required efficiency was approximately 99.9 percent for each case, the efficiency was varied in order to meet the particulate matter (PM) emissions limit exactly.

The Hg removal efficiency required to meet the emission limit is approximately 97 percent maximum in the 100 percent coal case. It was assumed that the total Hg removal rate resulting from the combination of pollution control technologies used (SCR, dry sorbent injection [DSI], activated carbon injection [ACI], fabric filters, and FGD) would meet the limit exactly. DSI is required to limit the effects of SO_3 on Hg capture due to the high sulfur content of the coal in this study. Section 3.6 provides a detailed discussion regarding Hg removal and the various systems involved.

2.4.2 Water Emissions Targets

EPA issued updated Effluent Limitation Guidelines (ELG) and standards for the steam electric power generation point source category in November 2015, to strengthen controls on wastewater discharges.[a] [28] The ELG are national technology-based NSPS derived from data collected from industry. They are intended to provide flexibility in implementation through use of technologies already installed and operating in the power industry. The federal standards established by this rule are the minimum discharge standards. As ELG are enforced under the

[a] In April 2017, EPA announced plans to reconsider the power plant ELG rule—as they apply to existing sources—and their intent to request a stay of the regulations, pending litigation. [29]

National Pollutant Discharge Elimination System, [29] more stringent water quality-based standards may be established by the local permitting authority; however, these additional requirements were not considered in this report.

The final ELG rule established new wastewater categories and discharge limits and updated discharge requirements for existing wastewater categories. The following are the new or updated categories in the rule:

- FGD wastewater
- Fly ash transport water
- Bottom ash transport water
- Landfill leachate
- Flue gas Hg control wastewater
- Non-chemical metal cleaning wastewater
- Wastewater from gasification of fuels such as coal and petroleum coke

Non-chemical metal cleaning wastewater was established as a new wastewater category in the updated ELG. However, new limits were not established for this category; therefore, treatment of this stream was not evaluated in this report.

The landfill of plant byproducts is assumed to be outside the scope of the plants considered in this study; therefore, landfill leachate is not evaluated in this report.

For the cases considered in this study, both fly ash and bottom ash handling systems are dry and do not result in a water stream requiring treatment under ELG. Similarly, the flue gas Hg control approach of combined sorbent injection followed by carbon injection does not generate a water stream for treatment. Therefore, only the FGD wastewater blowdown stream requires treatment.

Intermittent discharges (e.g., chemical metal cleaning wastewater), coal pile runoff, low volume waste (e.g., boiler blowdown), and cooling tower blowdown were assumed to be compliant with all applicable regulations with no additional treatment beyond conventional considerations. The applicable wastewater discharge limits are shown in Exhibit 2-12.

Exhibit 2-12. New source treated FGD wastewater discharge limits [28]

Effluent Characteristic	Long-Term Average	Daily Maximum Limit	Monthly Average Limit[A]
Arsenic, ppb	4.0	4	-
Mercury, ppt	17.8	39	24
Selenium, ppb	5.0	5	-
Total Dissolved Solids, ppm	14.9	50	24

[A]Monthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days

For the wastewater treatment systems, the limits are applied at the discharge, prior to commingling with other plant water systems. A spray dryer is a technology commonly used in the power industry for FGD, which can be applied as a thermal evaporation process to treat wastewater. The feasibility of using a spray dryer evaporator as the sole treatment system in PC cases is limited by the flow rate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flow rate. Section 3.10.2.1 provides a detailed discussion regarding the spray dryer as applied to the cases in this report.

2.5 Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) requires a minimum percentage of power generation to be produced by renewable sources. As of December 2019, 29 states, the District of Columbia, and three territories have established their own unique RPS, while eight more states and one territory have set renewable energy goals. Each of these states has guidelines or enforced requirements for the amount of renewable energy that must be produced within a pre-determined timeframe and what each state considers to be eligible, renewable, energy sources. In general, these standards vary widely, but state-by-state standards typically require a percentage of total renewable power generated to range between 10 percent and 30 percent of total power generated, with the average nearing 20 percent by the year 2020–2025. The eligible, renewable, energy sources generally include but are not limited to

- Biomass
- Wind
- Solar-derived
- Hydro-derived
- Geothermal

Without high carbon taxes, there is no economic motivation for carbon reduction. An RPS may, therefore, be a prime motivator for coal and biomass as a strategy for carbon mitigation.

Not all states agree on what energy sources are considered to be renewable. However, of the 42 proposed renewable targets, each one considers biomass to be an eligible renewable energy source for power generation.

Each RPS is constructed to mandate producing what each state considers to be a reasonable percentage of renewable power. However, this will inevitably drive up the average cost of power generation from that of the typical low cost, high-carbon power mix. A properly structured RPS may need to make allowances or provide cost recovery mechanisms in order to motivate utilities to generate renewable power. Even with these motivators, it is critical for the nation to be cognizant of the costs for generating power with each of the eligible renewable sources and the potential choices for utilizing these sources for power generation.

For instance, as this report will show, generating power with 49 percent biomass is not nearly as cost effective, from an LCOE perspective, as is generating power with a lower mixture of biomass to coal for a plant size of 650 MW. It is important to recognize that combining the renewable properties of biomass with the low-cost of coal power generation will provide large quantities of renewable power at a more affordable cost than if biomass were used exclusively in today's power generation market.

The results of this report will provide a baseline for comparison of biomass-generated power costs to the costs of generating power with the other eligible renewable energy sources so that informed decisions can be made at the utility level to minimize the costs of complying with RPS requirements.

2.6 CO_2 Emissions

CO_2 is not currently regulated. However, the possibility exists that carbon limits will be imposed in the future and this study examines cases that include a reduction in CO_2 emissions. CO_2 emissions in this study are reduced by adding biomass to create credit for the renewable carbon in the feed and/or by physically capturing and sequestering CO_2.

EPA promulgated an NSPS on October 23, 2015, for emissions of CO_2 for new fossil fuel-fired electric utility generating units. [30] The limit set by the regulation was 1,400 lb-CO_2/MWh-gross (635 kg-CO_2/MWh-gross) for PC plants. As of the writing of this report, EPA has proposed changes that increase the CO_2 emissions limit for the PC plants considered in this study to 1,900 lb-CO_2/MWh-gross (860 kg-CO_2/MWh-gross). [31]

The PC cases assume that all fuel-based carbon that is combusted (i.e., excluding unburned carbon) and converted to CO_2 in the flue gas. CO_2 is also generated from limestone in the FGD system. The CO_2 capture plant design is for 90 percent capture of the CO_2 exiting the FGD system, resulting in emissions of 185–193 lb-CO_2/MWh-gross (84–88 kg-CO_2/MWh-gross). The analogous non-capture plants report CO_2 emissions of 1,627–1,688 lb-CO_2/MWh-gross (738–766 kg-CO_2/MWh-gross).

2.7 Capacity Factor

The capacity factor (CF) used in this study is 85 percent for all cases. 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. The CF is the same as that used in previous studies for PC systems with CO_2 capture and is based on input from the North American Electric Reliability Council (NERC) and their work on the Generating Availability Data System (GADS). [32] The addition of a biomass feedstream was not considered to reduce the CF although commercial-scale demonstration (of anything larger than 80 MW) of high percentage biomass feed (up to 100 percent) has not been demonstrated.

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

The baseline study net PC unit capacity is 650 MW. The average EAF for coal-fired plants in the 600–799 MW size range was 83 percent in 2011 and declined to 81 percent in 2016. In 2017 the top 20 coal plants, irrespective of nameplate capacity, achieved CFs in excess of 82 percent, with the top 15 units achieving CFs of 85 percent or higher. [4]

GADS data show an average coal unit availability for all unit sizes greater than 80 percent and the 2017 plant level data show that coal units have demonstrated CFs greater than 85 percent. The current study costs are based on mature plant technology and market conditions that enable baseload operation. Based on a review of the available data, an 85 percent CF is selected for the PC coal units.

The addition of CO_2 capture to each technology was assumed not to impact the CF, assuming that CO_2 could be vented to the atmosphere if necessary.

2.8 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 subsystem was determined and internal recycle water available from various sources like boiler feed water (BFW) blowdown, condensate from the biomass dryer, and condensate flue gas (FG) (in CO_2 capture cases) 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 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, ash handling makeup, and FGD 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.

The cooling tower blowdown is 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. It was assumed that all cases utilized a mechanical draft, evaporative cooling tower. The design ambient wet bulb temperature of 11°C (51.5°F) (Exhibit 2-1) was used to achieve a cooling water temperature of 16°C (60°F) using an approach of 5°C (8.5°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following: [33]

- Evaporative losses of 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses calculated as follows:
    - 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

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.

2.9 Cost Estimating Methodology

Detailed information pertaining to topics such as contracting strategy; engineering, procurement, and construction (EPC) contractor services; estimation of capital cost contingencies; owner's costs; cost estimate scope; economic assumptions; finance structures; and LCOEs are available in the 2019 QGESS "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [4] Select portions are repeated in this report for completeness.

Capital Costs:

The capital cost estimates documented in this report reflect uncertainty ranges as shown in Exhibit 2-13.

Exhibit 2-13. Capital cost uncertainty ranges

Technology	Uncertainty Range	AACE Classification
PC	-15/+30	Class 4

PC cases fall within Association for the Advancement of Cost Engineering International (AACE) Class 4 estimates. [4] [34] [35] In all cases, this report intends to represent the next commercial offering and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs, which can be a challenge for emerging technologies.

Costs of Mature Technologies and Designs:

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale (e.g., PC power plants without CO_2 capture), reflect nth-of-a-kind on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to "learning by doing" and risk reduction benefits that result from serial deployments as well as from continuing research and development.

Costs of Emerging Technologies and Designs:

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., any plant with CO_2 capture) use the same cost estimating methodology as for mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that early deployments of PC plants with CO_2 capture may incur costs higher than those reflected within this report.

Other Factors:

Actual reported project costs for all the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g., contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends:

Continuing research, development, and demonstration is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated here.

2.9.1 Capital Costs

As illustrated in Exhibit 2-14, this report defines capital cost at five levels: BEC, EPCC, TPC, TOC, and TASC. BEC, EPCC, TPC, and TOC are "overnight" costs and are expressed in "base-year" dollars. The base year is the first year of capital expenditure. TASC is expressed in mixed, current-year dollars over the entire capital expenditure period. In this study it is assumed that the capital expenditure period, or construction lead time, is five years, consistent with other NETL studies.

The Bare Erected Cost (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 are not included in BEC.

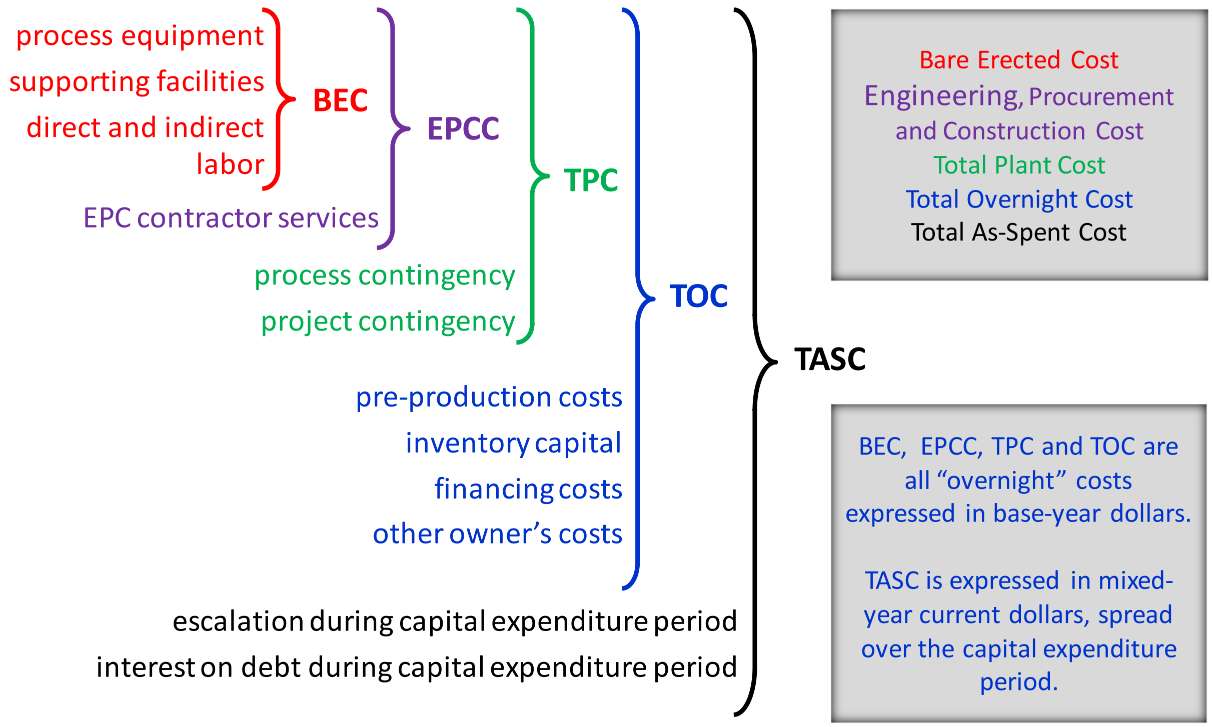
The Engineering, Procurement and Construction Cost (EPCC) comprises the BEC plus the cost of services provided by the EPC contractor. EPC services include detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs.

The Total Plant Cost (TPC) comprises the EPCC plus project and process contingencies.

The Total Overnight Cost (TOC) comprises the TPC plus all other overnight costs, including owner's costs. TOC does not include escalation during construction or interest during construction.

The Total As-Spent Cost (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, comprising interest on debt and a return on equity.

Exhibit 2-14. Capital cost levels and their elements



2.9.1.1 Cost Estimate Basis and Classification

The TPC and operating and maintenance (O&M) costs for each of the cases in the report were estimated by Black & Veatch using an in-house database and conceptual estimating models. Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects.

2.9.1.2 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).

2.9.1.3 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. CO_2 transport and storage (T&S) cost is not included in the reported capital cost or O&M costs but is treated separately and added to the LCOE.

2.9.1.4 Capital Cost Assumptions

Black & Veatch developed the capital cost estimates for each base case plant using the company's in-house database and conceptual estimating methodology for each of the specific technologies. This database and approach are maintained by Black & Veatch 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 bottom-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. The estimating models are based on a U.S. Gulf Coast location and the labor cost was factored to a Midwest location. Labor cost data were sourced from recent projects and proprietary Black & Veatch in-house references/cost databases.
- 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. No additional incentives such as per-diem allowances 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.
- Engineering and Construction Management are estimated based on Black & Veatch's historical experience in designing and building power projects. The cost, as a percentage of BEC, is 17.5 percent for PC. The percentage was selected such that the final total cost calculated is representative of Black & Veatch's historical engineering/construction management costs for similar plant types. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

2.9.1.5 Price Fluctuations

During the writing of this report, the prices of equipment and bulk materials fluctuated as a result of various market forces. Some reference quotes pre-dated the 2018-year cost basis while others may be considered more historical. All vendor quotes used to develop these estimates were adjusted to December 2018 dollars accounting for the price fluctuations. Price indices, e.g., The Chemical Engineering Plant Cost Index [36] and the Gross Domestic Product Chain-type Price Index [37], were used as needed for these adjustments. While these overall indices are nearly constant, it should be noted that the cost of individual equipment types may still deviate from the December 2018 reference point.

2.9.1.5.1 Process Contingency

Process contingencies were applied to the PC estimates in this report as follows:

- Cansolv System: 17 percent on PC capture cases—post-combustion capture process unproven at commercial scale for power plant applications
- Instrumentation and Controls: 5 percent on most line-items in the PC capture cases—integration issues

2.9.1.6 Owner's Costs

Detailed explanation of the owner's costs is available in the 2019 QGESS "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [4] Owner's costs are split into three categories: pre-production costs, inventory capital, and other costs.

Pre-production allocations are expected to carry the specific plants through substantial completion, and to commercial operation. Substantial completion is intended to represent the transfer point of the facility from the EPC contractor (development entity) to the end user or owner, and is typically contingent on mutually acceptable equipment closeout, successful completion of facility-wide performance testing, and full closeout of commercial items.

Two examples of what could be included in the "other" owner's costs are rail spur and switch yard costs.

Switch yard costs are dependent on voltage, configuration, number of breakers, layout, and air-insulated versus gas-insulated. As a rule of thumb, a 345-kV switchyard (air-insulated, ring bus) would cost roughly $850,000 per breaker.

On-site only rails (excludes long runs) would be expected to cost in the range of $850,000–950,000 per mile (relatively flat level terrain) plus the costs of any switches/turnouts (approximately $50,000 each) and road crossings (approximately $300 per linear foot).

2.9.2 Operating and Maintenance Costs

The production costs or O&M pertain to those charges associated with operating and maintaining the power plants over their expected life and include:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (i.e., 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. Taxes and insurance are included as fixed O&M costs, totaling 2 percent of the TPC.

2.9.2.1 Operating Labor

Operating labor cost was determined based on the number of operators required for each technology. The average base labor rate used to determine annual cost is $38.50/hour. The associated labor burden is estimated at 30 percent of the base labor rate.

2.9.2.2 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.

2.9.2.3 Administrative and Support Labor

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

2.9.2.4 Consumables

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

Quantities for major consumables such as fuel and sorbent were taken from technology-specific energy 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 may be accounted for directly in the O&M tables or included with the equipment pricing in the capital cost. Where applicable, the O&M tables state where this cost is included on a case-by-case basis.

2.9.2.5 Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. Chemical and catalyst waste streams are individually reported, in addition to others. Waste disposal costs were separated into two categories: non-hazardous and hazardous waste. Non-hazardous waste is disposed of at a rate of $41.90/tonne ($38.00/ton). Hazardous waste is disposed of at a rate of $88.20/tonne ($80/ton).

2.9.2.6 *Co-Products and By-Products*

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically gypsum and sulfur, no credit was taken for their potential salable value.

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 added capital should be included in the plant costs to produce a particular co-product. Slag is a potential by-product in certain markets. Similarly, ash may also be a potential by-product in certain markets; however, due to the ACI in the PC cases, the fly ash may not be marketable. Also, American Society for Testing and Materials C618 says only ash from coal can be used for the production of cement or dryboard. Therefore, biomass ash or a combination of coal/biomass ash is technically unacceptable. Despite this constraint, some local markets still accept the ash. As stated above, these material streams are considered waste in this report with a concomitant disposal cost.

2.9.3 CO_2 Transport and Storage

The cost of CO_2 T&S in a deep saline formation is estimated using the Fossil Energy (FE)/NETL CO_2 Transport Cost Model (CO_2 Transport Cost Model) and the FE/NETL CO_2 Saline Storage Cost Model (CO_2 Storage Cost Model). Additional detail on development of these costs is available in the 2019 QGESS "Carbon Dioxide Transport and Storage Costs in NETL Studies." [38]

Due to the variances in the geologic formations that make up saline formations across the United States, the cost to store CO_2 will vary depending on location. Storage cost results from the CO_2 Storage Cost Model align with generic plant locations from the NETL studies that utilize the coal found in those particular basins:

- Midwest plant location – Illinois Basin
- Texas plant location – East Texas Basin
- North Dakota plant location – Williston Basin
- Montana plant location – Powder River Basin

The far-right column of Exhibit 2-15 shows the total T&S costs used in NETL system studies for each plant location rounded to the nearest whole dollar. Only the $10/tonne ($9/ton) value is used in this report since all cases are in the Midwest.

Exhibit 2-15. CO_2 transport and storage costs

Plant Location	Basin	Transport (2018 $/tonne)	Storage Cost at 25 Gigatonne (2018 $/tonne)	T&S Value for System Studies[A] (2018 $/tonne)
Midwest	Illinois	2.07	8.32	10
Texas	East Texas		8.66	11
North Dakota	Williston		12.98	15
Montana	Powder River		19.84	22

[A]The sum of transport and storage costs rounded to the nearest whole dollar

2.9.4 LCOE and Breakeven CO_2 Value and Emissions Penalty

The LCOE is the amount of revenue required per net megawatt-hour during the power plant's operational life to meet all capital and operational costs. The real LCOE can be obtained from the following formula:

$$LCOE = LCC + LOM + LFP$$

Where:

LCOE – the levelized cost of electricity, reported in $/MWh

LCC – the levelized capital cost

LOM – the levelized O&M cost

LFP – the levelized fuel price

The method used to determine capital recovery factor and levelization factors for O&M and fuel costs is found in the Cost Estimating Quality Guideline.

The breakeven CO_2 value represents the minimum CO_2 plant gate value that will incentivize carbon capture relative to a defined reference non-capture plant. The breakeven CO_2 value is calculated using the following formula:

$$Breakeven\ CO_2\ Value\ \left(\frac{\$}{tonne}\right) = \frac{(LCOE_{CCS} - LCOE_{Non\ CCS})}{CO_2\ Captured}$$

The breakeven CO_2 emissions penalty represents the minimum CO_2 emissions value, when applied to both the capture and non-capture plant, that will incentivize carbon capture relative to a defined reference non-capture plant. The breakeven CO_2 emissions penalty is calculated using the following formula:

$$Breakeven\ CO_2\ Emissions\ Penalty\ \left(\frac{\$}{tonne}\right) = \frac{(LCOE_{CCS\ with\ T\&S} - LCOE_{Non\ CCS})}{CO_2\ Emissions_{Non\ CCS} - CO_2\ Emissions_{CCS}}$$

Where:

CCS – the capture plant for which the breakeven CO_2 value/emissions penalty is being calculated (excluding T&S unless otherwise noted)

Non-CCS – the reference non-capture plant, as described below

LCOE – the levelized cost of electricity, reported in $/MWh

The CCS plant includes CO_2 compression to 15.3 MPa (2,215 psia)

For CO_2 value, the LCOE excludes T&S costs

For CO_2 emissions penalty, the LCOE includes T&S costs

CO_2 Captured – the rate of CO_2 captured, reported in tonne/MWh

CO_2 Emissions – the rate of CO_2 emitted out the stack, reported in tonne/MWh

For today's greenfield coal with CCS plants, the reference non-capture plant used to calculate the breakeven CO_2 value/emission penalty is a 100 percent coal-fired supercritical (SC) PC plant without capture.

2.10 Life Cycle Analysis Methodology

In order to ensure a rigorous analysis, and to allow comparisons to similar studies, the LCA was conducted according to the methodology set out in ISO 14040 and ISO 14044. The crucial elements of this analysis are goal and scope definition, life cycle inventory (LCI) analysis, life cycle impact assessment (LCIA), and interpretation.

2.10.1 Goal and Scope Definition

The goal of this LCA is to determine the environmental impact of generating electricity using a combination of coal and hybrid poplar biomass. To do so, energy and material consumption was analyzed from cradle to grave, to enable comparisons to other forms of electricity generation. Fuel acquisition (coal mining, forestry), fuel transportation, plant consumables manufacturing, plant emissions, carbon sequestration, and plant byproducts were all considered. Emissions from construction of the plant and infrastructure were not modeled, as previous studies have found their impacts to be negligible when the entire life cycle of the plant is considered.

The functional unit for this study is 1 MWh of electricity generated by a thermal power plant co-firing Illinois No. 6 bituminous coal and hybrid poplar biomass as fuel. Environmental impacts from each plant configuration are normalized to the functional unit for comparison and analysis.

2.10.2 Life Cycle Inventory Analysis

Plant consumption and emissions data was provided by the process system simulations of the plant configurations performed in Aspen Plus® (Aspen). Impacts from coal production were modeled using NETL's Coal Upstream Model, which includes mining and processing. Biomass production was modeled using NETL's Unit Process data for biomass cultivation, harvesting, and forest residue decomposition. Rail and truck transportation (for coal and biomass fuel respectively), and electricity emissions were modeled using data from NETL's CO_2 Utilization database, which is an aggregate of previous NETL research. Production impacts for plant consumables (such as enhanced hydrated lime, limestone, and ammonia) were modeled using the NREL openLCA database.

2.10.3 Life Cycle Impact Assessment

This analysis uses a modified version of Tool for Reduction and Assessment of Chemicals and Other Environmental Impacts (TRACI) 2.1 method for calculating impact assessment results. [39] TRACI is an impact assessment method developed by the EPA National Risk Management Research Laboratory. TRACI implements midpoint metrics that describe impacts at some point between the inventory and ultimate damage to the environment (inventory→midpoint → ultimate damage) (e.g., chlorofluorocarbons (CFCs) [inventory]→ozone depletion [midpoint]→ allows higher ultraviolet B radiation and increases the rate of human skin cancer [ultimate damage]). The NETL modifications to TRACI include using updated global warming potential (GWP) factors from the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5). [40]

EPA released the first version of TRACI in 2002. [41] The tool was developed to provide a comprehensive method for life cycle impact assessment applicable to the United States. TRACI was updated in 2011 to TRACI 2.0. [42] The subsequent release of TRACI 2.1 included further changes to the impact categories of acidification potential, photochemical smog formation potential, and particulate matter formation potential The changes to acidification are from the adoption of a new reference flow (kg SO_2 rather than moles hydrogen ions [H+]). Photochemical smog formation potential and particulate matter formation potential have undergone more significant updates, and make use of new underlying models. This analysis utilizes the latest factors available in TRACI 2.1, with modified characterization factors for Global Warming Potential and Particulate Matter Formation Potential.

The following is a list of the impact categories included in this analysis:

- **Global Warming Potential (AR5, 100-yr)**: GWP is the average increase in the temperature of the Earth's surface and lower atmosphere. GWP can occur as a result of increased emissions of GHGs. [40] Reporting units are kg CO_2-equivalent (CO_2e). GHGs in this analysis are reported on a common mass basis of CO_2e using the GWPs of each gas from IPCC AR5, rather than the Fourth Assessment Report factors used in TRACI 2.1. [40] The choice to use AR5 is to reflect the latest research and assumes that TRACI will implement AR5 GWPs in the future. The default GWP used is the 100-year time frame, but in some cases, results for the 20-year time frame are presented as well. All GHG results in this analysis are expressed as 100-yr GWPs unless specified otherwise. The GWPs for methane (CH_4) account for climate carbon feedback and CO_2 from CH_4 oxidation (an appropriate adder for fossil CH_4). [40] Exhibit 2-16 shows the GWPs used for the GHGs that were inventoried.
- **Acidification Potential**: The increased concentration of H+ in a local environment. This can be from the direct addition of acids, or by indirect chemical reactions from the

addition of substances such as ammonia. [39] Reporting units are kg SO_2-equivalent (SO_2e).

- **Eutrophication Potential**: The "enrichment of an aquatic ecosystem with nutrients (nitrogen, phosphorus) that accelerate biological productivity (growth of algae and weeds) and an undesirable accumulation of algal biomass." [43] Reporting units are kg nitrogen-equivalent (N e). Photochemical Smog Formation Potential: Ground-level ozone, formed by the reaction of NOx and volatile organic compounds (VOCs) in the presence of sunlight. [39] Reporting units are kg trichlorofluoromethane-equivalent (CFC-11e).
- **Ozone Depletion Potential**: The deterioration of ozone within the stratosphere by chemicals such as CFCs. Stratospheric ozone provides protection for people, crops, and other plant life from radiation. [39] Reporting units are kg ozone-equivalent (O_3e).
- **Particulate Matter Formation Potential**: Particulate matter formation potential (PMFP) includes "a mixture of solid particles and liquid droplets found in the air" that are smaller than 10 microns in diameter. [29] These small diameter particles can enter deep inside the lungs and cause many serious health problems. Almost all PM health impacts are caused by particulate matter 2.5 microns or smaller (PM2.5). [44] Reporting units are kg PM2.5-equivalent (PM2.5e).

Exhibit 2-16. IPCC AR5 GWPs

GHG	20-year	100-year	Units
CO_2	1	1	kg CO_2e
CH_4	87	36	kg CO_2e
N_2O	268	298	kg CO_2e
SF_6	17,500	23,500	kg CO_2e

3 SYSTEM DESCRIPTIONS

System descriptions for the major PC process areas included in this study are described in this section. A base plant configuration with modifications to the configuration is described in Section 4. Unless otherwise stated for biomass conditions, these descriptions are based upon coal firing and assumed to be relevant for biomass co-firing.

3.1 COAL, ACTIVATED CARBON, SORBENT, AND BIOMASS RECEIVING, PREPARATION, 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. The system is designed to support short-term operation at the 5 percent over pressure/ valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

The scope of the sorbent receiving and storage system includes truck roadways, turnarounds, unloading hoppers, conveyors, and day storage bins.

Hybrid poplar logs are received at the plant by truck. For this study, it was assumed that there are no logistical barriers to transporting the proper amount of biomass to achieve 49 percent firing in the PC boiler. The trucks are unloaded using dedicated forklifts. The hybrid poplar is prepared by being chipped, dried to 10 percent moisture in a Wirbelschicht Trocknung Anlage (WTA) process (fluidized-bed drying with internal waste heat utilization), pelletized, and fed to the boiler. Storage consists of covered pellets with allowances for water drainage. The pellets are transferred from long-term storage to short-term storage, equivalent to 72 hours of uninterrupted production. From short-term storage, the pellets are conveyed to the feed system.

Operation Description – The coal is delivered to the site by 100-car unit trains comprising 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3 in 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 transfers the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 2.5 cm x 0 (1 in x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six boiler silos.

Limestone is delivered to the site using 23 tonne (25 ton) trucks. The trucks empty into a below grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin.

Brominated powdered activated carbon (PAC) is delivered to the site in 9 tonne (10 ton) batches by self-unloading pneumatic trucks. The carbon is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The carbon level in the silo is measured by system instrumentation.[b]

Hydrated lime is delivered and distributed in a manner very similar to that of the PAC. The hydrated lime is delivered in 11 tonne (12.5 ton) batches.[b] More comprehensive descriptions of the hydrated lime and PAC systems are provided in Section 3.6.1 and Section 3.6.2, respectively.

3.2 Steam Generator and Ancillaries

The steam generator for the SC plants is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace. It includes a superheater, reheater, economizer, and air preheater.

The combustion systems the SC steam conditions are equipped with LNBs and OFA. It is assumed for the purposes of this report that the power plant is designed for operation as a base-load unit but with some consideration for daily or weekly cycling.

3.2.1 Scope

The steam generator includes the following for SC PC:

- Once-through type steam generator
- Startup circuit, including integral separators
- Water cooled furnace, dry bottom
- Two-stage superheater
- Reheater
- Economizer
- Spray type desuperheater
- Soot blower system
- Air preheaters (Ljungstrom type)
- Coal feeders and pulverizers
- Biomass feeders and pulverizers
- Low NOx Coal burners and natural gas igniters/warm-up system
- OFA system
- Forced draft (FD) fans
- Primary air (PA) fans
- Induced draft (ID) fans

The following subsections describe the operation of the steam generator.

[b] The description of PAC and hydrated lime unloading were sourced from a quote provided by UCC to NETL, unless otherwise noted. The information relates to a Hg control system designed by UCC.

3.2.2 Feedwater and Steam

For the SC steam system, feedwater (FW) enters the bottom header of the economizer and passes upward through the economizer tube bank, through stringer tubes, which support the primary superheater, and discharges to the economizer outlet headers. From the outlet headers, water flows to the furnace hopper inlet headers via external downcomers. Water then flows upward through the furnace hopper and furnace wall tubes. From the furnace, water flows to the steam water separator. During low load operation (operation below the Benson point), the water from the separator is returned to the economizer inlet with the boiler recirculating pump. Operation at loads above the Benson point is once through.

Steam flows from the separator through the furnace roof to the convection pass enclosure walls, primary superheater, through the first stage of water attemperation, to the furnace platens. From the platens, the steam flows through the second stage of attemperation and then to the intermediate superheater. The steam then flows to the final superheater and on to the outlet pipe terminal. Two stages of spray attemperation are used to provide tight temperature control in all high temperature sections during rapid load changes.

Steam returning from the turbine passes through the primary reheater surface, then through crossover piping containing inter-stage attemperation. The crossover piping feeds the steam to the final reheater banks and then out to the turbine. Inter-stage attemperation is used to provide outlet temperature control during load changes.

3.2.3 Air and Combustion Products

Combustion air from the FD fans is heated in Ljungstrom type air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying PC to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the PC, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The fuel and air mixture flows to the inlet nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow to the SCR reactor, DSI manifold, ACI manifold, fabric filter, ID fan, FGD system, and stack.

3.2.4 Fuel Feed

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72 percent passing 200 mesh and less than 0.5 percent remaining on 50 mesh. [45] The PC exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans.

The hybrid poplar pellets are fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72 percent passing 200 mesh and less than 0.5 percent remaining on 50 mesh. [45] Size reduction of the pelletized biomass takes place in dedicated grinding pulverizers. The biomass exits each mill via the biomass piping and is distributed to the biomass nozzles in the furnace walls using air supplied by the PA fans.

3.2.5 Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. Each hopper incorporates a dry seal trough and is of welded steel construction, lined with refractory and block insulation for personnel safety and heat retention. Each hopper is paired with a pneumatic bottom ash transport line and is fully isolatable, with shutoffs downstream of the screw feeder and upstream of the clinker grinder, for ease of maintenance. The description of the balance of the bottom ash handling system is presented in Section 3.12. The steam generator incorporates fly ash hoppers under the economizer outlet and air preheater outlet.

3.2.6 Burners

A boiler of this capacity employs approximately 24–36 fuel nozzles arranged at multiple elevations. This nozzle account will increase significantly as the percentage of biomass fuel is increased. Each burner is designed at a low NOx configuration, with staging of the coal combustion and biomass combustion to minimize NOx formation. In addition, OFA nozzles are provided to further stage combustion and thereby minimize NOx formation.

Natural gas-fired pilot torches are provided for each fuel burner for ignition, warm-up and flame stabilization at startup and low loads.

3.2.7 Dry Sorbent Injection

The hydrated lime injection manifold is located directly before the air preheaters. This SO_3 control system is discussed in detail in Section 3.6.

3.2.8 Air Preheaters

Each steam generator is furnished with two vertical-shaft Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

3.2.9 Soot Blowers

The soot-blowing system utilizes an array of 50–150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of high pressure (HP) steam. The blowers are sequenced to provide an effective cleaning cycle depending on the coal quality, the amount of biomass used, and design of the furnace and convection surfaces. Electric motors drive the soot blowers through their cycles.

3.3 NOx Control System

The plants are designed to achieve the environmental target of 0.70 lb/MWh-gross (0.32 kg/MWh-gross). Two measures are taken to reduce the NOx. The first is a combination of

LNBs and the introduction of staged OFA in the boiler. The LNBs and OFA reduce the boiler emissions to about 0.15 kg/GJ (0.35 lb/MMBtu).

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses NH_3 and a catalyst to reduce NOx to Nitrogen (N_2) and water (H_2O). The SCR system consists of three subsystems: reactor vessel, NH_3 storage and injection, and gas flow control. The SCR system is designed for 75–79 percent reduction with 2 ppmv NH_3 slip at the end of the catalyst life.

The SCR capital costs are reported separately from the boiler costs; the cost for the initial load of catalyst is broken out separately in the O&M cost table. It should be noted that the effect of co-firing biomass and coal on NOx emissions is debatable; however, it is generally accepted that woody biomass like hybrid poplar, used in this study, helps to reduce the NOx emissions. However, switchgrass and other grass or reed-like biomass material actually increases NOx emissions. With that said, an actual plant would probably not reduce the size of its SCR even if the design biomass is a woody crop due to the potential need to fire 100 percent coal if biomass happens to become unavailable. Therefore, in this study, the SCR is not reduced depending on the percentage of biomass co-fired.

3.3.1 SCR Operation Description

The reactor vessel is designed to allow proper retention time for the NH_3 to contact the NOx in the boiler exhaust gas. NH_3 is mixed with dilution air before injection, and the mixture is injected into the gas path immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the NH_3 and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The operating range for vanadium/titanium-based catalysts is 260°C (500°F) to 455°C (850°F). The boiler is equipped with an economizer bypass to provide flue gas to the reactors at the desired temperature during periods of low flow rate, such as low load operation. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The NH_3 storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and associated dampers for low load temperature control are also included.

3.4 Activated Carbon Injection

The PAC injection manifold is located directly before the baghouse. [46] This system is discussed in detail in Section 3.6.

3.5 Particulate Control

The fabric filter (or baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9–1.5 m/min [3–5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide with intrinsic Teflon Polytetrafluoroethylene coating. [47] The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). Each compartment contains a number of gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

The use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of PM by approximately 14 percent.

3.6 Mercury Removal[c]

Mercury removal is partially achieved through flue gas reactions between Hg and available halogens and carbon.

The fraction of chlorine, and other halogens in the coal, impacts the amount of Hg oxidized in the SCR and air preheater. As oxidized Hg is removed by the fabric filter and wet FGD, the chlorine content of the coal can have a significant impact on the Hg removal rate of the plant. Data presented by Reaction Engineering International suggest that as coal chlorine concentrations increase, up to 500 ppmwd, the fraction of oxidized Hg increases rapidly. However, the rate of Hg oxidation diminishes at chlorine concentrations above 500 ppmwd. [48]

The rate of Hg oxidation is also affected by the NH_3 concentration. Since the SCR is operated more aggressively for NOx control, the NH_3 levels increase and the fraction of oxidized Hg decreases. [49]

In this study, it is assumed that 0.6 percent of the coal carbon is unreacted in the PC boiler. [50] This unburned carbon both promotes Hg oxidation and adsorbs Hg on the surface of the fabric filter. The unburned carbon, combined with the HCl in the flue gas, is sufficient to promote high levels of oxidized Hg and overall Hg removal in the plant. [51]

Depending on the chemistry in the wet FGD, a portion of the oxidized Hg that is captured by the scrubber could be reduced to elemental Hg and re-emitted. By minimizing the amount of Hg entering the wet FGD, and through careful operation of the scrubber, the risk of periodic spikes in Hg re-emissions can be minimized.

Wet FGD parameters such as oxidation reduction potential of the scrubber slurry, halogen concentration in the scrubber slurry, the form of Hg in the slurry (i.e., liquid or solid), and the effect of sulfite concentration were examined by Babcock & Wilcox Enterprises Inc. for their impact on Hg re-emissions. It was concluded that sulfite concentration in the slurry was the

[c]Much of the text, descriptions, and images within this section were sourced, with permission, from a quote provided by United Conveyor Corporation (UCC) to NETL, unless otherwise noted. The information relates to a Hg control system designed by UCC. The quote also provided all images credited to them.

most cost-effective parameter that can be controlled as a strategy to minimize Hg re-emission. [52]

Without mitigation, the concentration of SO_3 in the flue gas is estimated to be 59 ppmvd at the air preheater inlet. This elevated SO_3 concentration is the result of combusting a relatively high sulfur coal (2.82 wt%) and from oxidation of SO_2 across the SCR catalyst.

The presence of SO_3 significantly inhibits Hg adsorption, as SO_3 is preferentially adsorbed onto carbon. This effect was demonstrated in a testing program conducted at the Mercury Research Center using an electrostatic precipitator (ESP)-configured system with an ACI rate of 10 lb/MMacf upstream of the air preheater at 149°C (300°F), which showed that at SO_3 levels above 20 ppm, less than 50 percent Hg removal was achieved (at SO_3 levels above 10 and 3 ppm, less than 70 and 80 percent Hg removal was achieved, respectively). [53] Therefore, DSI is included in the PC plant designs to reduce the SO_3 levels to approximately 5 ppmvd at the air preheater inlet, as discussed in Section 3.6.1.

EPA used a statistical method to calculate the Hg co-benefit capture from units using a “best demonstrated technology” approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8–98.8 percent. [54] EPA’s documentation for their Integrated Planning Model (IPM) provides Hg emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency.

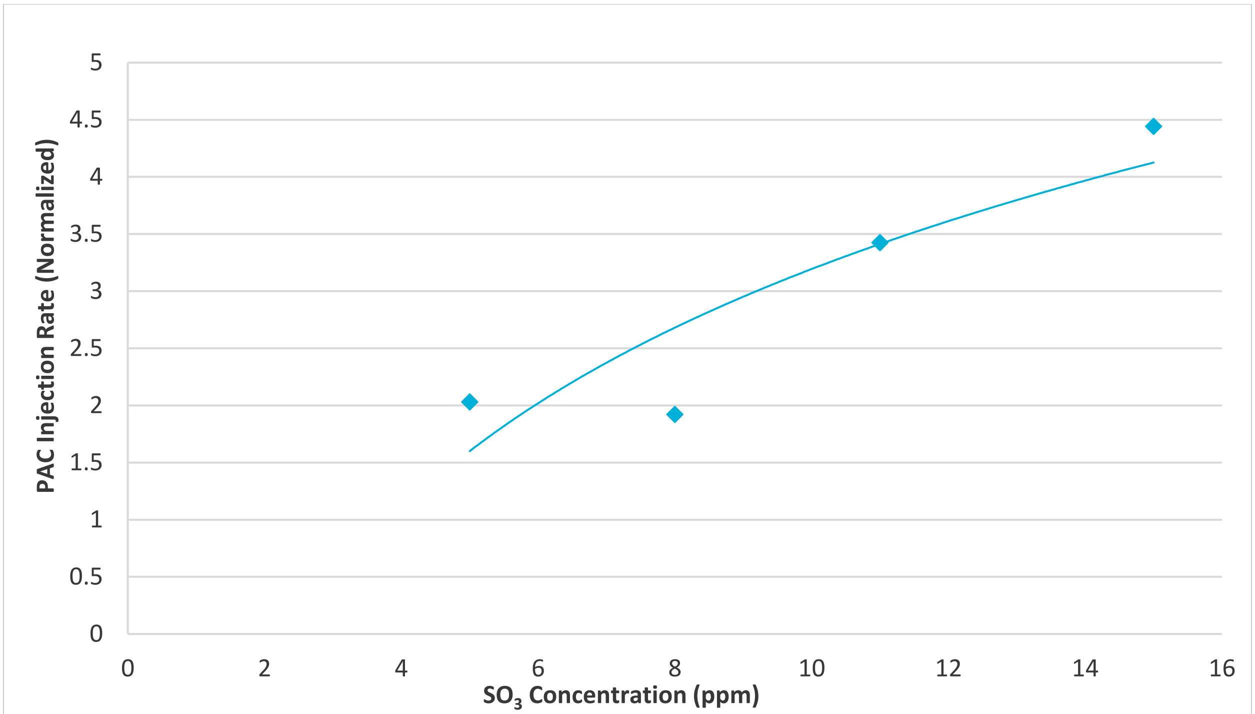
For PC boilers (as opposed to cyclones, stokers, fluidized beds, and others) with a fabric filter, SCR and wet FGD, the EMF is 0.1, which corresponds to a removal efficiency of 90 percent; [55] the average reduction in total Hg emissions developed from EPA’s Information Collection Request data on U.S. coal-fired boilers using bituminous coal, fabric filters, and wet FGD is 98 percent. [56] The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter, and a wet FGD system between 83.8 and 98 percent. It was assumed that the co-benefit potential of the equipment utilized in the PC cases of this report is 90 percent, as it is near the mid-point of the previously mentioned range, and it also matches the value used by EPA in their IPM. A further simplifying assumption was also made that the cofiring of biomass with coal in the PC cases of this report would not impact the performance of mercury removal (cobenefit capture or ACI performance).

The Hg removal rate required to comply with the Hg emission limit (Section 2.4.1) is calculated to be approximately 96–97 percent. Therefore, the potential co-benefit Hg capture rate (90 percent) of the systems utilized in the PC cases is not sufficient to achieve compliance with applicable regulations. A cost and performance estimate was obtained from United Conveyor Corporation (UCC), which applies ACI and DSI to increase the overall Hg removal rate in the plant.

3.6.1 Dry Sorbent Injection

Exhibit 3-1 provides data from a full-scale DSI/ACI test conducted by UCC on a midwestern coal-fired unit, which demonstrates the impact of SO_3 concentration (at the PAC injection point) on the PAC injection rate required to achieve a given Hg removal rate. The exhibit and data contained were supplied by UCC in the quote provided to NETL.

Exhibit 3-1. Effect of SO_3 concentration on PAC injection rate



As shown in Exhibit 3-1, higher SO_3 concentrations in the flue gas require significantly greater injection rates of PAC. Therefore, the DSI system considered in this report, with enhanced hydrated lime as the sorbent, targets an SO_3 concentration of 5 ppmvd at the air preheater inlet, with an SO_3 concentration of 2 ppmvd at the outlet of the fabric filter.

As the flue gas temperature must be maintained above the acid dew point temperature in the air preheater, locating the DSI injection point upstream of the air preheater allows for a lower operating temperature (143°C [289°F] air preheater temperature with DSI upstream versus 169°C [337°F] air preheater temperature with no DSI/DSI downstream) and higher overall plant efficiency, compared to a plant with no DSI or DSI downstream of the air preheater. Additionally, the reduction in operating temperature increases the Hg removal efficiency of carbon.

Since standard hydrated lime sorbents generally cannot achieve SO_3 removal rates greater than approximately 90 percent, the high level of SO_3 reduction required necessitates the use of an enhanced hydrated lime product to achieve the necessary Hg removal rate.

While DSI is included specifically to remove SO_3 from the flue gas, the enhanced hydrated lime also removes SO_2 and HCl, as shown in Exhibit 3-2. The rates shown are the total removal at the fabric filter outlet/FGD inlet, not the air preheater inlet.

Exhibit 3-2. Pollutant removal efficiency versus hydrated lime injection rate

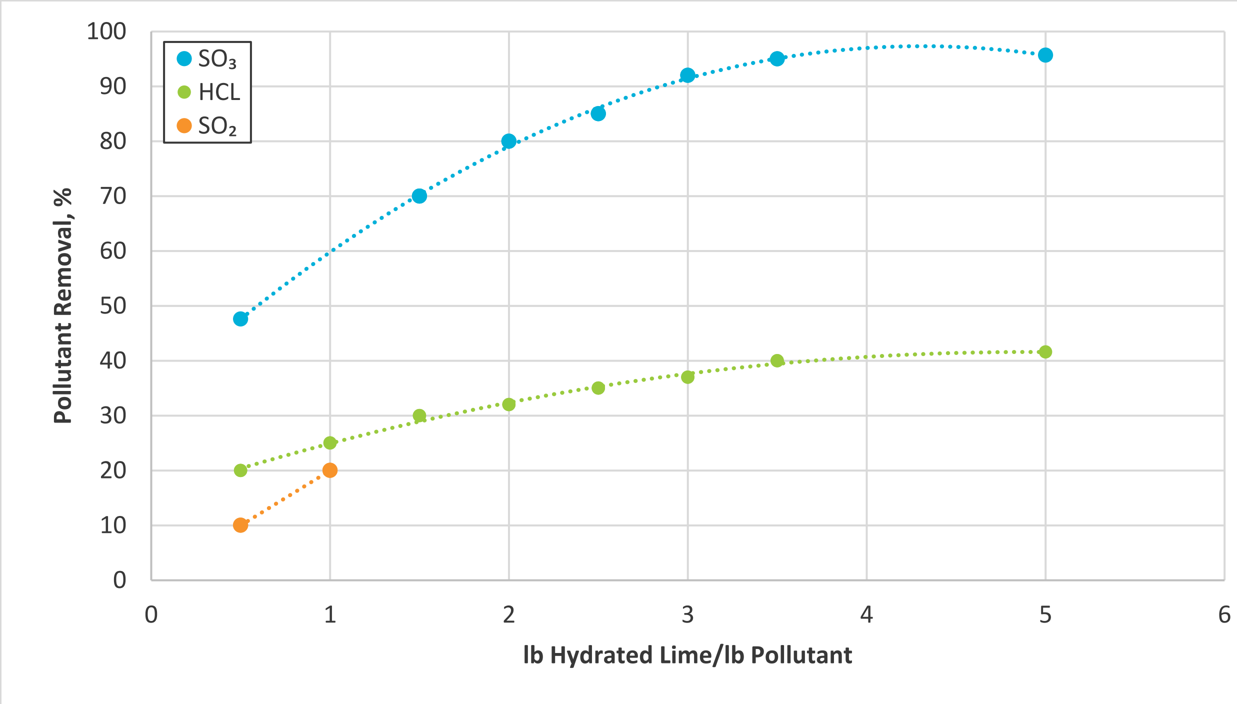


Exhibit 3-2 illustrates that approximately 3.5 lb of enhanced hydrated lime/lb of SO_3 is required to reduce the SO_3 concentration to 2 ppmvd at the outlet of the fabric filter (approximately 96.6 percent removal rate). At this injection rate, the enhanced hydrated lime is expected to also remove approximately 40 percent of HCl. The expected SO_2 reduction is very low, since SO_2 is a much weaker acid gas than SO_3 and HCl. In addition, the baseline SO_2 levels are far higher than either the SO_3 or HCl levels.

Operation Description – As shown in Exhibit 3-3, the DSI system is based on dilute-phase, pneumatic conveying of hydrated lime at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and reacts with the SO_3 to form calcium sulfate ($CaSO_4$), which is captured in the fabric filter.

The sorbent is typically delivered in 11,340-kg (25,000-lb) batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The sorbent is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The sorbent level in the silo is measured by system instrumentation.

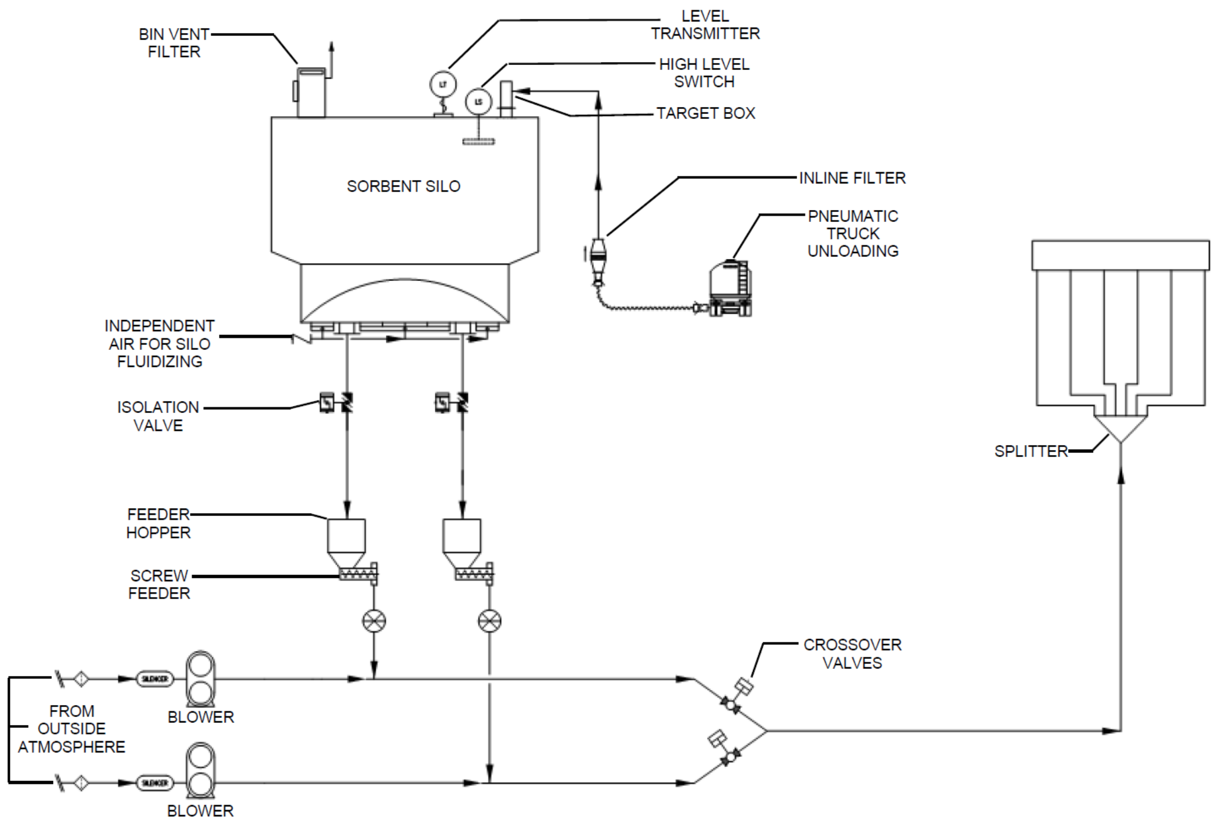
Silos are typically 14-ft diameter with skirt support, made of carbon steel (CS) and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide loss-in-weight monitoring and feed control.

The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized sorbent is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the intake tee. The speed of the screw feeder determines the feed rate into the intake tee. Sorbent is fed through the intake tee directly into the conveying air stream.

Exhibit 3-3. Typical DSI injection process flow diagram



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Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a CS weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a variable speed rotary vane feeder.

The silo fluidizing system promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets. The pressure blower provides an air stream for conveying sorbent from the storage silo to a splitter and lances for duct injection. Two 100 percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The DSI system is typically monitored and controlled by the distributed control system (DCS). The feed rate of the system can be adjusted in the following ways:

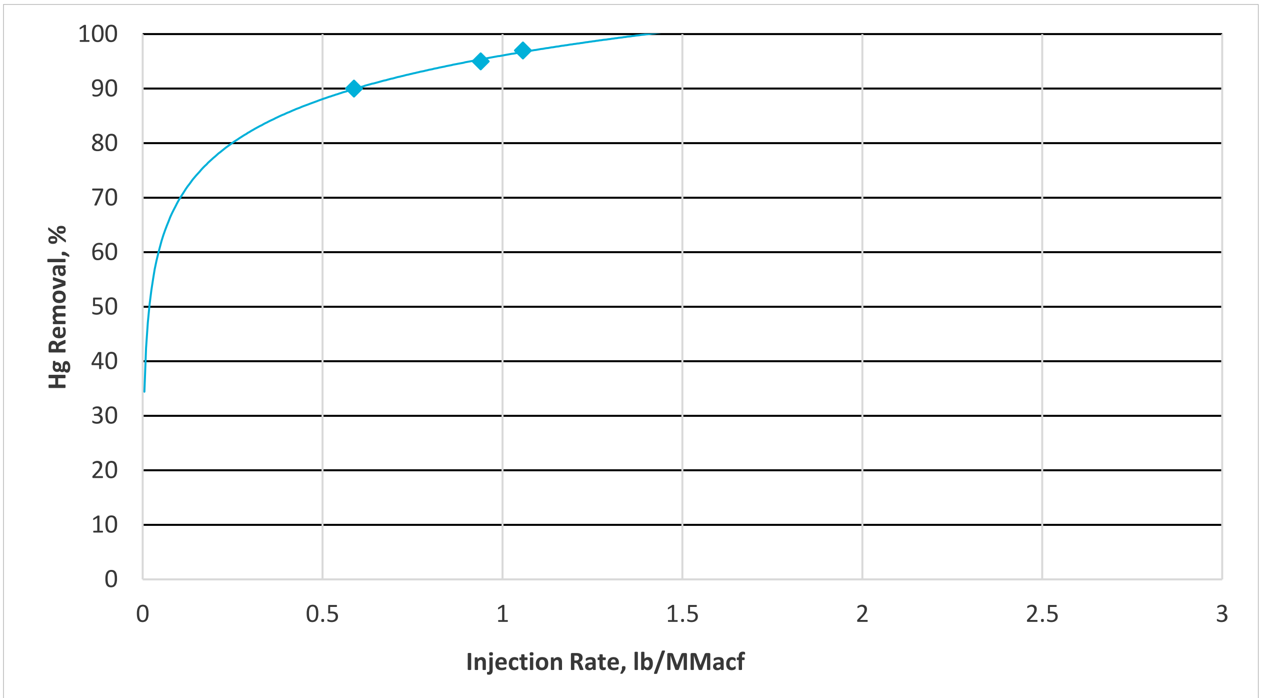
- Flat Rate (one continuous rate)
- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)

3.6.2 Activated Carbon Injection

By reducing the SO_3 with DSI (Section 3.6.1), most of the Hg will be oxidized in the SCR and removed in the fabric filter and wet FGD. Therefore, only a minimal amount of brominated PAC is injected upstream of the fabric filter to ensure the desired Hg emission rate is achieved.

Exhibit 3-4, provided by UCC, presents a typical performance curve for plants utilizing an SCR and a fabric filter firing bituminous coal. The points highlighted represent 90, 95, and 97 percent Hg removal.

Exhibit 3-4. Hg removal versus PAC injection rate for Case B12A



To meet the Hg emission limit, brominated PAC is injected at a rate of approximately 1.0 lb/MMacf in all PC cases.

Operation Description – As shown in Exhibit 3-5, the ACI system is based on dilute-phase, pneumatic conveying of activated carbon at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and absorbs Hg and SO_3, which is captured in the fabric filter.

The activated carbon is typically delivered in 9,070-kg (20,000-lb) batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The carbon is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The carbon level in the silo is measured by system instrumentation.

Silos are typically 14-ft diameter with skirt support, made of CS and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide loss-in-weight monitoring and feed control.

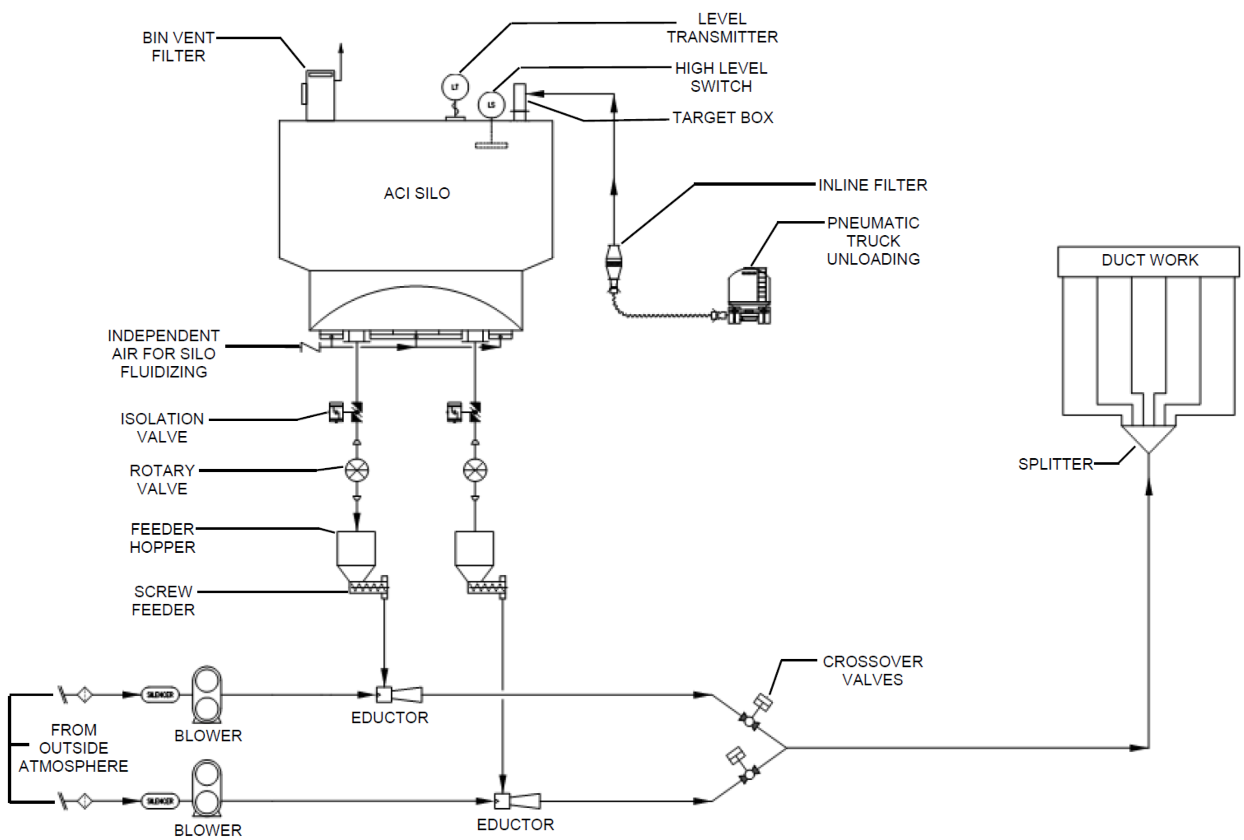
The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized carbon is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the drop tube. The speed of the screw feeder determines the feed rate into the drop tube. Carbon is fed through the drop tube directly into the eductor suction port.

Motive air, provided by low-pressure blowers and fed into the eductors, produces a vacuum at the suction port. This helps draw the carbon and air into the mixing zone directly downstream of the eductor discharge. The carbon is transported through the piping system and is distributed to an array of injection lances specifically designed to disperse the carbon across the cross section of the flue gas ductwork.

Exhibit 3-5. Typical ACI injection process flow diagram



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Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a CS weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a screw feeder.

The silo fluidizing systems promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets.

The pressure blower provides an air stream for conveying carbon from the storage silo to a splitter and lances for duct injection. Two 100 percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The ACI system is typically monitored and controlled by the DCS. The feed rate of the system can be adjusted in the following ways:

- Flat Rate (one continuous rate)
- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)
- Mercury Emission Following (varies feed rate to keep the Hg emission concentration below a given set point)

3.7 Flue Gas Desulfurization

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 prior to release to the environment or entering the Carbon Dioxide Recovery (CDR) facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. The CDR unit includes a polishing scrubber designed to reduce the flue gas SO_2 concentration from about 37 ppmv at the FGD exit to approximately 2 ppmv prior to the CDR absorber to minimize formation of amine heat stable salts during the CO_2 absorption process. The FGD removal efficiency of HCl is 99 percent for all cases. To minimize the required capacity and cost of specialized FGD wastewater treatment equipment, the FGD system is designed with materials capable of handling up to 20,000 ppm of chlorides.

Because of the inherently low sulfur content of most biomass, including hybrid poplar, co-firing with coal provides an added benefit of SO_2 reductions. The SO_2 environmental target assumed in this study is 1.0 lb/MWh-gross.

The benefit of FGD optimization in co-fire cases were determined to be negligible. Less than one percent of the FG could be bypassed around the FGD while still meeting the environmental target. Costs associated with modifying FGD process equipment were assumed to offset the small operational cost benefit of optimizing the FGD. All cases were modeled after this finding.

While the PC cases of this study produce gypsum suitable for wallboard production, changes in fuel or limestone characteristics or modifications to the wet FGD or dewatering system could impact the gypsum composition. Exhibit 3-6 provides the specification limits for gypsum used in wallboard and cement production, as well as typical characteristics of landfilled gypsum. The cases in this study do not consider a sale credit or a waste disposal cost for gypsum.

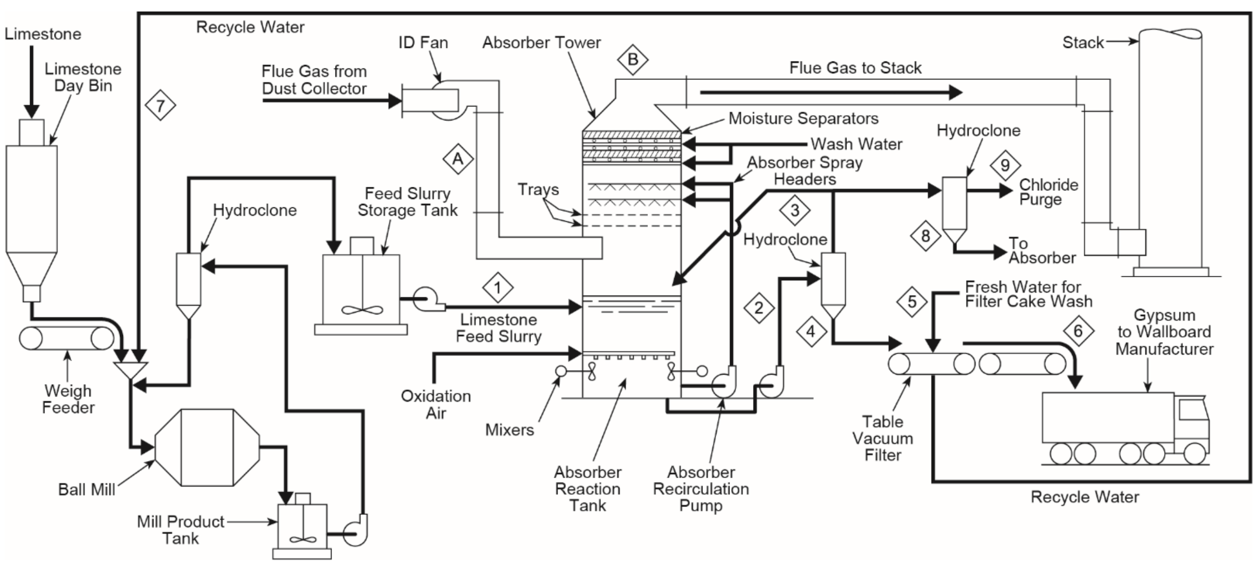
Exhibit 3-6. Typical disposal- and commercial-grade gypsum characteristics and limits

End Use	Disposal [A]	Wallboard	Cement
Moisture, % max	<20	<10	<14
$CaSO_4 \bullet 2H_2O$, % min	80–95+	>95	85–88
$CaSO_3 \bullet ½H_2O$, % max	<1–2+	0.5–1.0	
SiO_2, % max	<1–3+	1.0	2.0
Fe_2O_3, % max		1.5	1.0
Al_2O_3, % max			1.0
Fly ash, % max	<1–3+	1.0	
Total insolubles, % max	<5–20+	3.5	<15
Water soluble Cl^-, ppm max	2,000–50,000	100–120	50,000
Total dissolved solids, ppm max	5,000–150,000	600	
Mean particle size, µm	<20–90+	20–75	

[A] Disposal gypsum characteristics are based on a range of potential limestone supplies

The scope of the FGD system is from the outlet of the ID fans to the stack inlet (non-capture cases) or to the CDR process inlet (capture cases). Exhibit 3-7 provides a process flow diagram of a typical wet limestone forced oxidation positive pressure absorber non-reheat FGD system. [50] The descriptions in Section 3.7.1 through Section 3.7.5 align with this diagram.

Exhibit 3-7. Wet FGD process flow diagram



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3.7.1 Limestone Handling and Reagent Preparation System

The function of the limestone reagent preparation system is to grind and slurry the limestone delivered to the plant. The scope of the system is from the day bin up to the limestone feed system. The system is designed to support continuous base load operation.

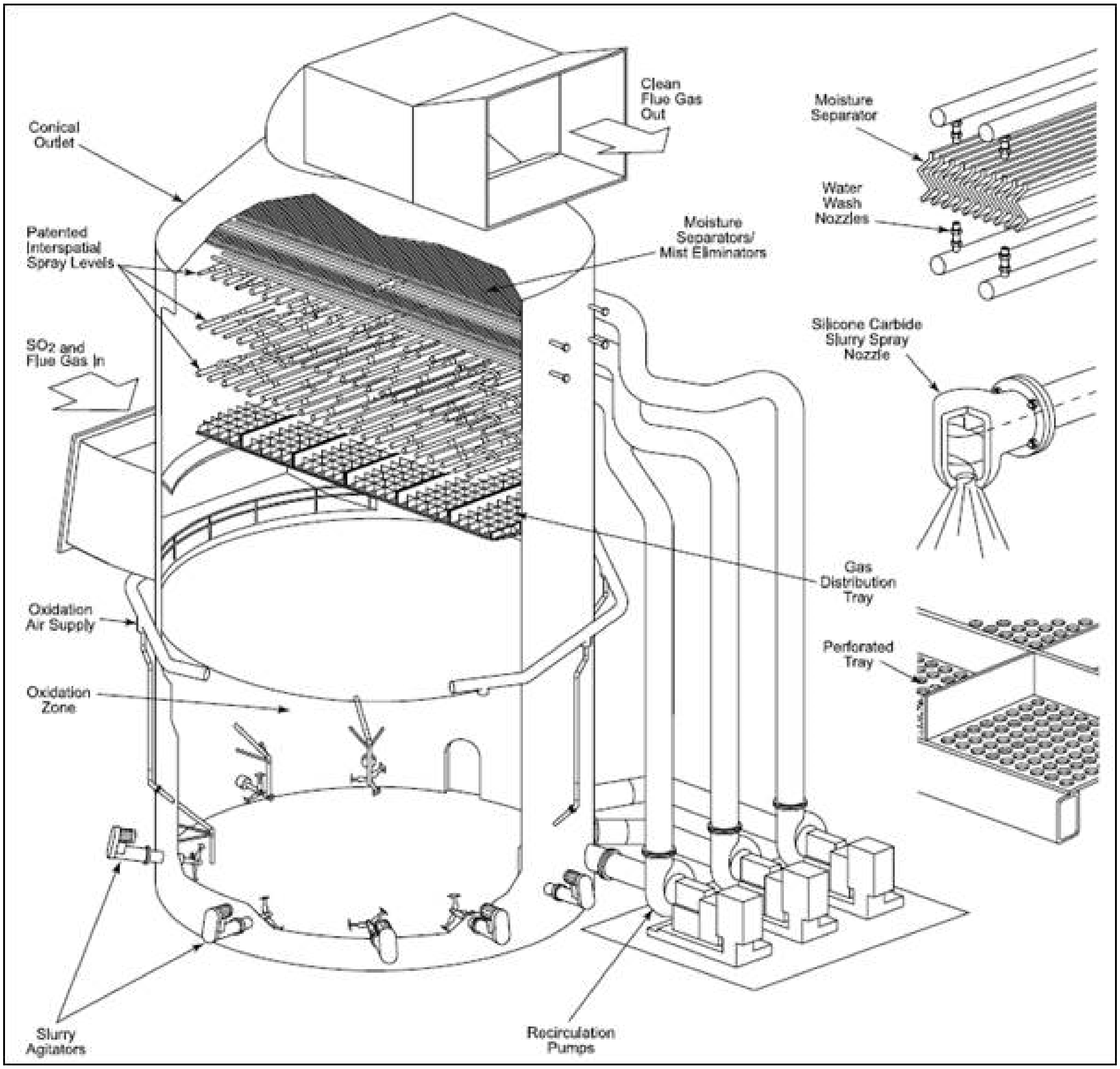
Operation Description – Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90–95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill product tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydrocyclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydrocyclone underflow with oversized limestone is directed back to the mill for further grinding. The hydrocyclone overflow with correctly-sized limestone is routed to a feed slurry storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

3.7.2 FGD Absorber Tower

The description of the FGD absorber tower follows Exhibit 3-7. Additional detail for the absorber tower cross section is presented in Exhibit 3-8 for reference. [50]

Exhibit 3-8. Cross section of the wet FGD absorber tower



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Upon entering the bottom of the absorber tower, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent. Multiple spray elevations with header piping and nozzles maintain a consistent reagent concentration in the spray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed flue gas exits at the top of the absorber tower and is routed to the plant stack or CDR process.

The scrubbing slurry falls to the lower portion of the absorber tower, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite contained in the slurry to calcium sulfate (gypsum). Multiple agitators (mixers) operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber tower to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of byproduct solids via the bleed pumps (not labeled in Exhibit 3-7). A spare bleed pump is provided to ensure availability of the absorber. The byproduct solids are routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue gas through the absorber enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the FGD discharge temperature of 56°C (133°F) is not necessary.

3.7.3 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber tower modules. The dewatering process selected for this plant is gypsum dewatering producing wallboard grade gypsum. The scope of the system is from the bleed pump discharge connections to the gypsum storage pile.

Operation Description – The recirculating reagent in the FGD absorber tower accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO_2 absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off byproduct solids and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of O_2 into the calcium sulfite produced in the absorber tower sump. The bleed from the absorber contains approximately 20 wt% gypsum. The absorber slurry is pumped by an absorber bleed pump to a primary dewatering hydrocyclone cluster. The primary hydrocyclone performs two process functions. The first function is to dewater the slurry from 20 wt% to 50 wt% solids. The second function of the primary hydrocyclone is to perform a calcium sulfite ($CaCO_3$) and $CaSO_4 \bullet 2H_2O$ separation. This process ensures an overall limestone stoichiometry of 1.03. This system reduces the overall operating cost of the FGD process. The underflow from the hydrocyclone flows into the filter feed tank (not shown in Exhibit 3-7), from which it is pumped to a horizontal belt vacuum filter (represented as a table vacuum filter in Exhibit 3-7). Two 100 percent filter systems are provided for redundant capacity.

3.7.4 Hydrocyclones

The hydrocyclone is a simple and reliable device (no moving parts) designed to increase the slurry concentration in one step to approximately 50 wt%. This high slurry concentration is necessary to optimize operation of the vacuum belt filter.

The hydrocyclone feed enters tangentially and experiences centrifugal motion so that the heavy particles move toward the wall and flow out the bottom. Some of the lighter particles collect at the center of the cyclone and flow out the top. The underflow is thus concentrated from 20 wt% at the feed to 50 wt%.

Multiple hydrocyclones are used to process the bleed stream from the absorber. The hydrocyclones are configured in a cluster with a common feed header. The system has two hydrocyclone clusters, each with five 15 cm (6 in) diameter units. Four cyclones are used to continuously process the bleed stream at design conditions, and one cyclone is spare.

Cyclone overflow and underflow are collected in separate launders. The overflow from the hydrocyclones contains about 5 wt% solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber.

The remainder of the overflow is fed to a secondary hydrocyclone, where the resulting underflow is returned to the absorber and the overflow is blown down to the process water treatment system, for chloride control (represented as chloride purge in Exhibit 3-7). The flow to the secondary hydrocyclones is controlled to maintain a chloride concentration of 20,000 ppmw in the blowdown.

The underflow of the primary hydrocyclones flows into the filter feed tank from where it is pumped to the horizontal belt vacuum filters.

3.7.5 Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is dewatered to approximately 90 wt% solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

3.7.6 FGD Wastewater Quality

The blowdown stream from the FGD process must be treated under the ELG rule, as stated in Section 2.4.2. The design wastewater composition for the FGD process blowdown considered is provided in Exhibit 3-9. The design water quality is based on a survey of plants burning bituminous, high sulfur coal [57] [58] and on internal information from Black & Veatch projects. Exhibit 3-9 includes a range of values, an average, and the final selected composition.

Exhibit 3-9. FGD process wastewater quality

Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
pH	5.5–7.4	6.6	7.2
Chemical O_2 Demand, ppm	304–1,060	682	350
Biological O_2 Demand, ppm	21–1,370	422	500
Specific Conductance, µS/cm	5,990–32,000	9,595	32,000
Ammonia as N, ppm	1.5–31.5	8.4	10
Suspended Solids, ppm	4,970–25,300	13,888	15,000
Total Dissolved Solids, ppm	4,740–44,600	21,310	43,494
Chloride as Cl, ppm	832–28,800	9,966	20,000
Sulfate as SO_4, ppm	1,290–11,900	4,212	7,600
Calcium as Ca, ppm	751–5,370	2,791	5,370
Magnesium as Mg, ppm	176–7,000	2,728	6,000
Sodium as Na, ppm	59–5,340	998	2900
Boron (total), ppm	3.0–626	220	430
Potassium as K, ppm	35–684	226	250
M-Alkalinity as $CaCO_3$, ppm[A]	131–625	275	200
Iron (total), ppm	3.4–824	200	290
Aluminum (total), ppm	1.0–289	93	150
Silica as SiO_2, ppm	1–91	33	100
Manganese (total), ppm	1.58–225	32.1	60
Nitrate/Nitrite as N, ppm	1.0–54.5	20.5	30
Total Kjeldahl N_2, ppm	6.2–51.6	19.2	20
Carbon, ppm			8
Phosphorus, ppm	0.05–10.5	4.61	7
Nickel (total), ppm	0.447–6.0	2.05	5
Selenium (total), ppm	0.651–8.66	2.75	5
Zinc (total), ppm	0.31–9.04	3.23	6
Barium (total), ppm	0.588–11.900	3.330	5
Titanium (total), ppm	0.377–8.18	2.57	4
Vanadium (total), ppm	0.078–1.58	0.67	1.3
Fluorine, ppm			1
Arsenic (total), ppm	0.0599–3.000	0.799	1.4

Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
Copper (total), ppm	0.0376–2.130	0.788	1.4
Lead (total), ppm	0.0312–4.000	0.896	1.3
Molybdenum (total), ppm	0.065–1.340	0.59	0.9
Mercury (total), ppm	0.0164–1.070	0.255	0.7
Chromium, ppm	0.176–1.380	0.777	1
Cobalt, ppm			0.1
Lithium, ppm			0.1
Beryllium (total), ppm	0.0036–3.000	0.438	0.140
Cadmium (total), ppm	0.00484–0.238	0.0728	0.140
Thallium (total), ppm	0.00633–0.300	0.0864	0.140
Antimony (total), ppm	0.00923–0.0518	0.0269	0.040
Uranium, ppm			0.03
Thorium, ppm			0.02
Tin, ppm			0.01

[A]Alkalinity is reported as $CaCO_3$ equivalent, rather than the concentration of HCO_3. The concentration of HCO_3 can be obtained by dividing the alkalinity by 0.82

The wastewater composition reported in Exhibit 3-9 is based on water qualities from actual operations and adjusted to account for chloride. The design concentration of each constituent is individually representative of a plant configuration comparable to those in this study. However, due to the interaction and interdependencies of each constituent and the multitude of potential species, the wastewater quality cannot be considered representative as a whole. The wastewater quality is intended to inform users of the contaminants likely present, and at what concentrations they may be expected, to facilitate appropriate equipment selection and design.

The FGD process blowdown wastewater composition will be dependent on several factors, including composition of the fuel, makeup water quality, flue gas treatment systems upstream of the FGD process, and other factors. The wastewater quality defined above will form the basis for discussion of the spray dryer evaporator system, discussed in Section 3.10.

3.8 Carbon Dioxide Recovery Facility[d]

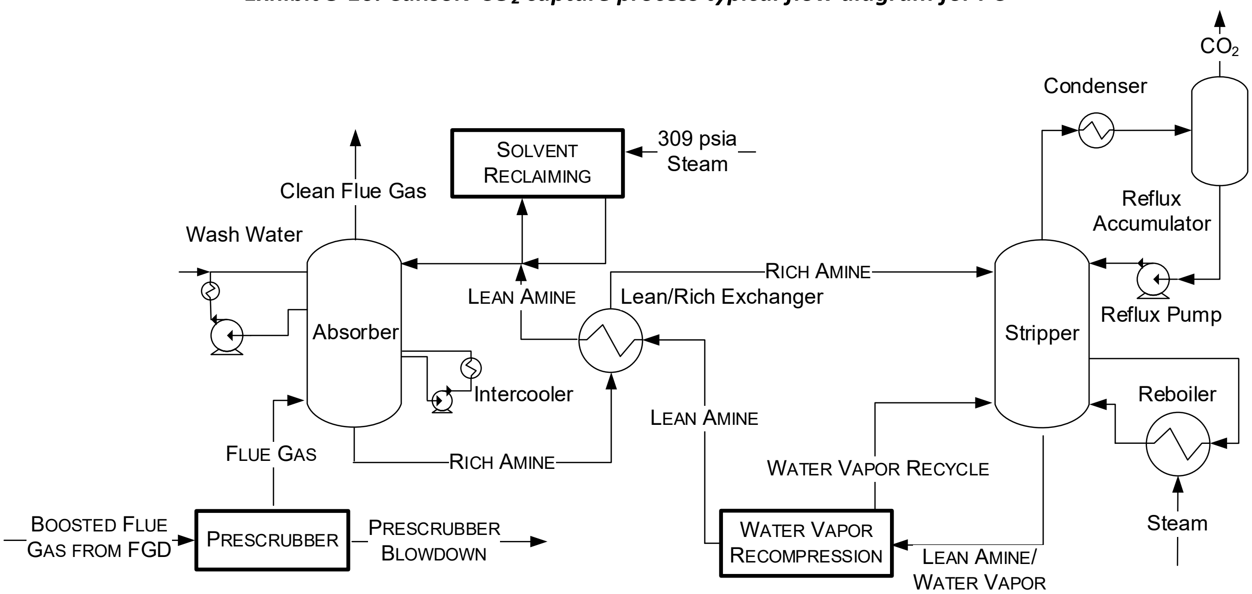
A CDR facility is used, along with compressors and a dryer, in capture cases to remove 90 percent of the CO_2 in the flue gas exiting the FGD unit. The facility then purifies it and compresses it to a SC condition. The flue gas exiting the FGD unit contains about 1 percent

[d] Much of the text and descriptions within this section were sourced, with permission, from data provided by Shell Cansolv to NETL, unless otherwise noted. The information relates to a CO_2 removal system designed by Shell Cansolv.

more CO_2 than the raw flue gas because of the CO_2 liberated from the limestone in the FGD absorber tower. The CDR comprises the pre-scrubber, CO_2 absorber, CO_2 stripper, and solvent reclaiming unit.

The CO_2 recovery process is based on data provided by Shell Cansolv in 2016. A typical flowsheet is shown in Exhibit 3-10. This process is designed to recover high-purity CO_2 from low pressure (LP) streams that contain O_2, such as flue gas from coal-fired power plants, combustion turbine exhaust gas, and other waste gases.

Exhibit 3-10. Cansolv CO_2 capture process typical flow diagram for PC



3.8.1 Pre-scrubber Section

The flue gas from the FGD section is sent through a booster fan to drive the gas through downstream equipment starting with the pre-scrubber inlet cooling section. The cooler is operated as a direct contact cooler that saturates and sub-cools the flue gas. Saturation and sub-cooling are beneficial to the system as they improve the amine absorption capacity, thus reducing amine circulation rate. After the cooling section, the flue gas is scrubbed with caustic in the pre-scrubber sulfur polishing section. This step reduces the SO_2 concentration entering the CO_2 absorber column to 2 ppmv.

3.8.2 CO_2 Absorber Section

The Cansolv absorber is a single, rectangular, acid resistant, lined concrete structure containing stainless-steel packing.

There are four packed sections in the Cansolv absorber. The first three are used for CO_2 absorption, and the final section is a water-wash section. This specific absorber geometry and design provides several cost advantages over more traditional column configurations while maintaining equivalent or elevated performance. The flue gas enters the absorber and flows counter-current to the Cansolv solvent. Approximately 90 percent of the inlet CO_2 is absorbed into the lean solvent, and the remaining CO_2 exits the main absorber section and enters the water-wash section of the absorber. Prior to entering the bottom packing section, hot amine is collected, removed, and pumped through a heat exchanger (HX) to provide intercooling and limit water losses. The cooled amine is then sent back to the absorber just above the final packed section.

The water-wash section at the top of the absorber is used to remove volatiles or entrained amine from the flue gas, as well as to condense and retain water in the system. The wash water is removed from the bottom of the wash section, pumped through a HX, and is then re-introduced at the top of the wash section. This wash water is made up of recirculated wash water as well as water condensed from the flue gas. The flue gas treated in the water-wash section is then released to atmosphere.

3.8.3 Amine Regeneration Section

The rich amine is collected at the bottom of the absorber and pumped through multiple parallel rich/lean HXs where heat from the lean amine is exchanged with the rich amine. The Cansolv rich/lean solvent HXs are a stainless-steel plate and frame type with a 5°C (9°F) approach temperature. Additional options for heat integration in the Cansolv system include a second HX after the rich/lean solvent HX where LP steam condensate from the regenerator reboiler or intermediate pressure (IP) steam condensate from the amine purification section may be used to further pre-heat the rich solvent. The rich amine continues and enters the stripper near the top of the column. The stripper is a stainless-steel vessel using structured stainless-steel packing. The regenerator reboiler indirectly uses LP steam to produce water vapor that flows upwards, counter-current to the rich amine flowing downwards, and removes CO_2 from the amine. The Cansolv regenerator reboiler is a stainless-steel plate and frame type with a 3°C (5°F) approach temperature. Lean amine is collected in the stripper bottoms and flows to a flash vessel where water vapor is released. Simultaneously, the condensate leaving the reboiler flows to a separate flash vessel, and water vapor is released. The water vapor recovered from both flash vessels is combined, and then recompressed and injected into the bottom of the stripper to enhance stripping of CO_2 within the column, thus reducing the amount of reboiler steam otherwise required. The lean amine is then pumped through the same rich/lean HX to exchange heat from the lean amine to the rich amine and continues to the lean amine tank.

The water vapor and stripped CO_2 flow up the stripper where they are contacted with recycled reflux to condense a portion of the vapor. The remaining gas continues to the condenser where it is partially condensed. The two-phase mixture then flows to a reflux accumulator where the CO_2 product gas is separated and sent to the CO_2 compressor at approximately 0.2 MPa (29 psia), and the remaining water is collected and returned to the stripper as reflux.

The flow of steam to the regenerator reboiler is proportional to the rich amine flow to the stripper; however, the flow of low-pressure steam is also dependent on the stripper top temperature. For the steady-state case described here, the low-pressure steam requirement for the reboiler only is calculated as approximately 2.4 MJ/kg (1,050 Btu/lb) CO_2 for the Cansolv process, which is satisfied by extracting steam from the crossover pipe between the IP and LP sections of the steam turbine.

3.8.4 Amine Purification Section

The purpose of the amine purification section is to remove a portion of the heat stable salts as well as ionic and non-ionic amine degradation products. The Cansolv amine purification process is performed in batch.

3.8.4.1 Thermal Reclaimer

The ionic and non-ionic amine degradation products are removed in the thermal reclaimer by distilling a slipstream—taken from the lean amine exiting the lean amine flash vessel, and prior to the lean solvent pump—under vacuum conditions to separate the water and amine. This process leaves the non-ionic degradation products in the bottom, which are pumped to a storage tank, diluted and cooled with process water, and then disposed. The condensed amine and water are returned to the lean amine tank.

3.9 Gas Compression and Drying System

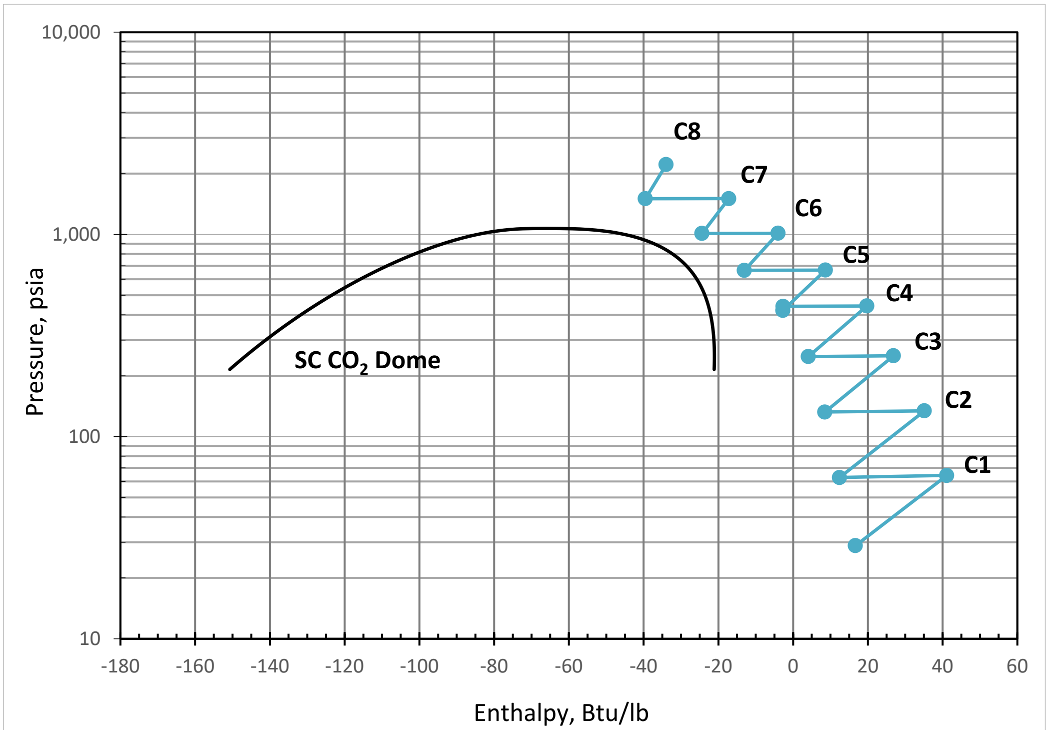
The compression system was modeled based on vendor supplied data, similar in design to that presented in the Carbon Capture Simulation Initiative's paper "Centrifugal Compressor Simulation User Manual." [59] The design is assumed to be an eight-stage front-loaded centrifugal compressor with stage discharge pressures presented in Exhibit 3-11.

Exhibit 3-11. CO_2 compressor interstage pressures

Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.44 (64)	2.22
2	0.92 (134)	2.14
3	1.73 (251)	1.90
4	3.05 (443)	1.78
5	4.59 (667)	1.58
6	6.99 (1,014)	1.53
7	10.38 (1,505)	1.49
8	15.29 (2,217)	1.47

Intercooling is included for each stage with the first three stages including water knockout. A CO_2 product aftercooler is also included to cool the CO_2 to 30°C (86°F). CO_2 transportation and storage costs assume that the CO_2 enters the transport pipeline as a dense phase liquid; thus, a pipeline inlet temperature of 30°C (86°F) is considered. Since PC cases with CO_2 capture utilize the Cansolv system, the compressor CO_2 suction pressure is identical, and the enthalpy versus pressure operating profile shown in Exhibit 3-12 is representative of all cases. Data points representing compression stage discharge pressures are labeled with the compression stage number (e.g., C1). Intercooling temperatures for the final two intercooling stages (after compression stages six and seven) were selected to provide a suitable buffer between the compressor operating profile and SC CO_2 dome. The base assumption that cooling water is available at a temperature of 60°F from the cooling tower is not a limiting factor in selection of these two stages' intercooling temperatures. Enthalpy reference conditions are 0.01°C and 0.0006 MPa (32.02°F and 0.089 psia), the same as those used for stream table results. The CO_2 aftercooler is not represented in the compressor operating profile plot.

Exhibit 3-12. PC CO_2 compressor enthalpy versus pressure operating profile



A triethylene glycol (TEG) dehydration unit is included between stages 4 and 5, operating at 3.04 MPa (441 psia), to reduce the moisture concentration of the CO_2 stream to 500 ppmv. The dryer is designed based on a paper published by the Norwegian University of Science and Technology. [60]

In an absorption process, such as in a TEG dehydration unit, the gas containing water flows up through a column while the TEG flows downward. The solvent binds the water by physical absorption; water is more soluble in the solvent than in other components of the gas mixture. The dried gas exits at the top of the column while the solvent, rich in water, exits at the bottom. After depressurization to around atmospheric pressure, the solvent is regenerated by heating it and passing it through a regeneration column where the water is boiled off. A TEG unit is capable of reducing water concentrations to meet the QGESS design point of 500 ppmv. [61]

3.10 Process Water Systems

3.10.1 Process Water Sources

As discussed in Section 2.4.2, the only system in the PC cases producing a wastewater stream that must be treated for compliance with the ELG rule is the wet FGD. A detailed process description of the wet FGD is provided in Section 3.7.

3.10.2 Process Water Treatment

The updated ELG rule established FGD wastewater as a new category, with discharge limits that must be met. The FGD wastewater is sourced from the overflow of the secondary hydrocyclone, as described in Section 3.7.3, with a composition described in Section 3.7.6.

The water recovered from the WTA dryer and flue gas cases with CO_2 capture is partially discharged from the plant. While the ELG rule does not regulate water from these sources and, therefore, does not need to be treated, the discharge of this water disqualifies the plants in this study from being considered zero liquid discharge (ZLD).

A variety of technologies are currently installed at PC plants to treat FGD wastewater, including surface impoundments, chemical precipitation, biological treatment, ZLD operating practices, evaporation ponds, and constructed wetlands. Approximately 37 percent of PC plants currently utilize ZLD operating practices. [62] [57]

While multiple process configurations were assessed for feasibility of complying with the ELG, given this study's intention of maintaining general applicability of the cases presented, and the prevalence of utilizing ZLD operating practices in existing PC plants, systems that would enable ZLD were selected in all cases, specifically a spray dryer evaporator (SDE).

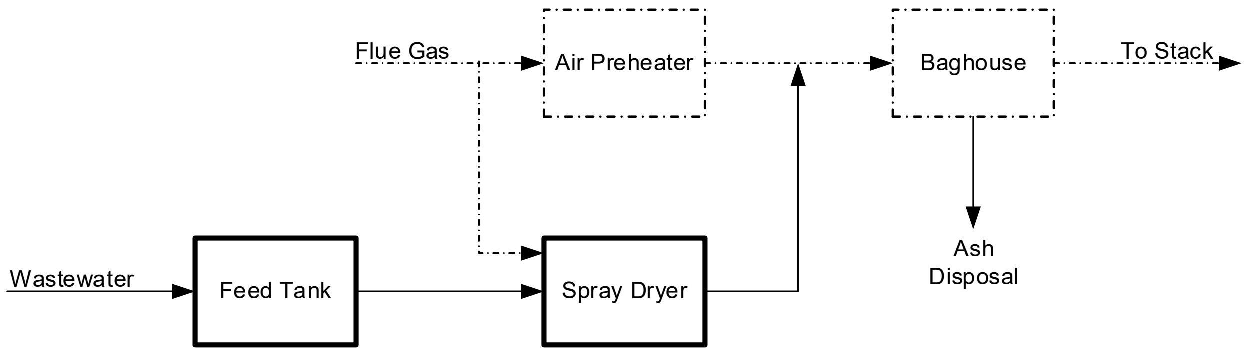
3.10.2.1 Spray Dryer Evaporator

A spray dryer is a technology commonly used in the power industry for FGD, which can also be applied as a thermal evaporation process to treat wastewater. An SDE was constructed and is currently operating at Kansas City Power & Light's Iatan Plant Unit 2. Operation of the SDE is described as straightforward, with periodic maintenance performed. [63] The feasibility of using an SDE as the sole treatment system in PC cases is limited by the flow rate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flow rate. Typically, a spray dryer for FGD wastewater is limited to approximately 150–200 gpm, depending on the flue gas conditions. As the system is designed based on flow rate, the solids concentration of the FGD wastewater does not impact the sizing of the system.

Spray dryers typically require a flue gas temperature above 316°C (600°F). A slipstream of flue gas is taken upstream of the air preheater for use as the heat source to evaporate the wastewater, which is sprayed into a tall cylindrical vessel using rotary atomizers. The heat from the slipstream is used to evaporate the wastewater, which contains dissolved and suspended solids, to produce a humidified gas stream containing additional suspended particulates. All the suspended particulates are assumed to exit the spray dryer vessel. The humidified gas stream is returned downstream of the air preheater and the combined flue gas passes through a baghouse, which removes most of the suspended solids.

Exhibit 3-13 provides a simplified block flow diagram of the spray dryer evaporation process.

Exhibit 3-13. Spray dryer block flow diagram



The atomizers and the spray dryer vessel are designed so that the wastewater mist droplets are evaporated before reaching the vessel wall. Therefore, the vessel is constructed of CS without concerns for corrosion. However, the wall metal temperature must be monitored to ensure there is no temperature drop, which is an indication that moisture is reaching the wall and can cause corrosion issues.

3.11 Power Generation

The steam turbine is designed for long-term operation (90 days or more) at MCR with throttle control valves 95 percent open. It is also capable of a short-term 5 percent OP/VWO condition (16 hours).

The steam turbine is a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen (H_2)-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft. [64] The exhaust pressure is 50.8 cm (2 in) Hg in the single pressure condenser. The capture SC plant has only seven extraction points and the non-capture SC plant has eight extraction points. The reason for the difference between the two SC plant configurations is discussed in Section 3.12. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

Turbine bearings are lubricated by a CL, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a LP steam seal system. The generator stator is cooled with a CL water system consisting of circulating pumps, shell and tube or plate and frame type HXs, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a H_2 gas recirculation system using fans mounted on the generator rotor shaft.

Operation Description – The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at the conditions provided in Exhibit 3-14.

Exhibit 3-14. PC steam conditions

Steam Conditions	
Steam Parameter	**SC**
Main Pressure, MPa (psig)	24.1 (3,500)
Main Temperature, °C (°F)	593 (1,100)
Reheat Temperature, °C (°F)	593 (1,100)

The steam initially enters the turbine near the middle of the HP span, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at the conditions provided in Exhibit 3-14. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser. The last stages of the LP sections operate as condensing turbines with an exhaust moisture content ranging from 9.2 percent to 9.5 percent.

The turbine is designed to operate at constant inlet steam pressure over the entire load range.

3.12 Balance of Plant

The balance of plant components consist of the condensate, FW, main and reheat steam, extraction steam, ash handling, ducting and stack, waste treatment and miscellaneous systems as described below.

3.12.1 Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator and through the LP FW heaters. Each system consists of one main condenser; two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity; four LP heaters (three in capture cases); and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP FW heaters 1 through 4 are 50 percent capacity, parallel flow, and are in the condenser neck. All remaining FW heaters are 100 percent capacity, shell and U-tube HXs. Each LP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Pneumatic level control valves control normal drain levels in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Pneumatic level control valves control dump line flow.

The SC capture cases require all process extraction steam (CO_2 capture and drying requirements) condensate to be returned after the condenser upstream of the condensate polisher. This is required because the SC cases do not have a blowdown stream. If the condensate was returned to the deaerator, there would be a buildup of contaminants.

3.12.2 Feedwater

The function of the FW system is to pump the FW from the deaerator storage tank through the HP FW heaters to the economizer. One turbine-driven BFW pump sized at 100 percent capacity is provided to pump FW through the HP FW heaters. One 25 percent motor-driven BFW pump is provided for startup. The pumps are provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Pneumatic level control valves control normal drain level in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel vent condenser and storage tank.

The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust provides steam to the boiler feed pump steam turbine.

3.12.3 Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the IP turbine stop valves.

Main steam exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve and is routed in a single line feeding the HP turbine.

Cold reheat steam exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine.

3.12.4 Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine extraction to heater 7 and 8
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc, non-return valves located in all extraction lines except the lines to the LP FW heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.12.5 Circulating Water System

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent circulating water pump (CWPs) are provided. The circulating water system (CWS) provides cooling water to the condenser, the auxiliary cooling water system, and the CDR facility and CO_2 compressors in capture cases.

The auxiliary cooling water system is a CL system. Plate and frame HXs with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc., are included for a complete operable system.

The CDR and CO_2 compression systems in capture cases require a substantial amount of cooling water that is provided by the PC plant CWS. The additional cooling loads imposed by the CDR and CO_2 compressors are reflected in the significantly larger CWPs and cooling tower in those cases.

3.12.6 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler, along with the hydrated lime and activated carbon injected for Hg control (discussed in Section 3.6), and dissolved solids from the SDE that are disposed of with the fly ash (discussed in Section 3.10.2.1). The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the separate bottom ash/fly ash storage silos and truck filling stations. The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using LP air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

As mentioned in Section 3.5, the use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of PM by approximately 26 percent.

The bottom ash from the boiler is fed into a series of dry storage hoppers, each equipped with a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. Accumulated bottom ash discharged from the hoppers passes through the clinker grinder, then to a screw feeder and finally to a pneumatic ash conveying system for transport to the bottom ash silos, before being transferred to trucks for offsite disposal.

Ash from the economizer hoppers is pneumatically conveyed to the fly ash storage silos(s) and pyrites (rejected from the coal pulverizers) are conveyed using water on a periodic basis to the dewatering system (i.e., dewatering bins) for offsite removal by truck.

The wet sluicing for the pyrite system is not an explicit requirement of the National Fire Protection Association, but it is viewed as a risk mitigation measure to avoid accidental ignition of combustible materials clinging to the mill rejects. This can also come into effect when a mill trips and the contained solids need to be safely removed from the mills. Wet sluicing of the mill rejects further reduces potential ignition of this coal that is being swept from the mills. The water used for wet sluicing is regarded as low volume wastewater, which is not specifically regulated under the ELG rule, and is assumed to be treated for the pyrites within the plant's standard low volume wastewater treatment facility described in Section 3.12.8.

3.12.7 Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete and is 152 m (500 ft) high for adequate particulate dispersion.

3.12.8 Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The waste treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water are provided. A storage tank provides a supply of No. 2 fuel oil used for a small auxiliary boiler; start-up fuel is assumed to be natural gas. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

3.12.9 Buildings and Structures

Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Fuel oil pump house
- Coal crusher building
- Continuous emissions monitoring building
- Pump house and electrical equipment building
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system building

3.13 Accessory Electric Plant

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

3.14 Instrumentation and Control

An integrated plant-wide control and monitoring DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual procedures, with operator selection of modular automation routines available.

3.15 Performance Summary Metrics

This section details the methodologies of several metrics reported in the performance summaries of the PC cases.

Steam Generator Efficiency

The steam generator efficiency is equal to the amount of heat transferred in the boiler divided by the thermal input provided by the coal. This calculation is represented by the following equation:

$$SGE = \frac{BH}{CH}$$

Where:

SGE – steam generator efficiency

BH – boiler thermal output

CH – coal thermal input

The heat transferred in the boiler is calculated in the Aspen models, and the thermal input of the coal is the product of the coal feed rate and the heating value of the coal, similarly for the biomass.

3.15.1.1 Steam Turbine Efficiency

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal consumption. This calculation is represented by the following equation:

$$STE = \frac{STP}{(TI - TC)}$$

Where:

STE – steam turbine efficiency

STP – steam turbine power

TI – thermal input

TC – thermal consumption

The thermal input is considered to be the main steam.

The thermal consumption is only present in the capture cases. It is the enthalpy difference between the streams extracted for the capture and CO_2 dryer systems and the condensate returned to the condenser (steam extraction – condensate return).

3.15.1.2 Steam Turbine Heat Rate

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the following equation:

$$STHR = \frac{1}{STE} * 3{,}412$$

Where:

STHR – steam turbine heat rate, Btu/kWh

STE – steam turbine efficiency, fraction

4 Plant Configurations

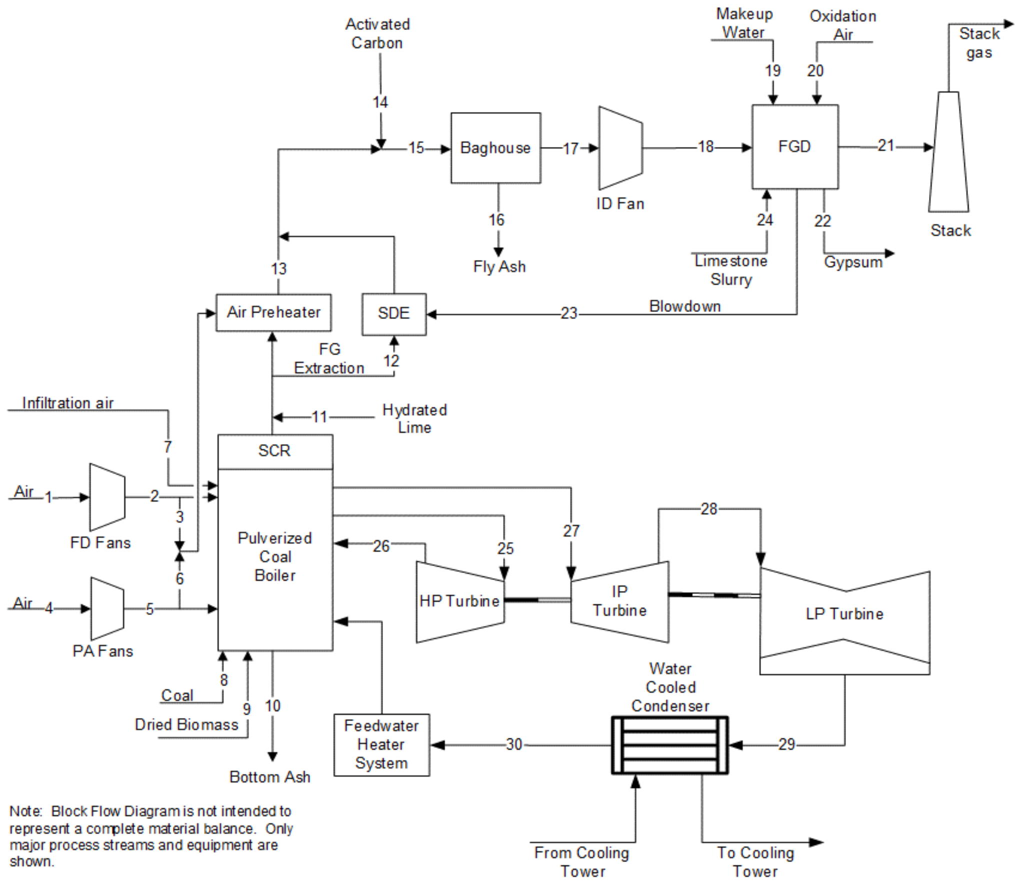
A key objective of this study is to determine how a typical PC design will respond to the demands of meeting a wide range of biomass feed with and without CCS technologies. Two distinct plant configurations were used in this study to achieve the various GHG goals, while providing the most practical plant design that can be envisioned considering process modeling limitations.

4.1 Non-Capture

The non-capture cases consist of SC plants with and without biomass. This configuration refers to four of the eight cases. One of the cases is taken directly from the NETL report "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4." [2] The case taken from this study is the baseline SC, coal-only PC plant without CCS. The SC case employs a single reheat cycle of 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F). The other three non-capture cases varying biomass feed levels are based on the SC plant design, using a single reheat cycle of 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F).

A simplified block flow diagram for the base configuration is shown in Exhibit 4-1.

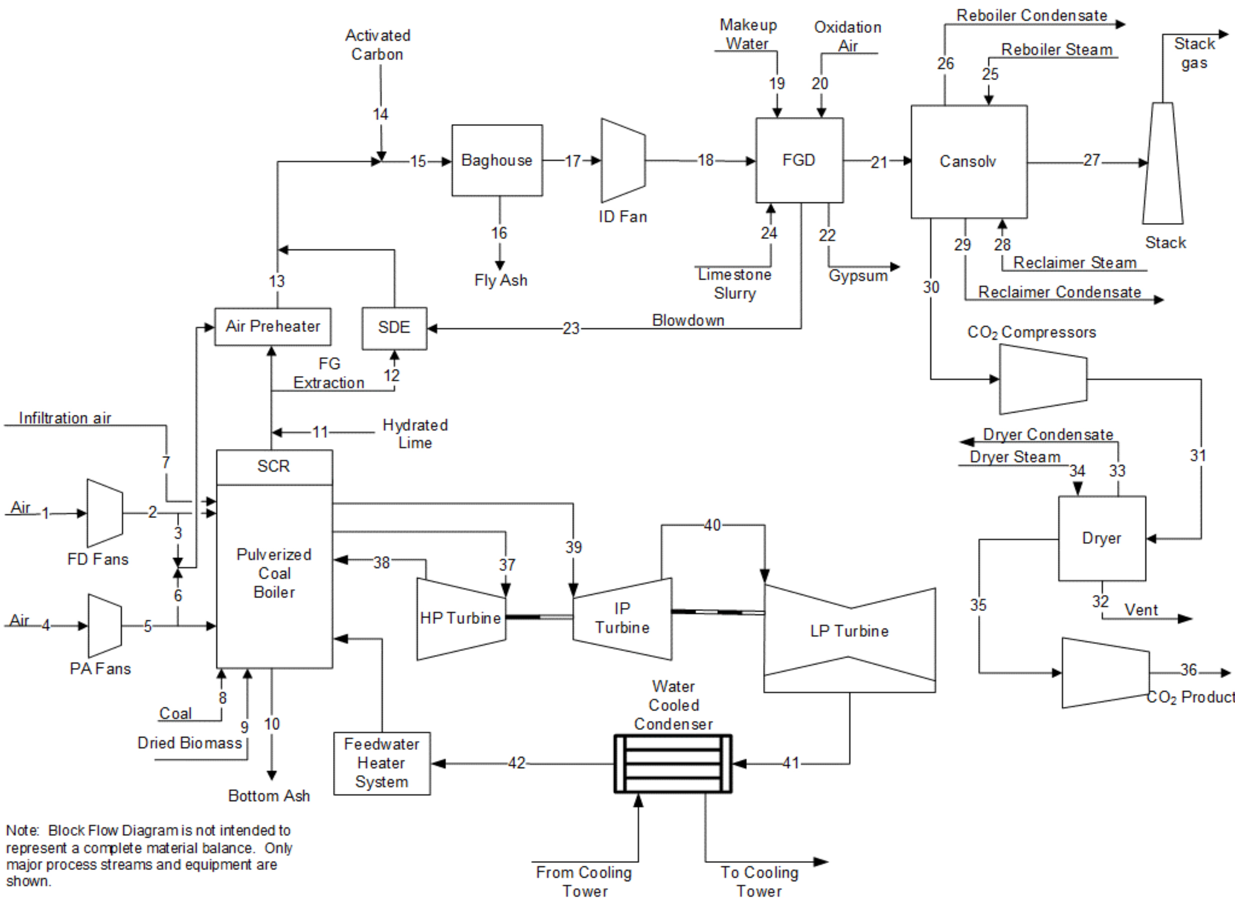
Exhibit 4-1. Non-capture configuration block flow diagram



4.2 Amine Based Carbon Capture

These four cases are similar to the non-capture, SC cases (24.1 MPa/593°C/593°C [3,500 psig/1,100°F/1,100°F]), except an amine-based CDR facility with a CO_2 capture rate of 90 percent is added. Exhibit 4-2 is the block flow diagram for the amine configuration.

Exhibit 4-2. Amine configuration block flow diagram



Because of the variety of plant configurations used in this study, Exhibit 4-3 summarizes where the eight cases fall under each of the configurations.

Exhibit 4-3. Case configuration summary

Configuration	Type	Cases Included
Non-Capture	SC	B12A, PN1, PN2, PN3
Amine	SC	B12B, PA1, PA2, PA3

5 Results and Analysis

The following sections present technical and economic data with and without co-firing hybrid poplar with Illinois No. 6 coal. Many of the plots are grouped by each of the two technologies, non-capture (designated "N") and capture with amine (designated "A"). The reference coal-only cases are B12A (non-capture) and B12B (capture with amine).

5.1 Technical Implications of Co-firing

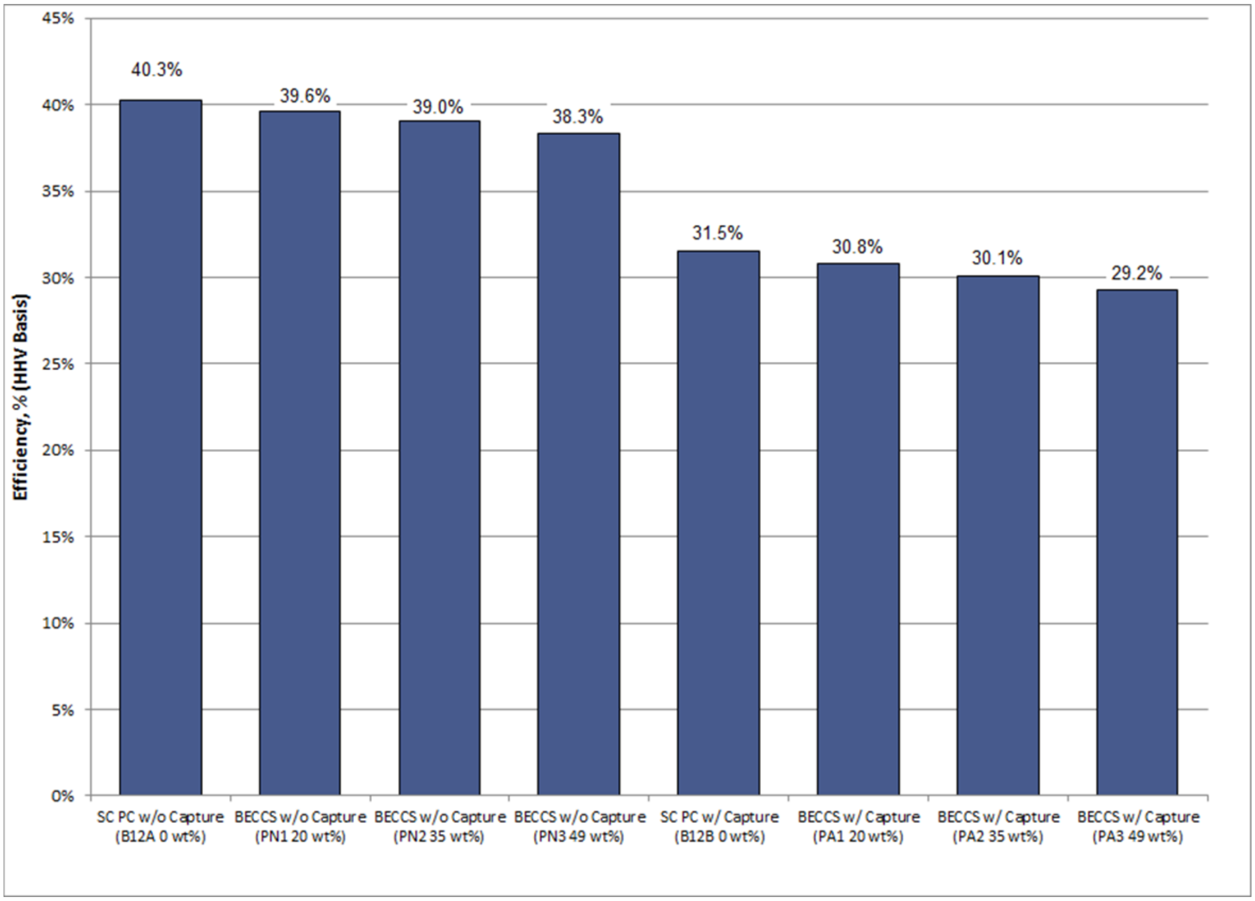
The objective of this study is to examine the performance, environmental response, and economics of co-firing biomass in PC power plants. Specifically, the emissions of the plant were calculated for various plant configurations (with and without CO_2 capture) using hybrid poplar biomass at three levels of co-fire (20 percent, 35 percent, and 49 percent) with Illinois No. 6 coal.

5.1.1 Net Plant Efficiency

Exhibit 5-1 compares the net plant efficiencies of the non-capture and amine capture cases. The non-capture cases produced the highest net plant efficiencies, followed by the amine cases. For all biomass co-firing cases, as the percentage of biomass feed increases, the efficiency decreases. This trend is expected because hybrid poplar is a lower quality fuel than Illinois No. 6 coal and thus, requires higher mass feed rates of coal and hybrid poplar to achieve the design fixed 650 MW-net plant output. This results in higher auxiliary loads for greater fuel feed rates. In addition, the process of drying the biomass adds auxiliary load to the plant, and as biomass feed rate increases, the auxiliary load increases proportionally. The base cases feeding only coal have the highest efficiencies.

The net plant efficiency of both capture technologies decreases as the biomass percentage of the feed increases. Rather than remaining constant, the difference in efficiency between the two technologies increases with biomass.

Exhibit 5-1. Net plant efficiency



5.1.2 Emissions

Exhibit 5-2 shows the relationship between the biomass feed percentage and normalized CO_2 stack emissions. CO_2 emissions increase as the amount of hybrid poplar in the feed increases for each technology again due to the lower quality fuel in hybrid poplar plus the increased auxiliary loads associated with handling and drying biomass. Non-capture plants have the highest level of CO_2 stack emissions at any feed composition, while the amine capture cases have the lowest. Life cycle results are shown in Section 5.3.

Exhibit 5-2. CO_2 stack emissions with biomass feed

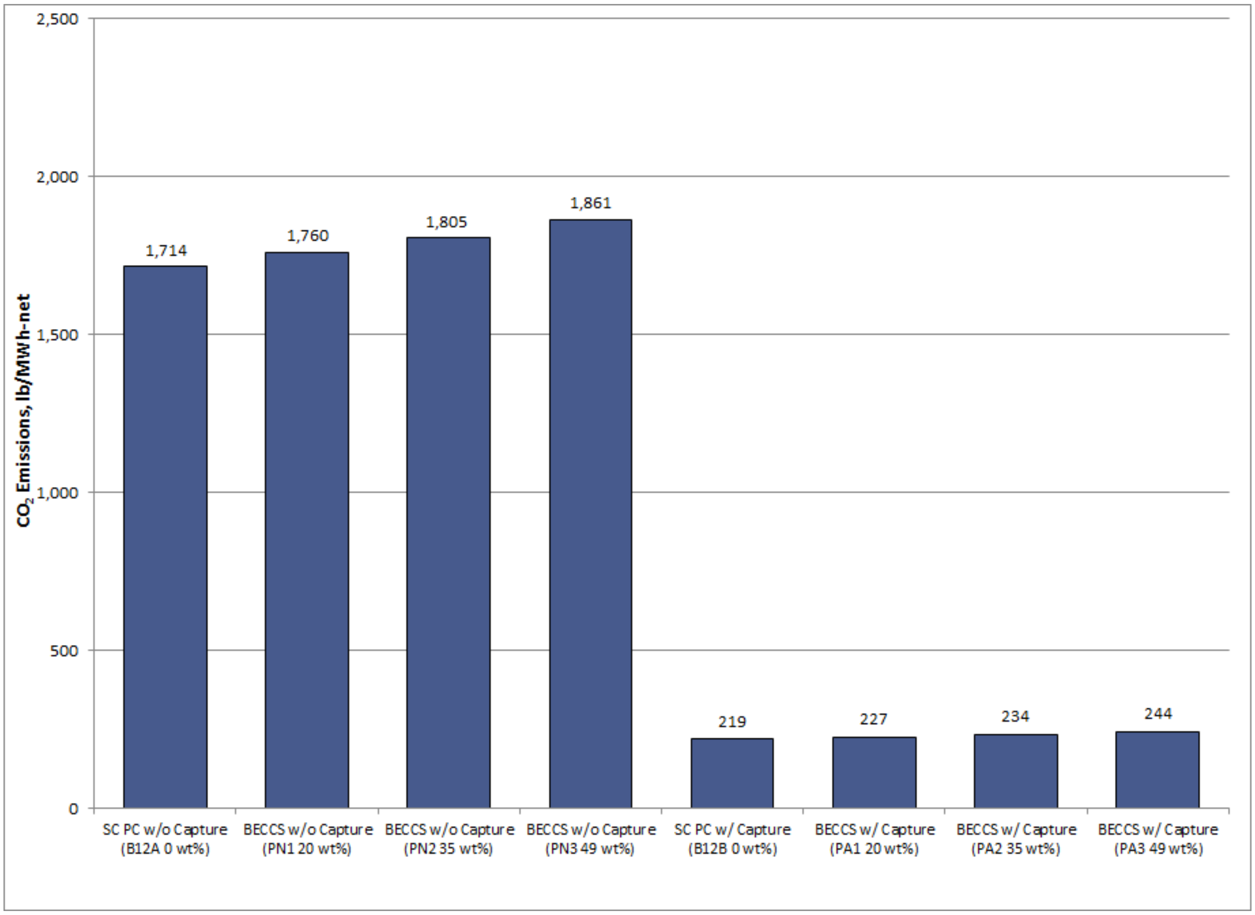
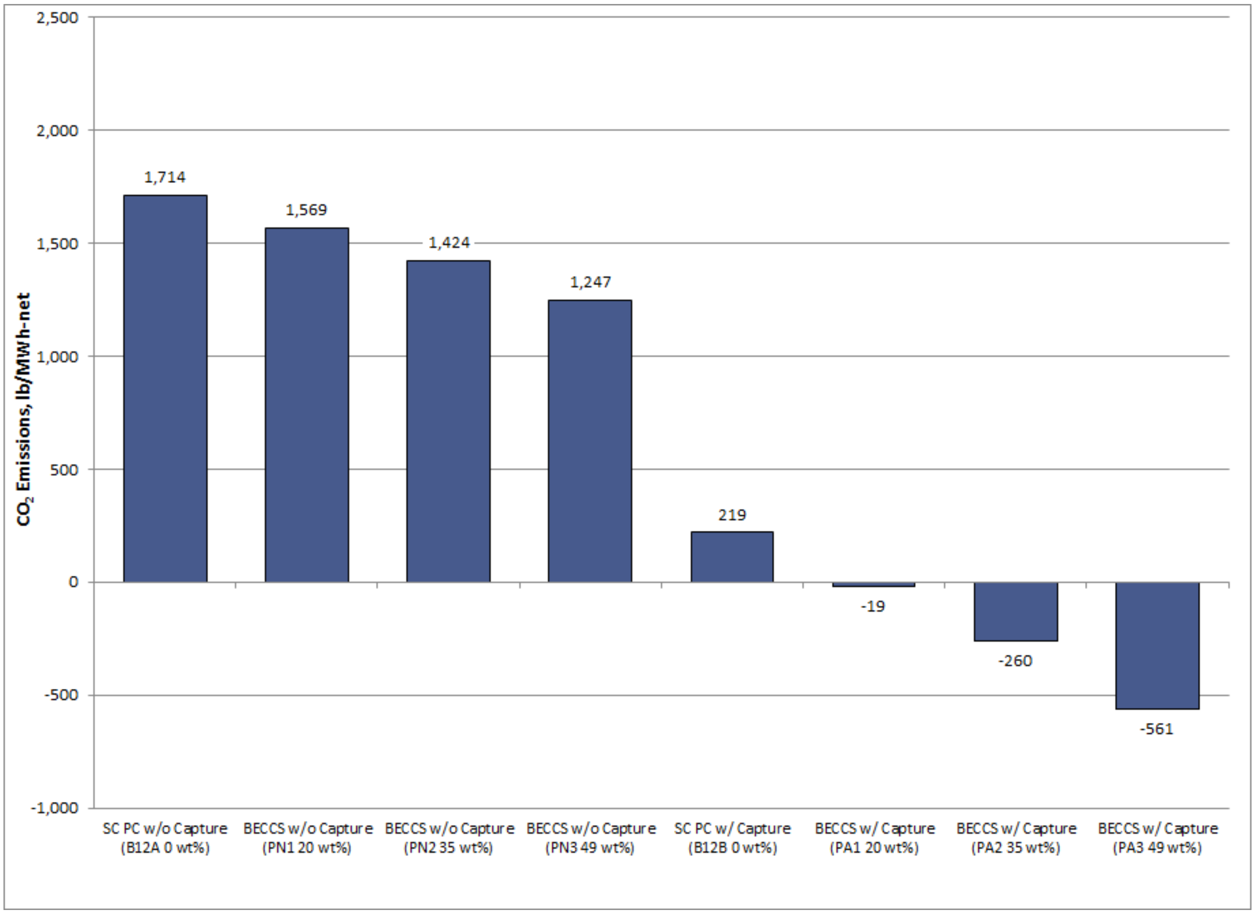


Exhibit 5-3 shows the relationship between the feed composition and normalized CO_2 emissions when the CO_2 produced by the carbon present in biomass is treated as GHG neutral. When the CO_2 emitted from co-firing biomass is deducted from the total stack emissions, increasing the co-fire rate reduces the overall CO_2 emissions in non-capture cases. When combined with 90 percent CO_2 capture, co-firing biomass generates net-negative emissions, when evaluated at the plant boundary.

Exhibit 5-3. CO_2 stack emissions with biomass feed carbon neutral



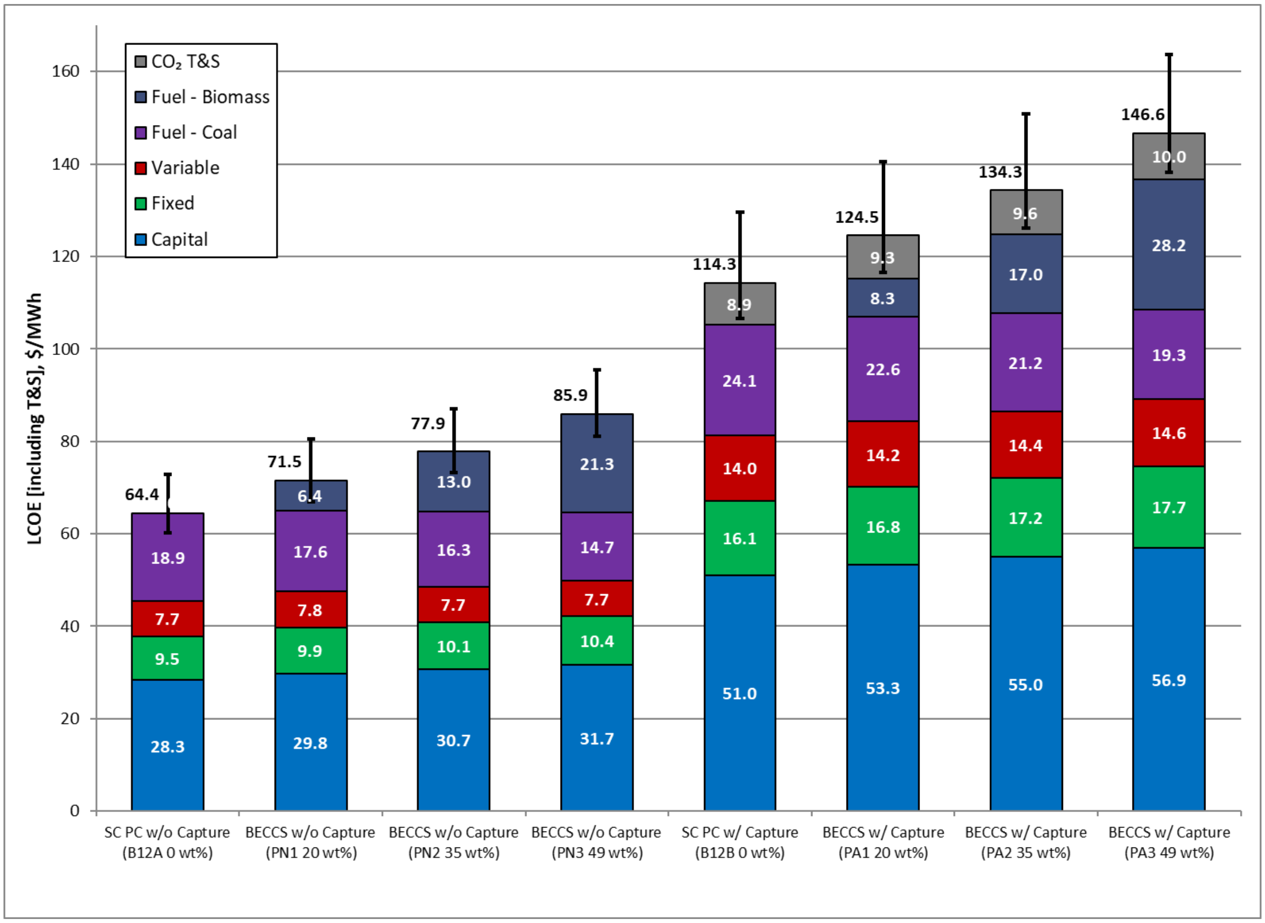
5.2 Economic Results

The following sections present the economic results of the study.

5.2.1 Levelized Cost of Electricity

An LCOE breakdown for each case is presented in Exhibit 5-4. Variance in the LCOE across the cases presented is caused primarily by differences in fuel cost and quantity. In all cases, the increased LCOE over the base case is dominated by the higher fuel cost of the hybrid poplar biomass over the coal, followed by increased capital costs due to increased equipment sizes and auxiliary handling equipment. The 100 percent coal-fired base cases have the lowest LCOE for both capture and non-capture cases. Increasing the co-fire rate to 20 percent increases the LCOE by 11 percent, a 35 percent co-fire increases the LCOE by 20.9 percent, and a 49 percent co-fire increases the LCOE by 33.3 percent for the non-capture cases. For capture cases, increasing the co-fire rate to 20 percent increases the LCOE by 9 percent, a 35 percent co-fire increases the LCOE by 17.5 percent, and a 49 percent co-fire increases the LCOE by 28.3 percent. The error bars represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges (-15 percent/+30 percent).

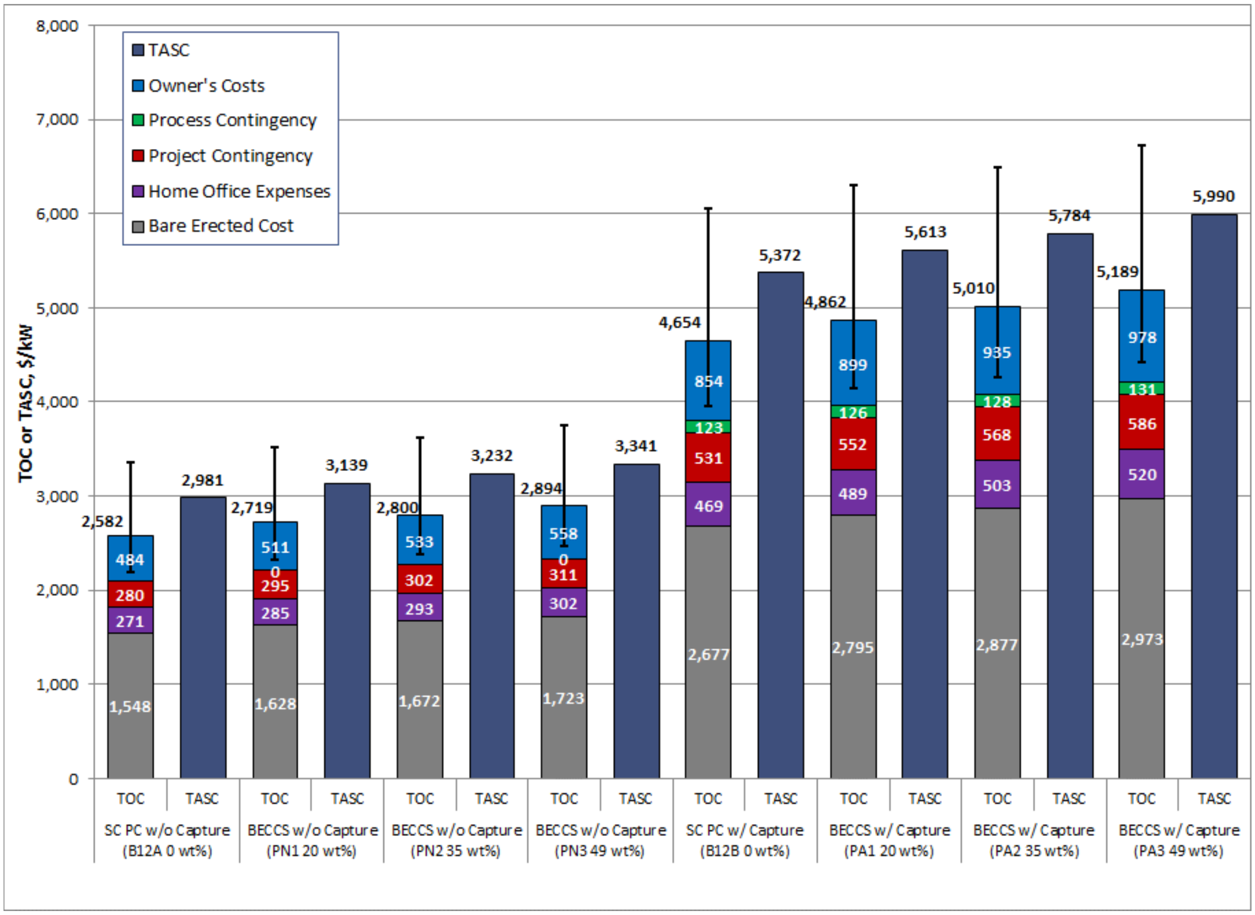
Exhibit 5-4. LCOE breakdown



5.2.2 Plant Costs

Exhibit 5-5 shows the normalized TOC and TASC as a function of biomass feed percentage. Costs increase with biomass feed percentage for each technology because of cost increases associated with larger equipment sizes and biomass processing and handling operations. For non-capture cases, TOC increase across the 20, 35, 49 percent co-fire range by 5.3, 8.4, and 12.1 percent, respectively. For capture cases, TOC increase across the 20, 35, 49 percent co-fire range by 4.5, 7.7, and 11.5 percent, respectively. The smaller TOC percent increases in capture versus non-capture are driven by the higher reference plant capital cost for capture versus non-capture, primarily for the addition of the amine system, and secondarily for the larger plant equipment required to achieve the design fixed 650 MW-net plant output. The error bars represent the potential cost range relative to the maximum and minimum capital cost uncertainty ranges (-15 percent/+30 percent).

Exhibit 5-5. Normalized TOC and TASC ($/kW-net)

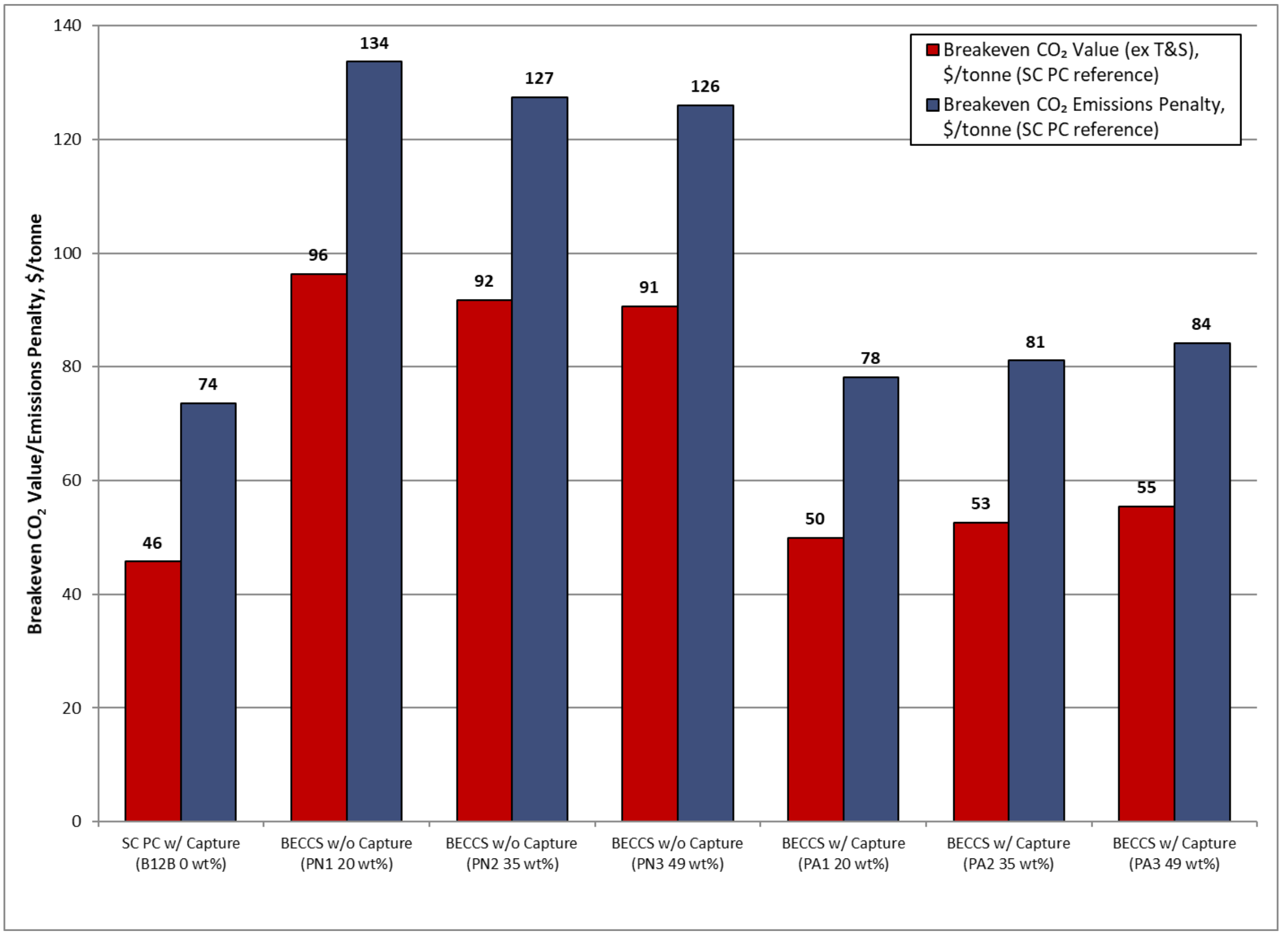


5.2.3 Breakeven CO_2 Valuation and Emissions Penalty

An incremental breakeven cost of CO_2 for co-firing various amounts of biomass was calculated for each case following the methodology as described in Section 2.9.4.

Exhibit 5-6 shows the breakeven valuation and emissions penalty of CO_2 for the cases co-firing biomass using the SC PC plant technology without capture and without biomass as the reference (Case B12A). Both the valuation and emissions penalty take into account the carbon neutral benefit of the co-fired biomass. With capture cases, the CO_2 valuation is analogous to a sales price, where without capture it is more representative of a necessary credit or incentive to breakeven against the base case. The valuation and emissions penalty both follow the same trend of being higher for the non-capture cases versus the capture cases. The breakeven point is marginally higher for the co-fire with capture cases when compared with the 100 percent coal with capture (Case B12B). These trends show that in terms of cost-effective mitigation of GHG, 90 percent carbon capture would be utilized before the benefits of biomass co-firing would be considered.

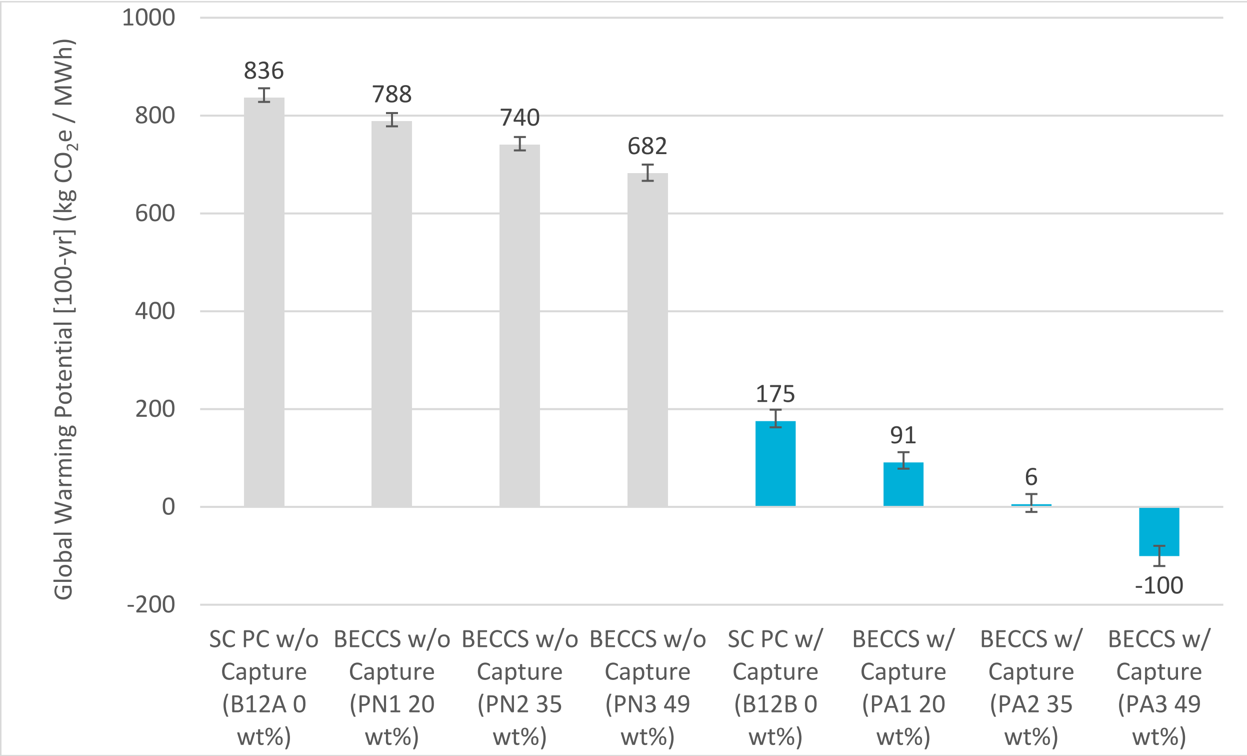
Exhibit 5-6. CO_2 breakeven valuation and emissions penalty



5.3 Life Cycle Analysis Results

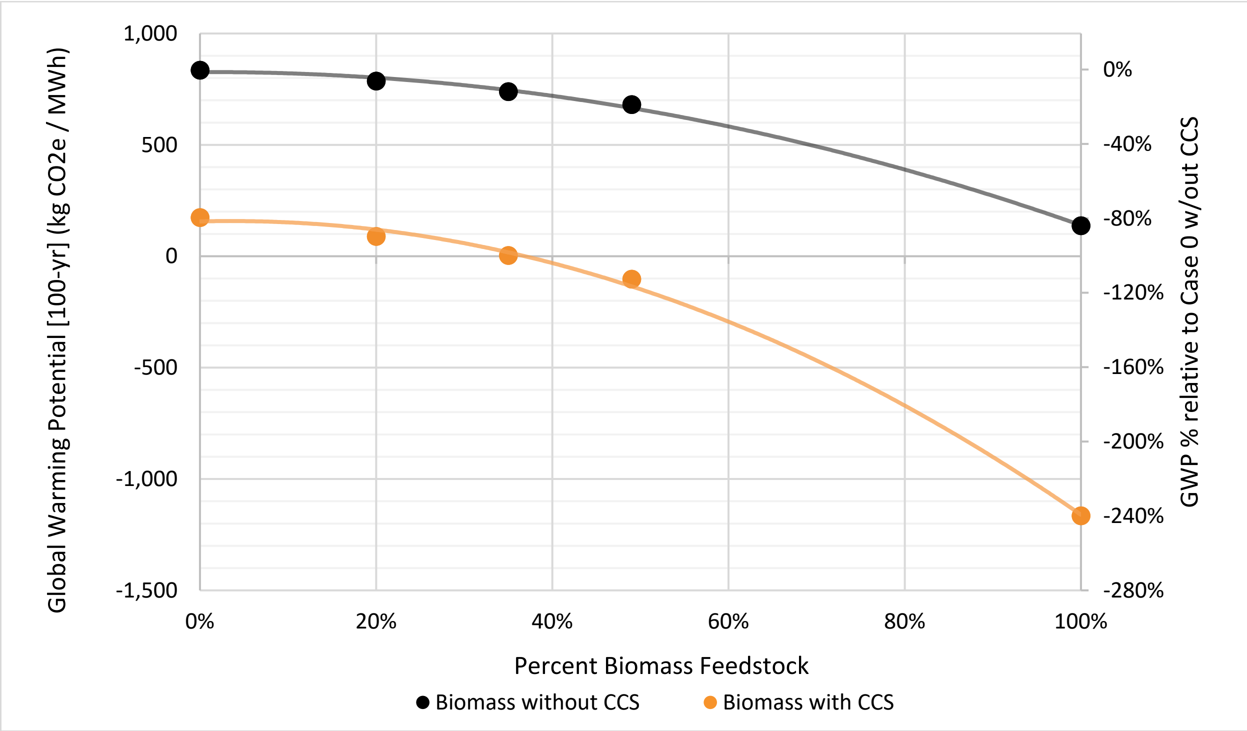
The results of this modeling tell two separate environmental stories. Replacing coal with biomass and adding carbon capture to the system both reduce the GHG emissions associated with a BECCS power plant. The addition of a capture system has a larger impact on plant GHGs than replacing coal with biomass. That is understood as the equivalent-sized coal plant with 90 percent carbon capture has a lower GHG impact than the 49 percent biomass plant without 90 percent carbon capture as shown in Exhibit 5-7. Note that the order of the scenarios modeled is different for GWP than other impacts to show that the addition of carbon capture systems causes a bigger reduction than replacing coal with biomass. It is also important to note that the BECCS system only has net negative GHGs at more than 35.9 percent biomass with 90 percent CCS; the 35 percent biomass with 90 percent CCS case still produces net positive GHGs. Each of the modeled scenarios are also shown in Exhibit 5-8 with GWP and GWP relative to Case 0 (0% biomass without CCS) with and without CCS for varying mass proportions of biomass.

Exhibit 5-7. Global warming potential results



Note: blue bars indicate the presence of 90% CCS

Exhibit 5-8. Effect of Variable Biomass Percentages on life Cycle Global Warming Potential of Power Generation via BECCS



The other side of the environmental story is that replacing coal with biomass and the addition of carbon capture systems increases other environmental burdens relative to power produced by coal. These burdens include eutrophication potential, ozone depletion potential, particulate matter formation potential, photochemical smog formation, and water consumption and are shown in Exhibit 5-11 and Exhibit 5-12. Acidification results are slightly more complicated because SO_2e decreases as a result of the addition of the capture system meaning the scenario with the lowest acidification potential that was modeled was the coal plant with 90 percent CCS as seen in Exhibit 5-9. The reduction in SO_2e is offset in the 49 percent biomass case because additional fuel is needed to process and dry the biomass, and additional combustion is necessary due to the lower energy density of the biomass fuel. The highest and lowest impact scenarios are outlined in Exhibit 5-9. The full life cycle results are shown in Exhibit 5-10. Additional results for 100 percent biomass scenarios are shown in Exhibit B-0-2 and

Exhibit C-0-1 through Exhibit C-0-7.

Exhibit 5-9. Highest and lowest scenarios for each impact category per MWh

Impact Category	Lowest Scenario	Lowest Value	Highest Scenario	Highest Value
Acidification Potential (kg SO_2e)	SC PC w/ Capture (B12B 0 wt%)	0.33	BECCS w/ Capture (PA3 49 wt%)	1.04
Eutrophication Potential (kg N e)	SC PC w/o Capture (B12A 0 wt%)	0.02	BECCS w/ Capture (PA3 49 wt%)	0.15
Global Warming Potential [100-yr] (kg CO_2e)	BECCS w/ Capture (PA3 49 wt%)	-104	SC PC w/o Capture (B12A 0 wt %)	816
Ozone Depletion Potential (kg CFC-11e)	SC PC w/o Capture (B12A 0 wt%)	4.6E-09	BECCS w/ Capture (PA3 49 wt%)	7.8E-08
Particulate Matter Formation Potential (kg PM2.5e)	SC PC w/o Capture (B12A 0 wt%)	0.12	BECCS w/ Capture (PA3 49 wt%)	0.15
Photochemical Smog Formation Potential (kg O_3e)	SC PC w/o Capture (B12A 0 wt%)	8.8	BECCS w/ Capture (PA3 49 wt%)	19.2
Water Consumption (kg)	SC PC w/o Capture (B12A 0 wt%)	1,967	BECCS w/ Capture (PA3 49 wt%)	27,011

Exhibit 5-10. Heat map demonstrating scenarios with the highest environmental impacts (red) and lowest impacts (green) for each impact category per MWh

Indicator	Unit	SC PC w/o Capture (B12A 0 wt%)	SC PC w/ Capture (B12B 0 wt%)	BECCS w/o Capture (PN1 20 wt%)	BECCS w/ Capture (PA1 20 wt%)	BECCS w/o Capture (PN2 35 wt%)	BECCS w/ Capture (PA2 35 wt%)	BECCS w/o Capture (PN3 49 wt%)	BECCS w/ Capture (PA3 49 wt%)
Acidification Potential	kg SO_2e	7.28E-01	5.04E-01	8.68E-01	7.18E-01	9.98E-01	9.19E-01	1.16E+00	1.17E+00
Eutrophication Potential	kg N e	2.25E-02	2.87E-02	5.33E-02	6.87E-02	8.41E-02	1.09E-01	1.22E-01	1.60E-01
Global Warming Potential [100-yr]	kg CO_2e	8.36E+02	1.75E+02	7.88E+02	9.09E+01	7.40E+02	5.66E+00	6.82E+02	-1.00E+02
Ozone Depletion Potential	kg CFC-11e	4.57E-09	5.87E-09	2.11E-08	2.73E-08	3.79E-08	4.95E-08	5.90E-08	7.76E-08
Particulate Matter Formation Potential	kg PM2.5e	1.30E-01	1.42E-01	1.34E-01	1.50E-01	1.37E-01	1.57E-01	1.41E-01	1.66E-01
Photochemical Smog Formation Potential-	kg O_3e	1.12E+01	1.31E+01	1.31E+01	1.57E+01	1.51E+01	1.83E+01	1.75E+01	2.16E+01
Water Consumption	kg	1.97E+03	2.82E+03	7.69E+03	1.02E+04	1.34E+04	1.77E+04	2.04E+04	2.70E+04

Exhibit 5-11. Acidification potential and particulate matter formation potential across BECCS modeled scenarios

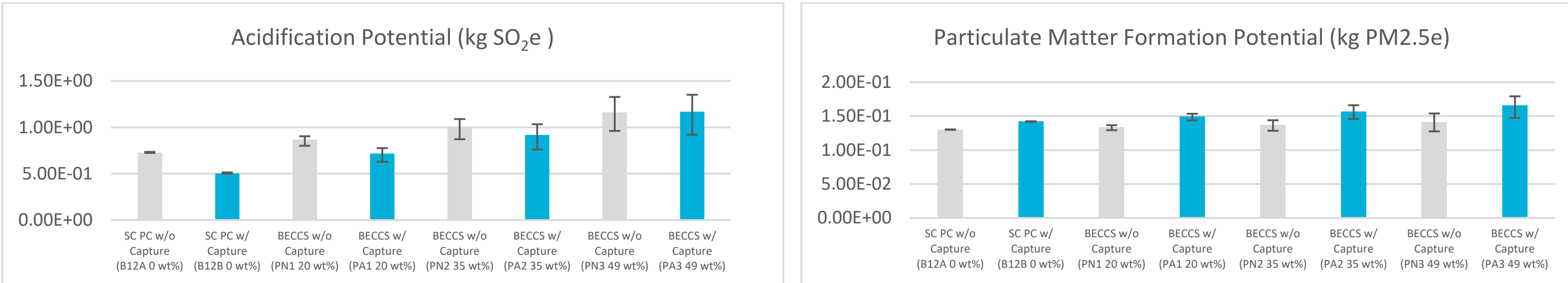
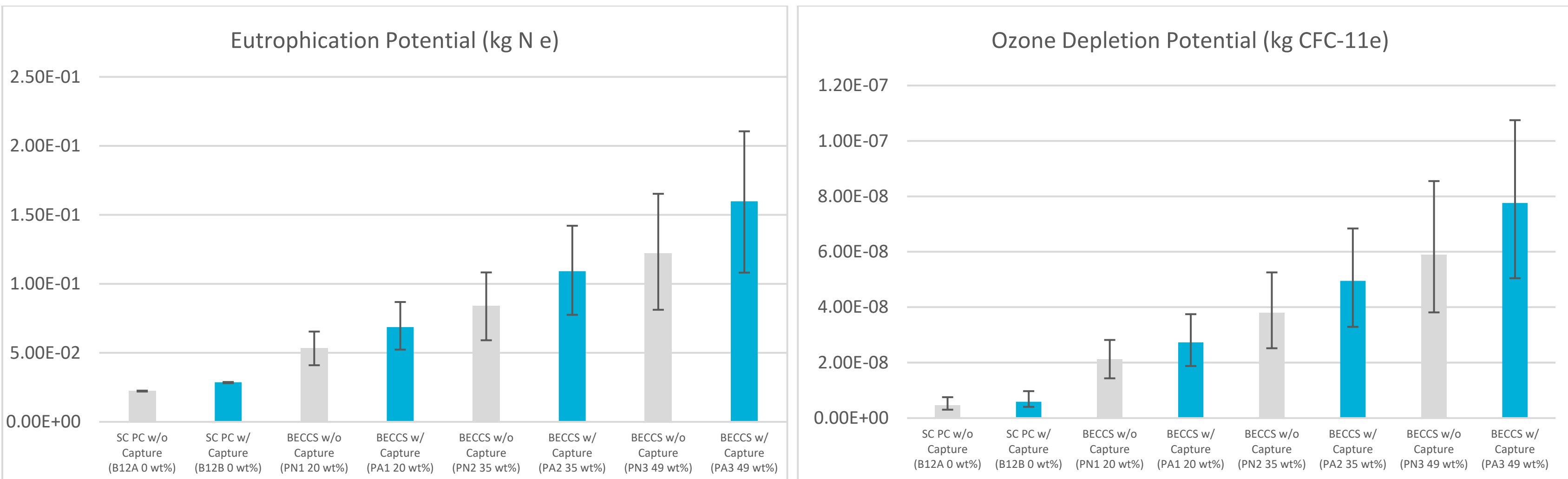
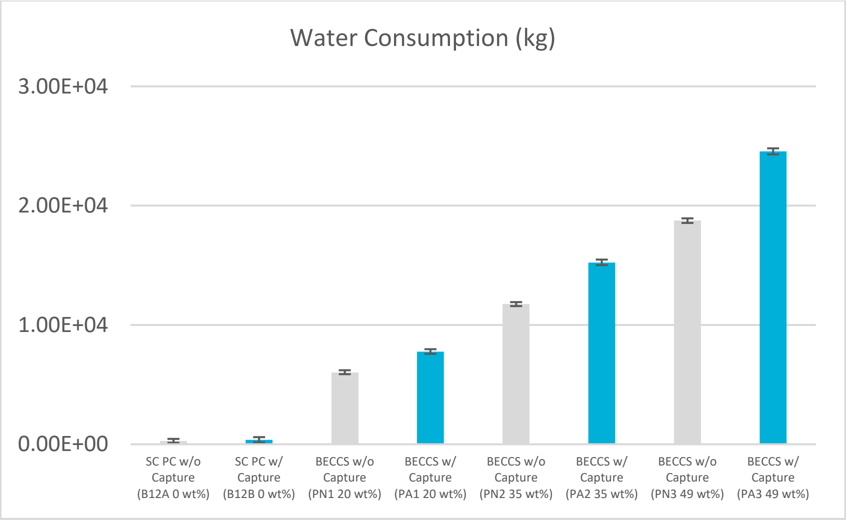
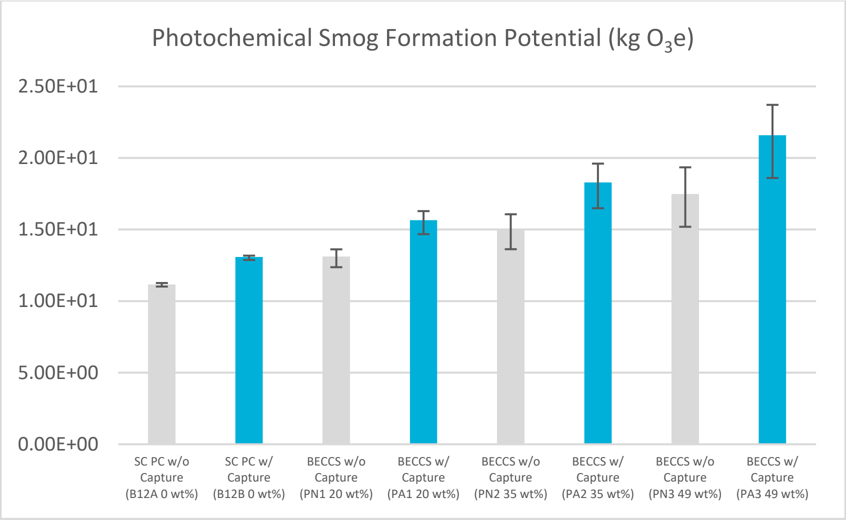


Exhibit 5-12. BECCS life cycle impacts for eutrophication potential, ozone depletion potential, water consumption, and particulate matter formation potential





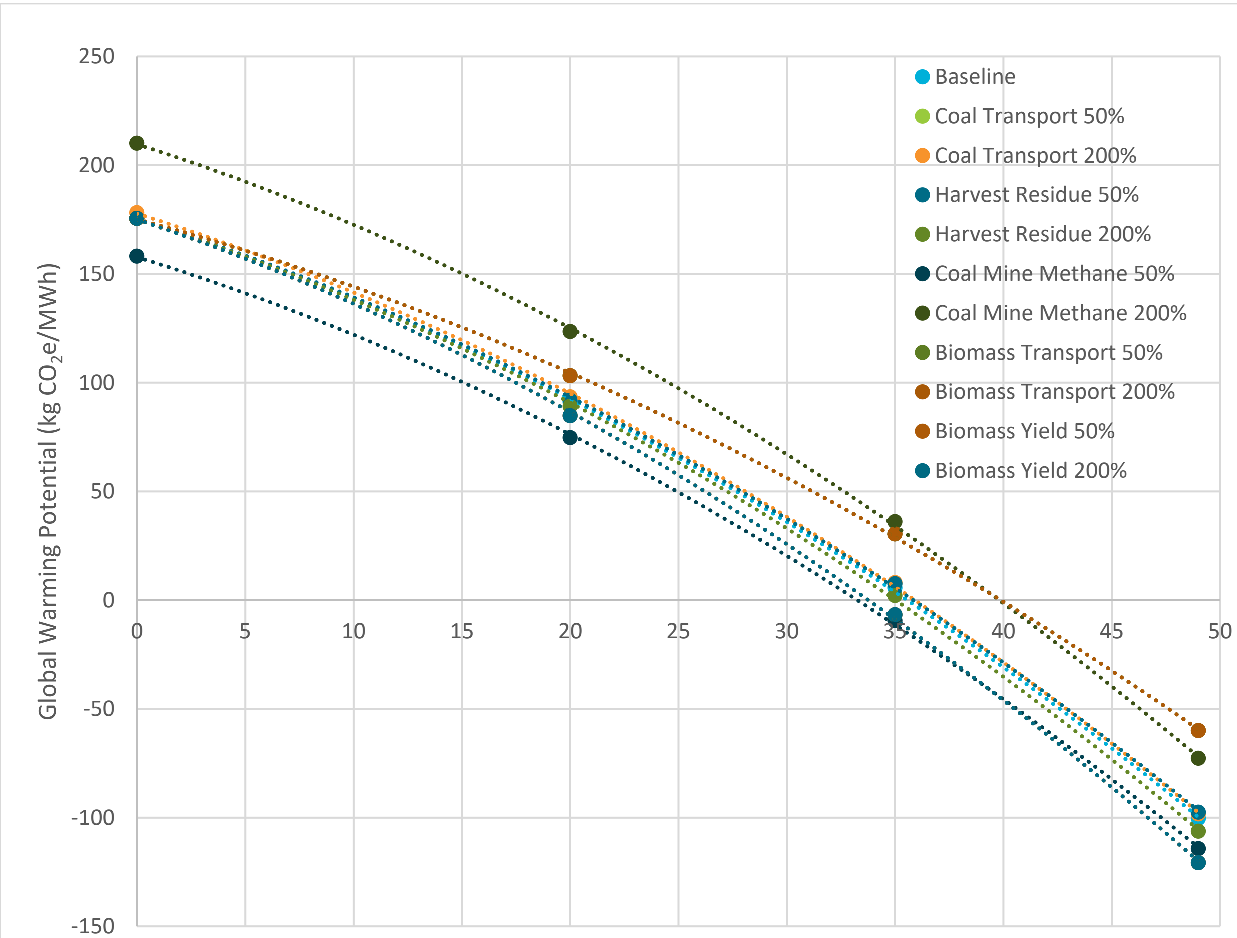


Note: blue bars indicate the presence of CCS

5.3.1 Sensitivity Analysis

This analysis includes a sensitivity analysis for the most important parameters to the life cycle results. These factors include coal transport, harvest residue, coal mine methane, biomass transport, and biomass yield impacts. As shown in Exhibit 5-13, these factors are not nearly as significant as the percentage of biomass firing. Break-even GHG cofiring percentages vary from 33.8 percent biomass (50 percent coal mine methane impacts) to 39.9 percent biomass (50 percent biomass yield impacts) for BECCS plants. Each of the other scenarios modeled have break-even GHG cofiring rates between 33.8 percent and 39.9 percent.

Exhibit 5-13. Trendlines for biomass weight needed for life cycle net-zero GHG emissions (BECCS w/ CCS)



Break-even values are not available for other indicators as they are only ever positive. As demonstrated in Exhibit 5-14, other parameters have less influence on life cycle impacts. To highlight how important these parameters can be, coal transport, harvest residue, biomass yield, biomass transport, and coal mine methane impacts are analyzed from 50 percent to 200 percent of the baseline analysis. Exhibit 5-14 and Exhibit 5-15 show that of these parameters, biomass yield is the only parameter that has the potential to significantly change life cycle results when it comes to BECCS and biomass scenarios.

Exhibit 5-14. Sensitivity analysis to coal mine methane, biomass transport, biomass yield, harvest residue, and coal transport impacts when varied from 50% of baseline to 200% for BECCS w/o Capture (PN3 49 wt%)

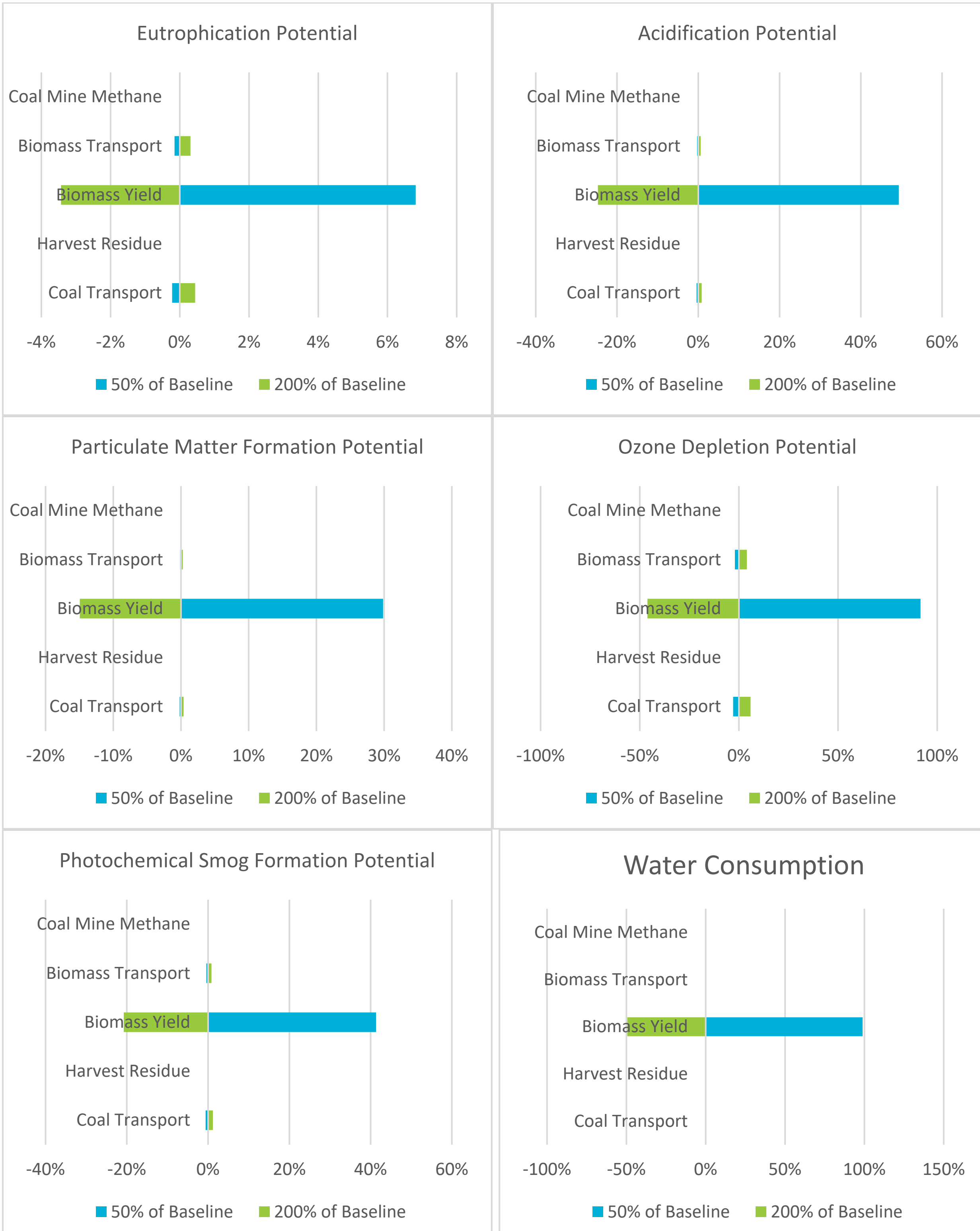
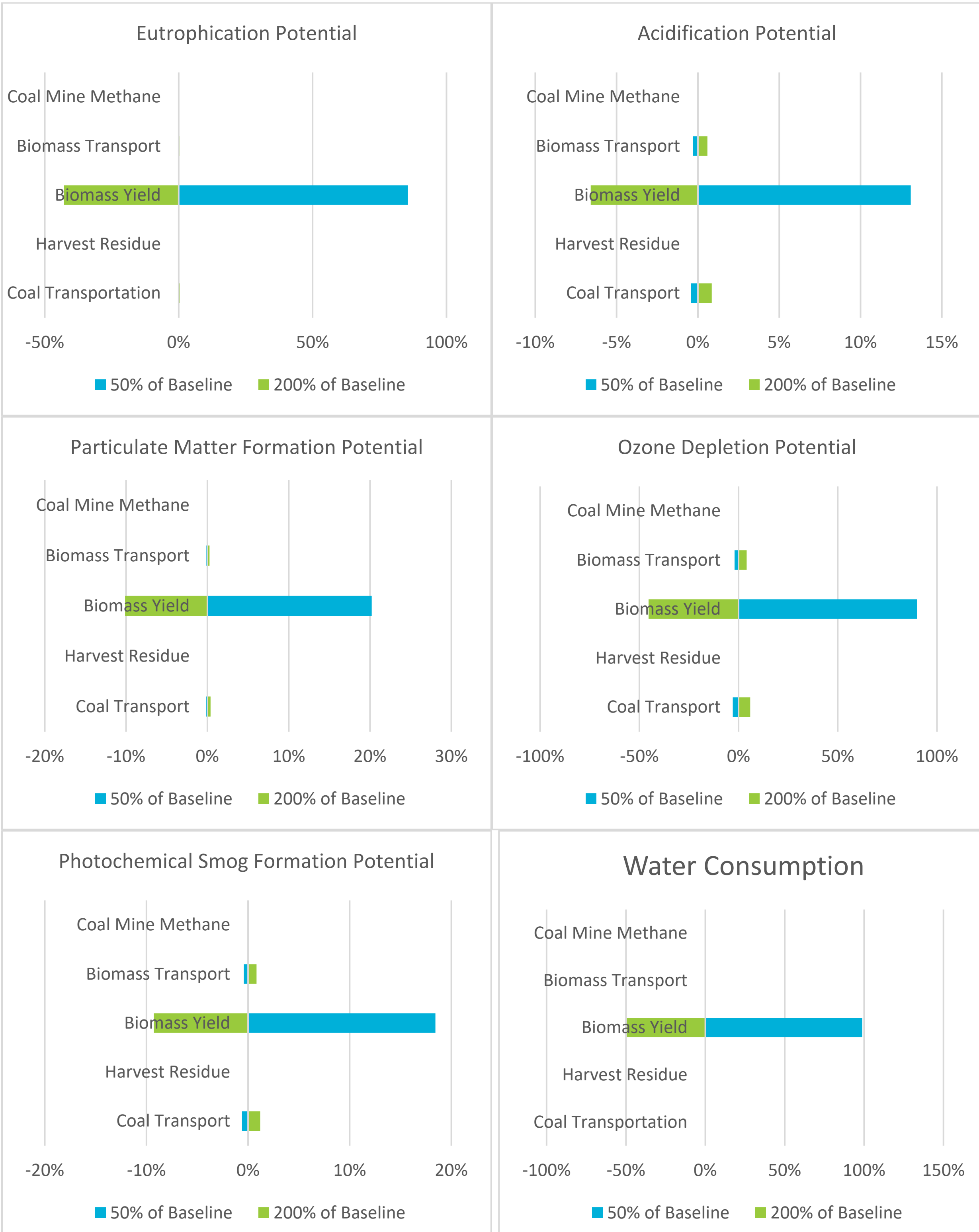
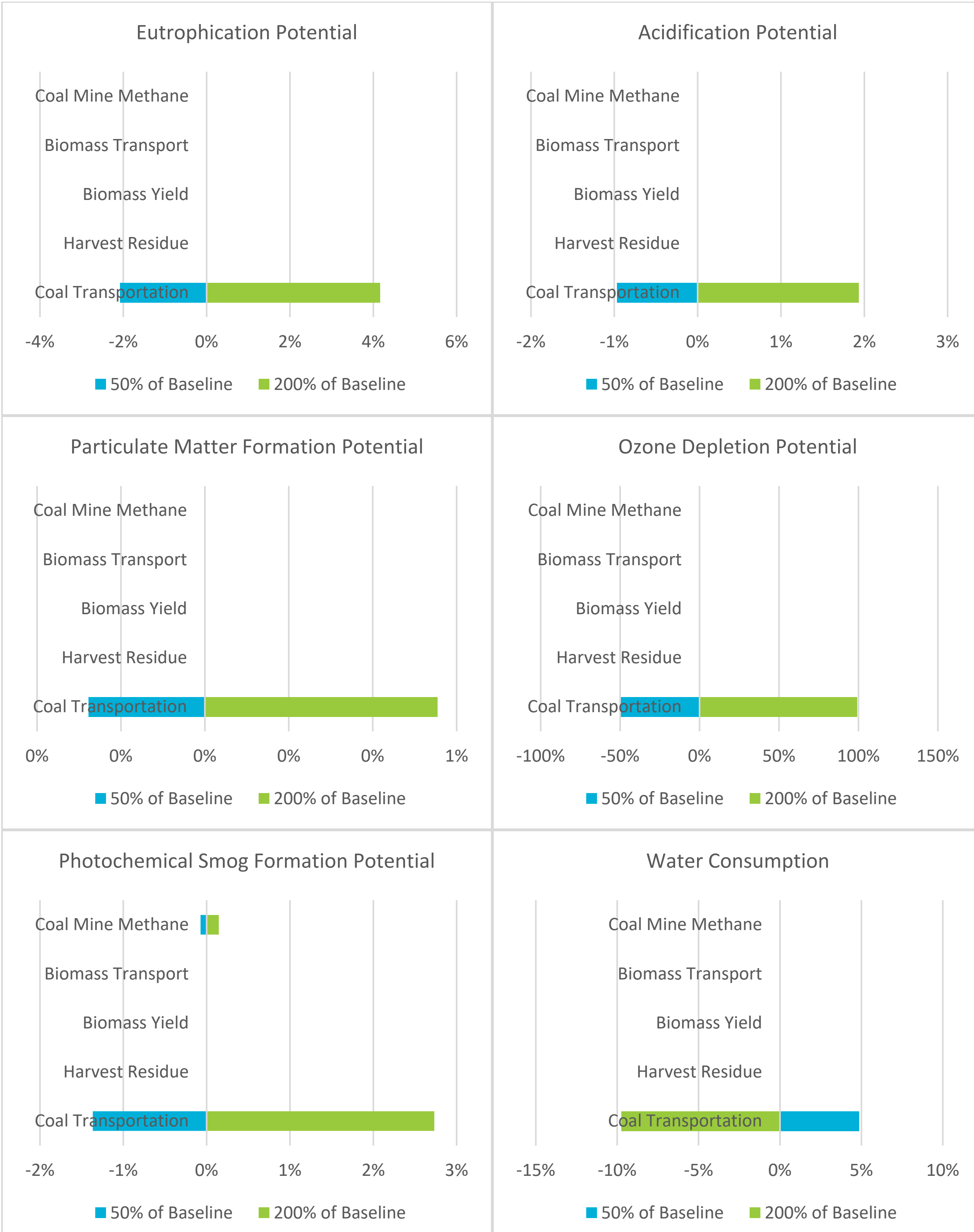


Exhibit 5-15. Sensitivity analysis to coal mine methane, biomass transport, biomass yield, harvest residue, and coal transport impacts when varied from 50% of baseline to 200% for BECCS w/ Capture (PA3 49 wt%)



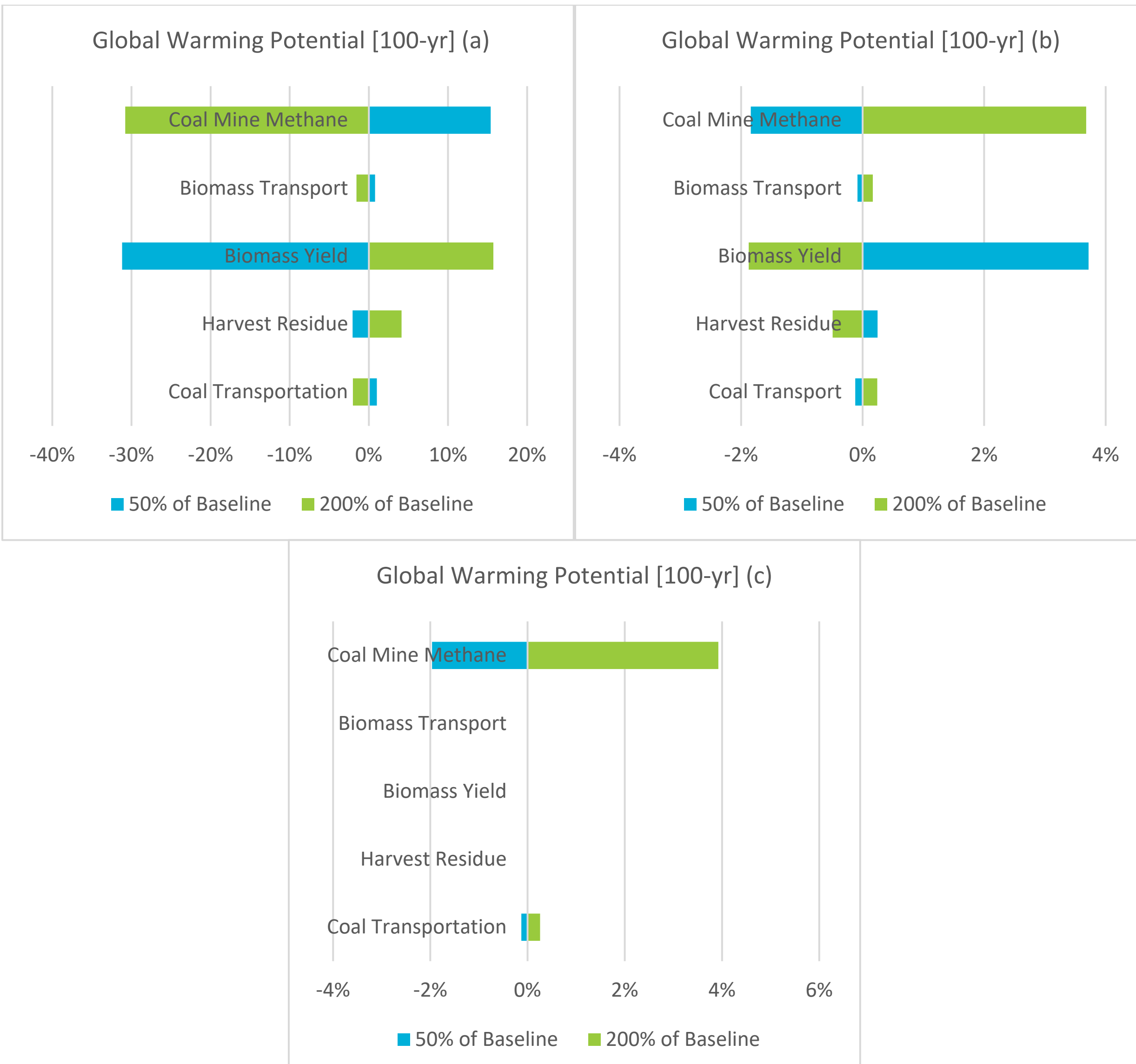
As shown in the sensitivity in Exhibit 5-14 and Exhibit 5-15, life cycle variance changes between modeled scenarios; however, the only parameter that has the potential to significantly affect results across all impact categories for scenarios involving biomass, beside co-firing rate, is biomass yield. For the coal scenarios modeled, the only significant parameter uncertainty is coal transport impacts, as shown in Exhibit 5-16. Biomass yield has no impact on coal plants modeled that do not use biomass.

Exhibit 5-16. Sensitivity analysis to coal mine methane, biomass transport, biomass yield, harvest residue, and coal transport impacts when varied from 50% of baseline to 200% for SC PC w/o Capture B12 A (0% wt%)



Global warming potential impacts are similarly affected by biomass yield for scenarios that use biomass, but also by coal mine methane as shown in Exhibit 5-17. Biomass yield has no impact on the 100 percent coal scenario because biomass is not used by the coal plant in that scenario.

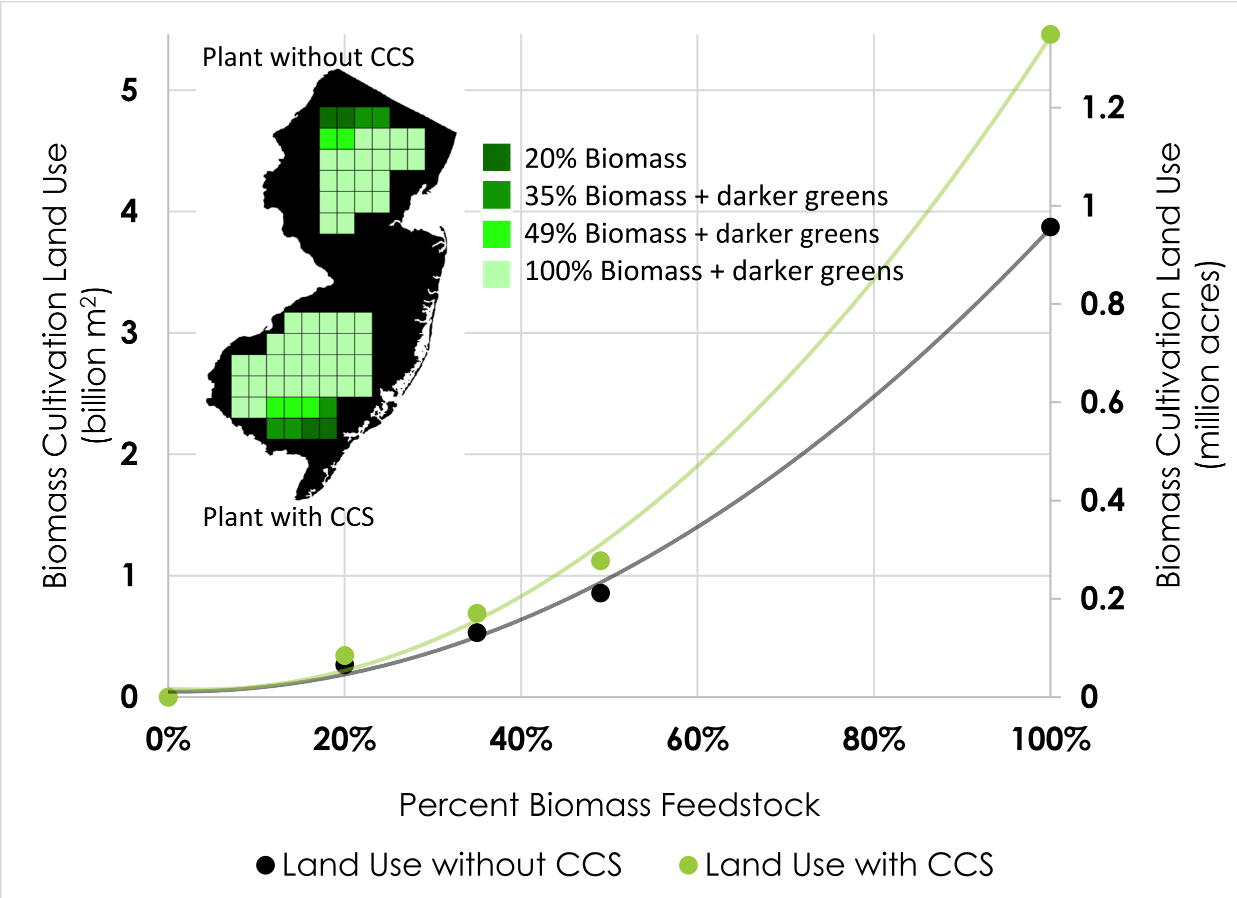
Exhibit 5-17. Parameter sensitivity for global warming potential for BECCS w/ Capture (PA3 49 wt%) (a), BECCS w/o Capture (PN3 49 wt%) (b), and SC PC w/o Capture (B12A 0 wt%) (c)



5.3.2 Biomass Land Use Requirements

Increasing the proportion of biomass fuel and the addition of the carbon capture system both increase the mass of biomass required by the system and thus the area of land that is required to grow that biomass. The land use required for each scenario modeled is shown in Exhibit 5-18. Land requirements are shown relative to the state of New Jersey (5.6 million acres) for perspective.

Exhibit 5-18. Effect of Biomass Feedstock Percentage on Land Use for Cultivation Relative to the state of New Jersey (5.6 Million Acres)



6 Issues with Retrofitting Biomass Co-firing Applications to Existing PC Plants

The design basis of this study included greenfield sites only. However, retrofitting biomass to an existing PC plant, whether co-firing with coal or full 100 percent biomass, is not only viable but more likely the next evolutionary step prior to biomass-based greenfield sites. The benefits to retrofitting are as follows:

- Significantly lower capital cost compared to a new greenfield plant
- Quicker implementation with minimal retrofit changes (depending on the percentage of biomass co-firing)
- Green incentives without building a new plant
- No observable physical changes to the community surrounding the plant as the changes will be unnoticed to most

This section discusses the requirements for co-firing biomass in existing PC plants. These retrofits will be assessed for the potential performance characteristics, performance limitations, integration issues, and costs associated with them.

6.1 Biomass Preparation/Transportation, and Feed

Biomass material has many differences relative to coal that cause concerns when retrofitting.

6.1.1 Preparation and Transportation

Moisture reduces the biomass heating value, requiring more biomass to displace coal. Additional preparation is typically required for biomass compared to coal due to grindability issues and particle sizes. Challenges associated with biomass handling are as follows: [65]

- Fuel Yard
    - Installation of new receiving equipment and accommodations of new truck traffic
    - Pile sizes for pelletized biomass are 4–5 times those of coal (for equivalent energy input)
    - Significant distances may require drag chain or pneumatic conveyors
    - Large biomass systems (greater than 25 MW) may require automated stackout/reclaim systems
- Belt Systems and Delivery to Boiler
    - Existing equipment (including belts, mills, chutes, and storage silos) may not have sufficient capacity to allow significant co-firing
    - For repowering options, these limitations may require a derate of the unit. This can be minimized with pretreatment of the fuel (pelletizing, torrefaction, washing, etc.)

- Safety Systems
    - Additional dust loading may require dust suppression and/or additional fire protection systems

6.1.2 Feed

Biomass can be fed into the boiler in multiple arrangements, each with their own advantages and disadvantages.

6.1.2.1 Co-Milling

Biomass can be fed into the boiler by blending it with coal using the same injection system into the boiler. This is the simplest and least expensive method, but it limits the amount of co-firing available. There is also the increased risk of mill fires as the biomass has higher volatile content. Burner tuning is required when switching from coal to coal/biomass. Coal pipes and burners will typically need upsizing for large biomass co-fire rates. If the biomass moisture content entering the boiler is higher than that of the coal, pipe icing and fuel buildup in the elbows can occur. In a retrofit situation, biomass feed via co-milling has limits of 2–3 percent of co-firing for PC boilers and 10–20 percent for cyclone or fluidized bed boilers. [65]

6.1.2.2 Separate Injection

Separate injection requires constructing a separate biomass handling and feed system, as well as boiler modifications for additional feed locations. This is more expensive, but it allows for much larger amounts of biomass. Locating the injection points is a crucial design parameter. Without testing, increased NOx production due to poor boiler tuning and combustion is possible. In a retrofit situation, biomass feed via separate injections can obtain 10 percent co-firing or greater for PC boilers and 20 percent or greater for cyclone or fluidized bed boilers. [65]

6.1.2.3 Gasification

The third method is where biomass is gasified and the syngas is used to co-fire with coal in the boiler. This method is not typically used, as it has a significantly higher capital cost. It also reduces biomass ash, which could reduce revenues if the plant is selling ash since woody biomass has less ash than coal. Exhibit 6-1 compares the capital and O&M costs for each retrofit. [65]

Exhibit 6-1. Biomass co-firing retrofit costs

Method	Nominal Size (MW)	Overnight EPC Costs ($/kW)	Total Non-fuel O&M ($/MWh)
Co-firing – Fuel Blending	25	500–1,000	10–15
Co-firing – Separate Injection	25	750–1,250	18–22
Co-firing – Gasification	25	2,000–2,500	20–25
Biomass Standalone	30	4,500–5,500	27–33

Note: Capital costs presented are in EPC costs (excluding owner's costs)

6.2 Steam Generation

Biomass combustion in a retrofitted steam generator is impacted by the particle drying and heating, the volatile yield, devolatilization rate, and the char oxidation rate. The woody biomass has larger and less spherical particles, which means the rate of burn and distribution pattern in the boiler is difficult to predict. The wood has more moisture, which often requires at least some drying before combustion. The volatile content is higher with less fixed carbon. Exhibit 6-2 is a summary of the major differences, which cause issues in the steam generator. [66]

Exhibit 6-2. Fuel characteristics influencing burn rates

Characteristic	Fuel	
	Biomass	Coal
Dry heating value	~16 MJ/kg	~25 MJ/kg
Volatile matter	80%+	40%+
Particle size	~100 micrometer	~3 millimeters

Because of the much higher volatile matter and lower density, the heat release is shifted to the front of the boiler. However, this is only temporary as the larger and less uniform particles begin to char, the slip velocity between them and local gas is higher for biomass than coal increasing the effective residence time of the particle for combustion. These changes in heat transfer profile can potentially raise back-end temperatures and increase sensible heat loss.

Another effect on heat transfer is the deposition from woody biomass where the alkali metals (mainly potassium) from the biomass and the sulfur from the coal interact. However, this effect is much less prevalent in woody biomass due to lower alkali metal content than herbaceous biomass like switchgrass or rice stalks.

6.2.1 Ash Formation and Removal

Many of the process problems with biomass retrofits have been ash related. The most important ash-related issues are the formation of bonded ash deposits and accumulation of ash materials at lower temperatures on the surfaces of the boiler convective sections, and the accelerated metal wastage due to gas-side corrosion. [67] Compared to coal, woody biomass has approximately 50 percent less ash but has a higher variability in its ash content. [66] Co-firing of less than 10 percent biomass by weight generally reduces problems caused by slagging and fouling as does using natural grown or wood wastes rather than urban waste. [68]

Tests by Brigham Young University show ash deposition rates of woody biomass are less than some coals. [66]

Issues associated with the ash-handling system are presented in Section 3.12. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

6.2.2 Biomass NOx

Biomass NOx consists of fuel NOx from the volatile products and char oxidation, as well as thermal NOx. Biomass' higher volatile content compared to coal can produce early fuel-rich zones in the flame and reduce subsequent fuel NOx formation. Biomass volatile nitrogen evolves more rapidly than total volatiles and tends to form NH_x instead of hydrogen cyanide. The char oxidation NOx is based on the char yield and NOx in the gas-phase, which is relatively low. Thermal NOx is based on the gas temperature, which is also relatively low due to the higher biomass moisture content producing a lower flame temperature.

However, biomass studies show that injection strategies seem to affect the NOx output. Research Engineering Institute conducted a test at the Southern Research Institute facility designed to reproduce PC boiler conditions. The study was to test the impact on NOx when co-milling biomass and coal versus using separate injection points. The study found that co-milling reduced NOx compared to 100 percent coal, but NOx increased in the separate injection scenario. [68]

6.3 AQCS

Biomass combustion and its effects on the air quality control system (AQCS) (FGD, SCR, ESP, or baghouse, etc.) and other equipment in the gas path have been studied, but results are inconclusive and vary. The following subsections provide assessments on different AQCS equipment as evaluated by Black & Veatch. [65]

6.3.1 SCR

The SCR catalyst is an expensive and sensitive item, so changing the fuel composition always causes concerns. Potassium, lead, zinc, and other alkali earth metals have all been found to poison SCR catalysts when in contact with the catalytic surface. Research suggests that biomass co-firing has more significant SCR poisoning than just coal but that woody biomass is less detrimental to the SCR catalyst than herbaceous biomass due to lower alkali content. The most significant sources of catalyst deactivation based on field and laboratory testing at Brigham Young University are as follows (in priority order): [69]

- Channel plugging
- Surface fouling
- Chemical poisoning
- Catalyst sintering

6.3.2 ESP

Biomass ash particles tend to be smaller and have lower sulfur content but with higher sodium content compared to coal. This can cause a reduction in collection on the cold-side ESPs. Research Cottrell recommends that plate spacing be greater than or equal to 12 inches and rapping frequency should be increased with biomass. [65]

The fire risk in an ESP increases with biomass co-firing due to biomass' higher loss-on-ignition content, which is more volatile than the loss-on-ignition content with coal only. Potential solutions to this are reducing air in-leakage and flush the hoppers more frequently.

6.3.3 Baghouse

Though the experience with biomass co-fired in a plant with a baghouse is limited, the risk of fires is still increased compared to coal-fired plants.

7 Conclusions

The objective of this study is to examine the performance, environmental response, and economics of co-firing biomass in PC power plants using two different plant configurations:

- Non-Capture: SC plants with and without biomass co-firing
- Post-Combustion Capture: SC plants with and without biomass co-firing (plants use a Shell Cansolv system)

For any GHG abatement technology to penetrate the market, there needs to be an immediate market need for captured CO_2 or a federal CO_2 or GHG tax must be mandated. The legislation would either tax GHGs emitted only by the plant or GHGs emitted over the entire plant life cycle.

However, several logistical and technological hurdles must also be overcome before large-scale use of PC co-firing is realized under a GHG tax scenario. This study draws several notable conclusions, including the following:

- Plant location selection is crucial. Local biomass growth potential and land availability must be considered along with the plant's feed requirements.
- Feed rate limitations due to transportation logistics can possibly be mitigated by technologies such as torrefaction and pelletization. Integration of satellite biomass torrefaction/pelletization facilities may help to streamline the supply chain.
- Biomass supply issues due to harvest time tables and storage must be addressed if continuous co-firing operations are required.
- Break-even GHG co-firing percentages vary from 33.8 percent to 39.9 percent biomass by weight for BECCS plants. Cofiring rates have the biggest impact on net GHG emissions.
- The addition of biomass cofiring reduces GHG emissions while increasing all other environmental impacts studied. In order to achieve carbon neutral or carbon negative systems both carbon capture and biomass co-firing are necessary. The addition of carbon capture systems has a greater reduction in GHG emissions than the addition of co-firing.

The point at which co-firing becomes an attractive option cost wise depends on the level of incentive/tax and the type of plant. However, carbon capture technologies would be evaluated before the benefits from co-firing would be realized.

Biomass would likely be incorporated into design of a coal-fired power plant after CCS has been implemented because carbon capture technology results in the lowest breakeven CO_2 cost.

Non-capture plants had the highest net plant efficiencies, followed by the amine cases. The net plant efficiency of both technologies decreases as the biomass percentage of the feed increases.

Biomass and coal co-firing in a PC boiler present many challenges to the operation of the plant. With its higher volatile content, lower density, higher moisture, and larger, less uniform particles compared to coal, biomass will affect the boiler, SCR, FGD, and other gas path equipment operations.

Design parameters for equipment from the boiler to stack must take into consideration the changes in ash quantity and content, flue gas chemical composition, boiler temperature, heat transfer profile, and corrosion. Greenfield sites, like the one considered in this study, can be designed to accommodate these changes along with additional laydown area for the biomass and additional material handling equipment.

Brownfield retrofit sites will have challenges in finding proper laydown area and will have to retrofit the feeding system if co-milling above 3 percent. [65] Changes in the heat transfer profile and gas and ash content will need to be worked through. Brownfield sites would most likely require a derate in plant output.

8 FUTURE WORK

Biomass and coal co-firing within a PC boiler is already occurring with multiple utilities experimenting with different levels of co-firing, including 100 percent biomass. This study identified multiple issues that would benefit from additional investigation:

- Increased carbon capture percentage
- Torrefaction and other advanced biomass pretreatment
- Biomass harvesting
- Biomass transportation and logistics
- Additional second-generation crops
- Third and fourth generation crops
- Biomass "carbon neutral" justification
- Biomass co-firing at reduced scale – Greenfield plants at sizes smaller than 650 MW
- Biomass retrofits – System studies of retrofit scenarios due to the opportunity for reduced capital cost at, albeit, a potentially lower power generation efficiency bound by existing plant constraints

8.1 INCREASED CARBON CAPTURE PERCENTAGE

This study assumed 90% carbon dioxide capture efficiency from the flue gas stream exiting the power plant. Increasing the efficiency of carbon dioxide capture to higher values (>97%) will further enhance the environmental performance of the power plant by sequestering more of the fossil and biogenic carbon within the feedstocks. There is evidence that these higher capture rates are achievable with today's post-combustion capture systems, accompanied by a modest cost and energy impact. Increased capture efficiency would also reduce the fraction of biomass required to achieve net zero carbon dioxide emissions. Further analysis as well as research, development, and demonstration of higher carbon capture efficiency technologies will improve the cost and environmental performance of net negative power production from BECCS systems.

8.2 TORREFACTION AND OTHER ADVANCED BIOMASS PRETREATMENT

Biomass cannot be handled and fed similar to coals, as the biomass properties are completely different (i.e., biomass has a fibrous structure and high compressibility). Therefore, either biomass has to be pre-treated to make it behave similarly to coal, or dedicated biomass handling systems have to be developed. The advantage of pre-treating the biomass to more closely match coal properties is that it allows short-term implementation of biomass firing in existing plants and can reduce the sheer volume of biomass required to match the volume of coal needed. The efficiency may be improved if a dedicated feeding system for solid biomass can be developed.

It is recommended to further study the technical and economic feasibility of manipulating biomass, including other forms of drying, torrefaction, washing/leaching, and pyrolysis as a biomass pre-treatment step.

8.2.1 Drying Options

This study included drying by means of the WTA process; however, there are multiple ways to dry biomass, including an FG slip stream from the boiler, FG from a gas turbine, and steam. Each drying option should be explored in more detail.

8.2.2 Torrefaction

Torrefaction is a thermo-chemical process conducted in the absence of oxygen, during which biomass partially decomposes, giving off volatiles and giving the remaining material improved properties for combustion, including an increase heating value per unit weight, improved hydrophobic nature, improved grinding properties, and increased uniformity. Torrefaction may add to plant and O&M costs, but feedstock costs, a significant contributor to LCOE, may be reduced. Torrefaction also has the possibility of increasing "logistical maximum" biomass supply rates.

Further optimization of the torrefaction conditions is recommended to further increase the grindability for optimal feeding. The torrefaction temperature is considered the most important parameter in this respect. The higher this temperature, the thinner and shorter and, hence, more spherical particles can be obtained after size reduction. In previous research, 270°C (518°F) was the highest temperature explored, and further optimization should be focused on the temperature range of 270–300°C (518–572°F). In previous work, the length-to-diameter ratio was qualitatively evaluated by visual observations. It is also recommended to apply a quantitative method (e.g., optical microscope) in future research.

Further optimization in terms of energy loss during the torrefaction process is also required. Additional research could focus on minimizing that loss. ECN of Netherlands conducted testing and found a range of energy yield of 78–95 percent depending on the biomass. [70]

8.2.3 Biomass/Coal Briquette

A technology to briquette coal and biomass is under development by Clean Coal Briquette, Inc. The process uses rejected coal fines at a minemouth mixed with biomass (30 wt% coal/70 wt% biomass) to form the briquette (or pellet). The product has a higher heating value of 10,000–10,500 Btu/lb using bituminous coal, but also can be done with other coal ranks. Transportation would be the same as for the coal produced at the mine. Current production capacity is 60,000 tons per year using a mobile facility. The fuel price is $5–6/MMBtu. Covered storage is preferred, but not necessary. There are possible spontaneous combustion issues in the pulverizer, but they have not been fully investigated. About 20–25 percent of the input fuel energy value is lost in the process. [71]

8.2.4 Washing/Leaching

A number of potential problems in biomass thermal conversion systems, such as ash deposit formation (slagging, fouling), corrosion, sintering, and agglomeration, are related to biomass chemical composition (mainly Cl, Na, and K contents).

There are several methods to reduce the negative effects related to alkali compounds in biomass:

- Additives such as dolomite and kaolin are capable of reducing sintering problems by raising the melting point of ash. For example, a case study of a 300-MW plant using a kaolinite material showed a large reduction in slagging and fouling, thereby increasing power output by 4.5 MW along with various other incentives, [72] which can also be applied to the biomass sector. [73] This process appears to be feasible, with kaolin costing $65/ton and only using 1–2 wt% of the fuel.
- Another alternative for removal of those troublesome elements can be performed by washing (leaching) biomass with water.

Further investigation into all of these techniques, including economical and technical feasibility, and their effects on boiler performance would be worthwhile.

8.3 BIOMASS HARVESTING

Cutting edge portable machinery technology, like Stem Power Resources' BioBailer [74] and CBI's Magnum Force 6800D, [75] is available for harvesting brush and small trees, but needs to be evaluated in regard to harvesting capabilities. Also, equipment designed for stationary use requires evaluation and should be compared to the portable machinery.

8.4 BIOMASS TRANSPORTATION AND LOGISTICS

Large amounts of biomass are involved in this study with the assumption that the logistics are feasible to provide this large quantity to a power plant. Further investigation is needed to determine the economic and technical feasibility of biomass planting, farming, harvesting, transportation, and all other activities prior to delivery onsite.

8.4.1 Feasibility Studies

Detailed evaluation and real-life examples should be used to determine this feasibility. There are multiple examples of information relevant to this topic:

- Resource Systems Group prepared an assessment of feasibility of biomass energy production facilities in the Southern Alleghenies region of Pennsylvania and found 450,000–650,000 tons per year of available wood resources. [76]
- WesMin Resource Conservation and Development calculated that the potential hybrid poplar biomass in Minnesota is 1.2 million dry tons of wood. [77]

8.4.2 Biomass Physical Infrastructure

In addition to the feasibility studies mentioned above, an evaluation of the physical infrastructure of the current and future biomass system needs to be evaluated. Essent Energie's co-firing plant in Germany has advanced barge-unloading equipment, and hopes to unload up to 600,000 tons of biomass a year. [78] That is equivalent to 400 barges carrying 1,500 tons each. This is one of many additional physical infrastructure options that can be explored.

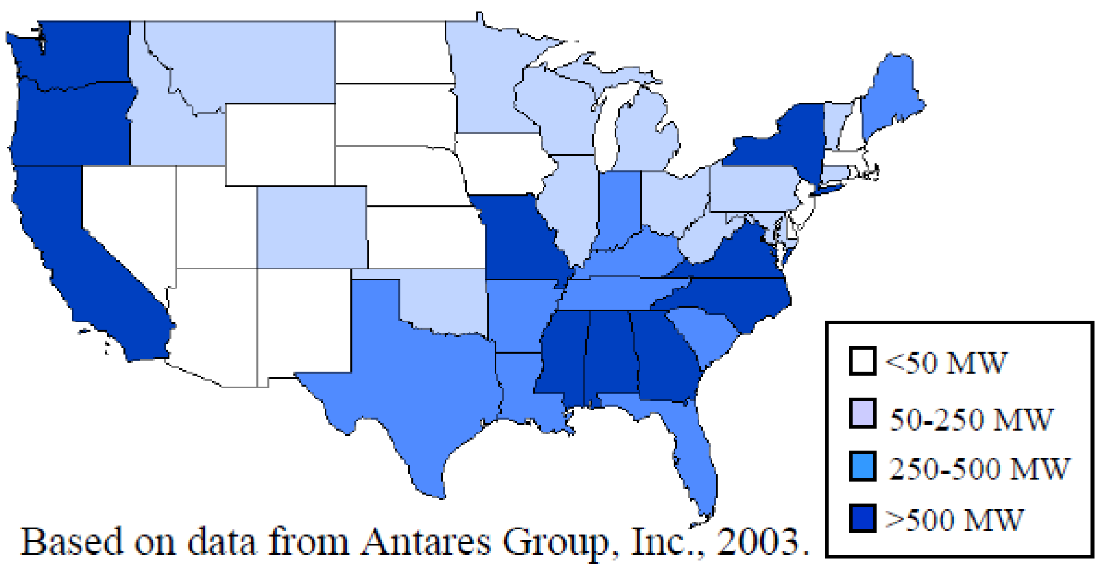
8.5 Additional Second-Generation Crops

A legacy NETL study evaluated switchgrass biomass with integrated gasification combined cycle technology. However, with PC plants being the standard for coal-fired units in the United States, additional second-generation crops and woody biomass should be investigated in regard to PC firing.

8.5.1 Additional Wood Resources

Forest residues are defined as the biomass material in the forest that remains after harvesting, usually timber for milling. Exhibit 8-1 shows potential capacity from forest residues based on data from Antares Group. [79]

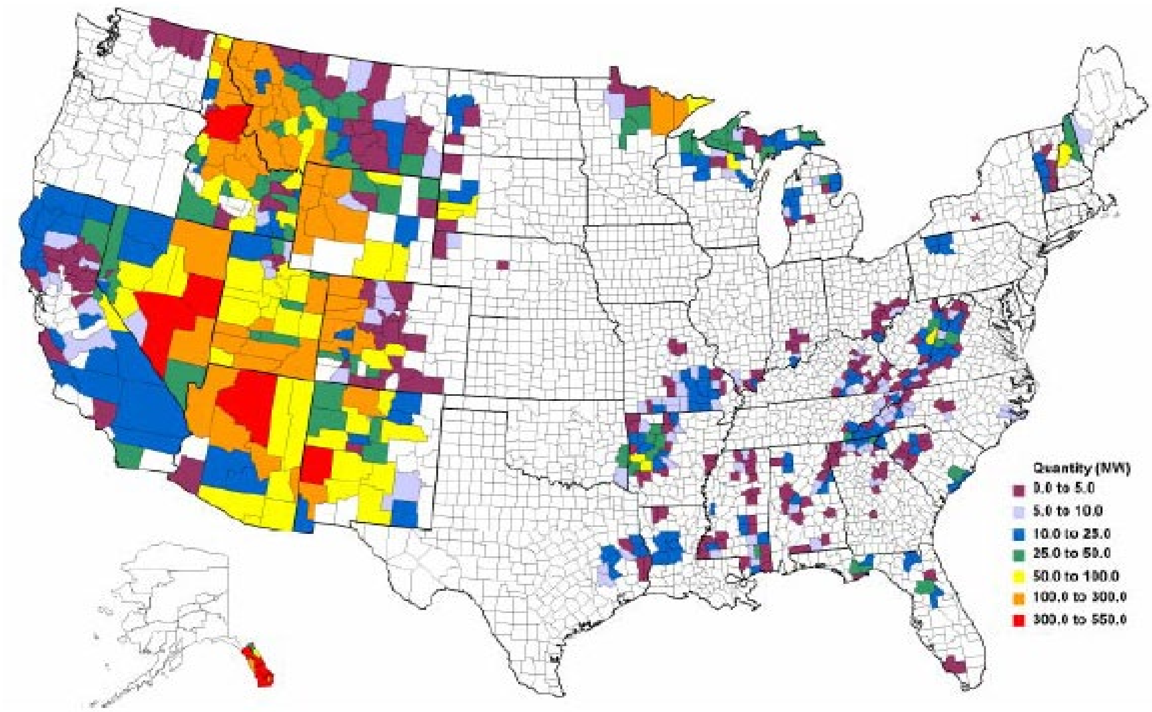
Exhibit 8-1. Forest residue potential capacity



Source: EPA Combined Heat and Power Partnership [79]

Forest thinning is when underbrush and saplings are cleared from a forest to help reduce potential forest fires and improve the quality of the land. Exhibit 8-2 shows forest thinning power generation potential from national forests and the Bureau of Land Management based on data from Antares Group. [79]

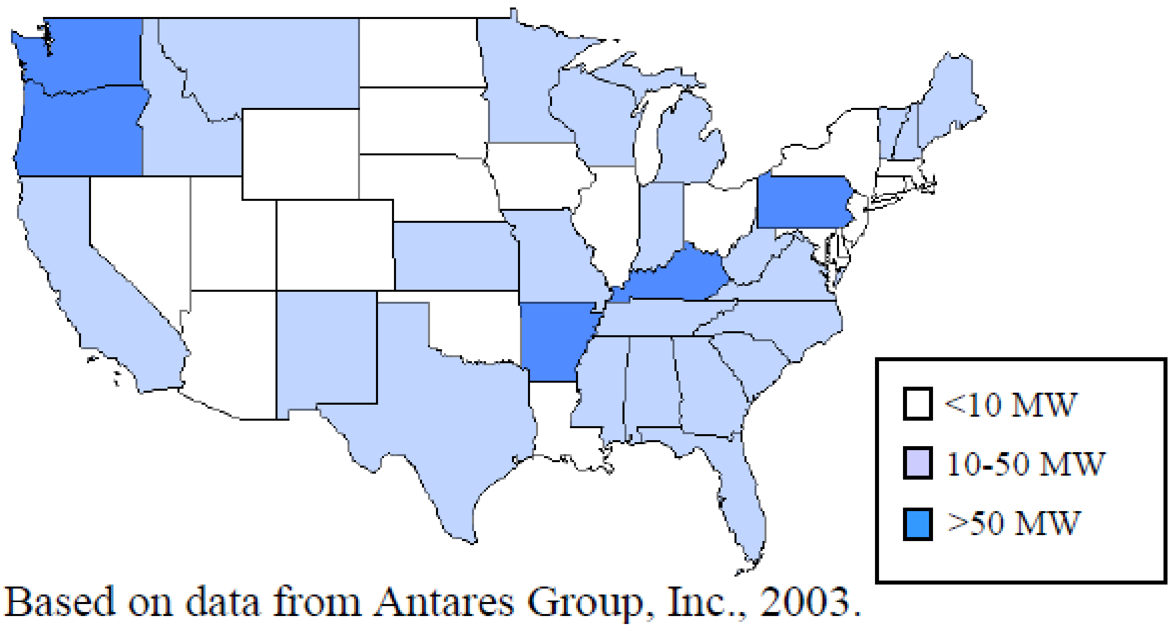
Exhibit 8-2. Forest thinning potential capacity



Source: EPA Combined Heat and Power Partnership [79]

Primary mill residue is waste wood from manufacturing operations that would typically be landfilled. Though a fairly well-tapped resource, the USDA estimates that 2–3 percent of the mill residues are available as additional fuel. Exhibit 8-3 shows primary mill residue power generation potential based on data from Antares Group. [79]

Exhibit 8-3. Primary mill residues potential capacity



Source: EPA Combined Heat and Power Partnership [79]

Since the ash content of woody biomass is generally quite low, the ash quality should not be impacted significantly depending on the relative levels of biomass feed. Ash quality may be an issue when co-firing higher ash content grasses.

8.6 Third and Fourth Generation Crops

Microalgae is considered to have one of the highest oil contents of any biological entity. Additional attributes include the following: [80]

- Ability to grow on marginal land
- Capacity to thrive in brackish and/or saline water
- Potential to recycle carbon from the power plants (As algae grow, they consume CO_2 and emit oxygen. Thus, co-locating next to power plants or other carbon emitters might serve as a low-cost feedstock for algae growth.)

Further research into the co-benefits of algae growth, the feasibility of the technology, and its economics and logistics is needed.

8.7 Biomass "Carbon Neutral" Justification

In June 2010, the biomass carbon neutral theory came into question when the Manomet Center for Conservation Sciences released a study for the Massachusetts Department of Energy Resources. The study argued that burning trees for power creates an initial "carbon debt" because it releases more CO_2 into the atmosphere before other trees can reduce that emission, sometimes taking decades. [81]

Further research into the study assumptions and validation of their calculations should be made to verify the implications. This is a current issue that is highly relevant and one that should be validated.

8.8 Biomass Co-Firing at Reduced Scale

This study used a greenfield reference plant with a net output of 650 MW. Nearly all existing plants that fire 100 percent biomass are much smaller, in the range of 5–100 MW. The primary reason for the smaller size was illustrated in this study, namely the cost to grow, harvest, and transport large quantities of biomass is currently prohibitive. To investigate the benefits of utilizing biomass at smaller scale, investigations should be made into the cost and performance characteristics of greenfield biomass only plants in the size range of 5–100 MW.

8.9 Biomass Retrofits

Biomass retrofit issues were briefly discussed in this study. Further investigation is recommended into retrofit scenarios potentially reducing capital cost, albeit, potentially lower power generation efficiency bound by existing plant constraints. Coal plants built in the last 20 years tend to be 300–500 MW; however, boilers under 100 MW in equivalent size and over 30 years old compose over 13 GW of domestic capacity. Therefore, this investigation should include a wide range of plants sizes from less than 100 MW to 600 MW and more, reflecting the diversity of the current coal fleet.

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Appendix A: Complete Case Information

Because this study consists of eight individual cases, it is not practical to include the stream table, performance summary, carbon balance, sulfur balance, water balance, emissions summary, energy balance, capital cost summary, and operating and maintenance (O&M) cost summary for every case in the body of the report. However, this appendix provides complete information for each case.

The reference capital costs are from previous systems analysis studies and are in December 2018 dollars.

Block Flow Diagrams and Stream Tables

Exhibit A-1. Cases B12A, PN1, PN2, and PN3 block flow diagram

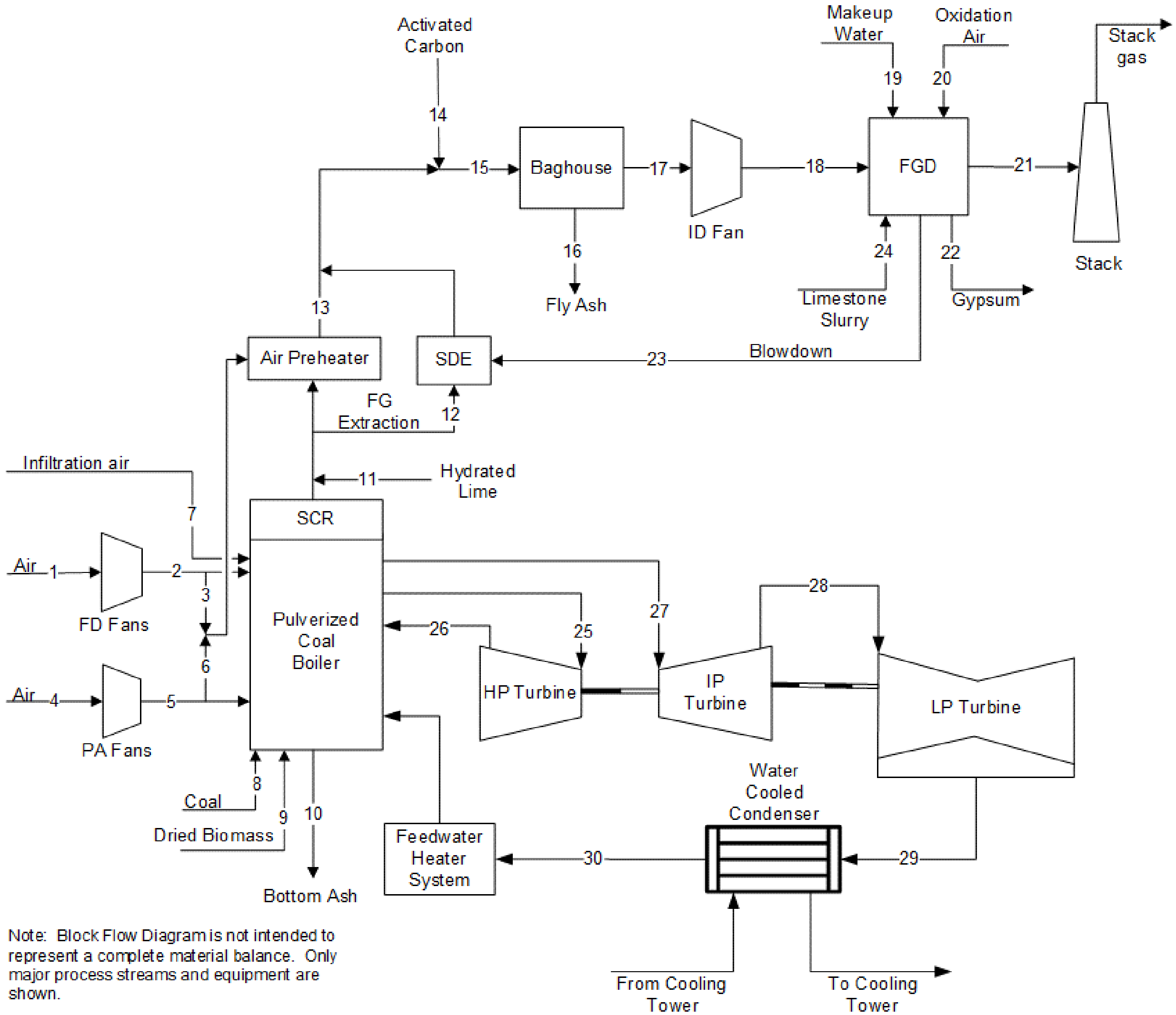


Exhibit A-2. Case B12A stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	-	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	-	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372
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	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	-	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	-	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	-	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	-	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	-	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020
SO_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
NaCl	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
$CaCl_2$	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	0.0001
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	-	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,373	58,373	1,729	17,932	17,932	2,468	1,290	0	-	0	1	3,845	78,033	0	82,528
V-L Flowrate (kg/hr)	1,684,480	1,684,480	49,892	517,455	517,455	71,215	37,233	0	-	0	12	114,345	2,317,137	0	2,443,518
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	214,112	-	4,316	1,167	924	17,737	46	18,890
Temperature (°C)	15	19	19	15	25	25	15	15	-	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	-	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	-	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-	1,267.06	-13,402.95	-2,261.17	-2,394.16	-6.79	-2,452.91
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	-	---	1,003.6	0.5	0.9	---	0.9
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	-	---	18.015	29.742	29.694	---	29.608
V-L Flowrate (lb_{mol}/hr)	128,691	128,691	3,812	39,533	39,533	5,441	2,845	0	-	0	1	8,476	172,033	0	181,944
V-L Flowrate (lb/hr)	3,713,642	3,713,642	109,992	1,140,792	1,140,792	157,002	82,085	0	-	0	26	252,087	5,108,413	0	5,387,034
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	472,037	-	9,516	2,573	2,036	39,103	102	41,644
Temperature (°F)	59	66	66	59	78	78	59	59	-	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	-	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb) [A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	-	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) [B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-	544.7	-5,762.2	-972.1	-1,029.3	-2.9	-1,054.6
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	-	---	62.650	0.034	0.053	---	0.053

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-2. Case B12A stream table (cont'd)

	16	17	18	19	20	21	22	23
V-L Mole Fraction								
Ar	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000
CO_2	0.0000	0.1372	0.1372	0.0000	0.0003	0.1246	0.0001	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0911	0.0911	0.9967	0.0099	0.1497	0.9998	0.9943
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.7281	0.0000	0.7732	0.6812	0.0000	0.0000
O_2	0.0000	0.0329	0.0329	0.0000	0.2074	0.0364	0.0000	0.0000
SO_2	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.1142	0.0000	0.0000	0.0005	0.0000	0.0000	0.0001	0.0009
$CaCl_2$	0.8858	0.0000	0.0000	0.0028	0.0000	0.0000	0.0000	0.0048
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	5	82,523	82,523	11,343	3,455	92,135	194	651
V-L Flowrate (kg/hr)	528	2,442,977	2,442,977	207,556	99,687	2,649,265	3,500	12,036
Solids Flowrate (kg/hr)	18,902	0	0	1,871	0	0	31,482	183
Temperature (°C)	143	143	154	27	15	57	15	57
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	---	287.72	299.40	---	30.23	294.95	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-1,065.86	-2,463.93	-2,452.26	-15,763.29	-97.58	-2,930.88	-12,513.34	-15,496.37
Density (kg/m^3)	2,150.2	0.8	0.9	1,002.5	1.2	1.1	881.2	979.6
V-L Molecular Weight	104.985	29.603	29.603	18.298	28.857	28.754	18.021	18.495
V-L Flowrate (lb_{mol}/hr)	11	181,933	181,933	25,007	7,616	203,123	428	1,435
V-L Flowrate (lb/hr)	1,164	5,385,842	5,385,842	457,582	219,773	5,840,630	7,716	26,535
Solids Flowrate (lb/hr)	41,672	0	0	4,125	0	0	69,406	404
Temperature (°F)	289	289	309	80	59	134	59	134
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7
Steam Table Enthalpy (Btu/lb) [A]	---	123.7	128.7	---	13.0	126.8	---	---
AspenPlus Enthalpy (Btu/lb) [B]	-458.2	-1,059.3	-1,054.3	-6,777.0	-42.0	-1,260.1	-5,379.8	-6,662.2
Density (lb/ft^3)	134.233	0.052	0.055	62.582	0.076	0.067	55.009	61.156

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-2. Case B12A stream table (cont'd)

	24	25	26	27	28	29	30
V-L Mole Fraction							
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	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
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	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
V-L Flowrate (kg_{mol}/hr)	2,685	104,712	87,540	87,540	75,438	57,177	75,649
V-L Flowrate (kg/hr)	48,383	1,886,415	1,577,053	1,577,053	1,359,039	1,030,068	1,362,835
Solids Flowrate (kg/hr)	20,712	0	0	0	0	0	0
Temperature (°C)	15	593	342	593	270	38	39
Pressure (MPa, abs)	0.10	24.23	4.90	4.80	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) [A]	---	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.43
AspenPlus Enthalpy (kJ/kg) [B]	-14,994.25	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.87
Density (kg/m^3)	1,003.7	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	5,920	230,850	192,992	192,992	166,313	126,055	166,777
V-L Flowrate (lb/hr)	106,666	4,158,834	3,476,806	3,476,806	2,996,169	2,270,910	3,004,537
Solids Flowrate (lb/hr)	45,662	0	0	0	0	0	0
Temperature (°F)	59	1,100	648	1,100	517	101	101
Pressure (psia)	14.7	3,514.7	710.8	696.6	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	---	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-6,446.4	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	62.658	4.319	1.197	0.768	0.131	0.003	62.010

[A]Steam table reference conditions are 32.02°F & 0.089 psia
[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-3. Case PN1 stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0087	0.0087	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.1466	0.1388	0.0000	0.1382
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	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	1.0000	0.0916	0.0872	0.0000	0.0940
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.7275	0.7299	0.0000	0.7245
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0236	0.0334	0.0000	0.0328
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0018	0.0000	0.0018
SO_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
NaCl	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
$CaCl_2$	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	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,485	58,485	1,756	19,033	19,033	2,507	1,310	0	0	0	1	3,595	80,040	0	84,245
V-L Flowrate (kg/hr)	1,687,700	1,687,700	50,685	549,242	549,242	72,347	37,816	0	0	0	12	106,825	2,374,470	0	2,492,559
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	199,526	27,712	4,096	1,188	807	16,998	47	18,023
Temperature (°C)	15	19	19	15	25	25	15	15	71	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-6,436.51	1,266.45	-13,402.95	-2,304.41	-2,436.78	-6.79	-2,490.54
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	1,003.6	0.5	0.9	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	18.015	29.711	29.666	---	29.587
V-L Flowrate (lb_{mol}/hr)	128,937	128,937	3,872	41,961	41,961	5,527	2,889	0	0	0	1	7,927	176,459	0	185,728
V-L Flowrate (lb/hr)	3,720,742	3,720,742	111,741	1,210,871	1,210,871	159,498	83,370	0	0	0	26	235,508	5,234,811	0	5,495,152
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	439,879	61,094	9,030	2,618	1,778	37,475	104	39,735
Temperature (°F)	59	66	66	59	78	78	59	59	160	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-2,767.2	544.5	-5,762.2	-990.7	-1,047.6	-2.9	-1,070.7
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	62.650	0.034	0.053	---	0.053

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-3. Case PN1 stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1382	0.1382	0.0000	0.0003	0.1261	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0940	0.0940	0.9963	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7246	0.7246	0.0000	0.7732	0.6792	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0328	0.0328	0.0000	0.2074	0.0358	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0018	0.0018	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_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
NaCl	0.1193	0.0000	0.0000	0.0006	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.8807	0.0000	0.0000	0.0031	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	5	84,240	84,240	13,312	3,217	93,533	181	609	2,500	106,215	88,797	88,797	76,521	57,998	76,735
V-L Flowrate (kg/hr)	493	2,492,053	2,492,053	243,948	92,819	2,690,314	3,259	11,264	45,049	1,913,500	1,599,695	1,599,695	1,378,552	1,044,857	1,382,402
Solids Flowrate (kg/hr)	18,036	0	0	2,420	0	0	29,312	172	19,285	0	0	0	0	0	0
Temperature (°C)	143	143	154	27	15	57	15	57	15	593	342	593	270	38	39
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	24.23	4.90	4.80	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) [A]	---	292.47	304.15	---	30.23	296.80	---	---	---	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.43
AspenPlus Enthalpy (kJ/kg) [B]	-1,120.65	-2,500.73	-2,489.04	-15,743.81	-97.58	-2,958.51	-12,513.30	-15,496.04	-14,994.25	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.87
Density (kg/m^3)	2,150.1	0.8	0.9	1,003.5	1.2	1.1	841.1	979.5	1,003.7	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	104.718	29.583	29.583	18.326	28.857	28.763	18.022	18.494	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	10	185,717	185,717	29,348	7,091	206,204	399	1,343	5,512	234,165	195,763	195,763	168,700	127,865	169,172
V-L Flowrate (lb/hr)	1,087	5,494,037	5,494,037	537,813	204,630	5,931,128	7,185	24,834	99,317	4,218,544	3,526,724	3,526,724	3,039,186	2,303,515	3,047,674
Solids Flowrate (lb/hr)	39,763	0	0	5,335	0	0	64,621	378	42,516	0	0	0	0	0	0
Temperature (°F)	289	289	309	80	59	135	59	135	59	1,100	648	1,100	517	101	101
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	3,514.7	710.8	696.6	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb) [A]	---	125.7	130.8	---	13.0	127.6	---	---	---	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) [B]	-481.8	-1,075.1	-1,070.1	-6,768.6	-42.0	-1,271.9	-5,379.7	-6,662.1	-6,446.4	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	134.229	0.052	0.055	62.644	0.076	0.067	52.509	61.145	62.658	4.319	1.197	0.768	0.131	0.003	62.010

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-4. Case PN2 stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0086	0.0087	0.0000	0.0086
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.1475	0.1397	0.0000	0.1391
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	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	1.0000	0.0951	0.0906	0.0000	0.0968
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.7234	0.7260	0.0000	0.7212
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0235	0.0332	0.0000	0.0326
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0016	0.0000	0.0016
SO_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
NaCl	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
$CaCl_2$	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	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,575	58,575	1,783	20,121	20,121	2,545	1,330	0	0	0	1	3,341	82,014	0	85,921
V-L Flowrate (kg/hr)	1,690,310	1,690,310	51,455	580,640	580,640	73,447	38,382	0	0	0	12	99,170	2,430,790	0	2,540,433
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	184,912	55,316	3,875	1,208	699	16,246	48	17,153
Temperature (°C)	15	19	19	15	25	25	15	15	71	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-6,436.51	1,265.78	-13,402.95	-2,345.84	-2,477.65	-6.79	-2,526.58
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	1,003.6	0.5	0.9	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	18.015	29.682	29.639	---	29.567
V-L Flowrate (lb_{mol}/hr)	129,137	129,137	3,931	44,360	44,360	5,611	2,932	0	0	0	1	7,366	180,809	0	189,423
V-L Flowrate (lb/hr)	3,726,497	3,726,497	113,440	1,280,091	1,280,091	161,923	84,618	0	0	0	27	218,633	5,358,974	0	5,600,697
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	407,662	121,950	8,543	2,662	1,540	35,817	106	37,815
Temperature (°F)	59	66	66	59	78	78	59	59	160	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb) [A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) [B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-2,767.2	544.2	-5,762.2	-1,008.5	-1,065.2	-2.9	-1,086.2
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	62.650	0.034	0.053	---	0.053

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-4. Case PN2 stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0000	0.0086	0.0086	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1391	0.1391	0.0000	0.0003	0.1276	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.0968	0.0968	0.9958	0.0099	0.1508	0.9997	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7212	0.7212	0.0000	0.7732	0.6781	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0326	0.0326	0.0000	0.2074	0.0354	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0016	0.0016	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_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
NaCl	0.1233	0.0000	0.0000	0.0007	0.0000	0.0000	0.0001	0.0010	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.8767	0.0000	0.0000	0.0035	0.0000	0.0000	0.0000	0.0047	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	4	85,917	85,917	17,585	2,978	94,770	167	566	2,315	107,673	90,015	90,015	77,571	58,794	77,788
V-L Flowrate (kg/hr)	459	2,539,961	2,539,961	323,037	85,938	2,728,015	3,018	10,474	41,710	1,939,752	1,621,643	1,621,643	1,397,465	1,059,192	1,401,368
Solids Flowrate (kg/hr)	17,166	0	0	3,651	0	0	27,138	160	17,855	0	0	0	0	0	0
Temperature (°C)	143	143	154	27	15	57	15	57	15	593	342	593	270	38	39
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	24.23	4.90	4.80	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) [A]	---	297.00	308.69	---	30.23	296.60	---	---	---	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.43
AspenPlus Enthalpy (kJ/kg) [B]	-1,180.86	-2,535.91	-2,524.22	-15,713.19	-97.58	-2,977.20	-12,513.20	-15,495.41	-14,994.25	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.87
Density (kg/m³)	2,150.1	0.8	0.9	1,005.0	1.2	1.1	763.5	979.5	1,003.7	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	104.508	29.563	29.563	18.370	28.857	28.786	18.025	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	10	189,414	189,414	38,769	6,566	208,931	369	1,248	5,103	237,377	198,449	198,449	171,015	129,619	171,493
V-L Flowrate (lb/hr)	1,012	5,599,656	5,599,656	712,174	189,461	6,014,243	6,653	23,090	91,954	4,276,422	3,575,110	3,575,110	3,080,883	2,335,119	3,089,487
Solids Flowrate (lb/hr)	37,844	0	0	8,049	0	0	59,829	352	39,364	0	0	0	0	0	0
Temperature (°F)	289	289	309	80	59	135	59	135	59	1,100	648	1,100	517	101	101
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	3,514.7	710.8	696.6	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb) [A]	---	127.7	132.7	---	13.0	127.5	---	---	---	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) [B]	-507.7	-1,090.2	-1,085.2	-6,755.5	-42.0	-1,280.0	-5,379.7	-6,661.8	-6,446.4	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft³)	134.225	0.052	0.055	62.743	0.076	0.067	47.662	61.148	62.658	4.319	1.197	0.768	0.131	0.003	62.010

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-5. Case PN3 stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0086	0.0086	0.0000	0.0086
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.1485	0.1408	0.0000	0.1402
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	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	1.0000	0.0993	0.0946	0.0000	0.1000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.7186	0.7215	0.0000	0.7172
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0234	0.0330	0.0000	0.0325
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0015	0.0014	0.0000	0.0014
SO_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
NaCl	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
$CaCl_2$	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	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,711	58,711	1,817	21,463	21,463	2,593	1,355	0	0	0	1	3,032	84,465	0	88,012
V-L Flowrate (kg/hr)	1,694,207	1,694,207	52,421	619,370	619,370	74,825	39,092	0	0	0	12	89,892	2,500,770	0	2,600,171
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	167,073	89,178	3,606	1,233	580	15,318	49	16,092
Temperature (°C)	15	19	19	15	25	25	15	15	71	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) B	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-6,436.51	1,264.85	-13,402.95	-2,394.51	-2,525.70	-6.79	-2,568.98
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	1,003.6	0.5	0.9	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	18.015	29.648	29.607	---	29.544
V-L Flowrate (lb_{mol}/hr)	129,435	129,435	4,005	47,319	47,319	5,717	2,987	0	0	0	2	6,684	186,214	0	194,032
V-L Flowrate (lb/hr)	3,735,086	3,735,086	115,569	1,365,476	1,365,476	164,962	86,183	0	0	0	27	198,177	5,513,253	0	5,732,395
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	368,334	196,605	7,949	2,717	1,279	33,771	108	35,478
Temperature (°F)	59	66	66	59	78	78	59	59	160	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb)A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)B	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-2,767.2	543.8	-5,762.2	-1,029.5	-1,085.9	-2.9	-1,104.5
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	62.650	0.034	0.053	---	0.053

ASteam table reference conditions are 32.02°F & 0.089 psia

BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

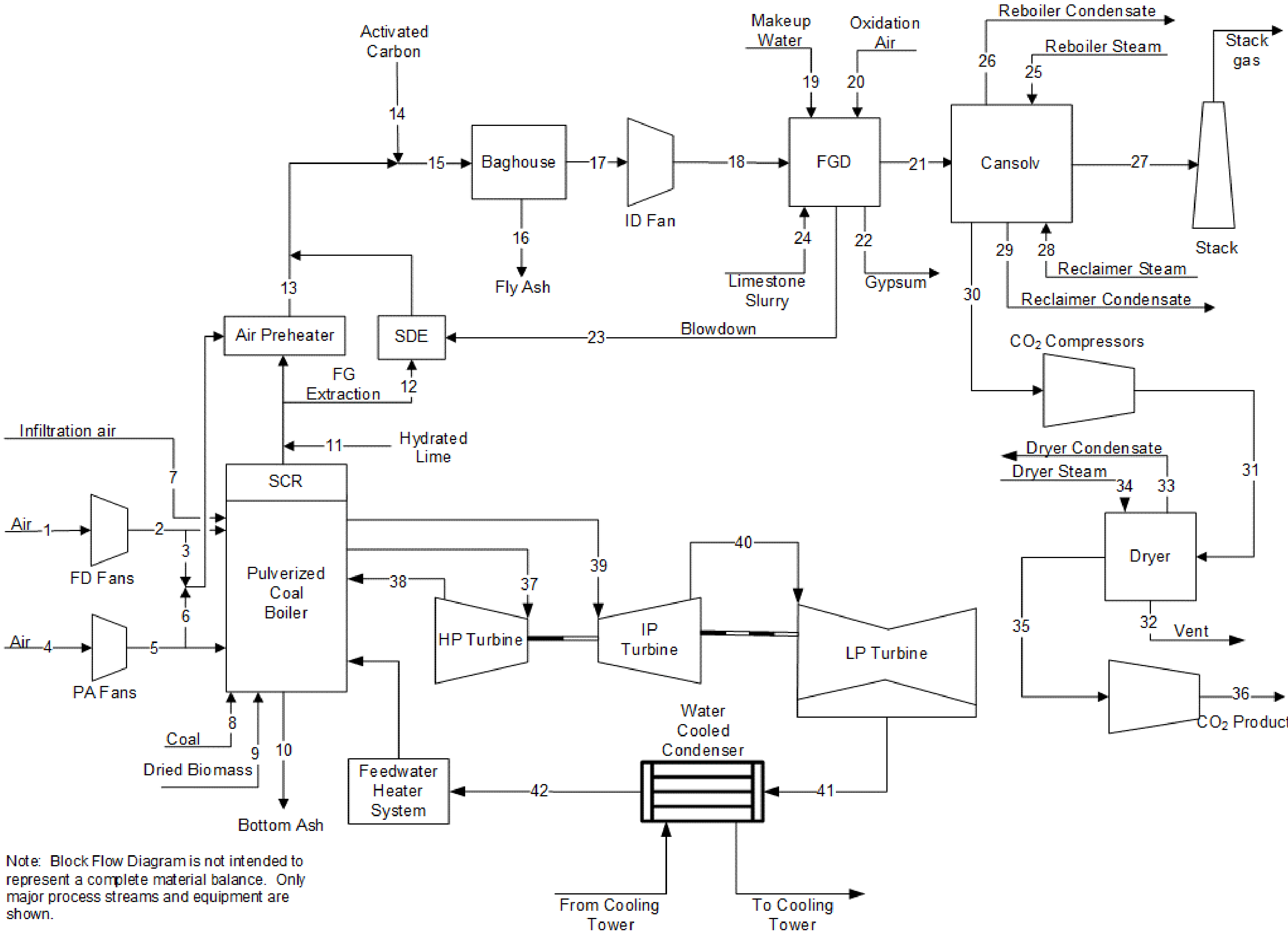
Exhibit A-5. Case PN3 stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0000	0.0086	0.0086	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1402	0.1402	0.0000	0.0003	0.1294	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0000	0.1000	0.1000	0.9954	0.0099	0.1508	0.9995	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7172	0.7172	0.0000	0.7732	0.6768	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0325	0.0325	0.0000	0.2074	0.0348	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0014	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_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
NaCl	0.1288	0.0000	0.0000	0.0008	0.0000	0.0000	0.0001	0.0010	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.8712	0.0000	0.0000	0.0038	0.0000	0.0000	0.0000	0.0047	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	4	88,008	88,008	22,834	2,687	96,325	151	514	2,089	109,503	91,545	91,545	78,890	59,794	79,110
V-L Flowrate (kg/hr)	415	2,599,742	2,599,742	420,143	77,538	2,775,356	2,724	9,510	37,633	1,972,733	1,649,215	1,649,215	1,421,226	1,077,201	1,425,194
Solids Flowrate (kg/hr)	16,106	0	0	5,163	0	0	24,485	145	16,110	0	0	0	0	0	0
Temperature (°C)	143	143	154	27	15	57	15	57	15	593	342	593	270	38	39
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	24.23	4.90	4.80	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) ^{A}	---	302.33	314.03	---	30.23	296.38	---	---	---	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.43
AspenPlus Enthalpy (kJ/kg) ^{B}	-1,263.06	-2,577.27	-2,565.57	-15,692.27	-97.58	-2,999.41	-12,513.06	-15,496.07	-14,994.25	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.87
Density (kg/m^3)	2,150.0	0.8	0.9	1,006.1	1.2	1.1	671.1	979.4	1,003.7	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	104.214	29.540	29.540	18.400	28.857	28.812	18.028	18.494	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	9	194,024	194,024	50,340	5,924	212,361	333	1,134	4,605	241,413	201,823	201,823	173,923	131,823	174,408
V-L Flowrate (lb/hr)	916	5,731,450	5,731,450	926,257	170,942	6,118,612	6,005	20,965	82,966	4,349,132	3,635,896	3,635,896	3,133,266	2,374,822	3,142,016
Solids Flowrate (lb/hr)	35,507	0	0	11,382	0	0	53,979	319	35,517	0	0	0	0	0	0
Temperature (°F)	289	289	309	80	59	135	59	135	59	1,100	648	1,100	517	101	101
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	3,514.7	710.8	696.6	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)^A	---	130.0	135.0	---	13.0	127.4	---	---	---	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)^B	-543.0	-1,108.0	-1,103.0	-6,746.5	-42.0	-1,289.5	-5,379.6	-6,662.1	-6,446.4	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	134.221	0.052	0.055	62.810	0.076	0.067	41.895	61.145	62.658	4.319	1.197	0.768	0.131	0.003	62.010

^{A}Steam table reference conditions are 32.02°F & 0.089 psia

^{B}Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-6. Case B12B, PA1, PA2, and PA3 block flow diagram



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

Exhibit A-7. Case B12B stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	-	0.0000	0.0000	0.0087	0.0088	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	-	0.0000	0.0000	0.1457	0.1379	0.0000	0.1372
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	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	-	0.0000	1.0000	0.0879	0.0837	0.0000	0.0911
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	-	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	-	0.0000	0.0000	0.7318	0.7340	0.0000	0.7281
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	-	0.0000	0.0000	0.0237	0.0336	0.0000	0.0329
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	-	0.0000	0.0000	0.0021	0.0020	0.0000	0.0020
SO_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
NaCl	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
$CaCl_2$	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	0.0001
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	-	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	74,599	74,599	2,210	22,916	22,916	3,154	1,649	0	-	0	1	4,914	99,723	0	105,468
V-L Flowrate (kg/hr)	2,152,703	2,152,703	63,760	661,288	661,288	91,010	47,582	0	-	0	15	146,141	2,961,204	0	3,122,727
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	273,628	-	5,516	1,491	1,180	22,667	59	24,140
Temperature (°C)	15	19	19	15	25	25	15	15	-	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	-	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	-	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-	1,267.06	-13,402.95	-2,261.17	-2,394.16	-6.79	-2,452.91
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	-	---	1,003.6	0.5	0.9	---	0.9
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	-	---	18.015	29.742	29.694	---	29.608
V-L Flowrate (lb_{mol}/hr)	164,463	164,463	4,871	50,521	50,521	6,953	3,635	0	-	0	2	10,833	219,851	0	232,518
V-L Flowrate (lb/hr)	4,745,898	4,745,898	140,566	1,457,890	1,457,890	200,642	104,901	0	-	0	33	322,185	6,528,337	0	6,884,434
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	603,246	-	12,161	3,288	2,602	49,972	130	53,220
Temperature (°F)	59	66	66	59	78	78	59	59	-	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	-	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb) [A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	-	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb) [B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-	544.7	-5,762.2	-972.1	-1,029.3	-2.9	-1,054.6
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	-	---	62.650	0.034	0.053	---	0.053

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-7. Case B12B stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0106	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.1372	0.0000	0.0003	0.1246	0.0001	0.0000	0.0000	0.0000	0.0000	0.0163	0.0000	0.0000	0.9861
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	0.0000	0.0000	0.0000
H_2O	0.0000	0.0911	0.0911	0.9967	0.0099	0.1497	0.9998	0.9943	0.9999	1.0000	1.0000	0.0358	1.0000	1.0000	0.0139
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.7281	0.0000	0.7732	0.6812	0.0000	0.0000	0.0000	0.0000	0.0000	0.8898	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0329	0.0000	0.2074	0.0364	0.0000	0.0000	0.0000	0.0000	0.0000	0.0475	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_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
NaCl	0.1141	0.0000	0.0000	0.0005	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.8859	0.0000	0.0000	0.0028	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	6	105,462	105,462	14,497	4,415	117,745	248	832	3,432	33,118	29,914	90,137	146	146	13,394
V-L Flowrate (kg/hr)	674	3,122,036	3,122,036	265,252	127,397	3,385,665	4,473	15,382	61,832	596,626	538,904	2,544,772	2,634	2,634	584,619
Solids Flowrate (kg/hr)	24,156	0	0	2,391	0	0	40,233	234	26,469	0	0	0	0	0	0
Temperature (°C)	143	143	154	27	15	57	15	57	15	269	100	30	342	214	30
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.51	0.10	0.10	4.90	2.04	0.20
Steam Table Enthalpy (kJ/kg) [A]	---	287.72	299.40	---	30.23	294.95	---	---	---	3,000.14	417.50	88.41	3,049.81	913.81	37.70
AspenPlus Enthalpy (kJ/kg) [B]	-1,065.72	-2,463.94	-2,452.26	-15,763.52	-97.58	-2,930.88	-12,513.34	-15,496.74	-14,994.25	-12,980.15	-15,562.79	-528.00	-12,930.48	-15,066.49	-8,964.74
Density (kg/m^3)	2,150.2	0.8	0.9	1,002.5	1.2	1.1	881.1	979.6	1,003.7	2.1	958.7	1.1	19.2	848.5	3.5
V-L Molecular Weight	104.986	29.603	29.603	18.297	28.857	28.754	18.021	18.495	18.019	18.015	18.015	28.232	18.015	18.015	43.648
V-L Flowrate (lb_{mol}/hr)	14	232,504	232,504	31,960	9,733	259,583	547	1,834	7,565	73,012	65,948	198,717	322	322	29,528
V-L Flowrate (lb/hr)	1,487	6,882,912	6,882,912	584,781	280,861	7,464,113	9,861	33,912	136,315	1,315,336	1,188,079	5,610,263	5,807	5,807	1,288,863
Solids Flowrate (lb/hr)	53,256	0	0	5,272	0	0	88,698	517	58,354	0	0	0	0	0	0
Temperature (°F)	289	289	309	80	59	134	59	134	59	517	211	87	648	416	86
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	73.5	14.5	14.8	710.8	296.6	28.9
Steam Table Enthalpy (Btu/lb) [A]	---	123.7	128.7	---	13.0	126.8	---	---	---	1,289.8	179.5	38.0	1,311.2	392.9	16.2
AspenPlus Enthalpy (Btu/lb) [B]	-458.2	-1,059.3	-1,054.3	-6,777.1	-42.0	-1,260.1	-5,379.8	-6,662.4	-6,446.4	-5,580.5	-6,690.8	-227.0	-5,559.1	-6,477.4	-3,854.1
Density (lb/ft^3)	134.233	0.052	0.055	62.581	0.076	0.067	55.008	61.155	62.658	0.128	59.847	0.071	1.197	52.968	0.218

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-7. Case B12B stream table (cont'd)

	31	32	33	34	35	36	37	38	39	40	41	42
V-L Mole Fraction												
Ar	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_2	0.9977	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0023	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	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	0.0000	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
SO_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
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	13,238	25	17	17	13,213	13,213	133,851	111,754	111,754	96,268	42,848	66,623
V-L Flowrate (kg/hr)	581,812	487	309	309	581,324	581,324	2,411,369	2,013,284	2,013,284	1,734,295	771,916	1,200,232
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	3.04	3.04	1.64	2.14	2.90	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg) [A]	-6.17	137.79	863.65	3,379.61	-6.32	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg) [B]	-8,975.08	-15,225.37	-15,116.65	-12,600.69	-8,969.87	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m^3)	63.6	375.2	861.8	6.4	60.1	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	43.950	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	29,185	56	38	38	29,129	29,129	295,092	246,376	246,376	212,235	94,463	146,879
V-L Flowrate (lb/hr)	1,282,675	1,074	681	681	1,281,601	1,281,601	5,316,158	4,438,532	4,438,532	3,823,465	1,701,783	2,646,058
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	441.1	441.1	237.4	310.1	421.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb) [A]	-2.7	59.2	371.3	1,453.0	-2.7	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) [B]	-3,858.6	-6,545.7	-6,499.0	-5,417.3	-3,856.4	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	3.973	23.421	53.801	0.402	3.755	39.338	4.319	1.197	0.768	0.131	0.003	62.009

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-8. Case PA1 stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0087	0.0087	0.0000	0.0087
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.1466	0.1388	0.0000	0.1382
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	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	1.0000	0.0916	0.0872	0.0000	0.0940
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.7275	0.7299	0.0000	0.7245
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0236	0.0334	0.0000	0.0328
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0019	0.0018	0.0000	0.0018
SO_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
NaCl	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
$CaCl_2$	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	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	75,334	75,334	2,262	24,516	24,516	3,229	1,688	0	0	0	1	4,631	103,098	0	108,514
V-L Flowrate (kg/hr)	2,173,899	2,173,899	65,286	707,470	707,470	93,189	48,710	0	0	0	15	137,602	3,058,513	0	3,210,625
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	257,006	35,695	5,276	1,530	1,039	21,895	61	23,215
Temperature (°C)	15	19	19	15	25	25	15	15	71	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-6,436.51	1,266.45	-13,402.95	-2,304.41	-2,436.78	-6.79	-2,490.54
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	1,003.6	0.5	0.9	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	18.015	29.711	29.666	---	29.587
V-L Flowrate (lb_{mol}/hr)	166,082	166,082	4,988	54,049	54,049	7,119	3,721	0	0	0	2	10,210	227,293	0	239,233
V-L Flowrate (lb/hr)	4,792,627	4,792,627	143,932	1,559,703	1,559,703	205,446	107,388	0	0	0	34	303,361	6,742,868	0	7,078,216
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	566,601	78,695	11,632	3,372	2,290	48,270	133	51,181
Temperature (°F)	59	66	66	59	78	78	59	59	160	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-2,767.2	544.5	-5,762.2	-990.7	-1,047.6	-2.9	-1,070.7
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	62.650	0.034	0.053	---	0.053

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-8. Case PA1 stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0106	0.0000	0.0000	0.0000
CO_2	0.0000	0.1382	0.1382	0.0000	0.0003	0.1261	0.0001	0.0000	0.0000	0.0000	0.0000	0.0165	0.0000	0.0000	0.9861
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	0.0000	0.0000	0.0000
H_2O	0.0000	0.0940	0.0940	0.9963	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000	1.0000	0.0358	1.0000	1.0000	0.0139
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7246	0.7246	0.0000	0.7732	0.6792	0.0000	0.0000	0.0000	0.0000	0.0000	0.8901	0.0000	0.0000	0.0000
O_2	0.0000	0.0328	0.0328	0.0000	0.2074	0.0358	0.0000	0.0000	0.0000	0.0000	0.0000	0.0470	0.0000	0.0000	0.0000
SO_2	0.0000	0.0018	0.0018	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_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
NaCl	0.1192	0.0000	0.0000	0.0006	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.8808	0.0000	0.0000	0.0031	0.0000	0.0000	0.0000	0.0047	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	6	108,508	108,508	17,147	4,143	120,478	233	785	3,220	34,272	30,956	91,931	151	151	13,861
V-L Flowrate (kg/hr)	635	3,209,973	3,209,973	314,229	119,558	3,465,350	4,198	14,510	58,027	617,419	557,684	2,595,584	2,726	2,726	604,994
Solids Flowrate (kg/hr)	23,232	0	0	3,116	0	0	37,756	221	24,841	0	0	0	0	0	0
Temperature (°C)	143	143	154	27	15	57	15	57	15	269	100	30	342	214	30
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.51	0.10	0.10	4.90	2.04	0.20
Steam Table Enthalpy (kJ/kg) [A]	---	292.47	304.15	---	30.23	296.80	---	---	---	3,000.14	417.50	88.41	3,049.81	913.81	37.68
AspenPlus Enthalpy (kJ/kg) [B]	-1,120.53	-2,500.73	-2,489.04	-15,743.93	-97.58	-2,958.51	-12,513.30	-15,496.23	-14,994.25	-12,980.15	-15,562.79	-531.30	-12,930.48	-15,066.49	-8,964.70
Density (kg/m³)	2,150.1	0.8	0.9	1,003.5	1.2	1.1	841.1	979.4	1,003.7	2.1	958.7	1.1	19.2	848.5	3.5
V-L Molecular Weight	104.718	29.583	29.583	18.325	28.857	28.763	18.022	18.494	18.019	18.015	18.015	28.234	18.015	18.015	43.649
V-L Flowrate (lb_{mol}/hr)	13	239,220	239,220	37,803	9,134	265,608	514	1,730	7,100	75,557	68,247	202,672	334	334	30,557
V-L Flowrate (lb/hr)	1,400	7,076,780	7,076,780	692,756	263,581	7,639,789	9,255	31,988	127,928	1,361,176	1,229,484	5,722,283	6,009	6,009	1,333,783
Solids Flowrate (lb/hr)	51,218	0	0	6,869	0	0	83,238	487	54,764	0	0	0	0	0	0
Temperature (°F)	289	289	309	80	59	135	59	135	59	517	211	87	648	416	86
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	73.5	14.5	14.8	710.8	296.6	28.9
Steam Table Enthalpy (Btu/lb)[A]	---	125.7	130.8	---	13.0	127.6	---	---	---	1,289.8	179.5	38.0	1,311.2	392.9	16.2
AspenPlus Enthalpy (Btu/lb)[B]	-481.7	-1,075.1	-1,070.1	-6,768.7	-42.0	-1,271.9	-5,379.7	-6,662.2	-6,446.4	-5,580.5	-6,690.8	-228.4	-5,559.1	-6,477.4	-3,854.1
Density (lb/ft³)	134.229	0.052	0.055	62.644	0.076	0.067	52.509	61.145	62.658	0.128	59.847	0.071	1.197	52.968	0.218

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-8. Case PA1 stream table (cont'd)

	31	32	33	34	35	36	37	38	39	40	41	42
V-L Mole Fraction												
Ar	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_2	0.9977	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0023	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	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	0.0000	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
SO_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
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	13,700	26	18	18	13,674	13,674	136,849	114,255	114,255	98,422	43,431	67,740
V-L Flowrate (kg/hr)	602,094	504	320	320	601,590	601,590	2,465,365	2,058,333	2,058,333	1,773,091	782,429	1,220,360
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	3.04	3.04	1.64	2.14	2.90	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg) [A]	-6.17	137.79	863.65	3,379.61	-6.32	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg) [B]	-8,975.08	-15,225.37	-15,116.65	-12,600.69	-8,969.87	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m³)	63.6	375.2	861.8	6.4	60.1	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	43.950	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	30,202	58	39	39	30,145	30,145	301,699	251,889	251,889	216,982	95,750	149,342
V-L Flowrate (lb/hr)	1,327,391	1,111	706	706	1,326,280	1,326,280	5,435,199	4,537,848	4,537,848	3,908,997	1,724,961	2,690,433
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	441.1	441.1	237.4	310.1	421.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb) [A]	-2.7	59.2	371.3	1,453.0	-2.7	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) [B]	-3,858.6	-6,545.7	-6,499.0	-5,417.3	-3,856.4	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft³)	3.973	23.421	53.801	0.402	3.755	39.338	4.319	1.197	0.768	0.131	0.003	62.009

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-9. Case PA2 stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0086	0.0087	0.0000	0.0086
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.1475	0.1397	0.0000	0.1391
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	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	1.0000	0.0951	0.0906	0.0000	0.0968
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.7234	0.7260	0.0000	0.7212
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0235	0.0332	0.0000	0.0326
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0017	0.0016	0.0000	0.0016
SO_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
NaCl	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
$CaCl_2$	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	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	76,031	76,031	2,315	26,118	26,118	3,304	1,726	0	0	0	1	4,337	106,454	0	111,526
V-L Flowrate (kg/hr)	2,194,035	2,194,035	66,789	753,673	753,673	95,334	49,820	0	0	0	16	128,746	3,155,157	0	3,297,499
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	240,018	71,799	5,030	1,567	907	21,088	62	22,264
Temperature (°C)	15	19	19	15	25	25	15	15	71	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-6,436.51	1,265.78	-13,402.95	-2,345.83	-2,477.65	-6.79	-2,526.58
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	1,003.6	0.5	0.9	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	18.015	29.682	29.639	---	29.567
V-L Flowrate (lb_{mol}/hr)	167,621	167,621	5,103	57,579	57,579	7,283	3,806	0	0	0	2	9,562	234,690	0	245,873
V-L Flowrate (lb/hr)	4,837,018	4,837,018	147,246	1,661,564	1,661,564	210,176	109,835	0	0	0	35	283,837	6,955,930	0	7,269,742
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	529,149	158,290	11,089	3,456	2,000	46,491	137	49,084
Temperature (°F)	59	66	66	59	78	78	59	59	160	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-2,767.2	544.2	-5,762.2	-1,008.5	-1,065.2	-2.9	-1,086.2
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	62.650	0.034	0.053	---	0.053

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-9. Case PA2 stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0000	0.0086	0.0086	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0106	0.0000	0.0000	0.0000
CO_2	0.0000	0.1391	0.1391	0.0000	0.0003	0.1276	0.0002	0.0000	0.0000	0.0000	0.0000	0.0168	0.0000	0.0000	0.9862
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	0.0000	0.0000	0.0000
H_2O	0.0000	0.0968	0.0968	0.9958	0.0099	0.1508	0.9997	0.9943	0.9999	1.0000	1.0000	0.0358	1.0000	1.0000	0.0138
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7212	0.7212	0.0000	0.7732	0.6781	0.0000	0.0000	0.0000	0.0000	0.0000	0.8904	0.0000	0.0000	0.0000
O_2	0.0000	0.0326	0.0326	0.0000	0.2074	0.0354	0.0000	0.0000	0.0000	0.0000	0.0000	0.0465	0.0000	0.0000	0.0000
SO_2	0.0000	0.0016	0.0016	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_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
NaCl	0.1232	0.0000	0.0000	0.0007	0.0000	0.0000	0.0001	0.0010	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.8768	0.0000	0.0000	0.0035	0.0000	0.0000	0.0000	0.0047	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	6	111,520	111,520	22,828	3,866	123,012	217	735	3,005	35,419	31,992	93,687	156	156	14,323
V-L Flowrate (kg/hr)	594	3,296,888	3,296,888	419,321	111,548	3,540,980	3,917	13,596	54,140	638,076	576,343	2,645,340	2,817	2,817	625,214
Solids Flowrate (kg/hr)	22,281	0	0	4,736	0	0	35,226	207	23,176	0	0	0	0	0	0
Temperature (°C)	143	143	154	27	15	57	15	57	15	269	100	30	342	214	30
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.51	0.10	0.10	4.90	2.04	0.20
Steam Table Enthalpy (kJ/kg) [A]	---	297.00	308.69	---	30.23	296.60	---	---	---	3,000.14	417.50	88.40	3,049.81	913.81	37.61
AspenPlus Enthalpy (kJ/kg) [B]	-1,180.42	-2,535.92	-2,524.23	-15,713.87	-97.58	-2,977.20	-12,513.20	-15,496.35	-14,994.25	-12,980.15	-15,562.79	-534.50	-12,930.48	-15,066.49	-8,964.57
Density (kg/m³)	2,150.1	0.8	0.9	1,005.0	1.2	1.1	763.4	979.4	1,003.7	2.1	958.7	1.1	19.2	848.5	3.5
V-L Molecular Weight	104.513	29.563	29.563	18.369	28.857	28.786	18.025	18.494	18.019	18.015	18.015	28.236	18.015	18.015	43.650
V-L Flowrate (lb_{mol}/hr)	13	245,861	245,861	50,327	8,522	271,194	479	1,621	6,624	78,085	70,530	206,545	345	345	31,577
V-L Flowrate (lb/hr)	1,310	7,268,394	7,268,394	924,445	245,922	7,806,525	8,636	29,974	119,358	1,406,718	1,270,620	5,831,976	6,211	6,211	1,378,361
Solids Flowrate (lb/hr)	49,122	0	0	10,440	0	0	77,659	456	51,095	0	0	0	0	0	0
Temperature (°F)	289	289	309	80	59	135	59	135	59	517	211	87	648	416	86
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	73.5	14.5	14.8	710.8	296.6	28.9
Steam Table Enthalpy (Btu/lb) [A]	---	127.7	132.7	---	13.0	127.5	---	---	---	1,289.8	179.5	38.0	1,311.2	392.9	16.2
AspenPlus Enthalpy (Btu/lb) [B]	-507.5	-1,090.2	-1,085.2	-6,755.7	-42.0	-1,280.0	-5,379.7	-6,662.2	-6,446.4	-5,580.5	-6,690.8	-229.8	-5,559.1	-6,477.4	-3,854.1
Density (lb/ft³)	134.226	0.052	0.055	62.741	0.076	0.067	47.660	61.144	62.658	0.128	59.847	0.071	1.197	52.968	0.218

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-9. Case PA2 stream table (cont'd)

	31	32	33	34	35	36	37	38	39	40	41	42
V-L Mole Fraction												
Ar	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_2	0.9977	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0023	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	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	0.0000	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
SO_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
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	14,158	27	18	18	14,131	14,131	139,796	116,714	116,714	100,539	43,994	68,827
V-L Flowrate (kg/hr)	622,235	521	331	331	621,714	621,714	2,518,456	2,102,628	2,102,628	1,811,241	792,566	1,239,946
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	3.04	3.04	1.64	2.14	2.90	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg) [A]	-6.17	137.79	863.65	3,379.61	-6.32	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg) [B]	-8,975.08	-15,225.37	-15,116.65	-12,600.69	-8,969.87	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m³)	63.6	375.2	861.8	6.4	60.1	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	43.950	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	31,213	59	41	41	31,153	31,153	308,196	257,309	257,309	221,651	96,990	151,739
V-L Flowrate (lb/hr)	1,371,793	1,148	730	730	1,370,644	1,370,644	5,552,244	4,635,501	4,635,501	3,993,103	1,747,309	2,733,613
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	441.1	441.1	237.4	310.1	421.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb) [A]	-2.7	59.2	371.3	1,453.0	-2.7	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb) [B]	-3,858.6	-6,545.7	-6,499.0	-5,417.3	-3,856.4	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft³)	3.973	23.421	53.801	0.402	3.755	39.338	4.319	1.197	0.768	0.131	0.003	62.009

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-10. Case PA3 stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0000	0.0086	0.0086	0.0000	0.0086
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.0000	0.1485	0.1408	0.0000	0.1402
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	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	1.0000	0.0993	0.0946	0.0000	0.1000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.0000	0.7186	0.7215	0.0000	0.7172
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0000	0.0234	0.0330	0.0000	0.0325
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0015	0.0014	0.0000	0.0014
SO_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
NaCl	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
$CaCl_2$	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	0.0000	1.0000	1.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	76,899	76,899	2,379	28,113	28,113	3,396	1,774	0	0	0	1	3,971	110,632	0	115,277
V-L Flowrate (kg/hr)	2,219,057	2,219,057	68,661	811,244	811,244	98,006	51,202	0	0	0	16	117,741	3,275,483	0	3,405,680
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	218,831	116,805	4,722	1,614	760	20,064	64	21,078
Temperature (°C)	15	19	19	15	25	25	15	15	71	1,316	15	385	143	15	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg) B	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	-6,436.51	1,264.85	-13,402.95	-2,394.51	-2,525.70	-6.79	-2,568.98
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	1,003.6	0.5	0.9	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	18.015	29.648	29.607	---	29.544
V-L Flowrate (lb_{mol}/hr)	169,532	169,532	5,246	61,978	61,978	7,487	3,912	0	0	0	2	8,755	243,902	0	254,142
V-L Flowrate (lb/hr)	4,892,183	4,892,183	151,371	1,788,488	1,788,488	216,066	112,882	0	0	0	36	259,575	7,221,204	0	7,508,238
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	482,441	257,510	10,411	3,559	1,675	44,233	142	46,468
Temperature (°F)	59	66	66	59	78	78	59	59	160	2,400	59	726	289	59	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.6	14.7	14.6	14.4	14.7	14.4
Steam Table Enthalpy (Btu/lb)A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)B	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	-2,767.2	543.8	-5,762.2	-1,029.5	-1,085.9	-2.9	-1,104.5
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	62.650	0.034	0.053	---	0.053

ASteam table reference conditions are 32.02°F & 0.089 psia

BAspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-10. Case PA3 stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0000	0.0086	0.0086	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0106	0.0000	0.0000	0.0000
CO_2	0.0000	0.1402	0.1402	0.0000	0.0003	0.1294	0.0003	0.0000	0.0000	0.0000	0.0000	0.0170	0.0000	0.0000	0.9863
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	0.0000	0.0000	0.0000
H_2O	0.0000	0.1000	0.1000	0.9954	0.0099	0.1508	0.9995	0.9943	0.9999	1.0000	1.0000	0.0358	1.0000	1.0000	0.0137
HCL	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7172	0.7172	0.0000	0.7732	0.6768	0.0000	0.0000	0.0000	0.0000	0.0000	0.8907	0.0000	0.0000	0.0000
O_2	0.0000	0.0325	0.0325	0.0000	0.2074	0.0348	0.0000	0.0000	0.0000	0.0000	0.0000	0.0459	0.0000	0.0000	0.0000
SO_2	0.0000	0.0014	0.0014	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_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
NaCl	0.1288	0.0000	0.0000	0.0008	0.0000	0.0000	0.0001	0.0010	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.8712	0.0000	0.0000	0.0038	0.0000	0.0000	0.0000	0.0047	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	5	115,272	115,272	29,908	3,519	126,166	198	674	2,736	36,846	33,281	95,873	163	163	14,899
V-L Flowrate (kg/hr)	544	3,405,118	3,405,118	550,292	101,559	3,635,135	3,568	12,456	49,291	663,794	599,573	2,707,272	2,931	2,931	650,399
Solids Flowrate (kg/hr)	21,095	0	0	6,759	0	0	32,070	190	21,101	0	0	0	0	0	0
Temperature (°C)	143	143	154	27	15	57	15	57	15	269	100	30	342	214	30
Pressure (MPa, abs)	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.51	0.10	0.10	4.90	2.04	0.20
Steam Table Enthalpy (kJ/kg) [A]	---	302.33	314.03	---	30.23	296.38	---	---	---	3,000.14	417.50	88.40	3,049.81	913.81	37.53
AspenPlus Enthalpy (kJ/kg) [B]	-1,262.94	-2,577.27	-2,565.57	-15,692.48	-97.58	-2,999.41	-12,513.05	-15,496.31	-14,994.25	-12,980.15	-15,562.79	-538.34	-12,930.48	-15,066.49	-8,964.43
Density (kg/m³)	2,150.0	0.8	0.9	1,006.1	1.2	1.1	671.1	979.4	1,003.7	2.1	958.7	1.1	19.2	848.5	3.5
V-L Molecular Weight	104.214	29.540	29.540	18.400	28.857	28.812	18.028	18.493	18.019	18.015	18.015	28.238	18.015	18.015	43.652
V-L Flowrate (lb_{mol}/hr)	12	254,130	254,130	65,936	7,759	278,148	436	1,485	6,031	81,232	73,373	211,365	359	359	32,848
V-L Flowrate (lb/hr)	1,199	7,507,001	7,507,001	1,213,186	223,899	8,014,102	7,865	27,460	108,669	1,463,416	1,321,832	5,968,513	6,461	6,461	1,433,884
Solids Flowrate (lb/hr)	46,507	0	0	14,901	0	0	70,702	418	46,519	0	0	0	0	0	0
Temperature (°F)	289	289	309	80	59	135	59	135	59	517	211	87	648	416	86
Pressure (psia)	14.4	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	73.5	14.5	14.8	710.8	296.6	28.9
Steam Table Enthalpy (Btu/lb)[A]	---	130.0	135.0	---	13.0	127.4	---	---	---	1,289.8	179.5	38.0	1,311.2	392.9	16.1
AspenPlus Enthalpy (Btu/lb)[B]	-543.0	-1,108.0	-1,103.0	-6,746.6	-42.0	-1,289.5	-5,379.6	-6,662.2	-6,446.4	-5,580.5	-6,690.8	-231.4	-5,559.1	-6,477.4	-3,854.0
Density (lb/ft³)	134.221	0.052	0.055	62.809	0.076	0.067	41.895	61.144	62.658	0.128	59.847	0.071	1.197	52.968	0.218

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit A-10. Case PA3 stream table (cont'd)

	31	32	33	34	35	36	37	38	39	40	41	42
V-L Mole Fraction												
Ar	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_2	0.9977	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0023	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	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	0.0000	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
SO_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
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	14,729	28	19	19	14,701	14,701	143,463	119,774	119,774	103,175	44,694	70,181
V-L Flowrate (kg/hr)	647,320	542	344	344	646,778	646,778	2,584,534	2,157,755	2,157,755	1,858,718	805,176	1,264,333
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	3.04	3.04	1.64	2.14	2.90	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg) A	-6.17	137.79	863.65	3,379.61	-6.32	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg) B	-8,975.08	-15,225.37	-15,116.65	-12,600.69	-8,969.87	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m³)	63.6	375.2	861.8	6.4	60.1	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	43.950	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	32,471	62	42	42	32,409	32,409	316,283	264,056	264,056	227,461	98,534	154,723
V-L Flowrate (lb/hr)	1,427,096	1,195	759	759	1,425,902	1,425,902	5,697,923	4,757,037	4,757,037	4,097,771	1,775,110	2,787,376
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	441.1	441.1	237.4	310.1	421.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb)A	-2.7	59.2	371.3	1,453.0	-2.7	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)B	-3,858.6	-6,545.7	-6,499.0	-5,417.3	-3,856.4	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft³)	3.973	23.421	53.801	0.402	3.755	39.338	4.319	1.197	0.768	0.131	0.003	62.009

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Heat and Material Balance Diagrams

Exhibit A-11. Case B12A energy and mass balance diagram

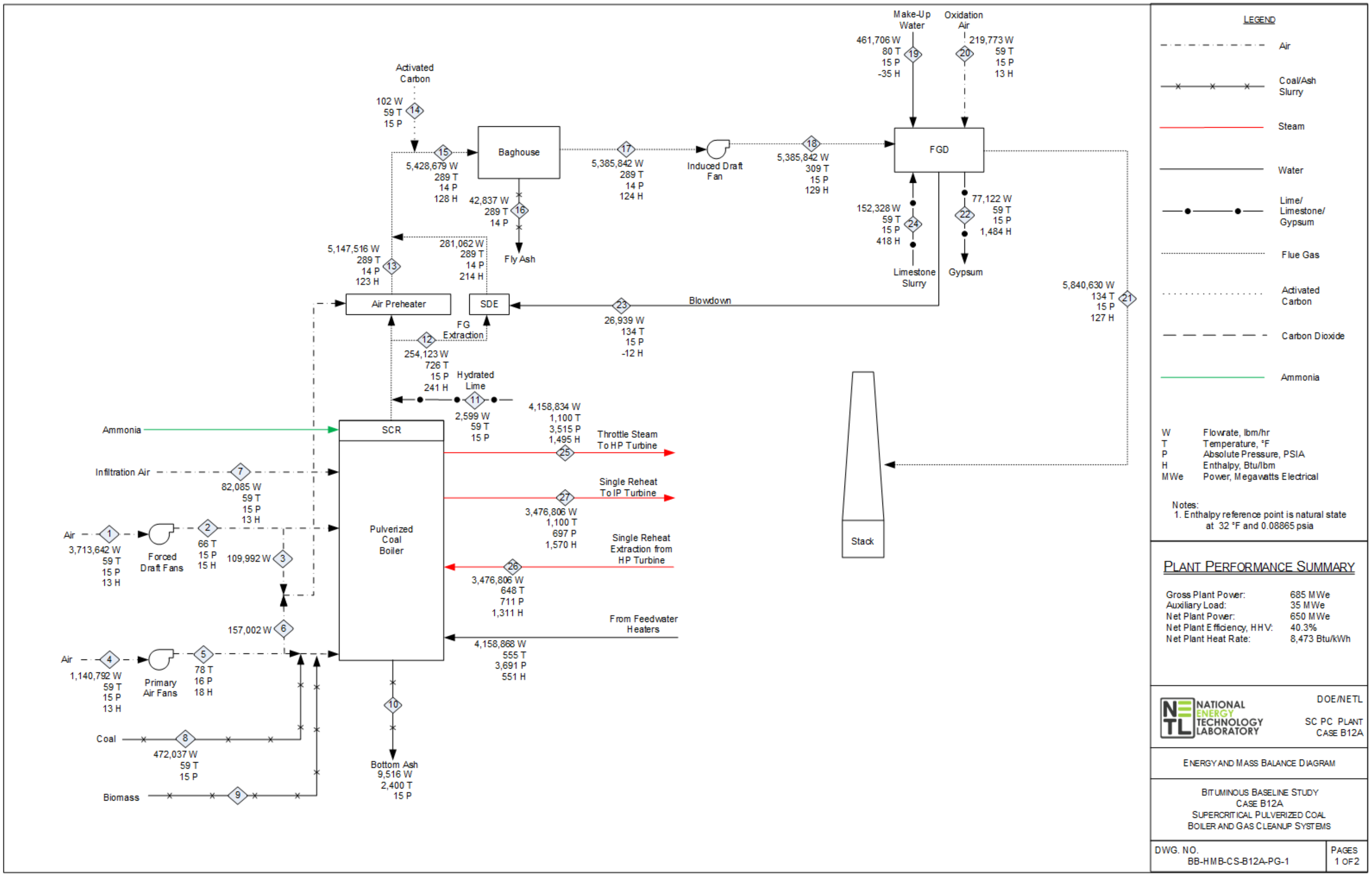


Exhibit A-11. Case B12A energy and mass balance diagram (cont'd)

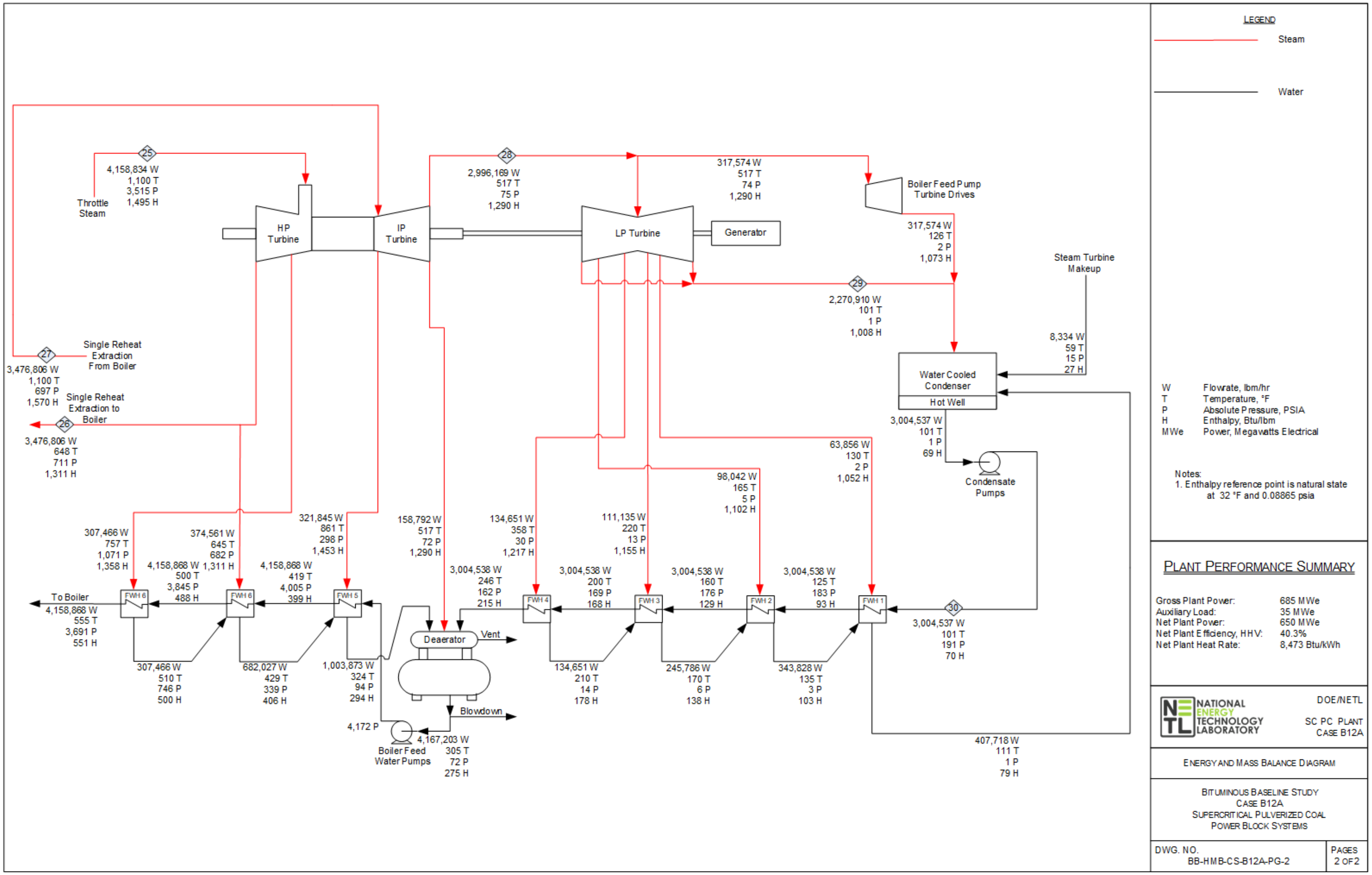


Exhibit A-12. Case PN1 energy and mass balance diagram

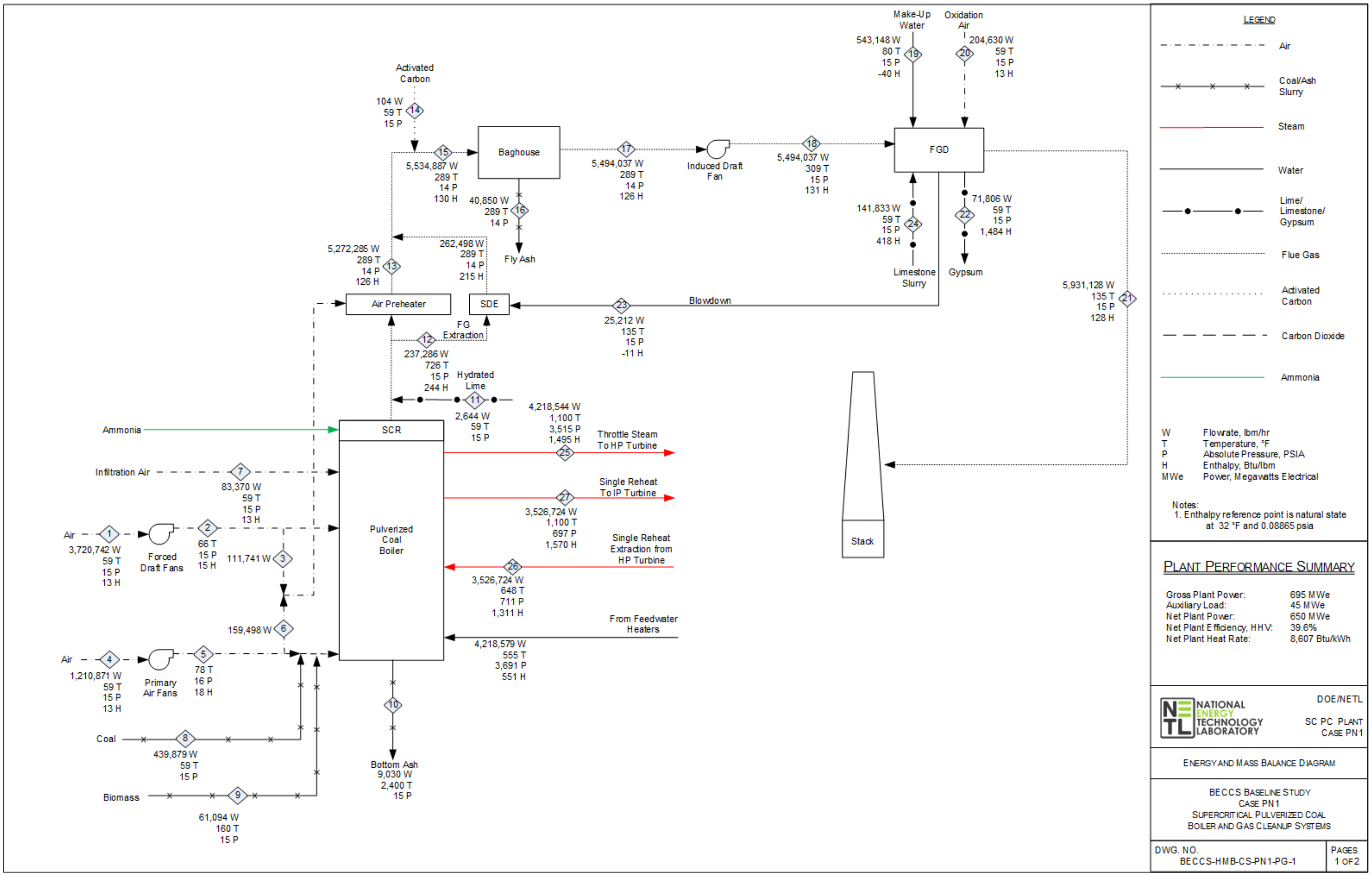


Exhibit A-12. Case PN1 energy and mass balance diagram (cont'd)

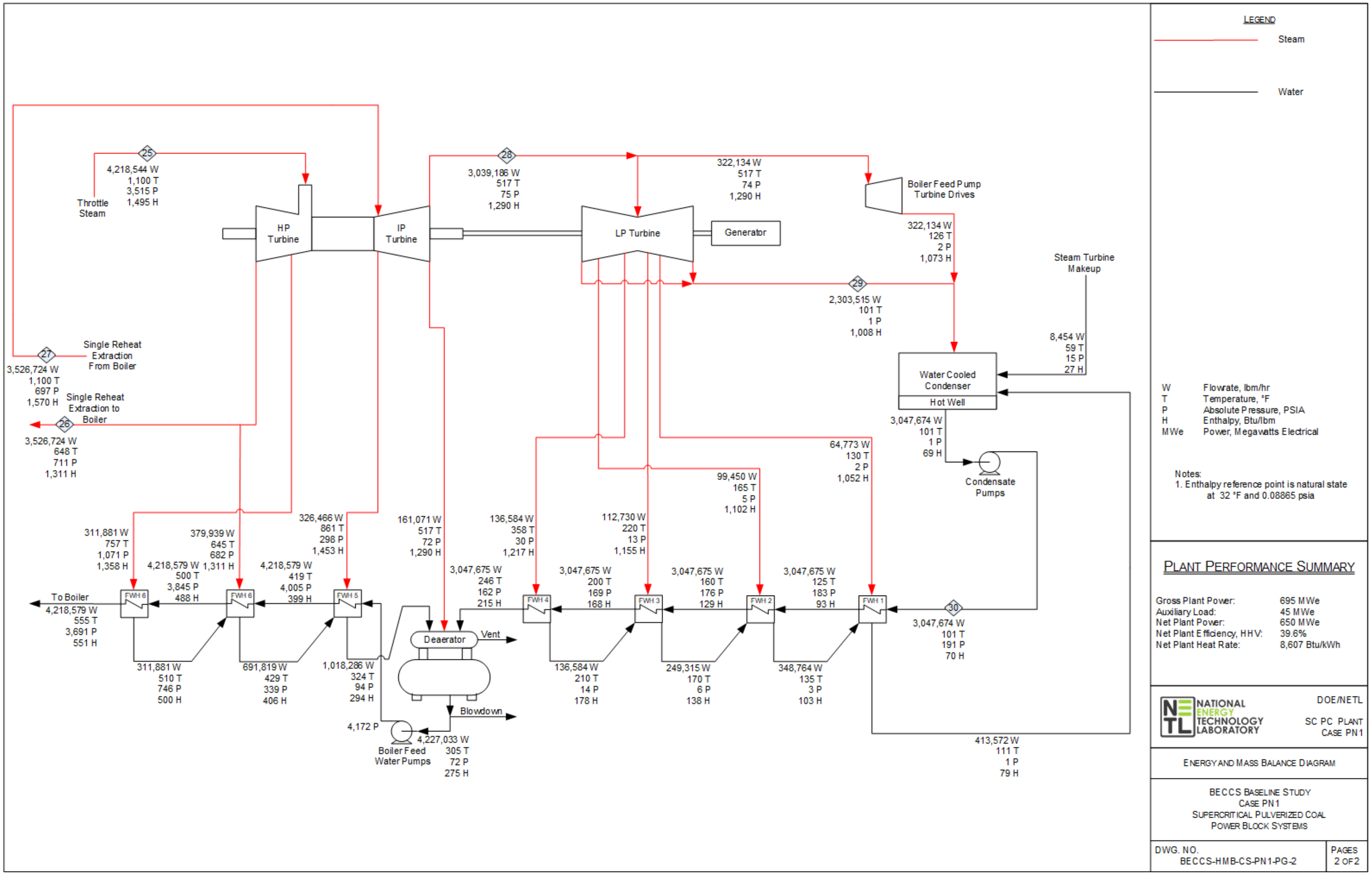


Exhibit A-13. Case PN2 energy and mass balance diagram

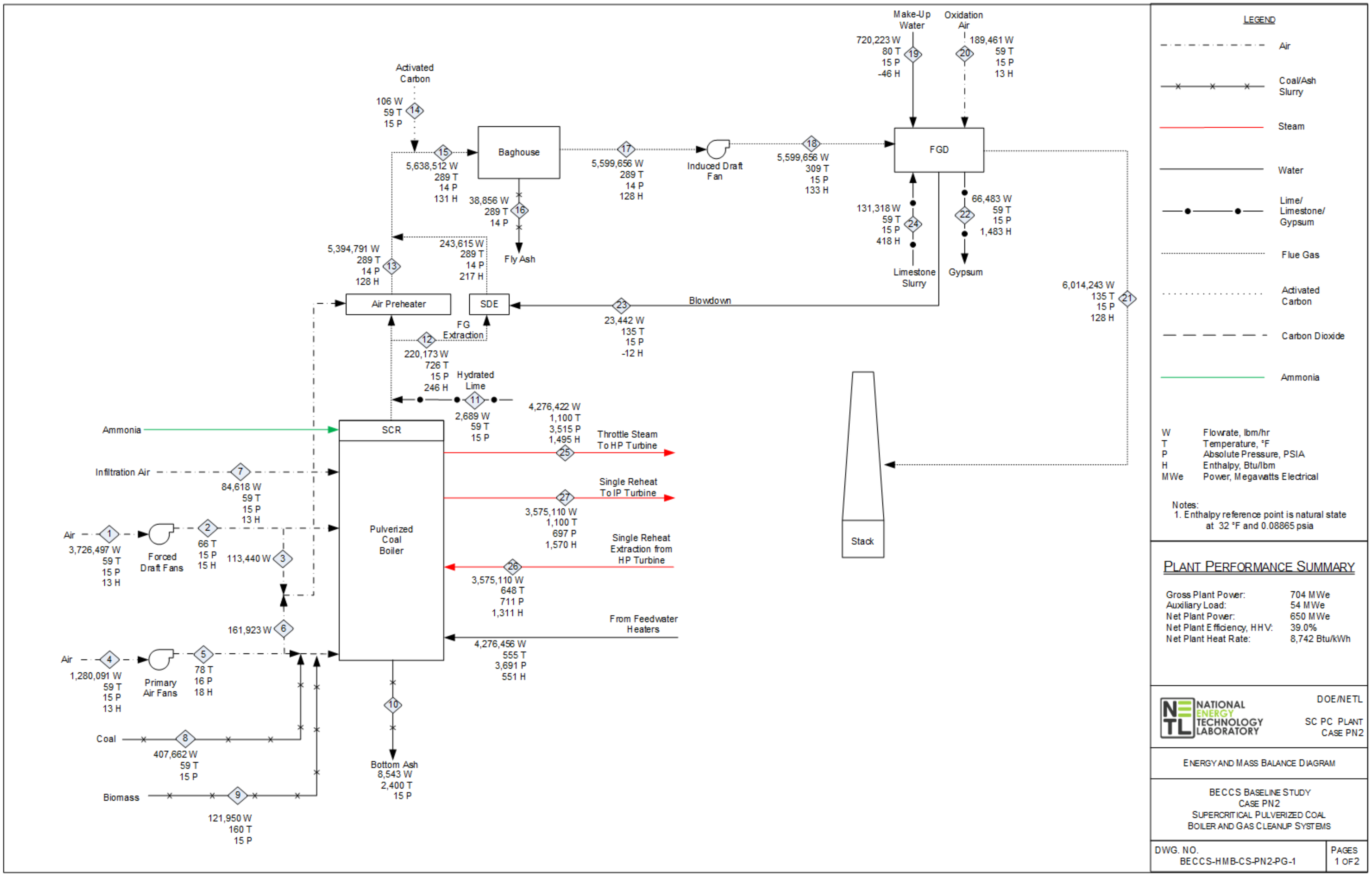


Exhibit A-13. Case PN2 energy and mass balance diagram (cont'd)

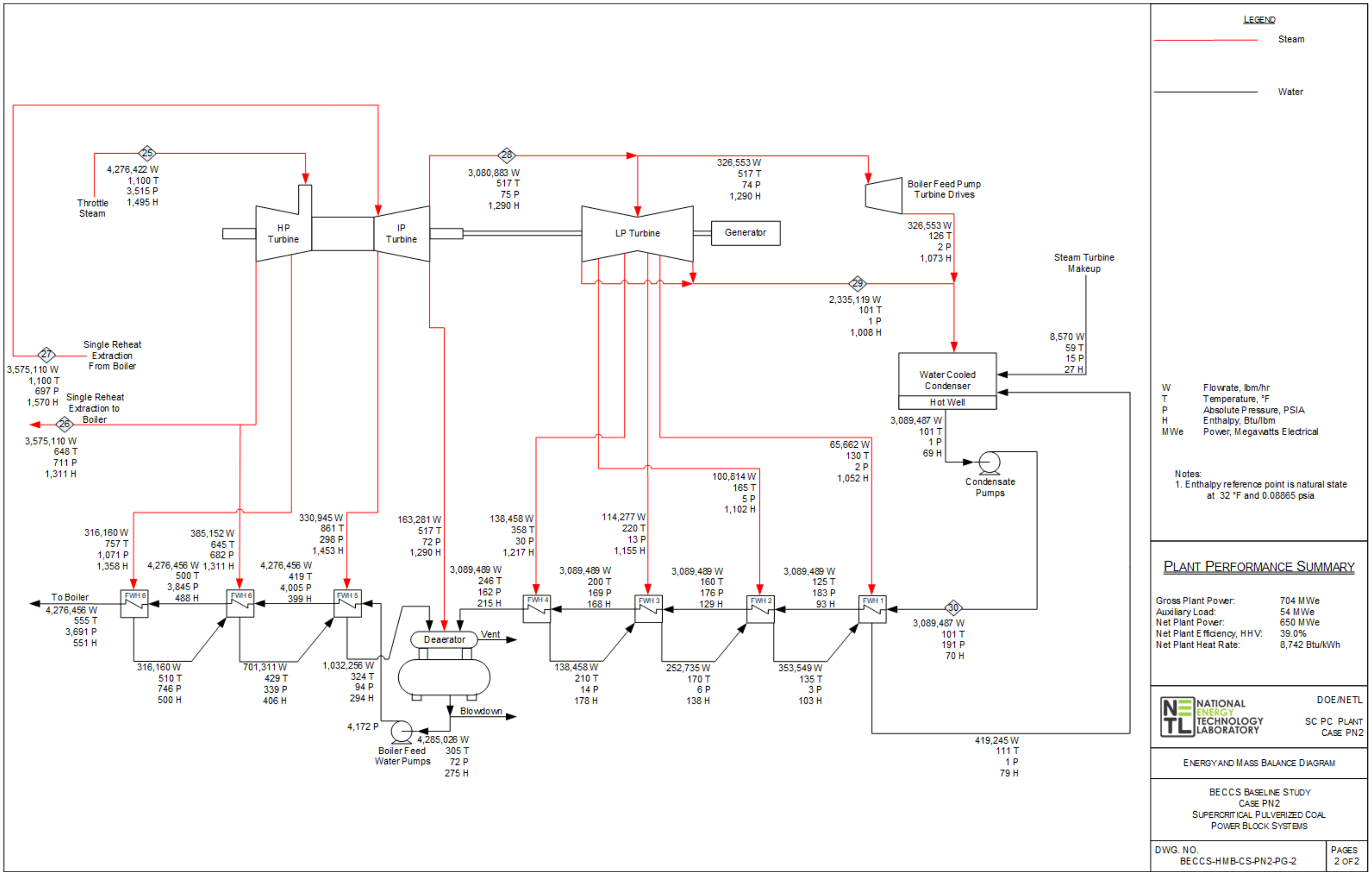


Exhibit A-14. Case PN3 energy and mass balance diagram

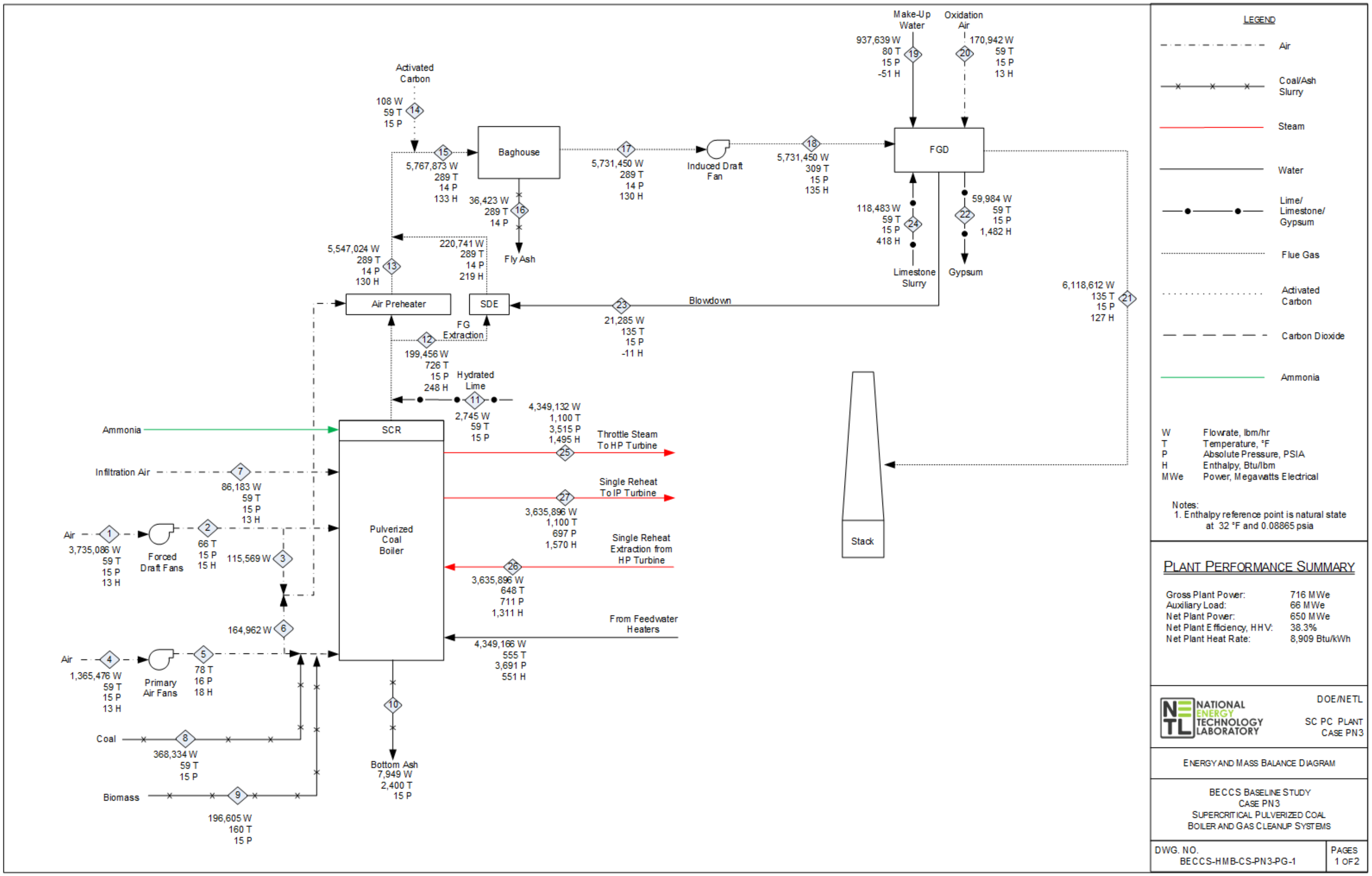


Exhibit A-14. Case PN3 energy and mass balance diagram (cont'd)

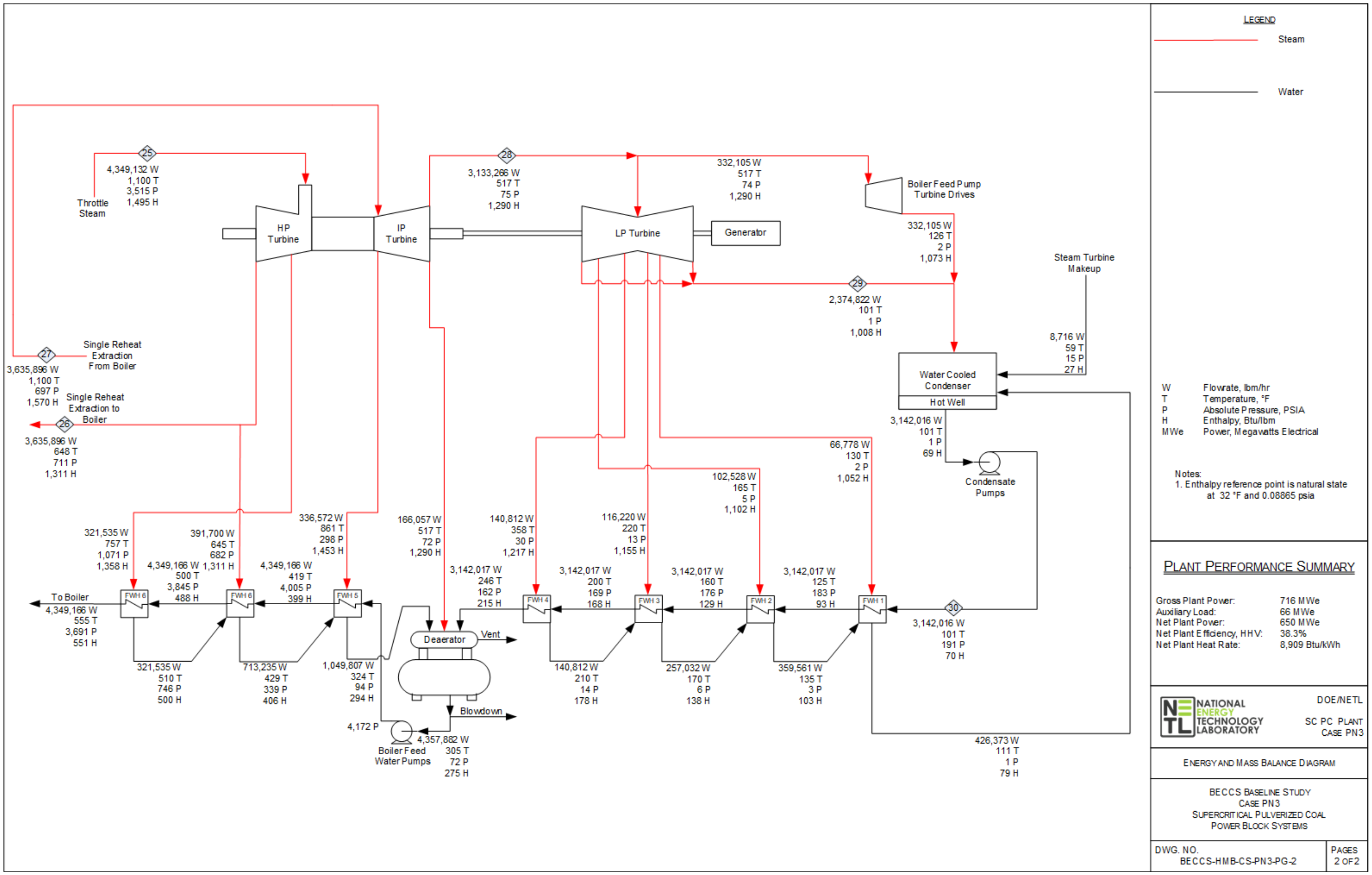


Exhibit A-15. Case B12B energy and mass balance diagram

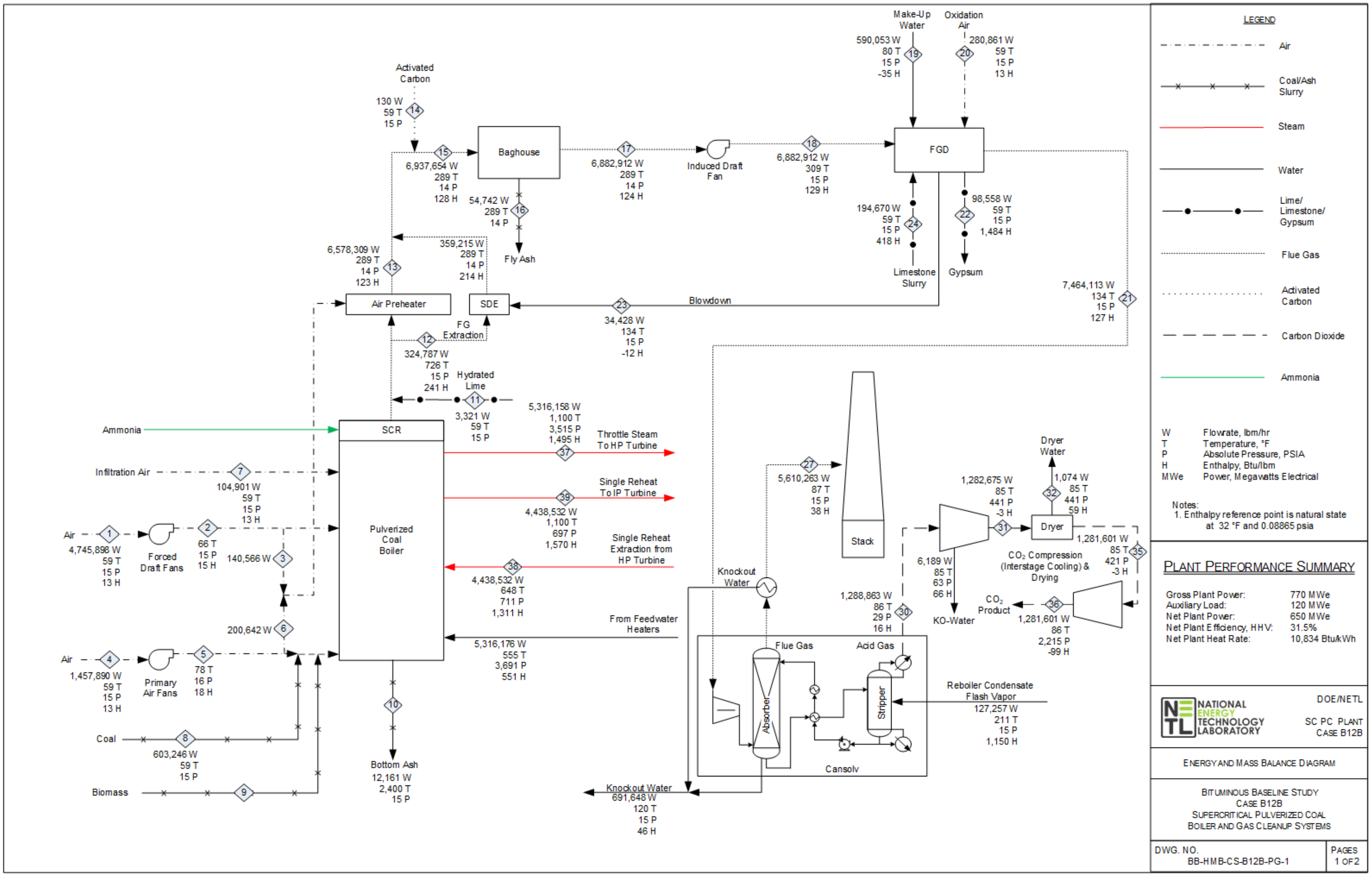


Exhibit A-15. Case B12B energy and mass balance diagram (cont'd)

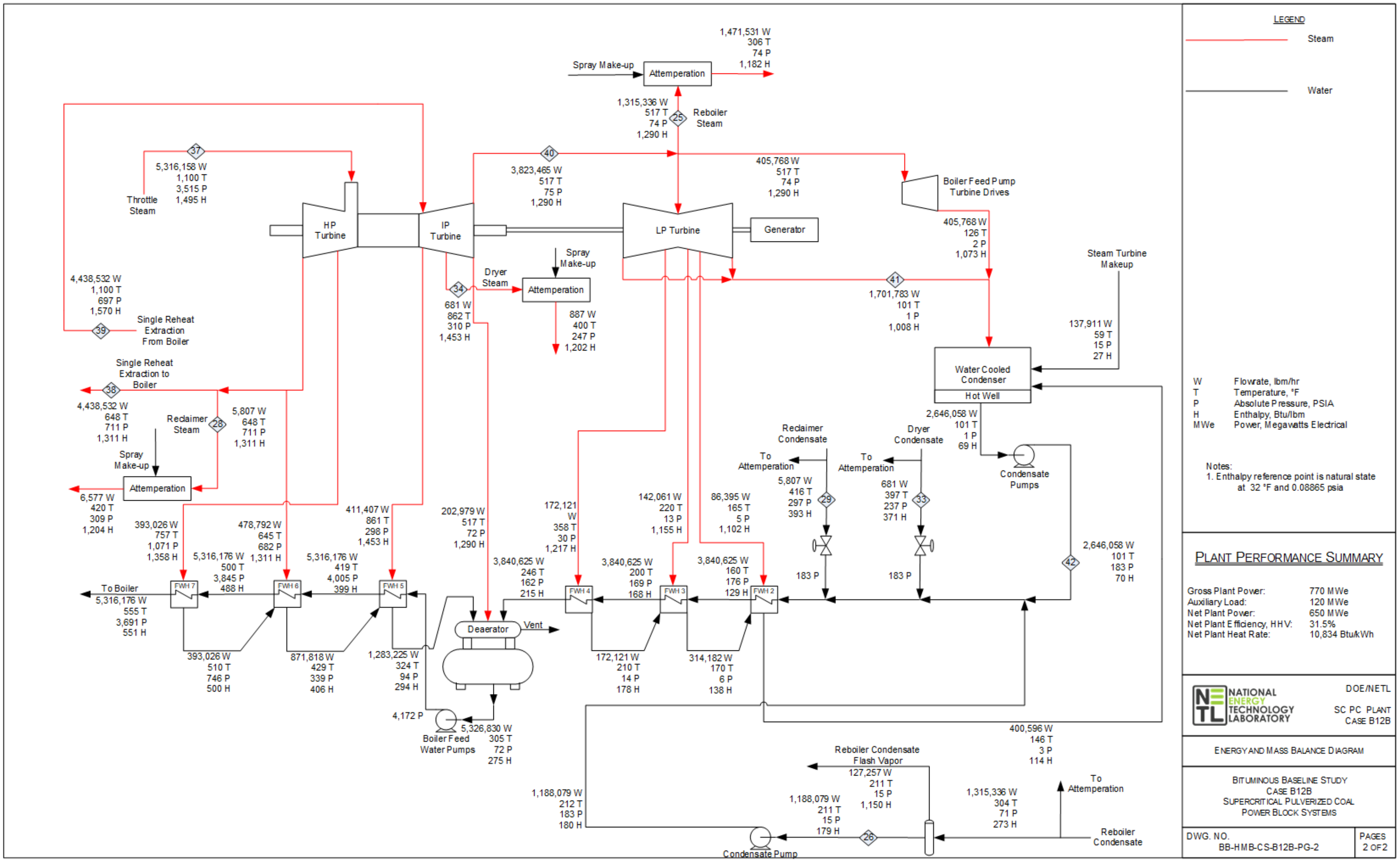


Exhibit A-16. Case PA1 energy and mass balance diagram

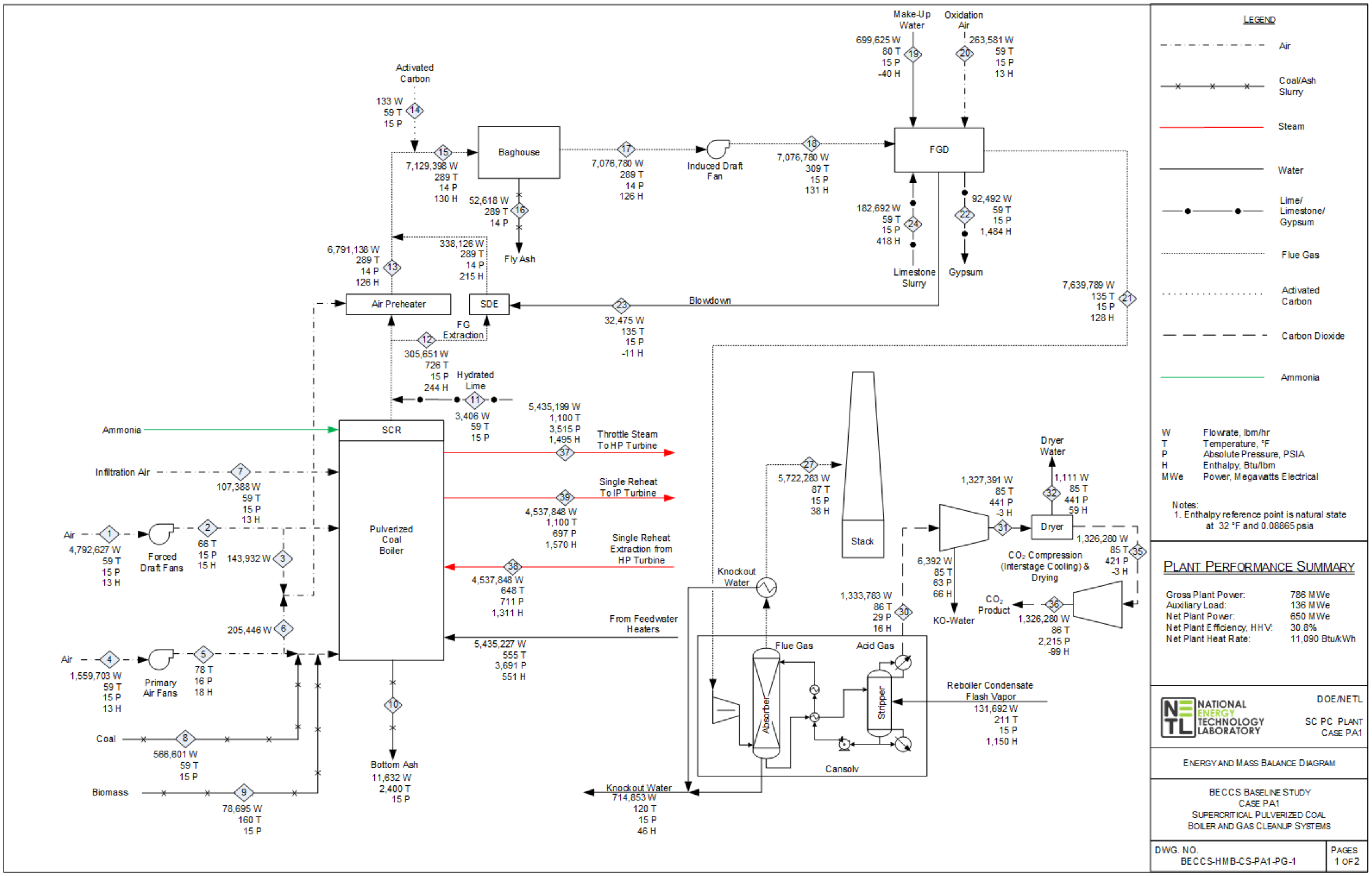


Exhibit A-16. Case PA1 energy and mass balance diagram (cont'd)

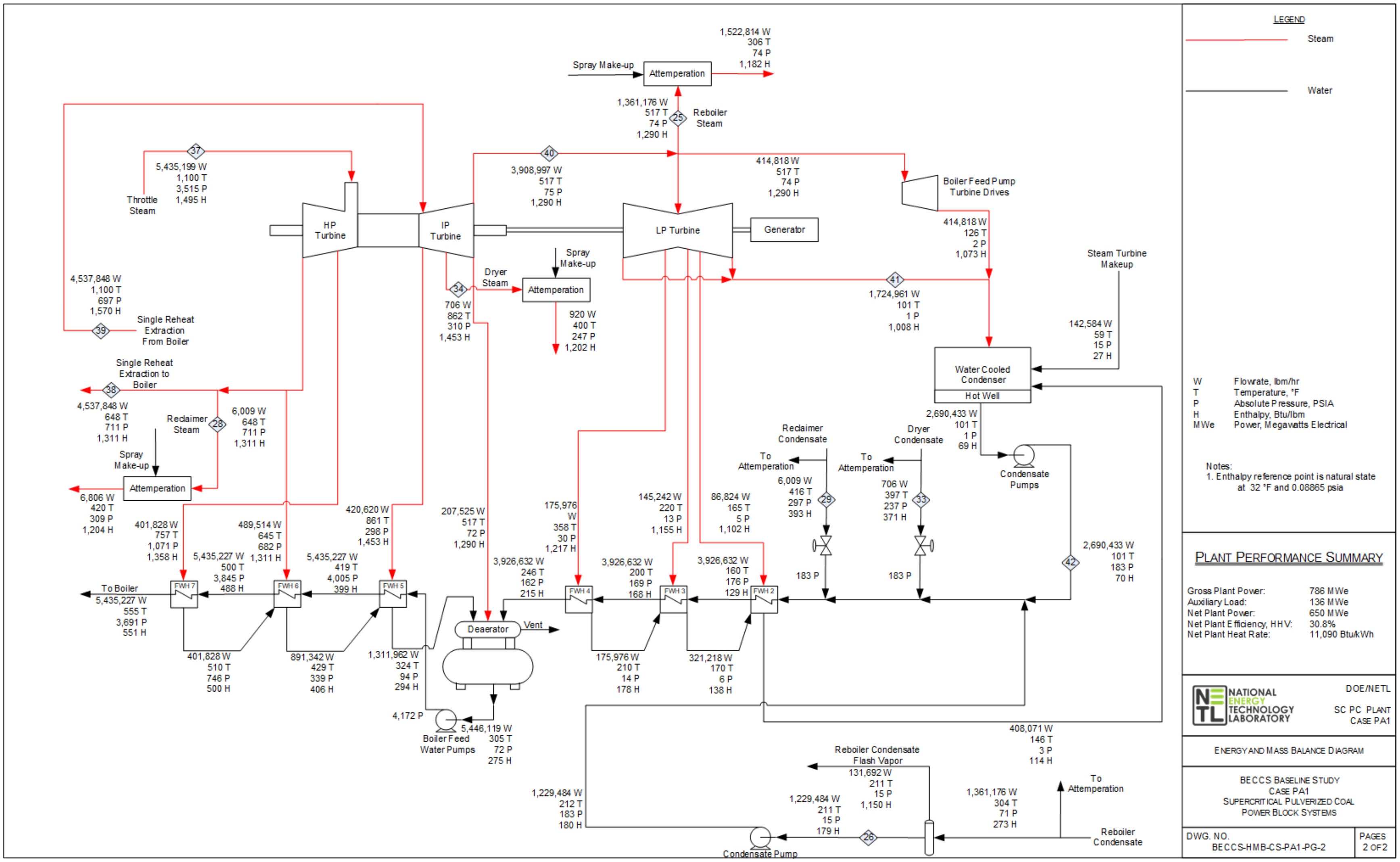


Exhibit A-17. Case PA2 energy and mass balance diagram

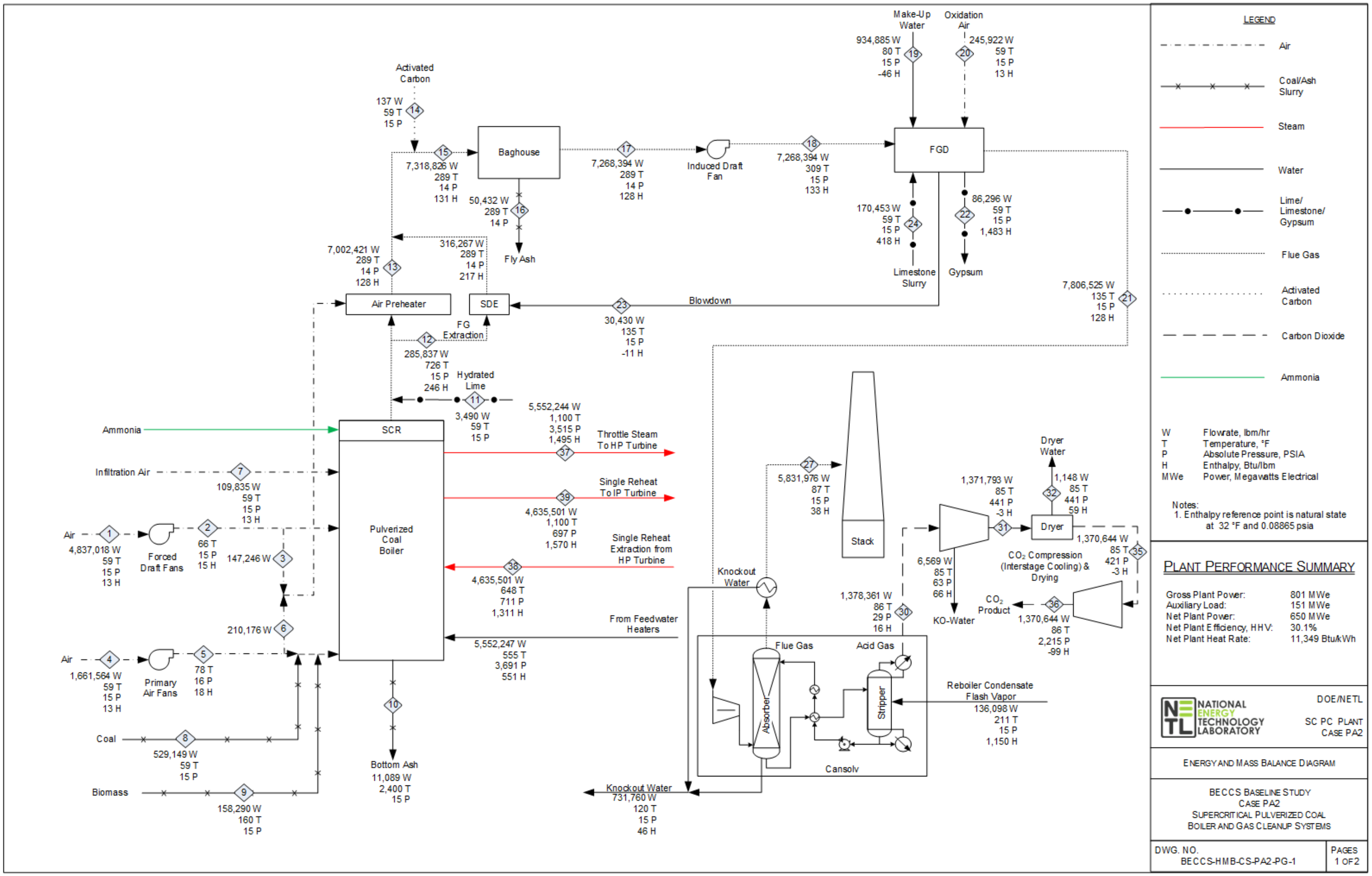


Exhibit A-17. Case PA2 energy and mass balance diagram (cont'd)

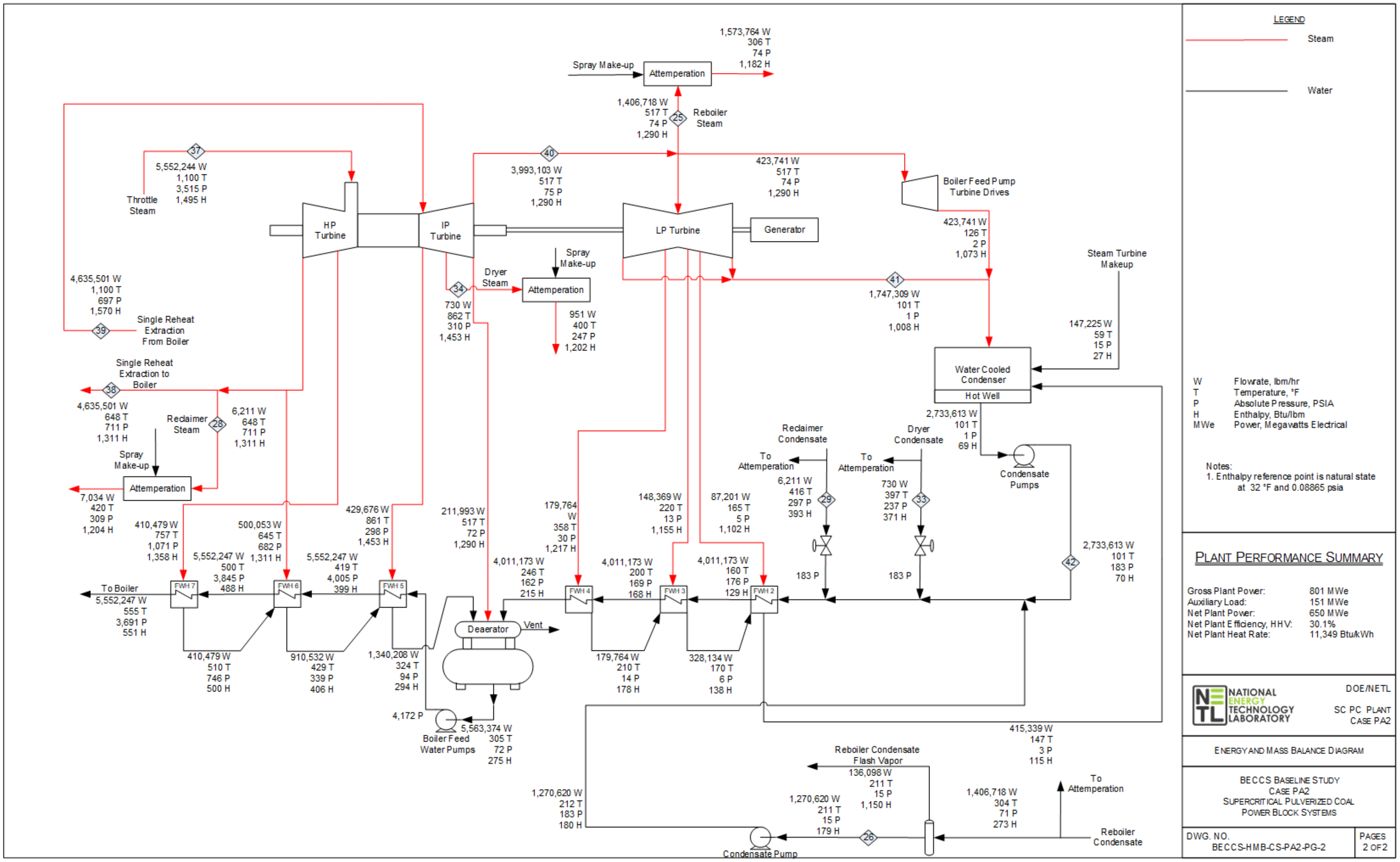


Exhibit A-18. Case PA3 energy and mass balance diagram

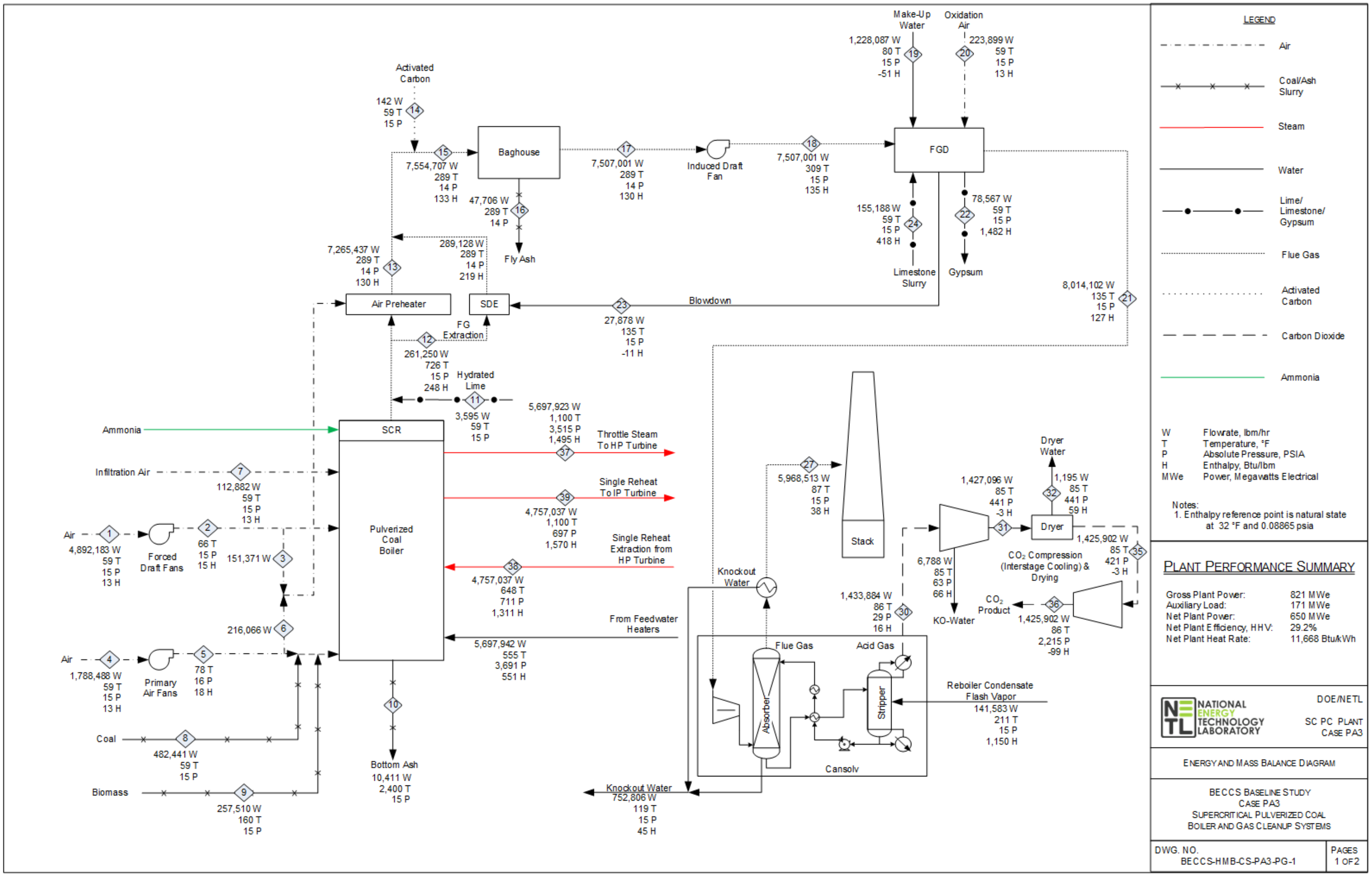
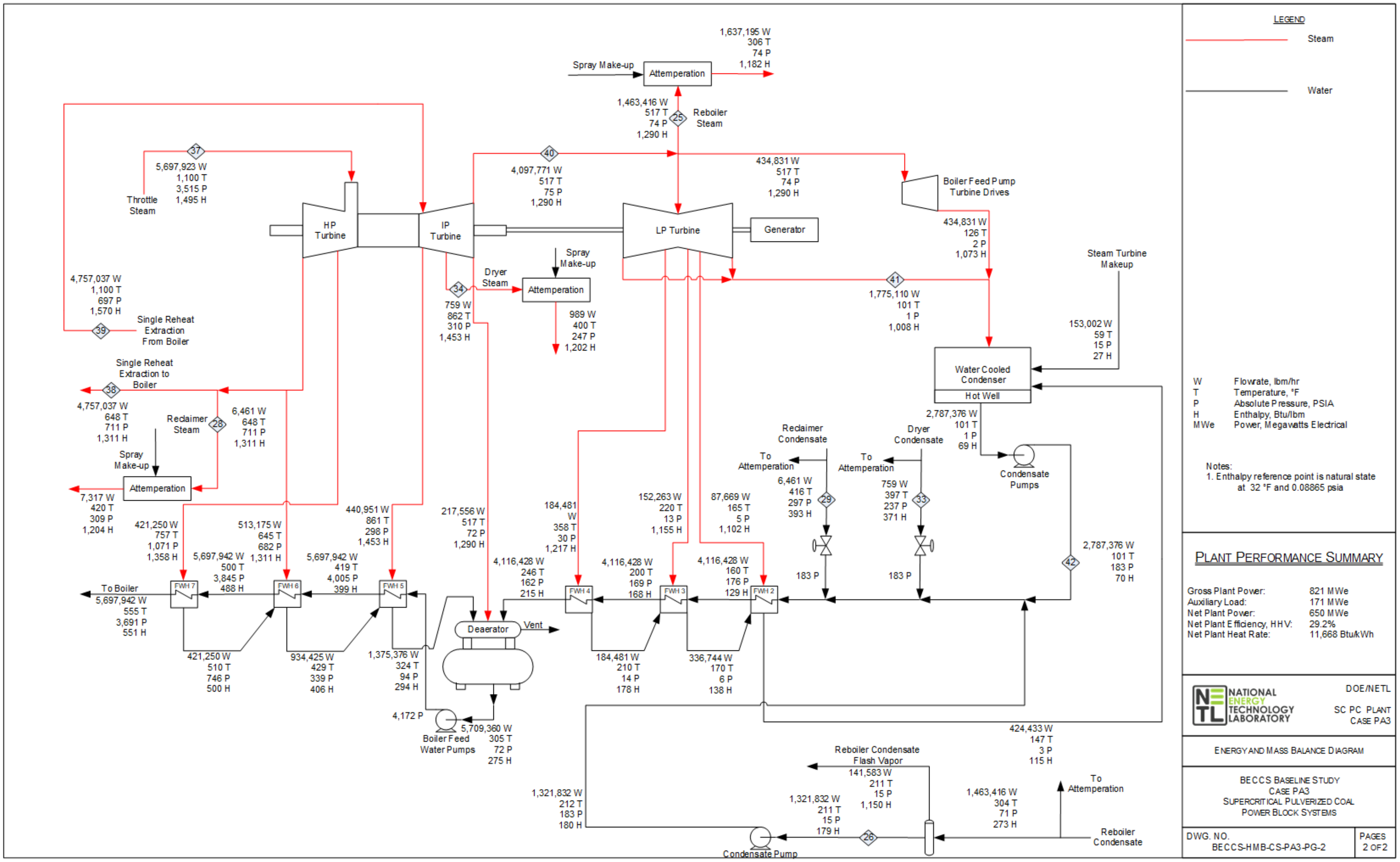


Exhibit A-18. Case PA3 energy and mass balance diagram (cont'd)



PERFORMANCE TABLES

Exhibit A-19. Non-capture SC PC plant performance summary (100 percent load)

CASE	B12A	PN1	PN2	PN3	Unit
Performance Summary					
Total Gross Power	**685**	**695**	**704**	**716**	**MWe**
CO_2 Capture/Removal Auxiliaries	0	0	0	0	kWe
CO_2 Compression	0	0	0	0	kWe
Balance of Plant	35,070	44,780	54,450	66,470	kWe
Total Auxiliaries	**35**	**45**	**54**	**66**	**MWe**
Net Power	**650**	**650**	**650**	**650**	**MWe**
HHV Net Plant Efficiency	40.3%	39.6%	39.0%	38.3%	%
HHV Net Plant Heat Rate	8,939 (8,473)	9,081 (8,607)	9,223 (8,742)	9,399 (8,909)	kJ/kWh (Btu/kWh)
LHV Net Plant Efficiency	41.8%	41.2%	40.6%	40.0%	%
LHV Net Plant Heat Rate	8,622 (8,172)	8,741 (8,285)	8,860 (8,398)	9,008 (8,538)	kJ/kWh (Btu/kWh)
HHV Boiler Efficiency	88.1%	87.9%	87.8%	87.6%	%
LHV Boiler Efficiency	91.3%	91.4%	91.4%	91.4%	%
Steam Turbine Cycle Efficiency	48.2%	48.2%	48.2%	48.2%	%
Steam Turbine Heat Rate	7,471 (7,082)	7,471 (7,081)	7,471 (7,081)	7,471 (7,081)	kJ/kWh (Btu/kWh)
Condenser Duty	2,589 (2,454)	2,626 (2,489)	2,662 (2,523)	2,707 (2,566)	GJ/hr (MMBtu/hr)
AGR Cooling Duty	– (–)	– (–)	– (–)	– (–)	GJ/hr (MMBtu/hr)
As-Received Coal Feed	214,112 (472,037)	199,526 (439,879)	184,912 (407,662)	167,073 (368,334)	kg/hr (lb/hr)
As-Received Biomass Feed	-(-)	49,881 (109,970)	99,568 (219,510)	160,521 (353,889)	kg/hr (lb/hr)
Limestone Sorbent Feed	20,712 (45,662)	19,285 (42,516)	17,855 (39,364)	16,110 (35,517)	kg/hr (lb/hr)
HHV Thermal Input	1,613,879	1,639,906	1,665,199	1,696,892	kWt
LHV Thermal Input	1,556,606	1,578,478	1,599,654	1,626,273	kWt
Raw Water Withdrawal	0.035 (9.3)	0.035 (9.3)	0.035 (9.2)	0.034 (9.1)	$(m^3/min)/MW_{net}$ (gpm/MW_{net})
Raw Water Consumption	0.028 (7.4)	0.028 (7.3)	0.027 (7.2)	0.027 (7.1)	$(m^3/min)/MW_{net}$ (gpm/MW_{net})
Excess Air	20.3%	20.3%	20.3%	20.4%	%

Exhibit A-20. Non-capture SC PC plant performance summary (100 percent load) (cont'd)

CASE	B12A	PN1	PN2	PN3	Unit
Power Summary					
Steam Turbine Power	685	695	704	716	MWe
Gross Power	685	**695**	**704**	**716**	**MWe**
Auxiliary Load Summary					
Activated Carbon Injection	30	30	30	30	kWe
Air Cooled Condenser Fans	0	0	0	0	kWe
Ash Handling	690	650	620	580	kWe
Baghouse	90	90	80	80	kWe
Biomass Handling and Conveying	-	70	150	260	kWe
Biomass Processing	-	6,420	12,810	20,660	kWe
Circulating Water Pumps	5,300	5,370	5,440	5,530	kWe
CO_2 Capture/Removal Auxiliaries	0	0	0	0	kWe
CO_2 Compression	0	0	0	0	kWe
Coal Handling and Conveying	470	450	440	420	kWe
Condensate Pumps	660	670	670	690	kWe
Cooling Tower Fans	2,740	2,780	2,810	2,860	kWe
Dry Sorbent Injection	60	60	60	60	kWe
Flue Gas Desulfurizer	3,310	3,080	2,850	2,570	kWe
Forced Draft Fans	2,010	2,010	2,010	2,020	kWe
Ground Water Pumps	550	540	540	540	kWe
Induced Draft Fans	8,210	8,380	8,550	8,760	kWe
Miscellaneous Balance of Plant[A,B]	2,250	2,250	2,250	2,250	kWe
Primary Air Fans	1,570	1,670	1,760	1,880	kWe
Pulverizers	3,210	4,990	6,750	8,920	kWe
SCR	30	30	40	40	kWe
Sorbent Handling & Reagent Preparation	1,000	930	860	780	kWe
Spray Dryer Evaporator	240	220	200	190	kWe
Steam Turbine Auxiliaries	500	500	500	500	kWe
Transformer Losses	2,150	2,200	2,250	2,310	kWe
WTA Biomass Dryer Compressor	-	1,280	2,550	4,170	kWe
WTA Biomass Dryer Auxiliaries	-	110	230	370	kWe
Total Auxiliaries	**35**	**45**	**54**	**66**	**MWe**
Net Power	**650**	**650**	**650**	**650**	**MWe**

[A] Boiler feed pumps are turbine driven

[B] Includes plant control systems; lighting; heating, ventilating, and air conditioning (HVAC); and miscellaneous low voltage loads

Exhibit A-21. SC PC with amine plant performance summary (100 percent load)

CASE	B12B	PA1	PA2	PA3	Unit
Performance Summary					
Total Gross Power	**770**	**786**	**801**	**821**	**MWe**
CO_2 Capture/Removal Auxiliaries	27,300	28,300	29,200	30,400	kWe
CO_2 Compression	44,380	45,920	47,460	49,370	kWe
Balance of Plant	48,320	61,340	74,580	90,890	kWe
Total Auxiliaries	**120**	**136**	**151**	**171**	**MWe**
Net Power	**650**	**650**	**650**	**650**	**MWe**
HHV Net Plant Efficiency	31.5%	30.8%	30.1%	29.2%	%
HHV Net Plant Heat Rate	11,430 (10,834)	11,700 (11,090)	11,974 (11,349)	12,311 (11,668)	kJ/kWh (Btu/kWh)
LHV Net Plant Efficiency	32.7%	32.0%	31.3%	30.5%	%
LHV Net Plant Heat Rate	11,024 (10,449)	11,262 (10,674)	11,502 (10,902)	11,798 (11,183)	kJ/kWh (Btu/kWh)
HHV Boiler Efficiency	88.1%	87.9%	87.8%	87.6%	%
LHV Boiler Efficiency	91.3%	91.4%	91.4%	91.4%	%
Steam Turbine Cycle Efficiency	57.5%	57.7%	57.8%	58.0%	%
Steam Turbine Heat Rate	6,256 (5,930)	6,239 (5,914)	6,223 (5,898)	6,203 (5,879)	kJ/kWh (Btu/kWh)
Condenser Duty	2,127 (2,016)	2,160 (2,048)	2,192 (2,078)	2,232 (2,115)	GJ/hr (MMBtu/hr)
AGR Cooling Duty	2,344 (2,222)	2,426 (2,299)	2,507 (2,376)	2,608 (2,472)	GJ/hr (MMBtu/hr)
As-Received Coal Feed	273,628 (603,246)	257,006 (566,601)	240,018 (529,149)	218,831 (482,441)	kg/hr (lb/hr)
As-Received Biomass Feed	-(-)	64,251 (141,650)	129,240 (284,926)	210,250 (463,521)	kg/hr (lb/hr)
Limestone Sorbent Feed	26,469 (58,354)	24,841 (54,764)	23,176 (51,095)	21,101 (46,519)	kg/hr (lb/hr)
HHV Thermal Input	2,062,478	2,112,337	2,161,445	2,222,578	kWt
LHV Thermal Input	1,989,286	2,033,212	2,076,366	2,130,082	kWt
Raw Water Withdrawal	0.058 (15.3)	0.059 (15.6)	0.061 (16.0)	0.062 (16.5)	$(m^3/min)/MW_{net}$ (gpm/MW_{net})
Raw Water Consumption	0.041 (10.8)	0.041 (10.8)	0.041 (10.8)	0.041 (10.8)	$(m^3/min)/MW_{net}$ (gpm/MW_{net})
Excess Air	20.3%	20.3%	20.3%	20.4%	%

Exhibit A-22. SC PC with amine plant performance summary (100 percent load) (cont'd)

CASE	B12B	PA1	PA2	PA3	Unit
Power Summary					
Steam Turbine Power	770	786	801	821	MWe
Gross Power	**770**	**786**	**801**	**821**	**MWe**
Auxiliary Load Summary					
Activated Carbon Injection	40	40	40	40	kWe
Air Cooled Condenser Fans	880	0	0	0	kWe
Ash Handling	120	840	810	760	kWe
Baghouse	40	110	110	100	kWe
Biomass Handling and Conveying	-	80	170	290	kWe
Biomass Processing	-	8,270	16,630	27,060	kWe
Circulating Water Pumps	9,610	9,860	10,100	10,350	kWe
CO_2 Capture/Removal Auxiliaries	27,300	28,300	29,200	30,400	kWe
CO_2 Compression	44,380	45,920	47,460	49,370	kWe
Coal Handling and Conveying	530	510	500	470	kWe
Condensate Pumps	790	810	830	850	kWe
Cooling Tower Fans	4,970	5,100	5,230	5,380	kWe
Dry Sorbent Injection	80	80	80	80	kWe
Flue Gas Desulfurizer	4,230	3,970	3,700	3,370	kWe
Forced Draft Fans	2,560	2,590	2,610	2,640	kWe
Ground Water Pumps	900	920	940	970	kWe
Induced Draft Fans	10,440	10,740	11,040	11,410	kWe
Miscellaneous Balance of Plant[A,B]	2,250	2,250	2,250	2,250	kWe
Primary Air Fans	2,010	2,150	2,290	2,460	kWe
Pulverizers	4,100	6,420	8,770	11,690	kWe
SCR	50	50	50	50	kWe
Sorbent Handling & Reagent Preparation	1,280	1,200	1,120	1,020	kWe
Spray Dryer Evaporator	300	280	270	240	kWe
Steam Turbine Auxiliaries	500	500	500	500	kWe
Transformer Losses	2,680	2,760	2,850	2,960	kWe
WTA Biomass Dryer Compressor	-	1,660	3,390	5,460	kWe
WTA Biomass Dryer Auxiliaries	-	150	300	490	kWe
Total Auxiliaries	**120**	**136**	**151**	**171**	**MWe**
Net Power	**650**	**650**	**650**	**650**	**MWe**

[A] Boiler feed pumps are turbine driven
[B] Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Carbon Balances

Exhibit A-23. Non-capture SC PC carbon balances

Carbon In, kg/hr (lb/hr)					Carbon Out, kg/hr (lb/hr)				
Case	B12A	PN1	PN2	PN3	Case	B12A	PN1	PN2	PN3
Coal	136,485 (300,899)	127,187 (280,400)	117,872 (259,863)	106,500 (234,793)	Stack Gas	137,924 (304,071)	141,611 (312,199)	145,229 (320,176)	149,725 (330,087)
Biomass	0 (0)	13,059 (28,790)	26,067 (57,468)	42,025 (92,648)	FGD Product	162 (357)	151 (332)	140 (308)	126 (278)
Air (CO_2)	318 (701)	322 (710)	326 (718)	330 (729)	Baghouse	701 (1,546)	657 (1,450)	614 (1,353)	560 (1,235)
PAC	46 (102)	47 (104)	48 (106)	49 (108)	Bottom Ash	164 (361)	153 (336)	141 (312)	128 (282)
FGD Reagent	2,102 (4,633)	1,957 (4,314)	1,812 (3,994)	1,635 (3,604)	CO_2 Product	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
					CO_2 Dryer Vent	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
					CO_2 Knockout	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
Total	**138,951 (306,335)**	**142,572 (314,317)**	**146,124 (322,149)**	**150,539 (331,882)**	**Total**	**138,951 (306,335)**	**142,572 (314,317)**	**146,124 (322,149)**	**150,539 (331,882)**

Exhibit A-24. SC PC with amine capture carbon balances

Carbon In, kg/hr (lb/hr)					Carbon Out, kg/hr (lb/hr)				
Case	B12B	PA1	PA2	PA3	Case	B12B	PA1	PA2	PA3
Coal	174,423 (384,538)	163,828 (361,178)	152,999 (337,305)	139,494 (307,531)	Stack Gas	17,626 (38,859)	18,241 (40,214)	18,851 (41,559)	19,611 (43,234)
Biomass	0 (0)	16,821 (37,084)	33,835 (74,594)	55,043 (121,350)	FGD Product	207 (456)	194 (428)	181 (400)	165 (364)
Air (CO_2)	406 (896)	415 (914)	423 (932)	433 (954)	Baghouse	896 (1,975)	847 (1,867)	797 (1,756)	734 (1,618)
PAC	59 (130)	61 (133)	62 (137)	64 (142)	Bottom Ash	209 (461)	197 (433)	184 (405)	167 (369)
FGD Reagent	2,686 (5,921)	2,521 (5,557)	2,352 (5,185)	2,141 (4,720)	CO_2 Product	158,621 (349,698)	164,150 (361,889)	169,641 (373,995)	176,480 (389,072)
					CO_2 Dryer Vent	15 (33)	16 (35)	16 (36)	17 (37)
					CO_2 Knockout	0.3 (0.8)	0.4 (0.8)	0.4 (0.8)	0.4 (0.8)
Total	**177,574 (391,485)**	**183,645 (404,867)**	**189,671 (418,152)**	**197,175 (434,697)**	**Total**	**177,574 (391,485)**	**183,645 (404,867)**	**189,671 (418,152)**	**197,175 (434,697)**

Sulfur Balances

Exhibit A-25. Non-capture SC PC sulfur balances

Sulfur In, kg/hr (lb/hr)					Sulfur Out, kg/hr (lb/hr)				
Case	**B12A**	**PN1**	**PN2**	**PN3**	**Case**	**B12A**	**PN1**	**PN2**	**PN3**
Coal	5,367 (11,831)	5,001 (11,025)	4,635 (10,218)	4,188 (9,232)	**FGD Product**	5,046 (11,124)	4,698 (10,357)	4,350 (9,589)	3,924 (8,652)
Biomass	0 (0)	7 (16)	15 (33)	24 (53)	**Stack Gas**	105 (231)	98 (216)	91 (201)	83 (182)
					Polishing Scrubber and Solvent Reclaiming	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
					Baghouse	216 (477)	213 (469)	209 (461)	205 (451)
Total	**5,367 (11,831)**	**5,008 (11,042)**	**4,650 (10,251)**	**4,212 (9,285)**	**Total**	**5,367 (11,831)**	**5,008 (11,042)**	**4,650 (10,251)**	**4,212 (9,285)**

Exhibit A-26. SC PC with amine capture sulfur balances

Sulfur In, kg/hr (lb/hr)					Sulfur Out, kg/hr (lb/hr)				
Case	**B12B**	**PA1**	**PA2**	**PA3**	**Case**	**B12B**	**PA1**	**PA2**	**PA3**
Coal	6,858 (15,120)	6,442 (14,201)	6,016 (13,263)	5,485 (12,092)	**FGD Product**	6,448 (14,215)	6,051 (13,341)	5,646 (12,447)	5,140 (11,332)
Biomass	0 (0)	10 (21)	19 (43)	32 (70)	**Stack Gas**	0 (0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
					Polishing Scrubber and Solvent Reclaiming	134 (295)	126 (278)	118 (260)	108 (239)
					Baghouse	276 (609)	274 (604)	271 (598)	268 (591)
Total	**6,858 (15,120)**	**6,451 (14,223)**	**6,035 (13,305)**	**5,516 (12,161)**	**Total**	**6,858 (15,120)**	**6,451 (14,223)**	**6,035 (13,305)**	**5,516 (12,161)**

AIR EMISSIONS

Exhibit A-27. Non-capture cases air emissions summary

	kg/GJ (lb/10^6 Btu)				tonne/year (tons/year) @ 85% Capacity Factor				kg/gross MWh (lb/gross MWh)			
Case	B12A	PN1	PN2	PN3	B12A	PN1	PN2	PN3	B12A	PN1	PN2	PN3
SO_2	0.035 (0.081)	0.032 (0.074)	0.029 (0.067)	0.026 (0.060)	1,500 (1,653)	1,397 (1,539)	1,293 (1,425)	1,166 (1,286)	0.294 (0.648)	0.270 (0.595)	0.247 (0.543)	0.219 (0.482)
NOx	0.037 (0.087)	0.037 (0.087)	0.037 (0.087)	0.037 (0.087)	1,619 (1,785)	1,643 (1,811)	1,665 (1,836)	1,694 (1,867)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate	0.005 (0.011)	0.005 (0.011)	0.005 (0.011)	0.005 (0.011)	208 (230)	211 (233)	214 (236)	218 (240)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg	1.60E-7 (3.73E-7)	1.60E-7 (3.73E-7)	1.60E-7 (3.72E-7)	1.60E-7 (3.71E-7)	0.007 (0.008)	0.007 (0.008)	0.007 (0.008)	0.007 (0.008)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO_2	87 (202)	88 (204)	89 (206)	90 (209)	3,763,000 (4,147,997)	3,863,588 (4,258,876)	3,962,305 (4,367,693)	4,084,956 (4,502,893)	738 (1,627)	747 (1,646)	755 (1,665)	766 (1,688)
CO_2[A]	-	-	-	-	-	-	-	-	778 (1,714)	798 (1,760)	819 (1,805)	844 (1,861)

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

Exhibit A-28. Non-capture cases air emissions summary (cont'd)

Case	B12A	PN1	PN2	PN3	Unit
Particulate Concentration[A,B]	15.1	15.03	14.94	14.83	**mg/Nm³**

[A]Concentration of particles in the flue gas after the baghouse
[B]Normal conditions given at 32°F and 14.696 psia

Exhibit A-29. Amine capture cases air emissions summary

	kg/GJ (lb/10^6 Btu)				tonne/year (tons/year) @ 85% Capacity Factor				kg/gross MWh (lb/gross MWh)			
Case	**B12B**	**PA1**	**PA2**	**PA3**	**B12B**	**PA1**	**PA2**	**PA3**	**B12B**	**PA1**	**PA2**	**PA3**
SO_2	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0 (0)	0 (0)	0 (0)	0 (0)	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)
NOx	0.033 (0.077)	0.033 (0.076)	0.033 (0.076)	0.033 (0.076)	1,819 (2,006)	1,857 (2,047)	1,894 (2,088)	1,940 (2,139)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate	0.004 (0.010)	0.004 (0.010)	0.004 (0.010)	0.004 (0.010)	234 (258)	239 (263)	244 (268)	249 (275)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg	1.41E-7 (3.28E-7)	1.41E-7 (3.27E-7)	1.40E-7 (3.26E-7)	1.40E-7 (3.25E-7)	0.008 (0.009)	0.008 (0.009)	0.008 (0.009)	0.008 (0.009)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO_2	9 (20)	9 (20)	9 (21)	9 (21)	480,897 (530,098)	497,662 (548,578)	514,309 (566,929)	535,043 (589,784)	84 (185)	85 (188)	86 (190)	88 (193)
CO_2[A]	-	-	-	-	-	-	-	-	99 (219)	103 (227)	106 (234)	111 (244)

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

Exhibit A-30. Amine capture cases air emissions summary (cont'd)

Case	B12B	PA1	PA2	PA3	Unit
Particulate Concentration[A,B]	13.3	13.19	13.09	12.97	**mg/Nm^3**

[A]Concentration of particles in the flue gas after the baghouse
[B]Normal conditions given at 32°F and 14.696 psia

WATER BALANCES

Exhibit A-31. Case B12A and PN1 water balance summary

Water Use	Water Demand m³/min (gpm)		Internal Recycle m³/min (gpm)		Raw Water Withdrawal m³/min (gpm)		Process Water Discharge m³/min (gpm)		Raw Water Consumption m³/min (gpm)	
Case	B12A	PN1	B12A	PN1	B12A	PN1	B12A	PN1	B12A	PN1
FGD Process Makeup	2.2 (587)	2.2 (574)	–	0.4 (98)	2.2 (587)	1.8 (476)	–	–	2.2 (587)	1.8 (476)
WTA Drying	–	–	–	–	–	–	–	–	–	–
CO_2 Drying	–	–	–	–	–	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	–	–	–	–	–	–	–
CO_2 Compression KO	–	–	–	–	–	–	–	–	–	–
Deaerator Vent	–	–	–	–	–	–	0.1 (17)	0.1 (17)	-0.1 (-17)	-0.1 (-17)
Condenser Makeup	**0.1 (17)**	**0.1 (17)**	**–**	**–**	**0.1 (17)**	**0.1 (17)**	**–**	**–**	**0.1 (17)**	**0.1 (17)**
BFW Makeup	0.1 (17)	0.1 (17)	–	–	0.1 (17)	0.1 (17)	–	–	0.1 (17)	0.1 (17)
Cooling Tower	**21 (5,450)**	**21 (5,525)**	**–**	**–**	**21 (5,450)**	**21 (5,525)**	**4.6 (1,226)**	**4.7 (1,243)**	**16 (4,225)**	**16 (4,283)**
BFW Blowdown	–	–	–	–	–	–	–	–	–	–
Total	**23 (6,054)**	**23 (6,116)**	**–**	**0.4 (98)**	**23 (6,054)**	**23 (6,019)**	**4.7 (1,242)**	**4.8 (1,260)**	**18 (4,811)**	**18 (4,759)**

Exhibit A-32. Case PN2 and PN3 water balance summary

Water Use	Water Demand m³/min (gpm)		Internal Recycle m³/min (gpm)		Raw Water Withdrawal m³/min (gpm)		Process Water Discharge m³/min (gpm)		Raw Water Consumption m³/min (gpm)	
Case	PN2	PN3	PN2	PN3	PN2	PN3	PN2	PN3	PN2	PN3
FGD Process Makeup	2.1 (551)	2.0 (524)	0.7 (195)	1.2 (315)	1.3 (356)	0.8 (209)	–	–	1.3 (356)	0.8 (209)
WTA Drying	–	–	–	–	–	–	–	–	–	–
CO_2 Drying	–	–	–	–	–	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	–	–	–	–	–	–	–
CO_2 Compression KO	–	–	–	–	–	–	–	–	–	–
Deaerator Vent	–	–	–	–	–	–	0.1 (17)	0.1 (17)	-0.1 (-17)	-0.1 (-17)
Condenser Makeup	**0.1 (17)**	**0.1 (17)**	**–**	**–**	**0.1 (17)**	**0.1 (17)**	**–**	**–**	**0.1 (17)**	**0.1 (17)**
BFW Makeup	0.1 (17)	0.1 (17)	–	–	0.1 (17)	0.1 (17)	–	–	0.1 (17)	0.1 (17)
Cooling Tower	**21 (5,598)**	**22 (5,690)**	**–**	**–**	**21 (5,598)**	**22 (5,690)**	**4.8 (1,259)**	**4.8 (1,280)**	**16 (4,339)**	**17 (4,410)**
BFW Blowdown	–	–	–	–	–	–	–	–	–	–
Total	**23 (6,167)**	**24 (6,231)**	**0.7 (195)**	**1.2 (315)**	**23 (5,972)**	**22 (5,917)**	**4.8 (1,276)**	**4.9 (1,297)**	**18 (4,696)**	**17 (4,620)**

Exhibit A-33. Case B12B and PA1 water balance summary

Water Use	Water Demand m³/min (gpm)		Internal Recycle m³/min (gpm)		Raw Water Withdrawal m³/min (gpm)		Process Water Discharge m³/min (gpm)		Raw Water Consumption m³/min (gpm)	
Case	**B12B**	**PA1**	**B12B**	**PA1**	**B12B**	**PA1**	**B12B**	**PA1**	**B12B**	**PA1**
FGD Process Makeup	2.8 (750)	2.8 (739)	2.8 (750)	2.8 (739)	–	–	–	–	–	–
WTA Drying	–	–	–	–	–	–	–	0.5 (126)	–	-0.5 (-126)
CO_2 Drying	–	–	–	–	–	–	0.0 (2.1)	0.0 (2.2)	0.0 (-2.1)	0.0 (-2.2)
CO_2 Capture Recovery	–	–	–	–	–	–	2.4 (633)	2.6 (690)	-2.4 (-633)	-2.6 (-690)
CO_2 Compression KO	–	–	–	–	–	–	0.0 (12)	0.0 (13)	0.0 (-12)	0.0 (-13)
Deaerator Vent	–	–	–	–	–	–	0.1 (21)	0.1 (22)	-0.1 (-21)	-0.1 (-22)
Condenser Makeup	**0.1 (21)**	**0.1 (22)**	**–**	**–**	**0.1 (21)**	**0.1 (22)**	**–**	**–**	**0.1 (21)**	**0.1 (22)**
BFW Makeup	0.1 (21)	0.1 (22)	–	–	0.1 (21)	0.1 (22)	–	–	0.1 (21)	0.1 (22)
Cooling Tower	**37 (9,890)**	**38 (10,144)**	**–**	**–**	**37 (9,890)**	**38 (10,144)**	**8.4 (2,224)**	**8.6 (2,281)**	**29 (7,666)**	**30 (7,862)**
BFW Blowdown	–	–	–	–	–	–	–	–	–	–
Total	**40 (10,661)**	**41 (10,905)**	**2.8 (750)**	**2.8 (739)**	**38 (9,911)**	**38 (10,165)**	**11 (2,893)**	**12 (3,134)**	**27 (7,018)**	**27 (7,031)**

Exhibit A-34. Case PA2 and PA3 water balance summary

Water Use	Water Demand m³/min (gpm)		Internal Recycle m³/min (gpm)		Raw Water Withdrawal m³/min (gpm)		Process Water Discharge m³/min (gpm)		Raw Water Consumption m³/min (gpm)	
Case	**PA2**	**PA3**	**PA2**	**PA3**	**PA2**	**PA3**	**PA2**	**PA3**	**PA2**	**PA3**
FGD Process Makeup	2.7 (716)	2.6 (686)	2.7 (716)	2.6 (686)	–	–	–	–	–	–
WTA Drying	–	–	–	–	–	–	1.0 (253)	1.6 (412)	-1.0 (-253)	-1.6 (-412)
CO_2 Drying	–	–	–	–	–	–	0.0 (2.3)	0.0 (2.4)	0.0 (-2.3)	0.0 (-2.4)
CO_2 Capture Recovery	–	–	–	–	–	–	2.8 (748)	3.1 (819)	-2.8 (-748)	-3.1 (-819)
CO_2 Compression KO	–	–	–	–	–	–	0.0 (13)	0.1 (14)	0.0 (-13)	-0.1 (-14)
Deaerator Vent	–	–	–	–	–	–	0.1 (22)	0.1 (23)	-0.1 (-22)	-0.1 (-23)
Condenser Makeup	**0.1 (22)**	**0.1 (23)**	**–**	**–**	**0.1 (22)**	**0.1 (23)**	**–**	**–**	**0.1 (22)**	**0.1 (23)**
BFW Makeup	0.1 (22)	0.1 (23)	–	–	0.1 (22)	0.1 (23)	–	–	0.1 (22)	0.1 (23)
Cooling Tower	**39 (10,394)**	**41 (10,706)**	**–**	**–**	**39 (10,394)**	**41 (10,706)**	**8.8 (2,338)**	**9.1 (2,408)**	**30 (8,056)**	**31 (8,298)**
BFW Blowdown	–	–	–	–	–	–	–	–	–	–
Total	**42 (11,132)**	**43 (11,415)**	**2.7 (716)**	**2.6 (686)**	**39 (10,416)**	**41 (10,729)**	**13 (3,376)**	**14 (3,678)**	**27 (7,040)**	**27 (7,051)**

ENERGY BALANCES

Exhibit A-35. Non-capture cases energy balance (0°C [32°F] reference)

	HHV		Sensible + Latent		Power		Total	
Case	**B12A**	**PN1**	**B12A**	**PN1**	**B12A**	**PN1**	**B12A**	**PN1**
Heat In GJ/hr (MMBtu/hr)								
Coal	5,810 (5,507)	5,414 (5,132)	4.9 (4.6)	4.5 (4.3)	–	–	5,815 (5,511)	5,419 (5,136)
Biomass	–	490 (464)	–	1.1 (1.1)	–	–	–	491 (465)
Air	–	–	68 (64)	69 (65)	–	–	68 (64)	69 (65)
Raw Water Makeup	–	–	86 (82)	86 (81)	–	–	86 (82)	86 (81)
Limestone	–	–	0.4 (0.4)	0.4 (0.4)	–	–	0.4 (0.4)	0.4 (0.4)
Auxiliary Power	–	–	–	–	126 (120)	161 (153)	126 (120)	161 (153)
TOTAL	**5,810 (5,507)**	**5,904 (5,596)**	**159 (151)**	**160 (152)**	**126 (120)**	**161 (153)**	**6,095 (5,777)**	**6,225 (5,901)**
Heat Out GJ/hr (MMBtu/hr)								
Bottom Ash	–	–	5.5 (5.2)	5.2 (4.9)	–	–	5.5 (5.2)	5.2 (4.9)
Fly Ash	–	–	2.0 (1.9)	1.9 (1.8)	–	–	2.0 (1.9)	1.9 (1.8)
Stack Gas	–	–	781 (741)	798 (757)	–	–	781 (741)	798 (757)
Sulfur	–	0.0 (0.0)	–	0.0 (0.0)	–	–	–	0.0 (0.0)
Gypsum	–	–	2.0 (1.9)	1.9 (1.8)	–	–	2.0 (1.9)	1.9 (1.8)
Motor Losses and Design Allowances	–	–	–	–	40 (38)	41 (38)	40 (38)	41 (38)
Cooling Tower Load[A]	–	–	2,694 (2,554)	2,731 (2,589)	–	–	2,694 (2,554)	2,731 (2,589)
CO_2 Product Stream	–	–	–	–	–	–	–	–
Blowdown Streams and Deaerator Vent	–	–	2.4 (2.3)	2.4 (2.3)	–	–	2.4 (2.3)	2.4 (2.3)
Ambient Losses[B]	–	–	*137 (129)*	*149 (141)*	–	–	*137 (129)*	*149 (141)*
Power	–	–	–	–	2,466 (2,337)	2,502 (2,371)	2,466 (2,337)	2,502 (2,371)
TOTAL	**0.0 (0.0)**	**0.0 (0.0)**	**3,624 (3,435)**	**3,690 (3,498)**	**2,506 (2,375)**	**2,542 (2,409)**	**6,130 (5,810)**	**6,232 (5,907)**
Unaccounted Energy[C]	–	–	–	–	–	–	*-35 (-33)*	*-6.9 (-6.5)*

[A]Includes condenser, AGR, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

Exhibit A-35. Non-capture cases energy balance (cont'd)

	HHV		Sensible + Latent		Power		Total	
Case	PN2	PN3	PN2	PN3	PN2	PN3	PN2	PN3
Heat In GJ/hr (MMBtu/hr)								
Coal	5,018 (4,756)	4,534 (4,297)	4.2 (4.0)	3.8 (3.6)	–	–	5,022 (4,760)	4,537 (4,301)
Biomass	977 (926)	1,575 (1,493)	2.3 (2.1)	3.6 (3.4)	–	–	979 (928)	1,579 (1,497)
Air	–	–	70 (66)	71 (67)	–	–	70 (66)	71 (67)
Raw Water Makeup	–	–	85 (81)	84 (80)	–	–	85 (81)	84 (80)
Limestone	–	–	0.4 (0.4)	0.3 (0.3)	–	–	0.4 (0.4)	0.3 (0.3)
Auxiliary Power	–	–	–	–	196 (186)	239 (227)	196 (186)	239 (227)
TOTAL	**5,995 (5,682)**	**6,109 (5,790)**	**162 (153)**	**163 (155)**	**196 (186)**	**239 (227)**	**6,352 (6,021)**	**6,511 (6,171)**
Heat Out GJ/hr (MMBtu/hr)								
Bottom Ash	–	–	4.9 (4.7)	4.6 (4.3)	–	–	4.9 (4.7)	4.6 (4.3)
Fly Ash	–	–	1.8 (1.7)	1.7 (1.6)	–	–	1.8 (1.7)	1.7 (1.6)
Stack Gas	–	–	809 (767)	823 (780)	–	–	809 (767)	823 (780)
Sulfur	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)	–	–	0.0 (0.0)	0.0 (0.0)
Gypsum	–	–	1.8 (1.7)	1.6 (1.5)	–	–	1.8 (1.7)	1.6 (1.5)
Motor Losses and Design Allowances	–	–	–	–	41 (39)	42 (40)	41 (39)	42 (40)
Cooling Tower Load[A]	–	–	2,767 (2,623)	2,813 (2,666)	–	–	2,767 (2,623)	2,813 (2,666)
CO_2 Product Stream	–	–	–	–	–	–	–	–
Blowdown Streams and Deaerator Vent	–	–	2.5 (2.3)	2.5 (2.4)	–	–	2.5 (2.3)	2.5 (2.4)
Ambient Losses[B]	–	–	*167 (158)*	*190 (180)*	–	–	*167 (158)*	*190 (180)*
Power	–	–	–	–	2,536 (2,404)	2,579 (2,444)	2,536 (2,404)	2,579 (2,444)
TOTAL	**0.0 (0.0)**	**0.0 (0.0)**	**3,755 (3,559)**	**3,835 (3,635)**	**2,577 (2,442)**	**2,621 (2,484)**	**6,332 (6,001)**	**6,456 (6,119)**
Unaccounted Energy[C]	–	–	–	–	–	–	*21 (20)*	*55 (52)*

[A]Includes condenser, AGR, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

Exhibit A-36. Capture cases energy balance (0°C [32°F] reference)

	HHV		Sensible + Latent		Power		Total	
Case	B12B	PA1	B12B	PA1	B12B	PA1	B12B	PA1
Heat In GJ/hr (MMBtu/hr)								
Coal	7,425 (7,037)	6,974 (6,610)	6.2 (5.9)	5.8 (5.5)	–	–	7,431 (7,043)	6,980 (6,615)
Biomass	–	631 (598)	–	1.5 (1.4)	–	–	–	632 (599)
Air	–	–	86 (82)	89 (84)	–	–	86 (82)	89 (84)
Raw Water Makeup	–	–	141 (134)	145 (137)	–	–	141 (134)	145 (137)
Limestone	–	–	0.6 (0.5)	0.5 (0.5)	–	–	0.6 (0.5)	0.5 (0.5)
Auxiliary Power	–	–	–	–	432 (409)	488 (463)	432 (409)	488 (463)
TOTAL	**7,425 (7,037)**	**7,604 (7,208)**	**234 (222)**	**241 (228)**	**432 (409)**	**488 (463)**	**8,091 (7,669)**	**8,334 (7,899)**
Heat Out GJ/hr (MMBtu/hr)								
Bottom Ash	–	–	7.0 (6.7)	6.7 (6.4)	–	–	7.0 (6.7)	6.7 (6.4)
Fly Ash	–	–	2.5 (2.4)	2.4 (2.3)	–	–	2.5 (2.4)	2.4 (2.3)
Stack Gas	–	–	225 (213)	230 (218)	–	–	225 (213)	230 (218)
Sulfur	2.5 (2.4)	2.4 (2.2)	0.0 (0.0)	0.0 (0.0)	–	–	2.5 (2.4)	2.4 (2.2)
Gypsum	–	–	2.6 (2.5)	2.4 (2.3)	–	–	2.6 (2.5)	2.4 (2.3)
Motor Losses and Design Allowances	–	–	–	–	50 (48)	51 (49)	50 (48)	51 (49)
Cooling Tower Load[A]	–	–	4,889 (4,634)	5,014 (4,753)	–	–	4,889 (4,634)	5,014 (4,753)
CO_2 Product Stream	–	–	-134 (-127)	-139 (-132)	–	–	-134 (-127)	-139 (-132)
Blowdown Streams and Deaerator Vent	–	–	3.1 (2.9)	3.1 (3.0)	–	–	3.1 (2.9)	3.1 (3.0)
Ambient Losses[B]	–	–	*177 (167)*	*194 (184)*	–	–	*177 (167)*	*194 (184)*
Power	–	–	–	–	2,771 (2,626)	2,828 (2,680)	2,771 (2,626)	2,828 (2,680)
TOTAL	**2.5 (2.4)**	**2.4 (2.2)**	**5,171 (4,901)**	**5,313 (5,036)**	**2,821 (2,674)**	**2,879 (2,729)**	**7,995 (7,577)**	**8,195 (7,767)**
Unaccounted Energy[C]	–	–	–	–	–	–	*97 (92)*	*139 (131)*

[A]Includes condenser, AGR, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

Exhibit A-37. Capture cases energy balance (cont'd)

	HHV		Sensible + Latent		Power		Total	
Case	**PA2**	**PA3**	**PA2**	**PA3**	**PA2**	**PA3**	**PA2**	**PA3**
Heat In GJ/hr (MMBtu/hr)								
Coal	6,513 (6,173)	5,938 (5,628)	5.4 (5.2)	5.0 (4.7)	–	–	6,518 (6,178)	5,943 (5,633)
Biomass	1,268 (1,202)	2,063 (1,956)	2.9 (2.8)	4.8 (4.5)	–	–	1,271 (1,205)	2,068 (1,960)
Air	–	–	91 (86)	93 (88)	–	–	91 (86)	93 (88)
Raw Water Makeup	–	–	148 (141)	153 (145)	–	–	148 (141)	153 (145)
Limestone	–	–	0.5 (0.5)	0.5 (0.4)	–	–	0.5 (0.5)	0.5 (0.4)
Auxiliary Power	–	–	–	–	544 (516)	614 (582)	544 (516)	614 (582)
TOTAL	**7,781 (7,375)**	**8,001 (7,584)**	**248 (235)**	**256 (243)**	**544 (516)**	**614 (582)**	**8,573 (8,126)**	**8,872 (8,409)**
Heat Out GJ/hr (MMBtu/hr)								
Bottom Ash	–	–	6.4 (6.1)	6.0 (5.7)	–	–	6.4 (6.1)	6.0 (5.7)
Fly Ash	–	–	2.4 (2.2)	2.2 (2.1)	–	–	2.4 (2.2)	2.2 (2.1)
Stack Gas	–	–	234 (222)	239 (227)	–	–	234 (222)	239 (227)
Sulfur	2.2 (2.1)	2.0 (1.9)	0.0 (0.0)	0.0 (0.0)	–	–	2.2 (2.1)	2.0 (1.9)
Gypsum	–	–	2.3 (2.2)	2.1 (2.0)	–	–	2.3 (2.2)	2.1 (2.0)
Motor Losses and Design Allowances	–	–	–	–	52 (50)	54 (51)	52 (50)	54 (51)
Cooling Tower Load[A]	–	–	5,138 (4,870)	5,292 (5,016)	–	–	5,138 (4,870)	5,292 (5,016)
CO_2 Product Stream	–	–	-144 (-136)	-149 (-142)	–	–	-144 (-136)	-149 (-142)
Blowdown Streams and Deaerator Vent	–	–	3.2 (3.0)	3.3 (3.1)	–	–	3.2 (3.0)	3.3 (3.1)
Ambient Losses[B]	–	–	*219 (208)*	*251 (238)*	–	–	*219 (208)*	*251 (238)*
Power	–	–	–	–	2,884 (2,733)	2,954 (2,800)	2,884 (2,733)	2,954 (2,800)
TOTAL	**2.2 (2.1)**	**2.0 (1.9)**	**5,462 (5,177)**	**5,646 (5,352)**	**2,936 (2,783)**	**3,008 (2,851)**	**8,400 (7,962)**	**8,656 (8,205)**
Unaccounted Energy[C]	–	–	–	–	–	–	*173 (164)*	*215 (204)*

[A]Includes condenser, AGR, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

EQUIPMENT LISTS

Case B12A

Case B12A – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	40 tonne (50 ton)	2	1
9	Feeder	Vibratory	180 tonne/hr (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	180 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	350 tonne/hr (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	790 tonne (900 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 9 tonne (9 ton) Feeder - 50 kg/hr (110 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 220 tonne (240 ton) Feeder - 1,300 kg/hr (2,860 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	87 tonne/hr (96 tph)	1	0
23	Limestone Conveyor No. 1	Belt	87 tonne/hr (96 tph)	1	0
24	Limestone Reclaim Hopper	N/A	17 tonne (19 ton)	1	0
25	Limestone Reclaim Feeder	Belt	68 tonne/hr (75 tph)	1	0
26	Limestone Conveyor No. 2	Belt	68 tonne/hr (75 tph)	1	0
27	Limestone Day Bin	w/ actuator	273 tonne (301 ton)	2	0

Case B12A – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	39 tonne/hr (43 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	39 tonne/hr (43 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	23 tonne/hr (25 tph)	1	1
4	Limestone Ball Mill	Rotary	23 tonne/hr (25 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	88,600 liters (23,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,460 lpm @ 10m H_2O (390 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	370 lpm (100 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	493,000 liters (130,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,030 lpm @ 9m H_2O (270 gpm @ 30 ft H_2O)	1	1

Case B12A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	250,000 liters (66,000 gal)	2	0
2	Condensate Pumps	Vertical canned	25,200 lpm @ 200 m H_2O (6,600 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,079,000 kg/hr (4,584,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	34,800 lpm @ 3,500 m H_2O (9,200 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	10,400 lpm @ 3,500 m H_2O (2,700 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	750,000 kg/hr (1,650,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	750,000 kg/hr (1,650,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	750,000 kg/hr (1,650,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	750,000 kg/hr (1,650,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,080,000 kg/hr (4,570,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,080,000 kg/hr (4,570,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,080,000 kg/hr (4,570,000 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	6,120 lpm @ 20 m H_2O (1,620 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,450 lpm @ 270 m H_2O (650 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	940 lpm @ 50 m H_2O (250 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	899,000 liter (238,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 1,940 m^3/min (68,360 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 110 lpm (30 gpm) @ 20,020 ppmw Cl^-	2	1

Case B12A – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	SC, drum, wall-fired, low NOx burners, overfire air	2,080,000 kg/hr steam @ 24.1 MPa/593°C/593°C (4,570,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	285,000 kg/hr, 3,900 m^3/min @ 123 cm WG (627,000 lb/hr, 137,100 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	926,000 kg/hr, 12,600 m^3/min @ 47 cm WG (2,043,000 lb/hr, 446,500 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,344,000 kg/hr, 26,700 m^3/min @ 93 cm WG (2,962,000 lb/hr, 944,600 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,540,000 kg/hr (5,600,000 lb/hr)	2	0

6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	90 m^3/min @ 108 cm WG (3,300 acfm @ 42 in WG)	2	1
8	Ammonia Storage	Horizontal tank	103,000 liter (27,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	20 lpm @ 90 m H_2O (5 gpm @ 300 ft H_2O)	2	1

Case B12A – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,344,000 kg/hr (2,963,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	45,000 m^3/min (1,605,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	158,000 lpm @ 65 m H_2O (42,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,370 lpm (1,160 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	750 m^3/min @ 0.3 MPa (26,420 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,100 lpm (290 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	35 tonne/hr (38 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	670 lpm @ 13 m H_2O (180 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	440,000 lpm (120,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,560 lpm @ 21 m H_2O (410 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (110 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,300 kg/hr (2,860 lb/hr)	1	0

Case B12A – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case B12A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	710 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0

2	Steam Turbine Generator	Hydrogen cooled, static excitation	790 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-ph	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,420 GJ/hr (2,700 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case B12A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	532,000 lpm @ 30 m (140,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2960 GJ/hr (2810 MMBtu/hr) heat duty	1	0

Case B12A – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	4.7 tonne/hr (5.2 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	19 m^3/min @ 0.2 MPa (678 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,260 tonne (1,390 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	120 tonne/hr (130 tph)	1	0

Case B12A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 750 MVA, 3-ph, 60 Hz	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 31 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12A – Account 12: Instrumentation and Control

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

Case PN1

Case PN1 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	40 tonne (50 ton)	2	1
9	Feeder	Vibratory	160 tonne/hr (180 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	330 tonne/hr (360 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	160 tonne (180 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	330 tonne/hr (360 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	330 tonne/hr (360 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	730 tonne (800 ton)	3	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 9 tonne (10 ton) Feeder - 50 kg/hr (110 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 220 tonne (240 ton) Feeder - 1,320 kg/hr (2,910 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	81 tonne/hr (89 tph)	1	0
23	Limestone Conveyor No. 1	Belt	81 tonne/hr (89 tph)	1	0
24	Limestone Reclaim Hopper	N/A	16 tonne (18 ton)	1	0
25	Limestone Reclaim Feeder	Belt	64 tonne/hr (70 tph)	1	0
26	Limestone Conveyor No. 2	Belt	64 tonne/hr (70 tph)	1	0
27	Limestone Day Bin	w/ actuator	255 tonne (281 ton)	2	0

Case PN1 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	37 tonne/hr (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	37 tonne/hr (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	21 tonne/hr (23 tph)	1	1
4	Limestone Ball Mill	Rotary	21 tonne/hr (23 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	81,800 liters (22,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,350 lpm @ 10m H_2O (360 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	340 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	459,000 liters (121,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	960 lpm @ 9m H_2O (250 gpm @ 30 ft H_2O)	1	1

Case PN1 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	253,000 liters (67,000 gal)	2	0
2	Condensate Pumps	Vertical canned	25,500 lpm @ 200 m H_2O (6,700 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,109,000 kg/hr (4,650,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	35,300 lpm @ 3,500 m H_2O (9,300 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	10,500 lpm @ 3,500 m H_2O (2,800 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	760,000 kg/hr (1,680,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	760,000 kg/hr (1,680,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	760,000 kg/hr (1,680,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	760,000 kg/hr (1,680,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,100,000 kg/hr (4,640,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,100,000 kg/hr (4,640,000 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	HP Feedwater heater 8	Horizontal U-tube	2,100,000 kg/hr (4,640,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	6,210 lpm @ 20 m H_2O (1,640 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,490 lpm @ 270 m H_2O (660 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	960 lpm @ 50 m H_2O (250 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	919,000 liter (243,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 1,810 m^3/min (63,900 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 110 lpm (30 gpm) @ 19,988 ppmw Cl^-	2	1

Case PN1 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,100,000 kg/hr steam @ 24.1 MPa/593°C/593°C (4,640,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	302,000 kg/hr, 4,100 m^3/min @ 123 cm WG (666,000 lb/hr, 145,600 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	928,000 kg/hr, 12,700 m^3/min @ 47 cm WG (2,046,000 lb/hr, 447,300 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,371,000 kg/hr, 27,300 m^3/min @ 93 cm WG (3,022,000 lb/hr, 964,300 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,590,000 kg/hr (5,720,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	100 m^3/min @ 108 cm WG (3,400 acfm @ 42 in WG)	2	1

8	Ammonia Storage	Horizontal tank	105,000 liter (28,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	20 lpm @ 90 m H_2O (5 gpm @ 300 ft H_2O)	2	1

Case PN1 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,371,000 kg/hr (3,022,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	46,000 m^3/min (1,630,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	160,000 lpm @ 65 m H_2O (42,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,070 lpm (1,080 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	700 m^3/min @ 0.3 MPa (24,600 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,020 lpm (270 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	32 tonne/hr (36 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	620 lpm @ 13 m H_2O (160 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	410,000 lpm (110,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,560 lpm @ 21 m H_2O (410 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (110 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,320 kg/hr (2,910 lb/hr)	1	0

Case PN1 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case PN1 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	720 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	800 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,440 GJ/hr (2,740 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case PN1 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	539,000 lpm @ 30 m (142,000 gpm @ 100 ft)	2	1

2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3000 GJ/hr (2850 MMBtu/hr) heat duty	1	0

Case PN1 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	4.5 tonne/hr (5 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	18 m^3/min @ 0.2 MPa (646 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,200 tonne (1,320 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	110 tonne/hr (120 tph)	1	0

Case PN1 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 750 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 39 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case PN1 – Account 12: Instrumentation and Control

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

Case PN2

Case PN2 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	40 tonne (40 ton)	2	1
9	Feeder	Vibratory	150 tonne/hr (170 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	310 tonne/hr (340 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	150 tonne (170 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	310 tonne/hr (340 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	310 tonne/hr (340 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	680 tonne (700 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 9 tonne (10 ton) Feeder - 50 kg/hr (120 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 230 tonne (250 ton) Feeder - 1,340 kg/hr (2,960 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	75 tonne/hr (83 tph)	1	0
23	Limestone Conveyor No. 1	Belt	75 tonne/hr (83 tph)	1	0
24	Limestone Reclaim Hopper	N/A	15 tonne (16 ton)	1	0
25	Limestone Reclaim Feeder	Belt	59 tonne/hr (65 tph)	1	0
26	Limestone Conveyor No. 2	Belt	59 tonne/hr (65 tph)	1	0
27	Limestone Day Bin	w/ actuator	236 tonne (260 ton)	2	0

Case PN2 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	34 tonne/hr (37 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	34 tonne/hr (37 tph)	6	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Limestone Weigh Feeder	Gravimetric	20 tonne/hr (22 tph)	1	1
4	Limestone Ball Mill	Rotary	20 tonne/hr (22 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	75,000 liters (20,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,240 lpm @ 10m H_2O (330 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	310 lpm (80 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	425,000 liters (112,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	880 lpm @ 9m H_2O (230 gpm @ 30 ft H_2O)	1	1

Case PN2 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	257,000 liters (68,000 gal)	2	0
2	Condensate Pumps	Vertical canned	25,900 lpm @ 200 m H_2O (6,800 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,138,000 kg/hr (4,714,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	35,800 lpm @ 3,500 m H_2O (9,500 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	10,700 lpm @ 3,500 m H_2O (2,800 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	770,000 kg/hr (1,700,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	770,000 kg/hr (1,700,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	770,000 kg/hr (1,700,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	770,000 kg/hr (1,700,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,130,000 kg/hr (4,700,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,130,000 kg/hr (4,700,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,130,000 kg/hr (4,700,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	6,280 lpm @ 20 m H_2O (1,660 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,510 lpm @ 270 m H_2O (660 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	940 lpm @ 50 m H_2O (250 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	899,000 liter (238,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 1,680 m^3/min (59,340 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 100 lpm (30 gpm) @ 20,032 ppmw Cl^-	2	1

Case PN2 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,130,000 kg/hr steam @ 24.1 MPa/593°C/593°C (4,700,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	319,000 kg/hr, 4,400 m^3/min @ 123 cm WG (704,000 lb/hr, 153,900 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	930,000 kg/hr, 12,700 m^3/min @ 47 cm WG (2,050,000 lb/hr, 448,000 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,397,000 kg/hr, 27,800 m^3/min @ 93 cm WG (3,080,000 lb/hr, 983,500 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,650,000 kg/hr (5,830,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	100 m^3/min @ 108 cm WG (3,400 acfm @ 42 in WG)	2	1
8	Ammonia Storage	Horizontal tank	107,000 liter (28,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	20 lpm @ 90 m H_2O (5 gpm @ 300 ft H_2O)	2	1

Case PN2 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,397,000 kg/hr (3,080,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	47,000 m^3/min (1,652,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	163,000 lpm @ 65 m H_2O (43,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	3,770 lpm (1,000 gpm) at 20 wt% solids	2	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	Oxidation Air Blowers	Centrifugal	640 m^3/min @ 0.3 MPa (22,780 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	950 lpm (250 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	30 tonne/hr (33 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	570 lpm @ 13 m H_2O (150 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	380,000 lpm (100,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,530 lpm @ 21 m H_2O (400 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (120 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,340 kg/hr (2,960 lb/hr)	1	0

Case PN2 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case PN2 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	730 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	810 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,460 GJ/hr (2,780 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case PN2 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	546,000 lpm @ 30 m (144,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3040 GJ/hr (2890 MMBtu/hr) heat duty	1	0

Case PN2 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	4.3 tonne/hr (4.7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	17 m^3/min @ 0.2 MPa (615 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,140 tonne (1,260 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	110 tonne/hr (120 tph)	1	0

Case PN2 – Account 11: Accessory Electric Plant

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

Case PN2 – Account 12: Instrumentation and Control

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

Case PN3

Case PN3 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	30 tonne (40 ton)	2	1
9	Feeder	Vibratory	140 tonne/hr (150 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	280 tonne/hr (300 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	140 tonne (150 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	280 tonne/hr (300 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	280 tonne/hr (300 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	610 tonne (700 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 9 tonne (10 ton) Feeder - 50 kg/hr (120 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 230 tonne (250 ton) Feeder - 1,370 kg/hr (3,020 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	68 tonne/hr (75 tph)	1	0
23	Limestone Conveyor No. 1	Belt	68 tonne/hr (75 tph)	1	0
24	Limestone Reclaim Hopper	N/A	13 tonne (15 ton)	1	0
25	Limestone Reclaim Feeder	Belt	54 tonne/hr (59 tph)	1	0
26	Limestone Conveyor No. 2	Belt	54 tonne/hr (59 tph)	1	0
27	Limestone Day Bin	w/ actuator	213 tonne (234 ton)	2	0

Case PN3 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	31 tonne/hr (34 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	31 tonne/hr (34 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	18 tonne/hr (20 tph)	1	1
4	Limestone Ball Mill	Rotary	18 tonne/hr (20 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	68,100 liters (18,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,140 lpm @ 10m H_2O (300 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	280 lpm (80 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	383,000 liters (101,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	800 lpm @ 9m H_2O (210 gpm @ 30 ft H_2O)	1	1

Case PN3 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	261,000 liters (69,000 gal)	2	0
2	Condensate Pumps	Vertical canned	26,300 lpm @ 200 m H_2O (7,000 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,174,000 kg/hr (4,794,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	36,400 lpm @ 3,500 m H_2O (9,600 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	10,900 lpm @ 3,500 m H_2O (2,900 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	780,000 kg/hr (1,730,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	780,000 kg/hr (1,730,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	780,000 kg/hr (1,730,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	780,000 kg/hr (1,730,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,170,000 kg/hr (4,780,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,170,000 kg/hr (4,780,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,170,000 kg/hr (4,780,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	6,360 lpm @ 20 m H_2O (1,680 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,550 lpm @ 270 m H_2O (670 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	920 lpm @ 50 m H_2O (240 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	879,000 liter (232,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 1,520 m^3/min (53,820 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 90 lpm (20 gpm) @ 19,976 ppmw Cl^-	2	1

Case PN3 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,170,000 kg/hr steam @ 24.1 MPa/593°C/593°C (4,780,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	341,000 kg/hr, 4,600 m^3/min @ 123 cm WG (751,000 lb/hr, 164,200 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	932,000 kg/hr, 12,700 m^3/min @ 47 cm WG (2,054,000 lb/hr, 449,000 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,430,000 kg/hr, 28,500 m^3/min @ 93 cm WG (3,152,000 lb/hr, 1,007,400 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,710,000 kg/hr (5,970,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	100 m^3/min @ 108 cm WG (3,500 acfm @ 42 in WG)	2	1
8	Ammonia Storage	Horizontal tank	109,000 liter (29,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	21 lpm @ 90 m H_2O (5 gpm @ 300 ft H_2O)	2	1

Case PN3 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,430,000 kg/hr (3,153,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	48,000 m^3/min (1,679,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	165,000 lpm @ 65 m H_2O (44,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	3,400 lpm (900 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	580 m^3/min @ 0.3 MPa (20,550 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	850 lpm (230 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	27 tonne/hr (30 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	520 lpm @ 13 m H_2O (140 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	340,000 lpm (90,000 gal)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
11	Process Makeup Water Pumps	Horizontal centrifugal	1,490 lpm @ 21 m H_2O (390 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (120 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,370 kg/hr (3,020 lb/hr)	1	0

Case PN3 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case PN3 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	743 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	830 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,490 GJ/hr (2,820 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case PN3 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	555,000 lpm @ 30 m (147,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3090 GJ/hr (2930 MMBtu/hr) heat duty	1	0

Case PN3 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	4.0 tonne/hr (4.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	16 m^3/min @ 0.2 MPa (577 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,070 tonne (1,180 ton)	2	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	100 tonne/hr (110 tph)	1	0

Case PN3 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 56 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 10 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case PN3 – Account 12: Instrumentation and Control

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

Case B12B

Case B12B – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	60 tonne (60 ton)	2	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Feeder	Vibratory	230 tonne/hr (250 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	450 tonne/hr (500 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	230 tonne (250 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	450 tonne/hr (500 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	450 tonne/hr (500 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,000 tonne (1,100 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (12 ton) Feeder - 60 kg/hr (140 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 280 tonne (310 ton) Feeder - 1,660 kg/hr (3,650 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	112 tonne/hr (123 tph)	1	0
23	Limestone Conveyor No. 1	Belt	112 tonne/hr (123 tph)	1	0
24	Limestone Reclaim Hopper	N/A	22 tonne (24 ton)	1	0
25	Limestone Reclaim Feeder	Belt	87 tonne/hr (96 tph)	1	0
26	Limestone Conveyor No. 2	Belt	87 tonne/hr (96 tph)	1	0
27	Limestone Day Bin	w/ actuator	349 tonne (385 ton)	2	0

Case B12B – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	50 tonne/hr (55 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	50 tonne/hr (55 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	29 tonne/hr (32 tph)	1	1
4	Limestone Ball Mill	Rotary	29 tonne/hr (32 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	113,600 liters (30,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,890 lpm @ 10m H_2O (500 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	470 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	629,000 liters (166,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,310 lpm @ 9m H_2O (350 gpm @ 30 ft H_2O)	1	1

Case B12B – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	319,000 liters (84,000 gal)	2	0
2	Condensate Pumps	Vertical canned	22,200 lpm @ 200 m H_2O (5,900 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,658,000 kg/hr (5,860,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	44,500 lpm @ 3,500 m H_2O (11,800 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	13,300 lpm @ 3,500 m H_2O (3,500 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	960,000 kg/hr (2,110,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	960,000 kg/hr (2,110,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	960,000 kg/hr (2,110,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	960,000 kg/hr (2,110,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,650,000 kg/hr (5,850,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,650,000 kg/hr (5,850,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,650,000 kg/hr (5,850,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	9,680 lpm @ 20 m H_2O (2,560 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	3,870 lpm @ 270 m H_2O (1,020 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,170 lpm @ 50 m H_2O (310 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	1,119,000 liter (296,000 gal)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,470 m^3/min (87,370 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 150 lpm (40 gpm) @ 19,992 ppmw Cl^-	2	1

Case B12B – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	SC, drum, wall-fired, low NOx burners, overfire air	2,650,000 kg/hr steam @ 24.1 MPa/593°C/593°C (5,850,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	364,000 kg/hr, 5,000 m^3/min @ 123 cm WG (802,000 lb/hr, 175,300 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	1,184,000 kg/hr, 16,200 m^3/min @ 47 cm WG (2,610,000 lb/hr, 570,600 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,717,000 kg/hr, 34,200 m^3/min @ 93 cm WG (3,786,000 lb/hr, 1,207,200 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,250,000 kg/hr (7,160,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	120 m^3/min @ 108 cm WG (4,400 acfm @ 42 in WG)	2	1
8	Ammonia Storage	Horizontal tank	137,000 liter (36,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	26 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B12B – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,717,000 kg/hr (3,786,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	58,000 m^3/min (2,052,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	202,000 lpm @ 65 m H_2O (53,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,590 lpm (1,480 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	960 m^3/min @ 0.3 MPa (33,770 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
7	Dewatering Cyclones	Radial assembly, 5 units each	1,400 lpm (370 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	44 tonne/hr (49 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	850 lpm @ 13 m H_2O (220 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	560,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,990 lpm @ 21 m H_2O (530 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	–	60 kg/hr (140 lb/hr)	1	0
13	Hydrated Lime Injectors	–	1,660 kg/hr (3,650 lb/hr)	1	0
14	Cansolv	Amine-based CO_2 capture technology	3,724,000 kg/hr (8,211,000 lb/hr) 19.1 wt% CO_2 concentration	1	0
15	Cansolv LP Condensate Pump	Centrifugal	1,287 lpm @ 1 m H_2O (340 gpm @ 4 ft H_2O)	1	1
16	Cansolv IP Condensate Pump	Centrifugal	6 lpm @ 4.6 m H_2O (2 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 152 m^3/min @ 3.0 MPa (5,381 acfm @ 441 psia) Outlet: 2.9 MPa (421 psia) Water Recovered: 487 kg/hr (1,074 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	8.0 m^3/min @ 15.3 MPa, 80°C (299 acfm @ 2,217 psia, 176°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215psia, 86°F) Duty: 88 MMkJ/hr (84 MMBtu/hr)	1	0

Case B12B – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.0 m (20 ft) diameter	1	0

Case B12B – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	798 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	890 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0

3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,170 GJ/hr (2,220 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case B12B – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	965,000 lpm @ 30 m (255,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5380 GJ/hr (5100 MMBtu/hr) heat duty	1	0

Case B12B – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	6.1 tonne/hr (6.7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	25 m^3/min @ 0.2 MPa (866 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,610 tonne (1,770 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	150 tonne/hr (170 tph)	1	0

Case B12B – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 750 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 25 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 61 MVA, 3-ph, 60 Hz	1	1

4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 20 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12B – Account 12: Instrumentation and Control

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

Case PA1

Case PA1 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	50 tonne (60 ton)	2	1
9	Feeder	Vibratory	210 tonne/hr (230 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	420 tonne/hr (470 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	210 tonne (230 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	420 tonne/hr (470 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	420 tonne/hr (470 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	940 tonne (1,000 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (12 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 290 tonne (310 ton) Feeder - 1,700 kg/hr (3,750 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	104 tonne/hr (115 tph)	1	0
23	Limestone Conveyor No. 1	Belt	104 tonne/hr (115 tph)	1	0
24	Limestone Reclaim Hopper	N/A	20 tonne (23 ton)	1	0
25	Limestone Reclaim Feeder	Belt	82 tonne/hr (90 tph)	1	0
26	Limestone Conveyor No. 2	Belt	82 tonne/hr (90 tph)	1	0
27	Limestone Day Bin	w/ actuator	328 tonne (361 ton)	2	0

Case PA1 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	47 tonne/hr (52 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	47 tonne/hr (52 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	27 tonne/hr (30 tph)	1	1
4	Limestone Ball Mill	Rotary	27 tonne/hr (30 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	106,700 liters (28,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,780 lpm @ 10m H_2O (470 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	450 lpm (120 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	591,000 liters (156,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,230 lpm @ 9m H_2O (330 gpm @ 30 ft H_2O)	1	1

Case PA1 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	327,000 liters (86,000 gal)	2	0
2	Condensate Pumps	Vertical canned	22,500 lpm @ 200 m H_2O (6,000 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,717,000 kg/hr (5,991,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	45,500 lpm @ 3,500 m H_2O (12,000 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	13,600 lpm @ 3,500 m H_2O (3,600 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	980,000 kg/hr (2,160,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	980,000 kg/hr (2,160,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	980,000 kg/hr (2,160,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	980,000 kg/hr (2,160,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,710,000 kg/hr (5,980,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,710,000 kg/hr (5,980,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,710,000 kg/hr (5,980,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	9,910 lpm @ 20 m H_2O (2,620 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	3,960 lpm @ 270 m H_2O (1,050 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,170 lpm @ 50 m H_2O (310 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	1,119,000 liter (296,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,330 m^3/min (82,300 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 140 lpm (40 gpm) @ 19,977 ppmw Cl^-	2	1

Case PA1 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,710,000 kg/hr steam @ 24.1 MPa/593°C/593°C (5,980,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	389,000 kg/hr, 5,300 m^3/min@ 123 cm WG (858,000 lb/hr, 187,500 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	1,196,000 kg/hr, 16,300 m^3/min @ 47 cm WG (2,636,000 lb/hr, 576,200 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,765,000 kg/hr, 35,200 m^3/min @ 93 cm WG (3,892,000 lb/hr, 1,242,100 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,340,000 kg/hr (7,370,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,500 acfm @ 42 in WG)	2	1
8	Ammonia Storage	Horizontal tank	141,000 liter (37,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	27 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case PA1 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,766,000 kg/hr (3,893,000 lb/hr) 99.9% efficiency	2	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Absorber Module	Counter-current open spray	59,000 m^3/min (2,100,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	207,000 lpm @ 65 m H_2O (55,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,250 lpm (1,390 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	900 m^3/min @ 0.3 MPa (31,690 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,320 lpm (350 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	42 tonne/hr (46 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	800 lpm @ 13 m H_2O (210 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	520,000 lpm (140,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,010 lpm @ 21 m H_2O (530 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	–	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	–	1,700 kg/hr (3,750 lb/hr)	1	0
14	Cansolv	Amine-based CO_2 capture technology	3,812,000 kg/hr (8,404,000 lb/hr) 19.3 wt% CO_2 concentration	1	0
15	Cansolv LP Condensate Pump	Centrifugal	1,363 lpm @ 1 m H_2O (360 gpm @ 4 ft H_2O)	1	1
16	Cansolv IP Condensate Pump	Centrifugal	7 lpm @ 4.6 m H_2O (2 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 158 m^3/min @ 3.0 MPa (5,569 acfm @ 441 psia) Outlet: 2.9 MPa (421 psia) Water Recovered: 504 kg/hr (1,111 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	9.0 m^3/min @ 15.3 MPa, 80°C (309 acfm @ 2,217 psia, 176°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215psia, 86°F) Duty: 91 MMkJ/hr (87 MMBtu/hr)	1	0

Case PA1 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.0 m (20 ft) diameter	1	0

Case PA1 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	814 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	900 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,190 GJ/hr (2,250 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case PA1 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	989,000 lpm @ 30 m (261,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5520 GJ/hr (5230 MMBtu/hr) heat duty	1	0

Case PA1 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	5.8 tonne/hr (6.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	24 m^3/min @ 0.2 MPa (833 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,550 tonne (1,710 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	140 tonne/hr (160 tph)	1	0

Case PA1 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 750 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 26 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 73 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 22 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case PA1 – Account 12: Instrumentation and Control

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

Case PA2

Case PA2 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	50 tonne (60 ton)	2	1
9	Feeder	Vibratory	200 tonne/hr (220 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	400 tonne/hr (440 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 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	400 tonne/hr (440 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	400 tonne/hr (440 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	880 tonne (1,000 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (13 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 290 tonne (320 ton) Feeder - 1,740 kg/hr (3,840 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	97 tonne/hr (107 tph)	1	0
23	Limestone Conveyor No. 1	Belt	97 tonne/hr (107 tph)	1	0
24	Limestone Reclaim Hopper	N/A	19 tonne (21 ton)	1	0
25	Limestone Reclaim Feeder	Belt	76 tonne/hr (84 tph)	1	0
26	Limestone Conveyor No. 2	Belt	76 tonne/hr (84 tph)	1	0
27	Limestone Day Bin	w/ actuator	306 tonne (337 ton)	2	0

Case PA2 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	44 tonne/hr (49 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	44 tonne/hr (49 tph)	6	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Limestone Weigh Feeder	Gravimetric	25 tonne/hr (28 tph)	1	1
4	Limestone Ball Mill	Rotary	25 tonne/hr (28 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	97,700 liters (26,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,620 lpm @ 10m H_2O (430 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5-cyclone bank	410 lpm (110 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	551,000 liters (146,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,150 lpm @ 9m H_2O (300 gpm @ 30 ft H_2O)	1	1

Case PA2 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	334,000 liters (88,000 gal)	2	0
2	Condensate Pumps	Vertical canned	22,900 lpm @ 200 m H_2O (6,000 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,776,000 kg/hr (6,120,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	46,500 lpm @ 3,500 m H_2O (12,300 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	13,900 lpm @ 3,500 m H_2O (3,700 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	1,000,000 kg/hr (2,210,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	1,000,000 kg/hr (2,210,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	1,000,000 kg/hr (2,210,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	1,000,000 kg/hr (2,210,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,770,000 kg/hr (6,110,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,770,000 kg/hr (6,110,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,770,000 kg/hr (6,110,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	10,140 lpm @ 20 m H_2O (2,680 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	4,060 lpm @ 270 m H_2O (1,070 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,170 lpm @ 50 m H_2O (310 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	1,119,000 liter (296,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,180 m^3/min (77,040 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 130 lpm (30 gpm) @ 19,966 ppmw Cl^-	2	1

Case PA2 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,770,000 kg/hr steam @ 24.1 MPa/593°C/593°C (6,110,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	415,000 kg/hr, 5,700 m^3/min @ 123 cm WG (914,000 lb/hr, 199,800 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	1,207,000 kg/hr, 16,500 m^3/min @ 47 cm WG (2,660,000 lb/hr, 581,500 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,813,000 kg/hr, 36,100 m^3/min @ 93 cm WG (3,998,000 lb/hr, 1,276,600 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,430,000 kg/hr (7,570,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,600 acfm @ 42 in WG)	2	1
8	Ammonia Storage	Horizontal tank	144,000 liter (38,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	27 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case PA2 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,814,000 kg/hr (3,998,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	61,000 m^3/min (2,144,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	211,000 lpm @ 65 m H_2O (56,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,890 lpm (1,290 gpm) at 20 wt% solids	2	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	Oxidation Air Blowers	Centrifugal	840 m^3/min @ 0.3 MPa (29,570 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,220 lpm (320 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	39 tonne/hr (43 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	750 lpm @ 13 m H_2O (200 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	490,000 lpm (130,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,990 lpm @ 21 m H_2O (520 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	–	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	–	1,740 kg/hr (3,840 lb/hr)	1	0
14	Cansolv	Amine-based CO_2 capture technology	3,895,000 kg/hr (8,587,000 lb/hr) 19.5 wt% CO_2 concentration	1	0
15	Cansolv LP Condensate Pump	Centrifugal	1,401 lpm @ 1 m H_2O (370 gpm @ 4 ft H_2O)	1	1
16	Cansolv IP Condensate Pump	Centrifugal	7 lpm @ 4.6 m H_2O (2 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 163 m^3/min @ 3.0 Mpa (5,755 acfm @ 441 psia) Outlet: 2.9 MPa (421 psia) Water Recovered: 521 kg/hr (1,148 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	9.0 m^3/min @ 15.3 MPa, 80°C (319 acfm @ 2,217 psia, 176°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215psia, 86°F) Duty: 94 MMkJ/hr (90 MMBtu/hr)	1	0

Case PA2 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.1 m (20 ft) diameter	1	0

Case PA2 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	831 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	920 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,210 GJ/hr (2,290 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case PA2 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,014,000 lpm @ 30 m (268,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb /16°C (60°F) CWT/ 27°C (80°F) HWT/ 5650 GJ/hr (5360 MMBtu/hr) heat duty	1	0

Case PA2 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	5.5 tonne/hr (6.1 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	23 m^3/min @ 0.2 MPa (798 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,480 tonne (1,640 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	140 tonne/hr (150 tph)	1	0

Case PA2 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 750 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 26 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 84 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 24 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case PA2 – Account 12: Instrumentation and Control

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

Case PA3

Case PA3 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	50 tonne (50 ton)	2	1
9	Feeder	Vibratory	180 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	180 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	360 tonne/hr (400 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	360 tonne/hr (400 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	800 tonne (900 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 12 tonne (13 ton) Feeder - 70 kg/hr (160 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 300 tonne (330 ton) Feeder - 1,790 kg/hr (3,950 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	89 tonne/hr (98 tph)	1	0
23	Limestone Conveyor No. 1	Belt	89 tonne/hr (98 tph)	1	0
24	Limestone Reclaim Hopper	N/A	17 tonne (19 ton)	1	0
25	Limestone Reclaim Feeder	Belt	70 tonne/hr (77 tph)	1	0
26	Limestone Conveyor No. 2	Belt	70 tonne/hr (77 tph)	1	0
27	Limestone Day Bin	w/ actuator	279 tonne (307 ton)	2	0

Case PA3 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	40 tonne/hr (44 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	40 tonne/hr (44 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	23 tonne/hr (26 tph)	1	1
4	Limestone Ball Mill	Rotary	23 tonne/hr (26 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	90,800 liters (24,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,510 lpm @ 10m H_2O (400 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	380 lpm (100 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	502,000 liters (133,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,050 lpm @ 9m H_2O (280 gpm @ 30 ft H_2O)	1	1

Case PA3 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	342,000 liters (90,000 gal)	2	0
2	Condensate Pumps	Vertical canned	23,300 lpm @ 200 m H_2O (6,200 gpm @ 500 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,849,000 kg/hr (6,280,000 lb/hr), 5 min tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	47,700 lpm @ 3,500 m H_2O (12,600 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	14,200 lpm @ 3,500 m H_2O (3,800 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	1,030,000 kg/hr (2,260,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	1,030,000 kg/hr (2,260,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	1,030,000 kg/hr (2,260,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	1,030,000 kg/hr (2,260,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,840,000 kg/hr (6,270,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,840,000 kg/hr (6,270,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,840,000 kg/hr (6,270,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	10,420 lpm @ 20 m H_2O (2,750 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	4,170 lpm @ 270 m H_2O (1,100 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,150 lpm @ 50 m H_2O (300 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	1,099,000 liter (290,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,000 m^3/min (70,490 acfm) @ 385°C (726°F) & 0.1 MPa (15 psia) Blowdown - 120 lpm (30 gpm) @ 19,960 ppmw Cl^-	2	1

Case PA3 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,840,000 kg/hr steam @ 24.1 MPa/593°C/593°C (6,270,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	446,000 kg/hr, 6,100 m^3/min@ 123 cm WG (984,000 lb/hr, 215,000 acfm @ 48 in WG)	2	0
3	Forced Draft Fan	Centrifugal	1,220,000 kg/hr, 16,700 m^3/min @ 47 cm WG (2,691,000 lb/hr, 588,200 acfm @ 19 in WG)	2	0
4	Induced Draft Fan	Centrifugal	1,873,000 kg/hr, 37,400 m^3/min @ 93 cm WG (4,129,000 lb/hr, 1,319,500 acfm @ 36 in WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,550,000 kg/hr (7,830,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,700 acfm @ 42 in WG)	2	1
8	Ammonia Storage	Horizontal tank	148,000 liter (39,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case PA3 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,873,000 kg/hr (4,130,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	62,000 m^3/min (2,199,000 acfm)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Recirculation Pumps	Horizontal centrifugal	216,000 lpm @ 65 m H_2O (57,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,460 lpm (1,180 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	760 m^3/min @ 0.3 MPa (26,920 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,120 lpm (300 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	35 tonne/hr (39 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	680 lpm @ 13 m H_2O (180 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	440,000 lpm (120,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,950 lpm @ 21 m H_2O (520 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	–	70 kg/hr (160 lb/hr)	1	0
13	Hydrated Lime Injectors	–	1,790 kg/hr (3,950 lb/hr)	1	0
14	Cansolv	Amine-based CO_2 capture technology	3,999,000 kg/hr (8,816,000 lb/hr) 19.8 wt% CO_2 concentration	1	0
15	Cansolv LP Condensate Pump	Centrifugal	1,438 lpm @ 1 m H_2O (380 gpm @ 4 ft H_2O)	1	1
16	Cansolv IP Condensate Pump	Centrifugal	7 lpm @ 4.6 m H_2O (2 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 170 m^3/min @ 3.0 MPa (5,987 acfm @ 441 psia) Outlet: 2.9 MPa (421 psia) Water Recovered: 542 kg/hr (1,195 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	9.0 m^3/min @ 15.3 MPa, 80°C (332 acfm @ 2,217 psia, 176°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215psia, 86°F) Duty: 98 MMkJ/hr (93 MMBtu/hr)	1	0

Case PA3 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.2 m (20 ft) diameter	1	0

Case PA3 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	851 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	950 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,230 GJ/hr (2,330 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case PA3 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,044,000 lpm @ 30 m (276,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5820 GJ/hr (5520 MMBtu/hr) heat duty	1	0

Case PA3 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	5.2 tonne/hr (5.7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	21 m^3/min @ 0.2 MPa (756 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,400 tonne (1,550 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	130 tonne/hr (140 tph)	1	0

Case PA3 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 27 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 98 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 27 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case PA3 – Account 12: Instrumentation and Control

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

Cost Estimates

Exhibit A-38. Case B12A total plant cost details

Case:		B12A	– SC PC w/o CO_2				Estimate Type:			Conceptual	
Plant Size (MWnet):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,011	$0	$455	$0	$1,466	$257	$0	$258	$1,981	$3
1.2	Coal Stackout & Reclaim	$3,318	$0	$742	$0	$4,060	$710	$0	$716	$5,486	$8
1.3	Coal Conveyors	$30,567	$0	$7,266	$0	$37,833	$6,621	$0	$6,668	$51,122	$79
1.4	Other Coal Handling	$4,250	$0	$893	$0	$5,143	$900	$0	$906	$6,949	$11
1.5	Sorbent Receive & Unload	$193	$0	$57	$0	$250	$44	$0	$44	$337	$1
1.6	Sorbent Stackout & Reclaim	$1,414	$0	$255	$0	$1,670	$292	$0	$294	$2,256	$3
1.7	Sorbent Conveyors	$2,141	$464	$518	$0	$3,123	$547	$0	$550	$4,220	$6
1.8	Other Sorbent Handling	$103	$24	$53	$0	$181	$32	$0	$32	$244	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,325	$1,747	$0	$3,072	$538	$0	$541	$4,151	$6
	Subtotal	**$42,997**	**$1,813**	**$11,986**	**$0**	**$56,797**	**$9,939**	**$0**	**$10,010**	**$76,747**	**$118**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$2,151	$0	$413	$0	$2,564	$449	$0	$452	$3,464	$5
2.2	Prepared Coal Storage & Feed	$7,238	$0	$1,558	$0	$8,796	$1,539	$0	$1,550	$11,885	$18
2.5	Sorbent Preparation Equipment	$949	$41	$194	$0	$1,185	$207	$0	$209	$1,601	$2
2.6	Sorbent Storage & Feed	$1,590	$0	$601	$0	$2,191	$383	$0	$386	$2,961	$5
2.9	Coal & Sorbent Feed Foundation	$0	$631	$554	$0	$1,185	$207	$0	$209	$1,602	$2
	Subtotal	**$11,928**	**$672**	**$3,321**	**$0**	**$15,921**	**$2,786**	**$0**	**$2,806**	**$21,513**	**$33**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$3,363	$5,765	$2,883	$0	$12,011	$2,102	$0	$2,117	$16,229	$25
3.2	Water Makeup & Pretreating	$5,763	$576	$3,266	$0	$9,605	$1,681	$0	$2,257	$13,543	$21
3.3	Other Feedwater Subsystems	$2,503	$821	$780	$0	$4,104	$718	$0	$723	$5,545	$9
3.4	Service Water Systems	$1,762	$3,363	$10,890	$0	$16,015	$2,803	$0	$3,764	$22,581	$35
3.5	Other Boiler Plant Systems	$617	$224	$561	$0	$1,403	$245	$0	$247	$1,895	$3
3.6	Natural Gas Pipeline and Start-Up System	$2,969	$128	$96	$0	$3,193	$559	$0	$563	$4,314	$7
3.7	Waste Water Treatment Equipment	$8,140	$0	$4,989	$0	$13,130	$2,298	$0	$3,085	$18,513	$28
3.8	Spray Dryer Evaporator	$13,925	$0	$8,064	$0	$21,989	$3,848	$0	$5,167	$31,004	$48
3.9	Miscellaneous Plant Equipment	$212	$28	$108	$0	$348	$61	$0	$82	$491	$1
	Subtotal	**$39,255**	**$10,905**	**$31,636**	**$0**	**$81,796**	**$14,314**	**$0**	**$18,005**	**$114,116**	**$176**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$222,878	$0	$126,995	$0	$349,872	$61,228	$0	$61,665	$472,765	$727
4.10	Selective Catalytic Reduction System	$24,777	$0	$14,118	$0	$38,895	$6,807	$0	$6,855	$52,557	$81
4.11	Boiler Balance of Plant	$1,493	$0	$851	$0	$2,343	$410	$0	$413	$3,167	$5
4.12	Primary Air System	$1,433	$0	$816	$0	$2,249	$394	$0	$396	$3,039	$5

	Case:	B12A	– SC PC w/o CO_2				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
4.13	Secondary Air System	$2,170	$0	$1,237	$0	$3,407	$596	$0	$600	$4,604	$7
4.14	Induced Draft Fans	$4,626	$0	$2,636	$0	$7,262	$1,271	$0	$1,280	$9,813	$15
4.15	Major Component Rigging	$79	$0	$45	$0	$123	$22	$0	$22	$167	$0
4.16	Boiler Foundations	$0	$337	$296	$0	$634	$111	$0	$112	$856	$1
	Subtotal	**$257,456**	**$337**	**$146,993**	**$0**	**$404,786**	**$70,838**	**$0**	**$71,344**	**$546,968**	**$842**
5						Flue Gas Cleanup					
5.2	WFGD Absorber Vessels & Accessories	$66,382	$0	$14,193	$0	$80,575	$14,101	$0	$14,201	$108,877	$168
5.3	Other FGD	$298	$0	$335	$0	$633	$111	$0	$112	$855	$1
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,175	$478	$2,138	$0	$4,791	$838	$0	$844	$6,473	$10
5.9	Particulate Removal (Bag House & Accessories)	$1,254	$0	$790	$0	$2,044	$358	$0	$360	$2,762	$4
5.12	Gas Cleanup Foundations	$0	$163	$143	$0	$306	$53	$0	$54	$413	$1
5.13	Gypsum Dewatering System	$663	$0	$112	$0	$774	$136	$0	$136	$1,046	$2
	Subtotal	**$70,771**	**$641**	**$17,711**	**$0**	**$89,123**	**$15,597**	**$0**	**$15,708**	**$120,427**	**$185**
7						Ductwork & Stack					
7.3	Ductwork	$0	$695	$483	$0	$1,179	$206	$0	$208	$1,593	$2
7.4	Stack	$8,822	$0	$5,126	$0	$13,948	$2,441	$0	$2,458	$18,848	$29
7.5	Duct & Stack Foundations	$0	$207	$246	$0	$453	$79	$0	$106	$638	$1
	Subtotal	**$8,822**	**$902**	**$5,855**	**$0**	**$15,580**	**$2,726**	**$0**	**$2,773**	**$21,079**	**$32**
8						Steam Turbine & Accessories					
8.1	Steam Turbine Generator & Accessories	$67,758	$0	$7,389	$0	$75,147	$13,151	$0	$13,245	$101,542	$156
8.2	Steam Turbine Plant Auxiliaries	$1,534	$0	$3,266	$0	$4,801	$840	$0	$846	$6,487	$10
8.3	Condenser & Auxiliaries	$13,886	$0	$4,711	$0	$18,597	$3,254	$0	$3,278	$25,129	$39
8.4	Steam Piping	$36,326	$0	$14,724	$0	$51,050	$8,934	$0	$8,998	$68,981	$106
8.5	Turbine Generator Foundations	$0	$240	$395	$0	$635	$111	$0	$149	$895	$1
	Subtotal	**$119,504**	**$240**	**$30,485**	**$0**	**$150,229**	**$26,290**	**$0**	**$26,515**	**$203,034**	**$312**
9						Cooling Water System					
9.1	Cooling Towers	$12,939	$0	$4,001	$0	$16,940	$2,965	$0	$2,986	$22,890	$35
9.2	Circulating Water Pumps	$1,726	$0	$108	$0	$1,834	$321	$0	$323	$2,478	$4
9.3	Circulating Water System Auxiliaries	$11,459	$0	$1,525	$0	$12,984	$2,272	$0	$2,288	$17,544	$27
9.4	Circulating Water Piping	$0	$5,302	$4,802	$0	$10,104	$1,768	$0	$1,781	$13,653	$21

Case:		B12A	– SC PC w/o CO_2					Estimate Type:		Conceptual	
Plant Size (MWnet):		650						Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
9.5	Make-up Water System	$1,006	$0	$1,292	$0	$2,298	$402	$0	$405	$3,105	$5
9.6	Component Cooling Water System	$826	$0	$634	$0	$1,460	$256	$0	$257	$1,973	$3
9.7	Circulating Water System Foundations	$0	$508	$844	$0	$1,351	$237	$0	$318	$1,906	$3
	Subtotal	**$27,955**	**$5,810**	**$13,206**	**$0**	**$46,971**	**$8,220**	**$0**	**$8,358**	**$63,549**	**$98**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,021	$0	$3,125	$0	$4,146	$726	$0	$731	$5,602	$9
10.7	Ash Transport & Feed Equipment	$3,475	$0	$3,444	$0	$6,919	$1,211	$0	$1,219	$9,349	$14
10.9	Ash/Spent Sorbent Foundation	$0	$712	$873	$0	$1,585	$277	$0	$372	$2,235	$3
	Subtotal	**$4,495**	**$712**	**$7,443**	**$0**	**$12,650**	**$2,214**	**$0**	**$2,323**	**$17,186**	**$26**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$2,500	$0	$1,886	$0	$4,385	$767	$0	$773	$5,926	$9
11.2	Station Service Equipment	$4,546	$0	$390	$0	$4,936	$864	$0	$870	$6,670	$10
11.3	Switchgear & Motor Control	$7,058	$0	$1,225	$0	$8,282	$1,449	$0	$1,460	$11,191	$17
11.4	Conduit & Cable Tray	$0	$917	$2,644	$0	$3,562	$623	$0	$628	$4,812	$7
11.5	Wire & Cable	$0	$2,430	$4,343	$0	$6,773	$1,185	$0	$1,194	$9,152	$14
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$783	$0	$723	$0	$1,506	$264	$0	$265	$2,035	$3
11.8	Main Power Transformers	$6,461	$0	$132	$0	$6,593	$1,154	$0	$1,162	$8,908	$14
11.9	Electrical Foundations	$0	$206	$523	$0	$728	$127	$0	$171	$1,027	$2
	Subtotal	**$21,403**	**$3,553**	**$12,056**	**$0**	**$37,012**	**$6,477**	**$0**	**$6,566**	**$50,055**	**$77**
12	**Instrumentation & Control**										
12.1	Pulverized Coal Boiler Control Equipment	$690	$0	$123	$0	$813	$142	$0	$143	$1,098	$2
12.3	Steam Turbine Control Equipment	$619	$0	$68	$0	$687	$120	$0	$121	$928	$1
12.5	Signal Processing Equipment	$783	$0	$140	$0	$923	$161	$0	$163	$1,247	$2
12.6	Control Boards, Panels & Racks	$240	$0	$146	$0	$386	$68	$0	$68	$521	$1
12.7	Distributed Control System Equipment	$6,757	$0	$1,205	$0	$7,962	$1,393	$0	$1,403	$10,759	$17
12.8	Instrument Wiring & Tubing	$473	$379	$1,514	$0	$2,366	$414	$0	$417	$3,197	$5
12.9	Other Instrumentation & Controls Equipment	$582	$0	$1,347	$0	$1,929	$338	$0	$340	$2,607	$4
	Subtotal	**$10,144**	**$379**	**$4,542**	**$0**	**$15,065**	**$2,636**	**$0**	**$2,655**	**$20,356**	**$31**
13	**Improvements to Site**										

Case:		B12A	– SC PC w/o CO_2				Estimate Type:			Conceptual	
Plant Size (MWnet):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
13.1	Site Preparation	$0	$419	$8,926	$0	$9,345	$1,635	$0	$2,196	$13,176	$20
13.2	Site Improvements	$0	$2,079	$2,746	$0	$4,825	$844	$0	$1,134	$6,803	$10
13.3	Site Facilities	$2,375	$0	$2,492	$0	$4,867	$852	$0	$1,144	$6,862	$11
	Subtotal	**$2,375**	**$2,498**	**$14,164**	**$0**	**$19,036**	**$3,331**	**$0**	**$4,474**	**$26,841**	**$41**
	14					**Buildings & Structures**					
14.2	Boiler Building	$0	$11,588	$10,184	$0	$21,772	$3,810	$0	$3,837	$29,419	$45
14.3	Steam Turbine Building	$0	$16,107	$15,002	$0	$31,109	$5,444	$0	$5,483	$42,036	$65
14.4	Administration Building	$0	$1,046	$1,106	$0	$2,152	$377	$0	$379	$2,909	$4
14.5	Circulation Water Pumphouse	$0	$134	$106	$0	$240	$42	$0	$42	$324	$0
14.6	Water Treatment Buildings	$0	$372	$339	$0	$712	$125	$0	$125	$961	$1
14.7	Machine Shop	$0	$552	$370	$0	$922	$161	$0	$163	$1,246	$2
14.8	Warehouse	$0	$415	$416	$0	$831	$145	$0	$146	$1,123	$2
14.9	Other Buildings & Structures	$0	$291	$247	$0	$538	$94	$0	$95	$727	$1
14.10	Waste Treating Building & Structures	$0	$627	$1,901	$0	$2,528	$442	$0	$446	$3,416	$5
	Subtotal	**$0**	**$31,133**	**$29,671**	**$0**	**$60,804**	**$10,641**	**$0**	**$10,717**	**$82,162**	**$126**
	Total	**$617,105**	**$59,594**	**$329,070**	**$0**	**$1,005,770**	**$176,010**	**$0**	**$182,253**	**$1,364,033**	**$2,099**

Exhibit A-39. Case B12A owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$9,292	$14
1 Month Maintenance Materials	$1,284	$2
1 Month Non-Fuel Consumables	$1,653	$3
1 Month Waste Disposal	$727	$1
25% of 1 Months Fuel Cost at 100% CF	$2,238	$3
2% of TPC	$27,281	$42
Total	**$42,475**	**$65**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$20,706	$32
0.5% of TPC (spare parts)	$6,820	$10
Total	**$27,527**	**$42**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,044	$3
Land	$900	$1
Other Owner's Costs	$204,605	$315
Financing Costs	$36,829	$57
Total Overnight Costs (TOC)	**$1,678,412**	**$2,582**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$1,937,579**	**$2,981**

Exhibit A-40. Case B12A initial and annual O&M costs

Case:	B12A	– SC PC w/o CO_2			Cost Base:	Dec 2018
Plant Size (MWnet):	**650**	**Heat Rate-net (Btu/kWh):**		**8,473**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	9.0	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**14.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,138,132	$9.444
Maintenance Labor:					$8,729,809	$13.432
Administrative & Support Labor:					$3,716,985	$5.719
Property Taxes and Insurance:					$27,280,654	$41.975
Total:					**$45,865,581**	**$70.570**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$13,094,714	$2.70587
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,359	$1.90	$0	$2,569,326	$0.53092
Makeup and Waste Water Treatment Chemicals (lbs):	0	13.0	$550.00	$0	$2,215,533	$0.45781
Brominated Activated Carbon (ton):	0	1.22	$1,600.00	$0	$604,623	$0.12494
Enhanced Hydrated Lime (ton):	0	31.2	$240.00	$0	$2,321,985	$0.47981
Limestone (ton):	0	548	$22.00	$0	$3,739,990	$0.77282
Ammonia (19 wt%, ton):	0	51.9	$300.00	$0	$4,830,710	$0.99821
SCR Catalyst (ft^3):	13,626	12.4	150.00	$2,043,971	$579,125	$0.11967
Subtotal:				**$2,043,971**	**$16,861,292**	**$3.48419**
Waste Disposal						
Fly Ash (ton)	0	514	$38.00	$0	$6,060,275	$1.25228
Bottom Ash (ton)	0	114	$38.00	$0	$1,346,208	$0.27818
SCR Catalyst (ft^3):	0	12.4	$2.50	$0	$9,652	$0.00199
Subtotal:				**$0**	**$7,416,134**	**$1.53246**
By-Products						
Gypsum (ton)	0	833	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$2,043,971**	**$37,372,141**	**$7.72251**
Fuel Cost						
Illinois Number 6 (ton):	0	5,664	$51.96	$0	$91,310,727	$18.86827
Total:				**$0**	**$91,310,727**	**$18.86827**

Exhibit A-41. Case B12A LCOE breakdown

Component	Value, $/MWh	Percentage
Capital	28.3	44%
Fixed	9.5	15%
Variable	7.7	12%
Fuel	18.9	29%
Total (Excluding T&S)	**64.4**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**64.4**	**N/A**

Exhibit A-42. Case PN1 total plant cost details

Case:		PN1	– SC PC and 20% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
Plant Size (MWnet):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
1	**Coal & Sorbent Handling**										
1.1	Coal Receive & Unload	$967	$0	$436	$0	$1,403	$246	$0	$247	$1,896	$3
1.2	Coal Stackout & Reclaim	$3,176	$0	$710	$0	$3,886	$680	$0	$685	$5,251	$8
1.3	Coal Conveyors	$29,259	$0	$6,955	$0	$36,214	$6,337	$0	$6,383	$48,934	$75
1.4	Other Coal Handling	$4,068	$0	$854	$0	$4,923	$861	$0	$868	$6,652	$10
1.5	Sorbent Receive & Unload	$184	$0	$54	$0	$238	$42	$0	$42	$322	$0
1.6	Sorbent Stackout & Reclaim	$1,351	$0	$244	$0	$1,595	$279	$0	$281	$2,155	$3
1.7	Sorbent Conveyors	$2,044	$443	$494	$0	$2,982	$522	$0	$526	$4,029	$6
1.8	Other Sorbent Handling	$99	$23	$51	$0	$173	$30	$0	$30	$233	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,268	$1,672	$0	$2,940	$515	$0	$518	$3,973	$6
1.10	Biomass Receiving and Processing	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$24,283	$4,250	$0	$4,280	$32,812	$50
	Subtotal	**$41,148**	**$1,735**	**$11,471**	**$0**	**$78,636**	**$13,761**	**$0**	**$13,860**	**$106,257**	**$113**
2	**Coal & Sorbent Preparation & Feed**										
2.1	Coal Crushing & Drying	$2,053	$0	$394	$0	$2,447	$428	$0	$431	$3,306	$5
2.2	Prepared Coal Storage & Feed	$6,909	$0	$1,487	$0	$8,396	$1,469	$0	$1,480	$11,345	$17
2.5	Sorbent Preparation Equipment	$954	$0	$186	$0	$1,139	$199	$0	$201	$1,540	$2
2.6	Sorbent Storage & Feed	$906	$39	$186	$0	$1,131	$198	$0	$199	$1,528	$2
2.9	Coal & Sorbent Feed Foundation	$1,518	$0	$574	$0	$2,092	$366	$0	$369	$2,827	$4
	Subtotal	**w/ BEC**	**w/ BEC**	**w/ BEC**	**w/ BEC**	**$17,420**	**$3,049**	**$0**	**$3,070**	**$23,539**	**$36**
3	**Feedwater & Miscellaneous BOP Systems**										
3.1	Feedwater System	$3,396	$5,822	$2,911	$0	$12,129	$2,123	$0	$2,138	$16,390	$25
3.2	Water Makeup & Pretreating	$5,739	$574	$3,252	$0	$9,564	$1,674	$0	$2,248	$13,486	$21
3.3	Other Feedwater Subsystems	$2,535	$831	$790	$0	$4,156	$727	$0	$732	$5,616	$9
3.4	Service Water Systems	$1,753	$3,347	$10,839	$0	$15,940	$2,790	$0	$3,746	$22,476	$35
3.5	Other Boiler Plant Systems	$625	$227	$568	$0	$1,421	$249	$0	$250	$1,920	$3
3.6	Natural Gas Pipeline and Start-Up System	$3,200	$138	$103	$0	$3,440	$602	$0	$606	$4,649	$7
3.7	Waste Water Treatment Equipment	$8,220	$0	$5,038	$0	$13,258	$2,320	$0	$3,116	$18,694	$29
3.8	Spray Dryer Evaporator	$13,243	$0	$7,648	$0	$20,891	$3,656	$0	$4,909	$29,456	$45

	Case:	PN1	– SC PC and 20% Biomass (w/o CO_2 Capture)					Estimate Type:			Conceptual	
	Plant Size (MWnet):	650								Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
3.9	Miscellaneous Plant Equipment	$220	$29	$112	$0	$361	$63	$0	$85	$510	$1
	Subtotal	**$38,931**	**$10,968**	**$31,262**	**$0**	**$81,161**	**$14,203**	**$0**	**$17,831**	**$113,195**	**$174**
4	**Pulverized Coal Boiler & Accessories**										
4.9	Pulverized Coal Boiler & Accessories	$225,305	$0	$128,378	$0	$353,683	$61,895	$0	$62,337	$477,915	$735
4.10	Selective Catalytic Reduction System	$25,148	$0	$14,329	$0	$39,478	$6,909	$0	$6,958	$53,344	$82
4.11	Boiler Balance of Plant	$1,659	$0	$945	$0	$2,604	$456	$0	$459	$3,518	$5
4.12	Primary Air System	$1,493	$0	$851	$0	$2,344	$410	$0	$413	$3,167	$5
4.13	Secondary Air System	$2,173	$0	$1,238	$0	$3,412	$597	$0	$601	$4,610	$7
4.14	Induced Draft Fans	$4,692	$0	$2,674	$0	$7,366	$1,289	$0	$1,298	$9,953	$15
4.15	Major Component Rigging	$87	$0	$50	$0	$137	$24	$0	$24	$185	$0
4.16	Boiler Foundations	$0	$375	$329	$0	$704	$123	$0	$124	$951	$1
	Subtotal	**$260,558**	**$375**	**$148,794**	**$0**	**$409,727**	**$71,702**	**$0**	**$72,214**	**$553,643**	**$852**
5	**Flue Gas Cleanup**										
5.2	WFGD Absorber Vessels & Accessories	$67,138	$0	$14,354	$0	$81,492	$14,261	$0	$14,363	$110,117	$169
5.3	Other FGD	$301	$0	$339	$0	$640	$112	$0	$113	$865	$1
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,210	$486	$2,172	$0	$4,868	$852	$0	$858	$6,578	$10
5.9	Particulate Removal (Bag House & Accessories)	$1,274	$0	$803	$0	$2,078	$364	$0	$366	$2,808	$4
5.12	Gas Cleanup Foundations	$0	$184	$161	$0	$345	$60	$0	$61	$466	$1
5.13	Gypsum Dewatering System	$636	$0	$107	$0	$743	$130	$0	$131	$1,004	$2
	Subtotal	**$71,559**	**$669**	**$17,938**	**$0**	**$90,166**	**$15,779**	**$0**	**$15,892**	**$121,837**	**$187**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$727	$505	$0	$1,232	$216	$0	$217	$1,665	$3
7.4	Stack	$8,830	$0	$5,131	$0	$13,961	$2,443	$0	$2,461	$18,865	$29
7.5	Duct & Stack Foundations	$0	$209	$248	$0	$457	$80	$0	$107	$644	$1
	Subtotal	**$8,830**	**$936**	**$5,884**	**$0**	**$15,650**	**$2,739**	**$0**	**$2,785**	**$21,174**	**$33**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$68,442	$0	$7,463	$0	$75,905	$13,283	$0	$13,378	$102,567	$158
8.2	Steam Turbine Plant Auxiliaries	$1,550	$0	$3,299	$0	$4,849	$849	$0	$855	$6,552	$10
8.3	Condenser & Auxiliaries	$14,093	$0	$4,782	$0	$18,874	$3,303	$0	$3,327	$25,504	$39

	Case:	PN1	– SC PC and 20% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
8.4	Steam Piping	$36,691	$0	$14,871	$0	$51,562	$9,023	$0	$9,088	$69,673	$107
8.5	Turbine Generator Foundations	$0	$242	$400	$0	$642	$112	$0	$151	$905	$1
	Subtotal	**$120,775**	**$242**	**$30,815**	**$0**	**$151,832**	**$26,571**	**$0**	**$26,798**	**$205,201**	**$316**
9	Cooling Water System										
9.1	Cooling Towers	$13,076	$0	$4,044	$0	$17,120	$2,996	$0	$3,017	$23,133	$36
9.2	Circulating Water Pumps	$1,746	$0	$109	$0	$1,856	$325	$0	$327	$2,507	$4
9.3	Circulating Water System Auxiliaries	$11,558	$0	$1,538	$0	$13,096	$2,292	$0	$2,308	$17,696	$27
9.4	Circulating Water Piping	$0	$5,348	$4,843	$0	$10,191	$1,783	$0	$1,796	$13,771	$21
9.5	Make-up Water System	$1,003	$0	$1,288	$0	$2,292	$401	$0	$404	$3,097	$5
9.6	Component Cooling Water System	$833	$0	$640	$0	$1,473	$258	$0	$260	$1,990	$3
9.7	Circulating Water System Foundations	$0	$512	$850	$0	$1,362	$238	$0	$320	$1,921	$3
	Subtotal	**$28,217**	**$5,860**	**$13,313**	**$0**	**$47,390**	**$8,293**	**$0**	**$8,432**	**$64,115**	**$99**
10	Ash & Spent Sorbent Handling Systems										
10.6	Ash Storage Silos	$993	$0	$3,042	$0	$4,035	$706	$0	$711	$5,453	$8
10.7	Ash Transport & Feed Equipment	$3,382	$0	$3,352	$0	$6,734	$1,178	$0	$1,187	$9,099	$14
10.9	Ash/Spent Sorbent Foundation	$0	$693	$850	$0	$1,543	$270	$0	$362	$2,175	$3
	Subtotal	**$4,375**	**$693**	**$7,244**	**$0**	**$12,312**	**$2,155**	**$0**	**$2,261**	**$16,727**	**$26**
11	Accessory Electric Plant										
11.1	Generator Equipment	$2,520	$0	$1,901	$0	$4,421	$774	$0	$779	$5,974	$9
11.2	Station Service Equipment	$5,050	$0	$433	$0	$5,483	$960	$0	$966	$7,410	$11
11.3	Switchgear & Motor Control	$7,840	$0	$1,360	$0	$9,200	$1,610	$0	$1,622	$12,432	$19
11.4	Conduit & Cable Tray	$0	$1,019	$2,937	$0	$3,956	$692	$0	$697	$5,346	$8
11.5	Wire & Cable	$0	$2,699	$4,824	$0	$7,523	$1,317	$0	$1,326	$10,166	$16
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$788	$0	$728	$0	$1,516	$265	$0	$267	$2,049	$3
11.8	Main Power Transformers	$6,526	$0	$133	$0	$6,659	$1,165	$0	$1,174	$8,998	$14
11.9	Electrical Foundations	$0	$208	$528	$0	$735	$129	$0	$173	$1,037	$2
	Subtotal	**$22,780**	**$3,926**	**$13,036**	**$0**	**$39,742**	**$6,955**	**$0**	**$7,048**	**$53,744**	**$83**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$712	$0	$127	$0	$839	$147	$0	$148	$1,134	$2

Case:		PN1	– SC PC and 20% Biomass (w/o CO_2 Capture)					Estimate Type:			Conceptual	
Plant Size (MWnet):		650								Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost		
				Direct	Indirect			Process	Project	$/1,000	$/kW	
12.3	Steam Turbine Control Equipment	$639	$0	$70	$0	$709	$124	$0	$125	$958	$1	
12.5	Signal Processing Equipment	$808	$0	$144	$0	$952	$167	$0	$168	$1,287	$2	
12.6	Control Boards, Panels & Racks	$247	$0	$151	$0	$398	$70	$0	$70	$538	$1	
12.7	Distributed Control System Equipment	$6,975	$0	$1,244	$0	$8,219	$1,438	$0	$1,449	$11,106	$17	
12.8	Instrument Wiring & Tubing	$489	$391	$1,563	$0	$2,443	$427	$0	$430	$3,300	$5	
12.9	Other Instrumentation & Controls Equipment	$601	$0	$1,391	$0	$1,991	$348	$0	$351	$2,691	$4	
	Subtotal	**$10,472**	**$391**	**$4,689**	**$0**	**$15,551**	**$2,721**	**$0**	**$2,741**	**$21,014**	**$32**	
13	Improvements to Site											
13.1	Site Preparation	$0	$423	$9,025	$0	$9,449	$1,654	$0	$2,220	$13,323	$20	
13.2	Site Improvements	$0	$2,102	$2,776	$0	$4,878	$854	$0	$1,146	$6,879	$11	
13.3	Site Facilities	$2,401	$0	$2,519	$0	$4,921	$861	$0	$1,156	$6,938	$11	
	Subtotal	**$2,401**	**$2,525**	**$14,321**	**$0**	**$19,248**	**$3,368**	**$0**	**$4,523**	**$27,139**	**$42**	
14	Buildings & Structures											
14.2	Boiler Building	$0	$11,588	$10,184	$0	$21,772	$3,810	$0	$3,837	$29,419	$45	
14.3	Steam Turbine Building	$0	$16,107	$15,002	$0	$31,109	$5,444	$0	$5,483	$42,036	$65	
14.4	Administration Building	$0	$1,046	$1,106	$0	$2,152	$377	$0	$379	$2,909	$4	
14.5	Circulation Water Pumphouse	$0	$135	$107	$0	$242	$42	$0	$43	$327	$1	
14.6	Water Treatment Buildings	$0	$371	$338	$0	$709	$124	$0	$125	$959	$1	
14.7	Machine Shop	$0	$552	$370	$0	$922	$161	$0	$163	$1,246	$2	
14.8	Warehouse	$0	$415	$416	$0	$831	$145	$0	$146	$1,123	$2	
14.9	Other Buildings & Structures	$0	$291	$247	$0	$538	$94	$0	$95	$727	$1	
14.10	Waste Treating Building & Structures	$0	$627	$1,900	$0	$2,527	$442	$0	$445	$3,415	$5	
	Subtotal	**$0**	**$31,133**	**$29,671**	**$0**	**$60,804**	**$10,641**	**$0**	**$10,717**	**$82,161**	**$126**	
	Total	**$624,560**	**$60,095**	**$332,262**	**$0**	**$1,058,620**	**$185,259**	**$0**	**$191,517**	**$1,435,396**	**$2,157**	

Exhibit A-43. Case PN1 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$9,578	$15
1 Month Maintenance Materials	$1,351	$2
1 Month Non-Fuel Consumables	$1,639	$3
1 Month Waste Disposal	$693	$1
25% of 1 Months Fuel Cost at 100% CF	$763	$1
2% of TPC	$28,708	$44
Total	**$42,732**	**$66**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$25,565	$39
0.5% of TPC (spare parts)	$7,177	$11
Total	**$32,741**	**$50**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,088	$3
Land	$900	$1
Other Owner's Costs	$215,309	$331
Financing Costs	$38,756	$60
Total Overnight Costs (TOC)	**$1,767,923**	**$2,669**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$2,040,911**	**$3,139**

Exhibit A-44. Case PN1 initial and annual O&M costs

Case:	PN1	– SC PC and 20% Biomass (w/o CO_2 Capture)			Cost Base:	Dec-18
Plant Size (MWnet):	650		Heat Rate-net (Btu/kWh):	8,607	Capacity Factor (%):	85.0
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	9.0	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**14.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,138,132	$9.442
Maintenance Labor:					$9,186,533	$14.131
Administrative & Support Labor:					$3,831,166	$5.893
Property Taxes and Insurance:					$28,707,914	$44.158
Total:					**$47,863,745**	**$73.623**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$13,779,799	$2.84660
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,333	$1.90	$0	$2,554,394	$0.52768
Makeup and Waste Water Treatment Chemicals (ton):	0	12.9	$550.00	$0	$2,202,658	$0.45502
Brominated Activated Carbon (ton):	0	1.24	$1,600.00	$0	$617,193	$0.12750
Enhanced Hydrated Lime (ton):	0	31.7	$240.00	$0	$2,362,894	$0.48812
Limestone (ton):	0	510	$22.00	$0	$3,482,304	$0.71937
Ammonia (19 wt%, ton):	0	52.8	$300.00	$0	$4,911,295	$1.01456
SCR Catalyst (ft^3):	13,923	12.7	150.00	$2,088,476	$591,735	$0.12224
Subtotal:				**$2,088,476**	**$16,722,472**	**$3.45449**
Waste Disposal						
Fly Ash (ton)	0	490	$38.00	$0	$5,779,271	$1.19387
Bottom Ash (ton)	0	108	$38.00	$0	$1,277,522	$0.26391
SCR Catalyst (ft^3):	0	12.7	$2.50	$0	$9,862	$0.00204
Subtotal:				**$0**	**$7,066,655**	**$1.45981**
By-Products						
Gypsum (ton)	0	775	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$2,088,476**	**$37,568,926**	**$7.76090**
Fuel Cost						
Illinois Number 6 (ton):	0	5,279	$51.96	$0	$85,090,115	$17.57772
Hybrid Poplar (ton):	0	1,320	$76.01	$0	$31,120,850	$6.42887
Total:				**$0**	**$116,210,965**	**$24.00659**

Exhibit A-45. Case PN1 LCOE breakdown

Component	Value, $/MWh	Percentage
Capital	29.8	42%
Fixed	9.9	14%
Variable	7.8	11%
Fuel	24.0	34%
Total (Excluding T&S)	**71.5**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**71.5**	**N/A**

Exhibit A-46. Case PN2 total plant cost details

	Case:	PN2	– SC PC and 35% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
1						Coal & Sorbent Handling					
1.1	Coal Receive & Unload	$923	$0	$416	$0	$1,338	$234	$0	$236	$1,809	$3
1.2	Coal Stackout & Reclaim	$3,030	$0	$677	$0	$3,707	$649	$0	$653	$5,009	$8
1.3	Coal Conveyors	$27,911	$0	$6,635	$0	$34,546	$6,046	$0	$6,089	$46,680	$72
1.4	Other Coal Handling	$3,881	$0	$815	$0	$4,696	$822	$0	$828	$6,345	$10
1.5	Sorbent Receive & Unload	$175	$0	$52	$0	$226	$40	$0	$40	$306	$0
1.6	Sorbent Stackout & Reclaim	$1,286	$0	$232	$0	$1,518	$266	$0	$268	$2,052	$3
1.7	Sorbent Conveyors	$1,944	$421	$470	$0	$2,836	$496	$0	$500	$3,832	$6
1.8	Other Sorbent Handling	$94	$22	$48	$0	$164	$29	$0	$29	$222	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,210	$1,595	$0	$2,805	$491	$0	$494	$3,790	$6
1.10	Biomass Receiving and Processing	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$26,003	$4,550	$0	$4,583	$35,136	$54
	Subtotal	**$39,243**	**$1,653**	**$10,941**	**$0**	**$77,839**	**$13,622**	**$0**	**$13,719**	**$105,181**	**$108**
2						Coal & Sorbent Preparation & Feed					
2.1	Coal Crushing & Drying	$1,952	$0	$375	$0	$2,327	$407	$0	$410	$3,145	$5
2.2	Prepared Coal Storage & Feed	$6,570	$0	$1,414	$0	$7,985	$1,397	$0	$1,407	$10,789	$17
2.3	Biomass Drying	$1,505	$0	$293	$0	$1,798	$315	$0	$317	$2,430	$4
2.5	Sorbent Preparation Equipment	$862	$37	$177	$0	$1,076	$188	$0	$190	$1,454	$2
2.6	Sorbent Storage & Feed	$1,444	$0	$546	$0	$1,990	$348	$0	$351	$2,689	$4
2.7	Biomass Pelletization	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$35,506	$6,214	$0	$6,258	$47,978	$74
2.8	Prepared Biomass Storage & Feed	$3,433	$0	$739	$0	$4,172	$730	$0	$735	$5,637	$9
2.9	Coal & Sorbent Feed Foundation	$0	$575	$504	$0	$1,079	$189	$0	$190	$1,458	$2
	Subtotal	**$15,766**	**$612**	**$4,048**	**$0**	**$55,932**	**$9,788**	**$0**	**$9,858**	**$75,578**	**$116**
3						Feedwater & Miscellaneous BOP Systems					
3.1	Feedwater System	$3,428	$5,877	$2,939	$0	$12,244	$2,143	$0	$2,158	$16,545	$25
3.2	Water Makeup & Pretreating	$5,706	$571	$3,233	$0	$9,510	$1,664	$0	$2,235	$13,409	$21
3.3	Other Feedwater Subsystems	$2,566	$841	$799	$0	$4,207	$736	$0	$741	$5,684	$9
3.4	Service Water Systems	$1,743	$3,327	$10,772	$0	$15,841	$2,772	$0	$3,723	$22,336	$34
3.5	Other Boiler Plant Systems	$633	$230	$575	$0	$1,438	$252	$0	$253	$1,943	$3
3.6	Natural Gas Pipeline and Start-Up System	$3,413	$147	$110	$0	$3,670	$642	$0	$647	$4,958	$8
3.7	Waste Water Treatment Equipment	$8,297	$0	$5,085	$0	$13,382	$2,342	$0	$3,145	$18,869	$29

	Case:	PN2	– SC PC and 35% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
3.8	Spray Dryer Evaporator	$12,533	$0	$7,224	$0	$19,757	$3,458	$0	$4,643	$27,858	$43
3.9	Miscellaneous Plant Equipment	$228	$30	$116	$0	$374	$65	$0	$88	$527	$1
	Subtotal	**$38,547**	**$11,022**	**$30,854**	**$0**	**$80,423**	**$14,074**	**$0**	**$17,633**	**$112,129**	**$173**
	4					**Pulverized Coal Boiler & Accessories**					
4.9	Pulverized Coal Boiler & Accessories	$227,651	$0	$129,714	$0	$357,365	$62,539	$0	$62,986	$482,890	$743
4.10	Selective Catalytic Reduction System	$25,509	$0	$14,535	$0	$40,044	$7,008	$0	$7,058	$54,109	$83
4.11	Boiler Balance of Plant	$1,816	$0	$1,035	$0	$2,851	$499	$0	$503	$3,853	$6
4.12	Primary Air System	$1,551	$0	$884	$0	$2,435	$426	$0	$429	$3,291	$5
4.13	Secondary Air System	$2,176	$0	$1,240	$0	$3,415	$598	$0	$602	$4,615	$7
4.14	Induced Draft Fans	$4,756	$0	$2,710	$0	$7,467	$1,307	$0	$1,316	$10,089	$16
4.15	Major Component Rigging	$96	$0	$54	$0	$150	$26	$0	$26	$203	$0
4.16	Boiler Foundations	$0	$410	$361	$0	$771	$135	$0	$136	$1,042	$2
	Subtotal	**$263,555**	**$410**	**$150,533**	**$0**	**$414,498**	**$72,537**	**$0**	**$73,055**	**$560,090**	**$862**
	5					**Flue Gas Cleanup**					
5.2	WFGD Absorber Vessels & Accessories	$67,785	$0	$14,493	$0	$82,278	$14,399	$0	$14,501	$111,178	$171
5.3	Other FGD	$304	$0	$342	$0	$646	$113	$0	$114	$873	$1
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,244	$493	$2,206	$0	$4,943	$865	$0	$871	$6,680	$10
5.9	Particulate Removal (Bag House & Accessories)	$1,294	$0	$816	$0	$2,110	$369	$0	$372	$2,852	$4
5.12	Gas Cleanup Foundations	$0	$204	$179	$0	$382	$67	$0	$67	$517	$1
5.13	Gypsum Dewatering System	$608	$0	$103	$0	$710	$124	$0	$125	$960	$1
	Subtotal	**$72,235**	**$697**	**$18,138**	**$0**	**$91,071**	**$15,937**	**$0**	**$16,051**	**$123,059**	**$189**
	7					**Ductwork & Stack**					
7.3	Ductwork	$67,785	$0	$14,493	$0	$82,278	$14,399	$0	$14,501	$111,178	$171
7.4	Stack	$304	$0	$342	$0	$646	$113	$0	$114	$873	$1
7.5	Duct & Stack Foundations	$2,244	$493	$2,206	$0	$4,943	$865	$0	$871	$6,680	$10
	Subtotal	**$1,294**	**$0**	**$816**	**$0**	**$2,110**	**$369**	**$0**	**$372**	**$2,852**	**$4**
	8					**Steam Turbine & Accessories**					
8.1	Steam Turbine Generator & Accessories	$69,096	$0	$7,534	$0	$76,630	$13,410	$0	$13,506	$103,547	$159
8.2	Steam Turbine Plant Auxiliaries	$1,564	$0	$3,331	$0	$4,895	$857	$0	$863	$6,615	$10

	Case:	PN2	– SC PC and 35% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
8.3	Condenser & Auxiliaries	$14,294	$0	$4,850	$0	$19,144	$3,350	$0	$3,374	$25,868	$40
8.4	Steam Piping	$37,042	$0	$15,014	$0	$52,056	$9,110	$0	$9,175	$70,341	$108
8.5	Turbine Generator Foundations	$0	$244	$403	$0	$648	$113	$0	$152	$913	$1
	Subtotal	**$121,997**	**$244**	**$31,133**	**$0**	**$153,373**	**$26,840**	**$0**	**$27,070**	**$207,284**	**$319**
9						Cooling Water System					
9.1	Cooling Towers	$13,209	$0	$4,085	$0	$17,293	$3,026	$0	$3,048	$23,368	$36
9.2	Circulating Water Pumps	$1,766	$0	$111	$0	$1,877	$328	$0	$331	$2,536	$4
9.3	Circulating Water System Auxiliaries	$11,654	$0	$1,551	$0	$13,205	$2,311	$0	$2,327	$17,843	$27
9.4	Circulating Water Piping	$0	$5,392	$4,883	$0	$10,276	$1,798	$0	$1,811	$13,885	$21
9.5	Make-up Water System	$999	$0	$1,283	$0	$2,283	$399	$0	$402	$3,085	$5
9.6	Component Cooling Water System	$840	$0	$645	$0	$1,485	$260	$0	$262	$2,007	$3
9.7	Circulating Water System Foundations	$0	$516	$857	$0	$1,373	$240	$0	$323	$1,935	$3
	Subtotal	**$28,468**	**$5,908**	**$13,415**	**$0**	**$47,791**	**$8,363**	**$0**	**$8,504**	**$64,658**	**$99**
10						Ash & Spent Sorbent Handling Systems					
10.6	Ash Storage Silos	$965	$0	$2,956	$0	$3,922	$686	$0	$691	$5,299	$8
10.7	Ash Transport & Feed Equipment	$3,286	$0	$3,258	$0	$6,544	$1,145	$0	$1,153	$8,843	$14
10.9	Ash/Spent Sorbent Foundation	$0	$673	$826	$0	$1,499	$262	$0	$352	$2,114	$3
	Subtotal	**$4,252**	**$673**	**$7,040**	**$0**	**$11,965**	**$2,094**	**$0**	**$2,197**	**$16,256**	**$25**
11						Accessory Electric Plant					
11.1	Generator Equipment	$2,540	$0	$1,916	$0	$4,456	$780	$0	$785	$6,021	$9
11.2	Station Service Equipment	$5,493	$0	$471	$0	$5,964	$1,044	$0	$1,051	$8,059	$12
11.3	Switchgear & Motor Control	$8,528	$0	$1,480	$0	$10,007	$1,751	$0	$1,764	$13,522	$21
11.4	Conduit & Cable Tray	$0	$1,109	$3,195	$0	$4,303	$753	$0	$758	$5,815	$9
11.5	Wire & Cable	$0	$2,936	$5,248	$0	$8,183	$1,432	$0	$1,442	$11,058	$17
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$793	$0	$732	$0	$1,526	$267	$0	$269	$2,062	$3
11.8	Main Power Transformers	$6,588	$0	$134	$0	$6,723	$1,177	$0	$1,185	$9,084	$14
11.9	Electrical Foundations	$0	$210	$533	$0	$742	$130	$0	$174	$1,047	$2
	Subtotal	**$23,997**	**$4,254**	**$13,899**	**$0**	**$42,151**	**$7,376**	**$0**	**$7,473**	**$57,000**	**$88**
12						Instrumentation & Control					
12.1	Pulverized Coal Boiler Control Equipment	$730	$0	$130	$0	$861	$151	$0	$152	$1,163	$2

	Case:	PN2	– SC PC and 35% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
12.3	Steam Turbine Control Equipment	$656	$0	$72	$0	$727	$127	$0	$128	$983	$2
12.5	Signal Processing Equipment	$829	$0	$148	$0	$977	$171	$0	$172	$1,320	$2
12.6	Control Boards, Panels & Racks	$254	$0	$155	$0	$408	$71	$0	$72	$552	$1
12.7	Distributed Control System Equipment	$7,155	$0	$1,276	$0	$8,431	$1,475	$0	$1,486	$11,392	$18
12.8	Instrument Wiring & Tubing	$501	$401	$1,603	$0	$2,505	$438	$0	$442	$3,385	$5
12.9	Other Instrumentation & Controls Equipment	$616	$0	$1,426	$0	$2,043	$357	$0	$360	$2,760	$4
	Subtotal	**$10,741**	**$401**	**$4,810**	**$0**	**$15,952**	**$2,792**	**$0**	**$2,811**	**$21,555**	**$33**
13						**Improvements to Site**					
13.1	Site Preparation	$0	$426	$9,077	$0	$9,502	$1,663	$0	$2,233	$13,398	$21
13.2	Site Improvements	$0	$2,114	$2,792	$0	$4,906	$859	$0	$1,153	$6,918	$11
13.3	Site Facilities	$2,415	$0	$2,534	$0	$4,949	$866	$0	$1,163	$6,978	$11
	Subtotal	**$2,415**	**$2,540**	**$14,402**	**$0**	**$19,357**	**$3,388**	**$0**	**$4,549**	**$27,294**	**$42**
14						**Buildings & Structures**					
14.2	Boiler Building	$0	$11,588	$10,184	$0	$21,772	$3,810	$0	$3,837	$29,419	$45
14.3	Steam Turbine Building	$0	$16,107	$15,002	$0	$31,109	$5,444	$0	$5,483	$42,036	$65
14.4	Administration Building	$0	$1,046	$1,106	$0	$2,152	$377	$0	$379	$2,909	$4
14.5	Circulation Water Pumphouse	$0	$136	$108	$0	$244	$43	$0	$43	$330	$1
14.6	Water Treatment Buildings	$0	$370	$337	$0	$707	$124	$0	$125	$955	$1
14.7	Machine Shop	$0	$552	$370	$0	$922	$161	$0	$163	$1,246	$2
14.8	Warehouse	$0	$415	$416	$0	$831	$145	$0	$146	$1,123	$2
14.9	Other Buildings & Structures	$0	$291	$247	$0	$538	$94	$0	$95	$727	$1
14.10	Waste Treating Building & Structures	$0	$627	$1,900	$0	$2,526	$442	$0	$445	$3,414	$5
	Subtotal	**$0**	**$31,132**	**$29,670**	**$0**	**$60,802**	**$10,640**	**$0**	**$10,716**	**$82,158**	**$126**
	Total	**$630,053**	**$60,513**	**$334,792**	**$0**	**$1,086,867**	**$190,202**	**$0**	**$196,433**	**$1,473,501**	**$2,213**

Exhibit A-47. Case PN2 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$9,730	$15
1 Month Maintenance Materials	$1,387	$2
1 Month Non-Fuel Consumables	$1,625	$2
1 Month Waste Disposal	$658	$1
25% of 1 Months Fuel Cost at 100% CF	$1,545	$2
2% of TPC	$29,470	$45
Total	**$44,415**	**$68**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$30,575	$47
0.5% of TPC (spare parts)	$7,368	$11
Total	**$37,943**	**$58**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,132	$3
Land	$900	$1
Other Owner's Costs	$221,025	$340
Financing Costs	$39,785	$61
Total Overnight Costs (TOC)	**$1,819,701**	**$2,746**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$2,100,684**	**$3,232**

Exhibit A-48. Case PN2 initial and annual O&M costs

Case:	PN2	– SC PC and 35% Biomass (w/o CO_2 Capture)			Cost Base:	Dec-18
Plant Size (MWnet):	650		Heat Rate-net (Btu/kWh):	8,742	Capacity Factor (%):	85.0
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	9.0	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**14.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,138,132	$9.444
Maintenance Labor:					$9,430,409	$14.509
Administrative & Support Labor:					$3,892,135	$5.988
Property Taxes and Insurance:					$29,470,027	$45.342
Total:					**$48,930,703**	**$75.284**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$14,145,613	$2.92293
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,300	$1.90	$0	$2,534,542	$0.52372
Makeup and Waste Water Treatment Chemicals (ton):	0	12.8	$550.00	$0	$2,185,539	$0.45160
Brominated Activated Carbon (ton):	0	1.27	$1,600.00	$0	$629,470	$0.13007
Enhanced Hydrated Lime (ton):	0	32.3	$240.00	$0	$2,402,729	$0.49648
Limestone (ton):	0	472	$22.00	$0	$3,224,157	$0.66621
Ammonia (19 wt%, ton):	0	53.6	$300.00	$0	$4,989,886	$1.03107
SCR Catalyst (ft^3):	14,213	13.0	150.00	$2,132,005	$604,068	$0.12482
Subtotal:				**$2,132,005**	**$16,570,392**	**$3.42397**
Waste Disposal						
Fly Ash (ton)	0	466	$38.00	$0	$5,497,094	$1.13587
Bottom Ash (ton)	0	103	$38.00	$0	$1,208,576	$0.24973
SCR Catalyst (ft^3):	0	13.0	$2.50	$0	$10,068	$0.00208
Subtotal:				**$0**	**$6,715,738**	**$1.38768**
By-Products						
Gypsum (ton)	0	718	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$2,132,005**	**$37,431,743**	**$7.73459**
Fuel Cost						
Illinois Number 6 (ton):	0	4,892	$51.96	$0	$78,857,976	$16.29456
Hybrid Poplar (ton):	0	2,634	$77.14	$0	$63,038,782	$13.02581
Total:				**$0**	**$141,896,759**	**$29.32037**

Exhibit A-49. Case PN2 LCOE breakdown

Component	Value, $/MWh	Percentage
Capital	30.7	39%
Fixed	10.1	13%
Variable	7.7	10%
Fuel	29.3	38%
Total (Excluding T&S)	**77.9**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**77.9**	**N/A**

Exhibit A-50. Case PN3 total plant cost details

	Case:	PN3	– SC PC and 49% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	1					**Coal & Sorbent Handling**					
1.1	Coal Receive & Unload	$866	$0	$390	$0	$1,257	$220	$0	$222	$1,698	$3
1.2	Coal Stackout & Reclaim	$2,845	$0	$636	$0	$3,481	$609	$0	$614	$4,704	$7
1.3	Coal Conveyors	$26,209	$0	$6,230	$0	$32,440	$5,677	$0	$5,718	$43,834	$67
1.4	Other Coal Handling	$3,644	$0	$765	$0	$4,410	$772	$0	$777	$5,959	$9
1.5	Sorbent Receive & Unload	$163	$0	$48	$0	$212	$37	$0	$37	$286	$0
1.6	Sorbent Stackout & Reclaim	$1,204	$0	$218	$0	$1,422	$249	$0	$251	$1,921	$3
1.7	Sorbent Conveyors	$1,819	$394	$440	$0	$2,653	$464	$0	$468	$3,584	$6
1.8	Other Sorbent Handling	$88	$21	$45	$0	$154	$27	$0	$27	$208	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,136	$1,498	$0	$2,634	$461	$0	$464	$3,559	$5
1.10	Biomass Receiving and Processing	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$27,262	$4,771	$0	$4,805	$36,837	$57
	Subtotal	**$36,839**	**$1,551**	**$10,271**	**$0**	**$75,922**	**$13,286**	**$0**	**$13,381**	**$102,590**	**$101**
	2					**Coal & Sorbent Preparation & Feed**					
2.1	Coal Crushing & Drying	$1,826	$0	$350	$0	$2,176	$381	$0	$384	$2,941	$5
2.2	Prepared Coal Storage & Feed	$6,145	$0	$1,323	$0	$7,467	$1,307	$0	$1,316	$10,090	$16
2.3	Biomass Drying	$2,063	$0	$402	$0	$2,465	$431	$0	$434	$3,331	$5
2.5	Sorbent Preparation Equipment	$806	$35	$165	$0	$1,006	$176	$0	$177	$1,360	$2
2.6	Sorbent Storage & Feed	$1,350	$0	$511	$0	$1,861	$326	$0	$328	$2,515	$4
2.7	Biomass Pelletization	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$57,693	$10,096	$0	$10,168	$77,957	$120
2.8	Prepared Biomass Storage & Feed	$4,705	$0	$1,013	$0	$5,717	$1,001	$0	$1,008	$7,725	$12
2.9	Coal & Sorbent Feed Foundation	$0	$538	$473	$0	$1,011	$177	$0	$178	$1,366	$2
	Subtotal	**$16,895**	**$573**	**$4,236**	**$0**	**$79,398**	**$13,895**	**$0**	**$13,994**	**$107,286**	**$165**
	3					**Feedwater & Miscellaneous BOP Systems**					
3.1	Feedwater System	$3,468	$5,946	$2,973	$0	$12,387	$2,168	$0	$2,183	$16,738	$26
3.2	Water Makeup & Pretreating	$5,668	$567	$3,212	$0	$9,446	$1,653	$0	$2,220	$13,319	$20
3.3	Other Feedwater Subsystems	$2,605	$854	$811	$0	$4,270	$747	$0	$753	$5,770	$9
3.4	Service Water Systems	$1,730	$3,302	$10,692	$0	$15,724	$2,752	$0	$3,695	$22,171	$34
3.5	Other Boiler Plant Systems	$643	$234	$584	$0	$1,460	$256	$0	$257	$1,973	$3
3.6	Natural Gas Pipeline and Start-Up System	$3,657	$157	$118	$0	$3,932	$688	$0	$693	$5,313	$8
3.7	Waste Water Treatment Equipment	$8,393	$0	$5,144	$0	$13,537	$2,369	$0	$3,181	$19,088	$29

Case:		PN3	– SC PC and 49% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
Plant Size (MWnet):		650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
3.8	Spray Dryer Evaporator	$11,653	$0	$6,695	$0	$18,348	$3,211	$0	$4,312	$25,870	$40
3.9	Miscellaneous Plant Equipment	$236	$31	$120	$0	$387	$68	$0	$91	$546	$1
	Subtotal	**$38,052**	**$11,091**	**$30,349**	**$0**	**$79,492**	**$13,911**	**$0**	**$17,385**	**$110,788**	**$170**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$230,587	$0	$131,387	$0	$361,974	$63,345	$0	$63,798	$489,117	$753
4.10	Selective Catalytic Reduction System	$25,955	$0	$14,789	$0	$40,744	$7,130	$0	$7,181	$55,055	$85
4.11	Boiler Balance of Plant	$2,002	$0	$1,141	$0	$3,143	$550	$0	$554	$4,247	$7
4.12	Primary Air System	$1,622	$0	$924	$0	$2,546	$446	$0	$449	$3,441	$5
4.13	Secondary Air System	$2,179	$0	$1,242	$0	$3,421	$599	$0	$603	$4,622	$7
4.14	Induced Draft Fans	$4,836	$0	$2,755	$0	$7,591	$1,328	$0	$1,338	$10,258	$16
4.15	Major Component Rigging	$105	$0	$60	$0	$165	$29	$0	$29	$223	$0
4.16	Boiler Foundations	$0	$452	$398	$0	$850	$149	$0	$150	$1,148	$2
	Subtotal	**$267,286**	**$452**	**$152,696**	**$0**	**$420,433**	**$73,576**	**$0**	**$74,101**	**$568,111**	**$874**
5	Flue Gas Cleanup										
5.2	WFGD Absorber Vessels & Accessories	$68,595	$0	$14,666	$0	$83,261	$14,571	$0	$14,675	$112,507	$173
5.3	Other FGD	$308	$0	$346	$0	$654	$114	$0	$115	$884	$1
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,286	$503	$2,248	$0	$5,037	$881	$0	$888	$6,806	$10
5.9	Particulate Removal (Bag House & Accessories)	$1,319	$0	$832	$0	$2,151	$376	$0	$379	$2,906	$4
5.12	Gas Cleanup Foundations	$0	$228	$200	$0	$428	$75	$0	$75	$578	$1
5.13	Gypsum Dewatering System	$573	$0	$97	$0	$669	$117	$0	$118	$904	$1
	Subtotal	**$73,081**	**$730**	**$18,388**	**$0**	**$92,200**	**$16,135**	**$0**	**$16,250**	**$124,585**	**$192**
7	Ductwork & Stack										
7.3	Ductwork	$0	$787	$547	$0	$1,333	$233	$0	$235	$1,802	$3
7.4	Stack	$8,846	$0	$5,140	$0	$13,986	$2,448	$0	$2,465	$18,898	$29
7.5	Duct & Stack Foundations	$0	$212	$252	$0	$464	$81	$0	$109	$655	$1
	Subtotal	**$8,846**	**$999**	**$5,939**	**$0**	**$15,784**	**$2,762**	**$0**	**$2,809**	**$21,355**	**$33**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$69,918	$0	$7,624	$0	$77,542	$13,570	$0	$13,667	$104,778	$161
8.2	Steam Turbine Plant Auxiliaries	$1,583	$0	$3,371	$0	$4,954	$867	$0	$873	$6,694	$10

Case:		PN3	– SC PC and 49% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
Plant Size (MWnet):		650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
8.3	Condenser & Auxiliaries	$14,547	$0	$4,936	$0	$19,483	$3,409	$0	$3,434	$26,326	$41
8.4	Steam Piping	$37,482	$0	$15,192	$0	$52,674	$9,218	$0	$9,284	$71,176	$110
8.5	Turbine Generator Foundations	$0	$247	$408	$0	$656	$115	$0	$154	$924	$1
	Subtotal	**$123,530**	**$247**	**$31,531**	**$0**	**$155,308**	**$27,179**	**$0**	**$27,411**	**$209,898**	**$323**
9	Cooling Water System										
9.1	Cooling Towers	$13,375	$0	$4,136	$0	$17,511	$3,064	$0	$3,086	$23,661	$36
9.2	Circulating Water Pumps	$1,791	$0	$112	$0	$1,903	$333	$0	$335	$2,572	$4
9.3	Circulating Water System Auxiliaries	$11,773	$0	$1,567	$0	$13,340	$2,335	$0	$2,351	$18,026	$28
9.4	Circulating Water Piping	$0	$5,448	$4,934	$0	$10,381	$1,817	$0	$1,830	$14,028	$22
9.5	Make-up Water System	$995	$0	$1,278	$0	$2,273	$398	$0	$401	$3,071	$5
9.6	Component Cooling Water System	$849	$0	$652	$0	$1,500	$263	$0	$264	$2,027	$3
9.7	Circulating Water System Foundations	$0	$521	$865	$0	$1,386	$242	$0	$326	$1,954	$3
	Subtotal	**$28,783**	**$5,968**	**$13,543**	**$0**	**$48,294**	**$8,451**	**$0**	**$8,593**	**$65,339**	**$101**
10	Ash & Spent Sorbent Handling Systems										
10.6	Ash Storage Silos	$930	$0	$2,849	$0	$3,779	$661	$0	$666	$5,107	$8
10.7	Ash Transport & Feed Equipment	$3,167	$0	$3,140	$0	$6,307	$1,104	$0	$1,112	$8,522	$13
10.9	Ash/Spent Sorbent Foundation	$0	$649	$796	$0	$1,445	$253	$0	$340	$2,037	$3
	Subtotal	**$4,098**	**$649**	**$6,785**	**$0**	**$11,531**	**$2,018**	**$0**	**$2,117**	**$15,666**	**$24**
11	Accessory Electric Plant										
11.1	Generator Equipment	$2,564	$0	$1,935	$0	$4,499	$787	$0	$793	$6,079	$9
11.2	Station Service Equipment	$5,985	$0	$513	$0	$6,499	$1,137	$0	$1,145	$8,781	$14
11.3	Switchgear & Motor Control	$9,291	$0	$1,612	$0	$10,903	$1,908	$0	$1,922	$14,733	$23
11.4	Conduit & Cable Tray	$0	$1,208	$3,481	$0	$4,689	$821	$0	$826	$6,335	$10
11.5	Wire & Cable	$0	$3,199	$5,718	$0	$8,916	$1,560	$0	$1,571	$12,048	$19
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$800	$0	$738	$0	$1,538	$269	$0	$271	$2,078	$3
11.8	Main Power Transformers	$6,667	$0	$136	$0	$6,803	$1,191	$0	$1,199	$9,192	$14
11.9	Electrical Foundations	$0	$212	$539	$0	$751	$131	$0	$176	$1,059	$2
	Subtotal	**$25,362**	**$4,618**	**$14,862**	**$0**	**$44,843**	**$7,848**	**$0**	**$7,948**	**$60,638**	**$93**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$749	$0	$134	$0	$883	$155	$0	$156	$1,193	$2

	Case:	PN3	– SC PC and 49% Biomass (w/o CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
12.3	Steam Turbine Control Equipment	$673	$0	$73	$0	$746	$131	$0	$132	$1,009	$2
12.5	Signal Processing Equipment	$851	$0	$152	$0	$1,002	$175	$0	$177	$1,355	$2
12.6	Control Boards, Panels & Racks	$260	$0	$159	$0	$419	$73	$0	$74	$566	$1
12.7	Distributed Control System Equipment	$7,343	$0	$1,309	$0	$8,652	$1,514	$0	$1,525	$11,691	$18
12.8	Instrument Wiring & Tubing	$514	$411	$1,646	$0	$2,571	$450	$0	$453	$3,474	$5
12.9	Other Instrumentation & Controls Equipment	$632	$0	$1,464	$0	$2,096	$367	$0	$369	$2,832	$4
	Subtotal	**$11,023**	**$411**	**$4,936**	**$0**	**$16,371**	**$2,865**	**$0**	**$2,885**	**$22,121**	**$34**
13						Improvements to Site					
13.1	Site Preparation	$0	$428	$9,135	$0	$9,564	$1,674	$0	$2,247	$13,485	$21
13.2	Site Improvements	$0	$2,128	$2,810	$0	$4,938	$864	$0	$1,160	$6,962	$11
13.3	Site Facilities	$2,431	$0	$2,550	$0	$4,981	$872	$0	$1,170	$7,023	$11
	Subtotal	**$2,431**	**$2,556**	**$14,495**	**$0**	**$19,482**	**$3,409**	**$0**	**$4,578**	**$27,470**	**$42**
14						Buildings & Structures					
14.2	Boiler Building	$0	$11,588	$10,184	$0	$21,772	$3,810	$0	$3,837	$29,419	$45
14.3	Steam Turbine Building	$0	$16,107	$15,002	$0	$31,109	$5,444	$0	$5,483	$42,036	$65
14.4	Administration Building	$0	$1,046	$1,106	$0	$2,152	$377	$0	$379	$2,909	$4
14.5	Circulation Water Pumphouse	$0	$137	$109	$0	$246	$43	$0	$43	$333	$1
14.6	Water Treatment Buildings	$0	$368	$335	$0	$703	$123	$0	$124	$951	$1
14.7	Machine Shop	$0	$552	$370	$0	$922	$161	$0	$163	$1,246	$2
14.8	Warehouse	$0	$415	$416	$0	$831	$145	$0	$146	$1,123	$2
14.9	Other Buildings & Structures	$0	$291	$247	$0	$538	$94	$0	$95	$727	$1
14.10	Waste Treating Building & Structures	$0	$626	$1,899	$0	$2,525	$442	$0	$445	$3,412	$5
	Subtotal	**$0**	**$31,132**	**$29,668**	**$0**	**$60,800**	**$10,640**	**$0**	**$10,716**	**$82,156**	**$126**
	Total	**$636,224**	**$60,978**	**$337,699**	**$0**	**$1,119,857**	**$195,975**	**$0**	**$202,170**	**$1,518,002**	**$2,279**

Exhibit A-51. Case PN3 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$9,908	$15
1 Month Maintenance Materials	$1,429	$2
1 Month Non-Fuel Consumables	$1,607	$2
1 Month Waste Disposal	$616	$1
25% of 1 Months Fuel Cost at 100% CF	$2,530	$4
2% of TPC	$30,360	$47
Total	**$46,450**	**$71**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$36,932	$57
0.5% of TPC (spare parts)	$7,590	$12
Total	**$44,522**	**$69**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,186	$3
Land	$900	$1
Other Owner's Costs	$227,700	$350
Financing Costs	$40,986	$63
Total Overnight Costs (TOC)	**$1,880,747**	**$2,837**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$2,171,156**	**$3,341**

Exhibit A-52. Case PN3 initial and annual O&M costs

Case:	PN3	– SC PC and 49% Biomass (w/o CO_2 Capture)			Cost Base:	Dec-18
Plant Size (MWnet):	650		Heat Rate-net (Btu/kWh):	8,909	Capacity Factor (%):	85.0
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	9.0	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**14.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,138,132	$9.444
Maintenance Labor:					$9,715,210	$14.948
Administrative & Support Labor:					$3,963,336	$6.098
Property Taxes and Insurance:					$30,360,032	$46.713
Total:					**$50,176,710**	**$77.203**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$14,572,815	$3.01130
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,260	$1.90	$0	$2,511,171	$0.51890
Makeup and Waste Water Treatment Chemicals (ton):	0	12.7	$550.00	$0	$2,165,386	$0.44745
Brominated Activated Carbon (ton):	0	1.30	$1,600.00	$0	$644,780	$0.13324
Enhanced Hydrated Lime (ton):	0	32.9	$240.00	$0	$2,452,555	$0.50679
Limestone (ton):	0	426	$22.00	$0	$2,909,018	$0.60111
Ammonia (19 wt%, ton):	0	54.7	$300.00	$0	$5,088,143	$1.05140
SCR Catalyst (ft^3):	14,575	13.3	150.00	$2,186,247	$619,437	$0.12800
Subtotal:				**$2,186,247**	**$16,390,491**	**$3.38690**
Waste Disposal						
Fly Ash (ton)	0	437	$38.00	$0	$5,152,910	$1.06479
Bottom Ash (ton)	0	95	$38.00	$0	$1,124,552	$0.23238
SCR Catalyst (ft^3):	0	13.3	$2.50	$0	$10,324	$0.00213
Subtotal:				**$0**	**$6,287,786**	**$1.29930**
By-Products						
Gypsum (ton)	0	648	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$2,186,247**	**$37,251,092**	**$7.69749**
Fuel Cost						
Illinois Number 6 (ton):	0	4,420	$51.96	$0	$71,250,352	$14.72304
Hybrid Poplar (ton):	0	4,247	$78.35	$0	$103,225,488	$21.33032
Total:				**$0**	**$174,475,841**	**$36.05335**

Exhibit A-53. Case PN3 LCOE breakdown

Component	Value, $/MWh	Percentage
Capital	31.7	37%
Fixed	10.4	12%
Variable	7.7	9%
Fuel	36.1	42%
Total (Excluding T&S)	**85.9**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**85.9**	**N/A**

Exhibit A-54. Case B12B total plant cost details

	Case:	B12B	– SC PC w/ CO_2				Estimate Type:		Conceptual	
	Plant Size (MWnet):	650					Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,176	$0	$530	$0	$1,707	$299	$0	$301	$2,306	$4
1.2	Coal Stackout & Reclaim	$3,862	$0	$863	$0	$4,726	$827	$0	$833	$6,385	$10
1.3	Coal Conveyors	$35,589	$0	$8,464	$0	$44,053	$7,709	$0	$7,764	$59,527	$92
1.4	Other Coal Handling	$4,945	$0	$1,040	$0	$5,984	$1,047	$0	$1,055	$8,086	$12
1.5	Sorbent Receive & Unload	$226	$0	$68	$0	$294	$51	$0	$52	$397	$1
1.6	Sorbent Stackout & Reclaim	$1,655	$0	$299	$0	$1,954	$342	$0	$344	$2,640	$4
1.7	Sorbent Conveyors	$2,507	$545	$607	$0	$3,659	$640	$0	$645	$4,944	$8
1.8	Other Sorbent Handling	$121	$28	$62	$0	$211	$37	$0	$37	$286	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,543	$2,034	$0	$3,577	$626	$0	$630	$4,833	$7
	Subtotal	**$50,081**	**$2,117**	**$13,967**	**$0**	**$66,164**	**$11,579**	**$0**	**$11,661**	**$89,404**	**$138**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$2,529	$0	$486	$0	$3,014	$527	$0	$531	$4,073	$6
2.2	Prepared Coal Storage & Feed	$8,510	$0	$1,833	$0	$10,343	$1,810	$0	$1,823	$13,976	$22
2.5	Sorbent Preparation Equipment	$1,113	$48	$228	$0	$1,389	$243	$0	$245	$1,877	$3
2.6	Sorbent Storage & Feed	$1,866	$0	$704	$0	$2,570	$450	$0	$453	$3,473	$5
2.9	Coal & Sorbent Feed Foundation	$0	$739	$648	$0	$1,387	$243	$0	$244	$1,874	$3
	Subtotal	**$14,018**	**$787**	**$3,898**	**$0**	**$18,703**	**$3,273**	**$0**	**$3,296**	**$25,272**	**$39**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$3,985	$6,832	$3,416	$0	$14,233	$2,491	$0	$2,509	$19,233	$30
3.2	Water Makeup & Pretreating	$8,253	$825	$4,677	$0	$13,755	$2,407	$0	$3,232	$19,395	$30
3.3	Other Feedwater Subsystems	$3,113	$1,021	$970	$0	$5,104	$893	$0	$900	$6,897	$11
3.4	Service Water Systems	$2,618	$4,998	$16,184	$0	$23,800	$4,165	$0	$5,593	$33,558	$52
3.5	Other Boiler Plant Systems	$770	$280	$700	$0	$1,751	$306	$0	$309	$2,366	$4
3.6	Natural Gas Pipeline and Start-Up System	$3,348	$144	$108	$0	$3,600	$630	$0	$634	$4,864	$7
3.7	Waste Water Treatment Equipment	$14,870	$0	$9,114	$0	$23,984	$4,197	$0	$5,636	$33,817	$52
3.8	Spray Dryer Evaporator	$16,746	$0	$9,695	$0	$26,441	$4,627	$0	$6,214	$37,282	$57
3.9	Miscellaneous Plant Equipment	$226	$30	$115	$0	$370	$65	$0	$87	$522	$1
	Subtotal	**$53,929**	**$14,130**	**$44,979**	**$0**	**$113,038**	**$19,782**	**$0**	**$25,113**	**$157,933**	**$243**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$268,915	$0	$153,226	$0	$422,141	$73,875	$0	$74,402	$570,418	$878
4.10	Selective Catalytic Reduction System	$29,346	$0	$16,721	$0	$46,068	$8,062	$0	$8,119	$62,249	$96
4.11	Boiler Balance of Plant	$1,768	$0	$1,007	$0	$2,776	$486	$0	$489	$3,751	$6
4.12	Primary Air System	$1,697	$0	$967	$0	$2,664	$466	$0	$470	$3,600	$6
4.13	Secondary Air System	$2,571	$0	$1,465	$0	$4,035	$706	$0	$711	$5,453	$8

	Case:	B12B	– SC PC w/ CO_2				Estimate Type:		Conceptual	
	Plant Size (MWnet):	650					Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
4.14	Induced Draft Fans	$5,479	$0	$3,122	$0	$8,601	$1,505	$0	$1,516	$11,622	$18
4.15	Major Component Rigging	$93	$0	$53	$0	$146	$26	$0	$26	$197	$0
4.16	Boiler Foundations	$0	$399	$351	$0	$751	$131	$0	$132	$1,014	$2
	Subtotal	**$309,869**	**$399**	**$176,913**	**$0**	**$487,181**	**$85,257**	**$0**	**$85,866**	**$658,303**	**$1,013**
5	Flue Gas Cleanup										
5.1	Cansolv Carbon Dioxide (CO_2) Removal System	$199,653	$86,357	$181,351	$0	$467,361	$81,788	$79,451	$110,005	$738,606	$1,137
5.2	WFGD Absorber Vessels & Accessories	$79,398	$0	$16,976	$0	$96,374	$16,865	$0	$16,986	$130,225	$200
5.3	Other FGD	$356	$0	$401	$0	$757	$133	$0	$133	$1,023	$2
5.4	Carbon Dioxide (CO_2) Compression & Drying	$41,405	$6,211	$13,844	$0	$61,460	$10,755	$0	$14,443	$86,659	$133
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$455	$72	$195	$0	$722	$126	$0	$170	$1,017	$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,634	$579	$2,590	$0	$5,803	$1,016	$0	$1,023	$7,841	$12
5.9	Particulate Removal (Bag House & Accessories)	$1,522	$0	$959	$0	$2,481	$434	$0	$437	$3,353	$5
5.12	Gas Cleanup Foundations	$0	$198	$173	$0	$371	$65	$0	$65	$501	$1
5.13	Gypsum Dewatering System	$764	$0	$129	$0	$892	$156	$0	$157	$1,206	$2
	Subtotal	**$326,187**	**$93,417**	**$216,617**	**$0**	**$636,222**	**$111,339**	**$79,451**	**$143,420**	**$970,432**	**$1,494**
7	Ductwork & Stack										
7.3	Ductwork	$0	$747	$519	$0	$1,266	$221	$0	$223	$1,710	$3
7.4	Stack	$8,767	$0	$5,094	$0	$13,861	$2,426	$0	$2,443	$18,730	$29
7.5	Duct & Stack Foundations	$0	$210	$249	$0	$459	$80	$0	$108	$647	$1
	Subtotal	**$8,767**	**$957**	**$5,862**	**$0**	**$15,586**	**$2,728**	**$0**	**$2,774**	**$21,087**	**$32**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$73,354	$0	$8,175	$0	$81,529	$14,268	$0	$14,369	$110,166	$170
8.2	Steam Turbine Plant Auxiliaries	$1,665	$0	$3,544	$0	$5,208	$911	$0	$918	$7,038	$11
8.3	Condenser & Auxiliaries	$11,298	$0	$3,833	$0	$15,132	$2,648	$0	$2,667	$20,447	$31
8.4	Steam Piping	$43,139	$0	$17,484	$0	$60,623	$10,609	$0	$10,685	$81,916	$126
8.5	Turbine Generator Foundations	$0	$260	$430	$0	$690	$121	$0	$162	$972	$1
	Subtotal	**$129,456**	**$260**	**$33,465**	**$0**	**$163,181**	**$28,557**	**$0**	**$28,801**	**$220,539**	**$339**
9	Cooling Water System										
9.1	Cooling Towers	$20,110	$0	$6,219	$0	$26,329	$4,608	$0	$4,640	$35,577	$55
9.2	Circulating Water Pumps	$2,849	$0	$209	$0	$3,058	$535	$0	$539	$4,133	$6
9.3	Circulating Water System Auxiliaries	$16,683	$0	$2,201	$0	$18,884	$3,305	$0	$3,328	$25,518	$39
9.4	Circulating Water Piping	$0	$7,712	$6,984	$0	$14,697	$2,572	$0	$2,590	$19,859	$31
9.5	Make-up Water System	$1,280	$0	$1,644	$0	$2,924	$512	$0	$515	$3,951	$6
9.6	Component Cooling Water System	$1,202	$0	$922	$0	$2,124	$372	$0	$374	$2,870	$4
9.7	Circulating Water System Foundations	$0	$717	$1,191	$0	$1,908	$334	$0	$448	$2,690	$4
	Subtotal	**$42,124**	**$8,430**	**$19,371**	**$0**	**$69,924**	**$12,237**	**$0**	**$12,436**	**$94,597**	**$146**

	Case:	B12B	– SC PC w/ CO_2				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
10	Ash & Spent Sorbent Handling Systems										
10.6	Ash Storage Silos	$1,172	$0	$3,586	$0	$4,758	$833	$0	$839	$6,429	$10
10.7	Ash Transport & Feed Equipment	$3,986	$0	$3,952	$0	$7,937	$1,389	$0	$1,399	$10,725	$17
10.9	Ash/Spent Sorbent Foundation	$0	$815	$1,003	$0	$1,818	$318	$0	$427	$2,564	$4
	Subtotal	**$5,158**	**$815**	**$8,541**	**$0**	**$14,513**	**$2,540**	**$0**	**$2,665**	**$19,718**	**$30**
11	Accessory Electric Plant										
11.1	Generator Equipment	$2,671	$0	$2,015	$0	$4,686	$820	$0	$826	$6,332	$10
11.2	Station Service Equipment	$7,716	$0	$662	$0	$8,378	$1,466	$0	$1,477	$11,320	$17
11.3	Switchgear & Motor Control	$11,978	$0	$2,078	$0	$14,056	$2,460	$0	$2,477	$18,993	$29
11.4	Conduit & Cable Tray	$0	$1,557	$4,487	$0	$6,044	$1,058	$0	$1,065	$8,167	$13
11.5	Wire & Cable	$0	$4,124	$7,371	$0	$11,494	$2,012	$0	$2,026	$15,532	$24
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$826	$0	$763	$0	$1,589	$278	$0	$280	$2,147	$3
11.8	Main Power Transformers	$7,010	$0	$143	$0	$7,153	$1,252	$0	$1,261	$9,665	$15
11.9	Electrical Foundations	$0	$223	$566	$0	$789	$138	$0	$185	$1,113	$2
	Subtotal	**$30,256**	**$5,903**	**$18,276**	**$0**	**$54,435**	**$9,526**	**$0**	**$9,641**	**$73,602**	**$113**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$809	$0	$144	$0	$954	$167	$0	$168	$1,289	$2
12.3	Steam Turbine Control Equipment	$725	$0	$81	$0	$806	$141	$0	$142	$1,089	$2
12.5	Signal Processing Equipment	$919	$0	$164	$0	$1,083	$189	$0	$191	$1,463	$2
12.6	Control Boards, Panels & Racks	$281	$0	$172	$0	$453	$79	$23	$83	$638	$1
12.7	Distributed Control System Equipment	$7,930	$0	$1,414	$0	$9,344	$1,635	$467	$1,717	$13,163	$20
12.8	Instrument Wiring & Tubing	$555	$444	$1,777	$0	$2,776	$486	$139	$510	$3,911	$6
12.9	Other Instrumentation & Controls Equipment	$683	$0	$1,581	$0	$2,263	$396	$113	$416	$3,189	$5
	Subtotal	**$11,903**	**$444**	**$5,332**	**$0**	**$17,679**	**$3,094**	**$742**	**$3,227**	**$24,742**	**$38**
13	Improvements to Site										
13.1	Site Preparation	$0	$470	$9,982	$0	$10,452	$1,829	$0	$2,456	$14,738	$23
13.2	Site Improvements	$0	$2,325	$3,072	$0	$5,397	$944	$0	$1,268	$7,609	$12
13.3	Site Facilities	$2,656	$0	$2,786	$0	$5,443	$952	$0	$1,279	$7,674	$12
	Subtotal	**$2,656**	**$2,795**	**$15,840**	**$0**	**$21,292**	**$3,726**	**$0**	**$5,004**	**$30,021**	**$46**
14	Buildings & Structures										

Case:		B12B	– SC PC w/ CO_2				Estimate Type:			Conceptual	
Plant Size (MWnet):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
14.2	Boiler Building	$0	$11,598	$10,193	$0	$21,791	$3,813	$0	$3,841	$29,445	$45
14.3	Steam Turbine Building	$0	$16,121	$15,014	$0	$31,136	$5,449	$0	$5,488	$42,072	$65
14.4	Administration Building	$0	$1,047	$1,107	$0	$2,154	$377	$0	$380	$2,911	$4
14.5	Circulation Water Pumphouse	$0	$191	$152	$0	$343	$60	$0	$60	$464	$1
14.6	Water Treatment Buildings	$0	$475	$433	$0	$908	$159	$0	$160	$1,227	$2
14.7	Machine Shop	$0	$553	$371	$0	$923	$162	$0	$163	$1,247	$2
14.8	Warehouse	$0	$416	$416	$0	$832	$146	$0	$147	$1,124	$2
14.9	Other Buildings & Structures	$0	$290	$247	$0	$537	$94	$0	$95	$726	$1
14.10	Waste Treating Building & Structures	$0	$644	$1,951	$0	$2,595	$454	$0	$457	$3,507	$5
	Subtotal	**$0**	**$31,336**	**$29,884**	**$0**	**$61,220**	**$10,713**	**$0**	**$10,790**	**$82,723**	**$127**
	Total	**$984,403**	**$161,790**	**$592,945**	**$0**	**$1,739,137**	**$304,349**	**$80,193**	**$344,694**	**$2,468,373**	**$3,800**

Exhibit A-55. Case B12B owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$14,349	$22
1 Month Maintenance Materials	$2,323	$4
1 Month Non-Fuel Consumables	$3,322	$5
1 Month Waste Disposal	$999	$2
25% of 1 Months Fuel Cost at 100% CF	$2,860	$4
2% of TPC	$49,367	$76
Total	**$73,221**	**$113**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$28,700	$44
0.5% of TPC (spare parts)	$12,342	$19
Total	**$41,042**	**$63**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,612	$4
Land	$900	$1
Other Owner's Costs	$370,256	$570
Financing Costs	$66,646	$103
Total Overnight Costs (TOC)	**$3,023,051**	**$4,654**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$3,489,846**	**$5,372**

Exhibit A-56. Case B12B initial and annual O&M costs

Case:	B12B	– SC PC w/ CO_2			Cost Base:	Dec 2018
Plant Size (MWnet):	**650**	**Heat Rate-net (Btu/kWh):**		**10,834**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**16.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,161,008	$11.024
Maintenance Labor:					$15,797,590	$24.319
Administrative & Support Labor:					$5,739,649	$8.836
Property Taxes and Insurance:					$49,367,468	$75.997
Total:					**$78,065,715**	**$120.175**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$23,696,385	$4.89906
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,136	$1.90	$0	$4,206,523	$0.86967
Makeup and Waste Water Treatment Chemicals (ton):	0	21.3	$550.00	$0	$3,627,291	$0.74992
Brominated Activated Carbon (ton):	0	1.56	$1,600.00	$0	$772,686	$0.15975
Enhanced Hydrated Lime (ton):	0	39.9	$240.00	$0	$2,967,412	$0.61349
Limestone (ton):	0	700	$22.00	$0	$4,779,570	$0.98814
Ammonia (19 wt%, ton):	0.00	69.0	$300.00	0.00	$6,420,577	$1.32741
SCR Catalyst (ft^3):	17,414	15.9	$150.00	$2,612,120	$740,101	$0.15301
CO_2 Capture System Chemicals[A]	Proprietary				$9,225,455	$1.90730
Triethylene Glycol (gal):	w/equip.	544	$6.80	$0	$1,147,315	$0.23720
Subtotal:				**$2,612,120**	**$33,886,930**	**$7.00589**
Waste Disposal						
Fly Ash (ton)	0	657	$38.00	$0	$7,744,619	$1.60115
Bottom Ash (ton)	0	146	$38.00	$0	$1,720,404	$0.35568
SCR Catalyst (ft^3):	0	16	$2.50	$0	$12,335	$0.00255
Triethylene Glycol (gal):		544	$0.35	$0	$59,053	$0.01221
Thermal Reclaimer Unit Waste (ton)	0	3.51	$38.00	$0	$41,395	$0.00856
Prescrubber Blowdown Waste (ton)	0	52.1	$38.00	$0	$614,467	$0.12704
Subtotal:				**$0**	**$10,192,273**	**$2.10718**
By-Products						
Gypsum (ton)	0	1064	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$2,612,120**	**$67,775,588**	**$14.01213**
Fuel Cost						
Illinois Number 6 (ton):	0	7,239	$51.96	$0	$116,691,765	$24.12521
Total:				**$0**	**$116,691,765**	**$24.12521**

[A]CO_2 Capture System Chemicals includes sodium hydroxide (NaOH) and Cansolv Solvent

Exhibit A-57. Case B12B LCOE breakdown

Component	Value, $/MWh	Percentage
Capital	51.0	45%
Fixed	16.1	14%
Variable	14.0	12%
Fuel	24.1	21%
Total (Excluding T&S)	**105.3**	**N/A**
CO_2 T&S	8.9	8%
Total (Including T&S)	**114.3**	**N/A**

Exhibit A-58. Case PA1 total plant cost details

	Case:	PA1	– SC PC and 20% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	1					Coal & Sorbent Handling					
1.1	Coal Receive & Unload	$1,132	$0	$510	$0	$1,641	$287	$0	$289	$2,218	$3
1.2	Coal Stackout & Reclaim	$3,715	$0	$830	$0	$4,546	$795	$0	$801	$6,142	$9
1.3	Coal Conveyors	$34,233	$0	$8,142	$0	$42,374	$7,416	$0	$7,468	$57,258	$88
1.4	Other Coal Handling	$4,756	$0	$1,000	$0	$5,756	$1,007	$0	$1,015	$7,778	$12
1.5	Sorbent Receive & Unload	$217	$0	$65	$0	$281	$49	$0	$50	$380	$1
1.6	Sorbent Stackout & Reclaim	$1,589	$0	$287	$0	$1,876	$328	$0	$331	$2,535	$4
1.7	Sorbent Conveyors	$2,406	$523	$582	$0	$3,511	$614	$0	$619	$4,744	$7
1.8	Other Sorbent Handling	$116	$27	$60	$0	$203	$36	$0	$36	$274	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,484	$1,956	$0	$3,440	$602	$0	$606	$4,649	$7
1.10	Biomass Receiving and Processing	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$24,899	$4,357	$0	$4,388	$33,645	$52
	Subtotal	**$48,163**	**$2,034**	**$13,432**	**$0**	**$88,529**	**$15,493**	**$0**	**$15,603**	**$119,624**	**$132**
	2					Coal & Sorbent Preparation & Feed					
2.1	Coal Crushing & Drying	$2,426	$0	$466	$0	$2,892	$506	$0	$510	$3,908	$6
2.2	Prepared Coal Storage & Feed	$8,166	$0	$1,758	$0	$9,924	$1,737	$0	$1,749	$13,410	$21
2.3	Biomass Drying	$1,127	$0	$220	$0	$1,347	$236	$0	$237	$1,820	$3
2.5	Sorbent Preparation Equipment	$1,068	$46	$219	$0	$1,333	$233	$0	$235	$1,801	$3
2.6	Sorbent Storage & Feed	$1,791	$0	$675	$0	$2,466	$432	$0	$435	$3,332	$5
2.7	Biomass Pelletization	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$22,651	$3,964	$0	$3,992	$30,607	$47
2.8	Prepared Biomass Storage & Feed	$2,571	$0	$554	$0	$3,125	$547	$0	$551	$4,222	$6
2.9	Coal & Sorbent Feed Foundation	$0	$710	$622	$0	$1,332	$233	$0	$235	$1,800	$3
	Subtotal	**$17,149**	**$756**	**$4,514**	**$0**	**$45,069**	**$7,887**	**$0**	**$7,943**	**$60,900**	**$94**
	3					Feedwater & Miscellaneous BOP Systems					
3.1	Feedwater System	$4,047	$6,937	$3,469	$0	$14,452	$2,529	$0	$2,547	$19,529	$30
3.2	Water Makeup & Pretreating	$8,407	$841	$4,764	$0	$14,012	$2,452	$0	$3,293	$19,756	$30
3.3	Other Feedwater Subsystems	$3,175	$1,041	$989	$0	$5,206	$911	$0	$917	$7,034	$11
3.4	Service Water Systems	$2,672	$5,100	$16,515	$0	$24,287	$4,250	$0	$5,708	$34,245	$53
3.5	Other Boiler Plant Systems	$786	$286	$714	$0	$1,786	$313	$0	$315	$2,414	$4
3.6	Natural Gas Pipeline and Start-Up System	$3,622	$156	$117	$0	$3,894	$681	$0	$686	$5,262	$8
3.7	Waste Water Treatment Equipment	$15,739	$0	$9,647	$0	$25,386	$4,443	$0	$5,966	$35,794	$55

	Case:	PA1	– SC PC and 20% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
3.8	Spray Dryer Evaporator	$16,018	$0	$9,250	$0	$25,268	$4,422	$0	$5,938	$35,629	$55
3.9	Miscellaneous Plant Equipment	$235	$31	$119	$0	$385	$67	$0	$90	$543	$1
	Subtotal	**$54,701**	**$14,392**	**$45,584**	**$0**	**$114,677**	**$20,068**	**$0**	**$25,460**	**$160,206**	**$246**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$273,479	$0	$155,827	$0	$429,306	$75,128	$0	$75,665	$580,099	$893
4.10	Selective Catalytic Reduction System	$29,948	$0	$17,064	$0	$47,012	$8,227	$0	$8,286	$63,525	$98
4.11	Boiler Balance of Plant	$1,975	$0	$1,125	$0	$3,101	$543	$0	$546	$4,190	$6
4.12	Primary Air System	$1,778	$0	$1,013	$0	$2,791	$488	$0	$492	$3,772	$6
4.13	Secondary Air System	$2,588	$0	$1,475	$0	$4,063	$711	$0	$716	$5,490	$8
4.14	Induced Draft Fans	$5,588	$0	$3,184	$0	$8,772	$1,535	$0	$1,546	$11,853	$18
4.15	Major Component Rigging	$104	$0	$59	$0	$163	$29	$0	$29	$220	$0
4.16	Boiler Foundations	$0	$446	$392	$0	$838	$147	$0	$148	$1,133	$2
	Subtotal	**$315,460**	**$446**	**$180,140**	**$0**	**$496,045**	**$86,808**	**$0**	**$87,428**	**$670,281**	**$1,031**
5	Flue Gas Cleanup										
5.1	Cansolv Carbon Dioxide (CO_2) Removal System	$203,864	$87,922	$184,636	$0	$476,422	$83,374	$80,992	$112,138	$752,926	$1,158
5.2	WFGD Absorber Vessels & Accessories	$80,765	$0	$17,268	$0	$98,034	$17,156	$0	$17,278	$132,468	$204
5.3	Other FGD	$362	$0	$408	$0	$770	$135	$0	$136	$1,041	$2
5.4	Carbon Dioxide (CO_2) Compression & Drying	$42,276	$6,342	$14,135	$0	$62,752	$10,982	$0	$14,747	$88,481	$136
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$468	$74	$200	$0	$742	$130	$0	$174	$1,047	$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,693	$592	$2,648	$0	$5,933	$1,038	$0	$1,046	$8,017	$12
5.9	Particulate Removal (Bag House & Accessories)	$1,557	$0	$981	$0	$2,538	$444	$0	$447	$3,429	$5
5.12	Gas Cleanup Foundations	$0	$224	$197	$0	$421	$74	$0	$74	$569	$1
5.13	Gypsum Dewatering System	$736	$0	$124	$0	$860	$151	$0	$152	$1,162	$2
	Subtotal	**$332,721**	**$95,154**	**$220,598**	**$0**	**$648,473**	**$113,483**	**$80,992**	**$146,192**	**$989,140**	**$1,522**
7	Ductwork & Stack										
7.3	Ductwork	$0	$782	$544	$0	$1,326	$232	$0	$234	$1,792	$3
7.4	Stack	$8,777	$0	$5,100	$0	$13,877	$2,429	$0	$2,446	$18,752	$29
7.5	Duct & Stack Foundations	$0	$212	$252	$0	$464	$81	$0	$109	$654	$1
	Subtotal	$8,777	$994	$5,896	$0	$15,667	$2,742	$0	$2,789	$21,197	$33
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$74,412	$0	$8,293	$0	$82,704	$14,473	$0	$14,577	$111,754	$172
8.2	Steam Turbine Plant Auxiliaries	$1,689	$0	$3,595	$0	$5,283	$925	$0	$931	$7,139	$11

	Case:	PA1	– SC PC and 20% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
8.3	Condenser & Auxiliaries	$11,480	$0	$3,895	$0	$15,375	$2,691	$0	$2,710	$20,775	$32
8.4	Steam Piping	$43,813	$0	$17,757	$0	$61,570	$10,775	$0	$10,852	$83,196	$128
8.5	Turbine Generator Foundations	$0	$264	$436	$0	$700	$122	$0	$164	$986	$2
	Subtotal	**$131,393**	**$264**	**$33,975**	**$0**	**$165,632**	**$28,986**	**$0**	**$29,234**	**$223,851**	**$344**
9						Cooling Water System					
9.1	Cooling Towers	$20,506	$0	$6,342	$0	$26,848	$4,698	$0	$4,732	$36,278	$56
9.2	Circulating Water Pumps	$2,912	$0	$214	$0	$3,126	$547	$0	$551	$4,224	$6
9.3	Circulating Water System Auxiliaries	$16,952	$0	$2,237	$0	$19,188	$3,358	$0	$3,382	$25,928	$40
9.4	Circulating Water Piping	$0	$7,837	$7,097	$0	$14,933	$2,613	$0	$2,632	$20,178	$31
9.5	Make-up Water System	$1,296	$0	$1,665	$0	$2,960	$518	$0	$522	$4,000	$6
9.6	Component Cooling Water System	$1,221	$0	$937	$0	$2,158	$378	$0	$380	$2,916	$4
9.7	Circulating Water System Foundations	$0	$728	$1,209	$0	$1,936	$339	$0	$455	$2,730	$4
	Subtotal	**$42,886**	**$8,564**	**$19,699**	**$0**	**$71,149**	**$12,451**	**$0**	**$12,654**	**$96,254**	**$148**
10						Ash & Spent Sorbent Handling Systems					
10.6	Ash Storage Silos	$1,146	$0	$3,505	$0	$4,651	$814	$0	$820	$6,285	$10
10.7	Ash Transport & Feed Equipment	$3,896	$0	$3,863	$0	$7,760	$1,358	$0	$1,368	$10,485	$16
10.9	Ash/Spent Sorbent Foundation	$0	$797	$981	$0	$1,777	$311	$0	$418	$2,506	$4
	Subtotal	**$5,042**	**$797**	**$8,349**	**$0**	**$14,188**	**$2,483**	**$0**	**$2,605**	**$19,276**	**$30**
11						Accessory Electric Plant					
11.1	Generator Equipment	$2,703	$0	$2,039	$0	$4,741	$830	$0	$836	$6,407	$10
11.2	Station Service Equipment	$8,131	$0	$698	$0	$8,829	$1,545	$0	$1,556	$11,930	$18
11.3	Switchgear & Motor Control	$12,623	$0	$2,190	$0	$14,813	$2,592	$0	$2,611	$20,015	$31
11.4	Conduit & Cable Tray	$0	$1,641	$4,729	$0	$6,370	$1,115	$0	$1,123	$8,607	$13
11.5	Wire & Cable	$0	$4,346	$7,767	$0	$12,113	$2,120	$0	$2,135	$16,368	$25
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$834	$0	$770	$0	$1,604	$281	$0	$283	$2,168	$3
11.8	Main Power Transformers	$7,111	$0	$145	$0	$7,256	$1,270	$0	$1,279	$9,804	$15
11.9	Electrical Foundations	$0	$226	$574	$0	$800	$140	$0	$188	$1,128	$2
	Subtotal	**$31,456**	**$6,212**	**$19,103**	**$0**	**$56,771**	**$9,935**	**$0**	**$10,053**	**$76,759**	**$118**
12						Instrumentation & Control					
12.1	Pulverized Coal Boiler Control Equipment	$822	$0	$147	$0	$969	$170	$0	$171	$1,309	$2

	Case:	PA1	– SC PC and 20% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
12.3	Steam Turbine Control Equipment	$737	$0	$82	$0	$819	$143	$0	$144	$1,107	$2
12.5	Signal Processing Equipment	$934	$0	$166	$0	$1,100	$192	$0	$194	$1,486	$2
12.6	Control Boards, Panels & Racks	$286	$0	$174	$0	$460	$80	$23	$84	$648	$1
12.7	Distributed Control System Equipment	$8,057	$0	$1,436	$0	$9,493	$1,661	$475	$1,744	$13,374	$21
12.8	Instrument Wiring & Tubing	$564	$451	$1,805	$0	$2,821	$494	$141	$518	$3,974	$6
12.9	Other Instrumentation & Controls Equipment	$694	$0	$1,606	$0	$2,300	$402	$115	$423	$3,240	$5
	Subtotal	**$12,093**	**$451**	**$5,417**	**$0**	**$17,961**	**$3,143**	**$754**	**$3,279**	**$25,137**	**$39**
13						Improvements to Site					
13.1	Site Preparation	$0	$475	$10,074	$0	$10,548	$1,846	$0	$2,479	$14,873	$23
13.2	Site Improvements	$0	$2,346	$3,100	$0	$5,446	$953	$0	$1,280	$7,679	$12
13.3	Site Facilities	$2,681	$0	$2,812	$0	$5,493	$961	$0	$1,291	$7,745	$12
	Subtotal	**$2,681**	**$2,821**	**$15,986**	**$0**	**$21,487**	**$3,760**	**$0**	**$5,049**	**$30,297**	**$47**
14						Buildings & Structures					
14.2	Boiler Building	$0	$11,598	$10,193	$0	$21,791	$3,813	$0	$3,841	$29,445	$45
14.3	Steam Turbine Building	$0	$16,121	$15,014	$0	$31,136	$5,449	$0	$5,488	$42,072	$65
14.4	Administration Building	$0	$1,047	$1,107	$0	$2,154	$377	$0	$380	$2,911	$4
14.5	Circulation Water Pumphouse	$0	$194	$154	$0	$348	$61	$0	$61	$471	$1
14.6	Water Treatment Buildings	$0	$481	$438	$0	$920	$161	$0	$162	$1,243	$2
14.7	Machine Shop	$0	$553	$371	$0	$923	$162	$0	$163	$1,247	$2
14.8	Warehouse	$0	$416	$416	$0	$832	$146	$0	$147	$1,124	$2
14.9	Other Buildings & Structures	$0	$290	$247	$0	$537	$94	$0	$95	$726	$1
14.10	Waste Treating Building & Structures	$0	$645	$1,954	$0	$2,599	$455	$0	$458	$3,511	$5
	Subtotal	**$0**	**$31,345**	**$29,895**	**$0**	**$61,240**	**$10,717**	**$0**	**$10,794**	**$82,751**	**$127**
	Total	**$1,002,521**	**$164,232**	**$602,587**	**$0**	**$1,816,890**	**$317,956**	**$81,745**	**$359,083**	**$2,575,673**	**$3,911**

Exhibit A-59. Case PA1 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$14,778	$23
1 Month Maintenance Materials	$2,424	$4
1 Month Non-Fuel Consumables	$3,370	$5
1 Month Waste Disposal	$959	$1
25% of 1 Months Fuel Cost at 100% CF	$3,673	$6
2% of TPC	$51,513	$79
Total	**$76,718**	**$118**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$35,280	$54
0.5% of TPC (spare parts)	$12,878	$20
Total	**$48,159**	**$74**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,690	$4
Land	$900	$1
Other Owner's Costs	$386,351	$594
Financing Costs	$69,543	$107
Total Overnight Costs (TOC)	**$3,160,035**	**$4,810**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$3,647,982**	**$5,613**

Exhibit A-60. Case PA1 initial and annual O&M costs

Case:	PA1	– SC PC and 20% Biomass (w/ CO_2 Capture)			Cost Base:	Dec-18
Plant Size (MWnet):	**650**		**Heat Rate-net (Btu/kWh):**	**11,090**	**Capacity Factor (%):**	**85.0**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	11.3	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**16.3**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,161,008	$11.018
Maintenance Labor:					$16,484,310	$25.363
Administrative & Support Labor:					$5,911,330	$9.095
Property Taxes and Insurance:					$51,513,470	$79.259
Total:					**$81,070,118**	**$124.735**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$24,726,466	$5.10935
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,319	$1.90	$0	$4,314,420	$0.89151
Makeup and Waste Water Treatment Chemicals (ton):	0	21.8	$550.00	$0	$3,720,330	$0.76875
Brominated Activated Carbon (ton):	0	1.60	$1,600.00	$0	$794,997	$0.16427
Enhanced Hydrated Lime (ton):	0	40.9	$240.00	$0	$3,043,605	$0.62892
Limestone (ton):	0	657	$22.00	$0	$4,485,499	$0.92686
Ammonia (19 wt%, ton):	0	70.7	$300.00	$0	$6,582,103	$1.36009
SCR Catalyst (ft^3):	17,934	16.4	150.00	$2,690,131	$762,204	$0.15750
CO_2 Capture System Chemicals[A]:	Proprietary				$9,485,615	$1.96006
Triethylene Glycol (gal):	w/equip.	563	$6.80	$0	$1,187,312	$0.24534
Subtotal:				**$2,690,131**	**$34,376,085**	**$7.10330**
Waste Disposal						
Fly Ash (ton)	0	631	$38.00	$0	$7,444,064	$1.53820
Bottom Ash (ton)	0	140	$38.00	$0	$1,645,555	$0.34003
SCR Catalyst (ft^3):	0	16.4	$2.50	$0	$12,703	$0.00262
Triethylene Glycol (gal):		563	$0.35	$0	$61,112	$0.01263
Thermal Reclaimer Unit Waste (ton)	0	3.63	$38.00	$0	$42,838	$0.00885
Prescrubber Blowdown Waste (ton)	0	48.8	$38.00	$0	$575,655	$0.11895
Subtotal:				**$0**	**$9,781,927**	**$2.02129**
By-Products						
Gypsum (ton)	0	999	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$2,690,131**	**$68,884,478**	**$14.23394**
Fuel Cost						
Illinois Number 6 (ton):	0	6,799	$51.96	$0	$109,603,186	$22.64784
Hybrid Poplar (ton):	0	1,700	$76.35	$0	$40,264,789	$8.32011
Total:				**$0**	**$149,867,975**	**$30.96796**

[A]CO_2 Capture System Chemicals includes NaOH and Cansolv Solvent

Exhibit A-61. Case PA1 LCOE breakdown

Component	Value, \$/MWh	Percentage
Capital	53.3	43%
Fixed	16.8	13%
Variable	14.2	11%
Fuel	31.0	25%
Total (Excluding T&S)	**115.3**	**N/A**
CO_2 T&S	9.3	7%
Total (Including T&S)	**124.5**	**N/A**

Exhibit A-62. Case PA2 total plant cost details

Case:		PA2	– SC PC and 35% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
Plant Size (MWnet):		650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,085	$0	$489	$0	$1,573	$275	$0	$277	$2,126	$3
1.2	Coal Stackout & Reclaim	$3,561	$0	$796	$0	$4,357	$762	$0	$768	$5,887	$9
1.3	Coal Conveyors	$32,812	$0	$7,804	$0	$40,615	$7,108	$0	$7,158	$54,882	$84
1.4	Other Coal Handling	$4,559	$0	$958	$0	$5,517	$965	$0	$972	$7,455	$11
1.5	Sorbent Receive & Unload	$207	$0	$62	$0	$269	$47	$0	$47	$363	$1
1.6	Sorbent Stackout & Reclaim	$1,520	$0	$275	$0	$1,795	$314	$0	$316	$2,425	$4
1.7	Sorbent Conveyors	$2,300	$500	$557	$0	$3,356	$587	$0	$592	$4,535	$7
1.8	Other Sorbent Handling	$111	$26	$57	$0	$194	$34	$0	$34	$262	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,422	$1,875	$0	$3,297	$577	$0	$581	$4,456	$7
1.10	Biomass Receiving and Processing	w/ BEC	w/BEC	w/ BEC	w/BEC	$26,683	$4,670	$0	$4,703	$36,055	$55
	Subtotal	**$46,153**	**$1,949**	**$12,872**	**$0**	**$87,657**	**$15,340**	**$0**	**$15,449**	**$118,446**	**$127**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$2,319	$0	$445	$0	$2,764	$484	$0	$487	$3,735	$6
2.2	Prepared Coal Storage & Feed	$7,805	$0	$1,681	$0	$9,486	$1,660	$0	$1,672	$12,818	$20
2.3	Biomass Drying	$1,788	$0	$348	$0	$2,136	$374	$0	$377	$2,887	$4
2.5	Sorbent Preparation Equipment	$1,021	$44	$209	$0	$1,274	$223	$0	$225	$1,722	$3
2.6	Sorbent Storage & Feed	$1,712	$0	$645	$0	$2,357	$413	$0	$415	$3,185	$5
2.7	Biomass Pelletization	w/ BEC	w/BEC	w/ BEC	w/BEC	$46,306	$8,104	$0	$8,161	$62,571	$96
2.8	Prepared Biomass Storage & Feed	$4,078	$0	$878	$0	$4,956	$867	$0	$873	$6,697	$10
2.9	Coal & Sorbent Feed Foundation	$0	$679	$596	$0	$1,275	$223	$0	$225	$1,723	$3
	Subtotal	**$18,723**	**$723**	**$4,803**	**$0**	**$70,555**	**$12,347**	**$0**	**$12,435**	**$95,338**	**$147**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$4,107	$7,040	$3,520	$0	$14,666	$2,567	$0	$2,585	$19,818	$30
3.2	Water Makeup & Pretreating	$8,558	$856	$4,850	$0	$14,263	$2,496	$0	$3,352	$20,111	$31
3.3	Other Feedwater Subsystems	$3,236	$1,061	$1,008	$0	$5,305	$928	$0	$935	$7,169	$11
3.4	Service Water Systems	$2,724	$5,201	$16,841	$0	$24,766	$4,334	$0	$5,820	$34,920	$54
3.5	Other Boiler Plant Systems	$801	$291	$728	$0	$1,821	$319	$0	$321	$2,460	$4
3.6	Natural Gas Pipeline and Start-Up System	$3,877	$167	$125	$0	$4,169	$730	$0	$735	$5,633	$9

	Case:	PA2	– SC PC and 35% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
3.7	Waste Water Treatment Equipment	$16,593	$0	$10,170	$0	$26,763	$4,683	$0	$6,289	$37,735	$58
3.8	Spray Dryer Evaporator	$15,250	$0	$8,788	$0	$24,037	$4,207	$0	$5,649	$33,893	$52
3.9	Miscellaneous Plant Equipment	$243	$32	$124	$0	$399	$70	$0	$94	$562	$1
	Subtotal	**$55,389**	**$14,648**	**$46,152**	**$0**	**$116,189**	**$20,333**	**$0**	**$25,779**	**$162,302**	**$250**
4	**Pulverized Coal Boiler & Accessories**										
4.9	Pulverized Coal Boiler & Accessories	$277,943	$0	$158,371	$0	$436,314	$76,355	$0	$76,900	$589,569	$907
4.10	Selective Catalytic Reduction System	$30,539	$0	$17,401	$0	$47,939	$8,389	$0	$8,449	$64,778	$100
4.11	Boiler Balance of Plant	$2,174	$0	$1,239	$0	$3,413	$597	$0	$602	$4,612	$7
4.12	Primary Air System	$1,857	$0	$1,058	$0	$2,916	$510	$0	$514	$3,940	$6
4.13	Secondary Air System	$2,605	$0	$1,484	$0	$4,089	$716	$0	$721	$5,525	$9
4.14	Induced Draft Fans	$5,694	$0	$3,245	$0	$8,939	$1,564	$0	$1,575	$12,079	$19
4.15	Major Component Rigging	$114	$0	$65	$0	$180	$31	$0	$32	$243	$0
4.16	Boiler Foundations	$0	$491	$432	$0	$923	$162	$0	$163	$1,247	$2
	Subtotal	**$320,927**	**$491**	**$183,294**	**$0**	**$504,712**	**$88,325**	**$0**	**$88,955**	**$681,992**	**$1,049**
5	**Flue Gas Cleanup**										
5.1	Cansolv Carbon Dioxide (CO_2) Removal System	$207,933	$89,417	$187,775	$0	$485,125	$84,897	$82,471	$114,186	$766,680	$1,180
5.2	WFGD Absorber Vessels & Accessories	$82,002	$0	$17,533	$0	$99,535	$17,419	$0	$17,543	$134,496	$207
5.3	Other FGD	$368	$0	$414	$0	$782	$137	$0	$138	$1,057	$2
5.4	Carbon Dioxide (CO_2) Compression & Drying	$43,135	$6,471	$14,422	$0	$64,028	$11,205	$0	$15,047	$90,279	$139
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$481	$76	$206	$0	$763	$134	$0	$179	$1,076	$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,751	$605	$2,705	$0	$6,061	$1,061	$0	$1,068	$8,190	$13
5.9	Particulate Removal (Bag House & Accessories)	$1,591	$0	$1,003	$0	$2,593	$454	$0	$457	$3,504	$5
5.12	Gas Cleanup Foundations	$0	$250	$220	$0	$470	$82	$0	$83	$635	$1
5.13	Gypsum Dewatering System	$707	$0	$119	$0	$826	$145	$0	$146	$1,116	$2
	Subtotal	**$338,968**	**$96,819**	**$224,397**	**$0**	**$660,183**	**$115,532**	**$82,471**	**$148,847**	**$1,007,033**	**$1,550**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$815	$566	$0	$1,381	$242	$0	$243	$1,866	$3
7.4	Stack	$8,787	$0	$5,106	$0	$13,893	$2,431	$0	$2,449	$18,773	$29

	Case:	PA2	– SC PC and 35% Biomass (w/ CO_2 Capture)					Estimate Type:		Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
7.5	Duct & Stack Foundations	$0	$214	$254	$0	$468	$82	$0	$110	$659	$1
	Subtotal	**$8,787**	**$1,028**	**$5,926**	**$0**	**$15,741**	**$2,755**	**$0**	**$2,802**	**$21,298**	**$33**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$75,443	$0	$8,407	$0	$83,851	$14,674	$0	$14,779	$113,303	$174
8.2	Steam Turbine Plant Auxiliaries	$1,712	$0	$3,645	$0	$5,357	$937	$0	$944	$7,238	$11
8.3	Condenser & Auxiliaries	$11,656	$0	$3,955	$0	$15,611	$2,732	$0	$2,751	$21,094	$32
8.4	Steam Piping	$44,471	$0	$18,024	$0	$62,495	$10,937	$0	$11,015	$84,446	$130
8.5	Turbine Generator Foundations	$0	$268	$442	$0	$709	$124	$0	$167	$1,000	$2
	Subtotal	**$133,282**	**$268**	**$34,473**	**$0**	**$168,023**	**$29,404**	**$0**	**$29,656**	**$227,082**	**$349**
9	**Cooling Water System**										
9.1	Cooling Towers	$20,895	$0	$6,462	$0	$27,356	$4,787	$0	$4,822	$36,965	$57
9.2	Circulating Water Pumps	$2,973	$0	$219	$0	$3,192	$559	$0	$563	$4,313	$7
9.3	Circulating Water System Auxiliaries	$17,214	$0	$2,271	$0	$19,485	$3,410	$0	$3,434	$26,330	$41
9.4	Circulating Water Piping	$0	$7,958	$7,206	$0	$15,164	$2,654	$0	$2,673	$20,491	$32
9.5	Make-up Water System	$1,311	$0	$1,685	$0	$2,996	$524	$0	$528	$4,048	$6
9.6	Component Cooling Water System	$1,240	$0	$951	$0	$2,191	$383	$0	$386	$2,961	$5
9.7	Circulating Water System Foundations	$0	$738	$1,226	$0	$1,964	$344	$0	$462	$2,769	$4
	Subtotal	**$43,634**	**$8,696**	**$20,019**	**$0**	**$72,349**	**$12,661**	**$0**	**$12,867**	**$97,877**	**$151**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,118	$0	$3,421	$0	$4,540	$794	$0	$800	$6,134	$9
10.7	Ash Transport & Feed Equipment	$3,803	$0	$3,770	$0	$7,573	$1,325	$0	$1,335	$10,233	$16
10.9	Ash/Spent Sorbent Foundation	$0	$778	$957	$0	$1,735	$304	$0	$408	$2,446	$4
	Subtotal	**$4,921**	**$778**	**$8,149**	**$0**	**$13,848**	**$2,423**	**$0**	**$2,543**	**$18,813**	**$29**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$2,733	$0	$2,062	$0	$4,795	$839	$0	$845	$6,479	$10
11.2	Station Service Equipment	$8,523	$0	$731	$0	$9,254	$1,619	$0	$1,631	$12,505	$19
11.3	Switchgear & Motor Control	$13,231	$0	$2,296	$0	$15,526	$2,717	$0	$2,737	$20,980	$32
11.4	Conduit & Cable Tray	$0	$1,720	$4,957	$0	$6,677	$1,168	$0	$1,177	$9,022	$14
11.5	Wire & Cable	$0	$4,555	$8,142	$0	$12,697	$2,222	$0	$2,238	$17,156	$26

	Case:	PA2	– SC PC and 35% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$842	$0	$777	$0	$1,619	$283	$0	$285	$2,187	$3
11.8	Main Power Transformers	$7,209	$0	$147	$0	$7,356	$1,287	$0	$1,297	$9,940	$15
11.9	Electrical Foundations	$0	$229	$582	$0	$811	$142	$0	$191	$1,144	$2
	Subtotal	**$32,593**	**$6,504**	**$19,884**	**$0**	**$58,981**	**$10,322**	**$0**	**$10,443**	**$79,745**	**$123**
	12					Instrumentation & Control					
12.1	Pulverized Coal Boiler Control Equipment	$834	$0	$149	$0	$983	$172	$0	$173	$1,328	$2
12.3	Steam Turbine Control Equipment	$747	$0	$83	$0	$831	$145	$0	$146	$1,122	$2
12.5	Signal Processing Equipment	$947	$0	$169	$0	$1,116	$195	$0	$197	$1,508	$2
12.6	Control Boards, Panels & Racks	$290	$0	$177	$0	$466	$82	$23	$86	$657	$1
12.7	Distributed Control System Equipment	$8,172	$0	$1,457	$0	$9,629	$1,685	$481	$1,769	$13,565	$21
12.8	Instrument Wiring & Tubing	$572	$458	$1,831	$0	$2,861	$501	$143	$526	$4,031	$6
12.9	Other Instrumentation & Controls Equipment	$704	$0	$1,629	$0	$2,333	$408	$117	$429	$3,286	$5
	Subtotal	**$12,266**	**$458**	**$5,495**	**$0**	**$18,219**	**$3,188**	**$764**	**$3,326**	**$25,497**	**$39**
	13					Improvements to Site					
13.1	Site Preparation	$0	$477	$10,134	$0	$10,611	$1,857	$0	$2,494	$14,962	$23
13.2	Site Improvements	$0	$2,360	$3,119	$0	$5,479	$959	$0	$1,287	$7,725	$12
13.3	Site Facilities	$2,697	$0	$2,829	$0	$5,525	$967	$0	$1,298	$7,791	$12
	Subtotal	**$2,697**	**$2,837**	**$16,081**	**$0**	**$21,615**	**$3,783**	**$0**	**$5,080**	**$30,478**	**$47**
	14					Buildings & Structures					
14.2	Boiler Building	$0	$11,598	$10,193	$0	$21,791	$3,813	$0	$3,841	$29,445	$45
14.3	Steam Turbine Building	$0	$16,121	$15,014	$0	$31,136	$5,449	$0	$5,488	$42,072	$65
14.4	Administration Building	$0	$1,047	$1,107	$0	$2,154	$377	$0	$380	$2,911	$4
14.5	Circulation Water Pumphouse	$0	$197	$156	$0	$353	$62	$0	$62	$478	$1
14.6	Water Treatment Buildings	$0	$487	$444	$0	$931	$163	$0	$164	$1,258	$2
14.7	Machine Shop	$0	$553	$371	$0	$923	$162	$0	$163	$1,247	$2
14.8	Warehouse	$0	$416	$416	$0	$832	$146	$0	$147	$1,124	$2
14.9	Other Buildings & Structures	$0	$290	$247	$0	$537	$94	$0	$95	$726	$1

Case:		PA2	– SC PC and 35% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
Plant Size (MWnet):		650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
14.10	Waste Treating Building & Structures	$0	$646	$1,956	$0	$2,602	$455	$0	$459	$3,516	$5
	Subtotal	**$0**	**$31,355**	**$29,905**	**$0**	**$61,260**	**$10,720**	**$0**	**$10,797**	**$82,777**	**$127**
	Total	**$1,018,340**	**$166,553**	**$611,450**	**$0**	**$1,869,332**	**$327,133**	**$83,236**	**$368,978**	**$2,648,679**	**$4,020**

Exhibit A-63. Case PA2 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$15,070	$23
1 Month Maintenance Materials	$2,493	$4
1 Month Non-Fuel Consumables	$3,417	$5
1 Month Waste Disposal	$918	$1
25% of 1 Months Fuel Cost at 100% CF	$4,530	$7
2% of TPC	$52,974	$82
Total	**$79,401**	**$122**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$42,208	$65
0.5% of TPC (spare parts)	$13,243	$20
Total	**$55,451**	**$85**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,767	$4
Land	$900	$1
Other Owner's Costs	$397,302	$611
Financing Costs	$71,514	$110
Total Overnight Costs (TOC)	**$3,256,015**	**$4,955**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$3,758,782**	**$5,784**

Exhibit A-64. Case PA2 initial and annual O&M costs

Case:	PA2	– SC PC and 35% Biomass (w/ CO_2 Capture)			Cost Base:	Dec-18
Plant Size (MWnet):	650	Heat Rate-net (Btu/kWh):		11,349	Capacity Factor (%):	85.0
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	11.3	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**16.3**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,161,008	$11.019
Maintenance Labor:					$16,951,544	$26.085
Administrative & Support Labor:					$6,028,138	$9.276
Property Taxes and Insurance:					$52,973,576	$81.515
Total:					**$83,114,266**	**$127.896**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$25,427,317	$5.25482
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,500	$1.90	$0	$4,420,901	$0.91362
Makeup and Waste Water Treatment Chemicals (ton):	0	22.3	$550.00	$0	$3,812,149	$0.78782
Brominated Activated Carbon (ton):	0	1.65	$1,600.00	$0	$817,057	$0.16885
Enhanced Hydrated Lime (ton):	0	41.9	$240.00	$0	$3,118,766	$0.64453
Limestone (ton):	0	613	$22.00	$0	$4,184,988	$0.86487
Ammonia (19 wt%, ton):	0	72.4	$300.00	$0	$6,741,341	$1.39317
SCR Catalyst (ft^3):	18,449	16.8	150.00	$2,767,356	$784,084	$0.16204
CO_2 Capture System Chemicals[A]:	Proprietary				$9,742,845	$2.01346
Triethylene Glycol (gal):	w/equip.	582	$6.80	$0	$1,227,029	$0.25358
Subtotal:				**$2,767,356**	**$34,849,160**	**$7.20194**
Waste Disposal						
Fly Ash (ton)	0	605	$38.00	$0	$7,134,793	$1.47448
Bottom Ash (ton)	0	133	$38.00	$0	$1,568,743	$0.32420
SCR Catalyst (ft^3):	0	16.8	$2.50	$0	$13,068	$0.00270
Triethylene Glycol (gal):		582	$0.35	$0	$63,156	$0.01305
Thermal Reclaimer Unit Waste (ton)	0	3.76	$38.00	$0	$44,271	$0.00915
Prescrubber Blowdown Waste (ton)	0	45.5	$38.00	$0	$536,024	$0.11077
Subtotal:				**$0**	**$9,360,055**	**$1.93435**
By-Products						
Gypsum (ton)	0	932	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$2,767,356**	**$69,636,531**	**$14.39111**
Fuel Cost						
Illinois Number 6 (ton):	0	6,350	$51.96	$0	$102,358,432	$21.15343
Hybrid Poplar (ton):	0	3,419	$77.75	$0	$82,473,596	$17.04402
Total:				**$0**	**$184,832,029**	**$38.19745**

[A]CO_2 Capture System Chemicals includes NaOH and Cansolv Solvent

Exhibit A-65. Case PA2 LCOE breakdown

Component	Value, $/MWh	Percentage
Capital	55.0	41%
Fixed	17.2	13%
Variable	14.4	11%
Fuel	38.2	28%
Total (Excluding T&S)	**124.7**	**N/A**
CO_2 T&S	9.6	7%
Total (Including T&S)	**134.3**	**N/A**

Exhibit A-66. Case PA3 total plant cost details

	Case:	PA3	– SC PC and 49% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,024	$0	$461	$0	$1,486	$260	$0	$262	$2,008	$3
1.2	Coal Stackout & Reclaim	$3,363	$0	$752	$0	$4,114	$720	$0	$725	$5,559	$9
1.3	Coal Conveyors	$30,984	$0	$7,369	$0	$38,354	$6,712	$0	$6,760	$51,825	$80
1.4	Other Coal Handling	$4,305	$0	$905	$0	$5,210	$912	$0	$918	$7,040	$11
1.5	Sorbent Receive & Unload	$195	$0	$58	$0	$253	$44	$0	$45	$342	$1
1.6	Sorbent Stackout & Reclaim	$1,431	$0	$259	$0	$1,690	$296	$0	$298	$2,284	$4
1.7	Sorbent Conveyors	$2,164	$471	$524	$0	$3,158	$553	$0	$557	$4,267	$7
1.8	Other Sorbent Handling	$104	$25	$54	$0	$183	$32	$0	$32	$247	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,343	$1,771	$0	$3,114	$545	$0	$549	$4,207	$6
1.10	Biomass Receiving and Processing	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$28,000	$4,900	$0	$4,935	$37,835	$58
	Subtotal	**$43,570**	**$1,838**	**$12,152**	**$0**	**$85,560**	**$14,973**	**$0**	**$15,080**	**$115,613**	**$120**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$2,182	$0	$419	$0	$2,601	$455	$0	$458	$3,514	$5
2.2	Prepared Coal Storage & Feed	$7,343	$0	$1,581	$0	$8,925	$1,562	$0	$1,573	$12,059	$19
2.3	Biomass Drying	$2,466	$0	$480	$0	$2,946	$516	$0	$519	$3,981	$6
2.5	Sorbent Preparation Equipment	$961	$42	$197	$0	$1,199	$210	$0	$211	$1,620	$2
2.6	Sorbent Storage & Feed	$1,611	$0	$607	$0	$2,218	$388	$0	$391	$2,997	$5
2.7	Biomass Pelletization	w/ BEC	w/ BEC	w/ BEC	w/ BEC	$75,793	$13,264	$0	$13,359	$102,416	$158
2.8	Prepared Biomass Storage & Feed	$5,622	$0	$1,211	$0	$6,833	$1,196	$0	$1,204	$9,233	$14
2.9	Coal & Sorbent Feed Foundation	$0	$640	$561	$0	$1,202	$210	$0	$212	$1,624	$2
	Subtotal	**$20,184**	**$682**	**$5,057**	**$0**	**$101,716**	**$17,800**	**$0**	**$17,927**	**$137,444**	**$211**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$4,181	$7,167	$3,583	$0	$14,931	$2,613	$0	$2,632	$20,175	$31
3.2	Water Makeup & Pretreating	$8,745	$874	$4,955	$0	$14,574	$2,551	$0	$3,425	$20,550	$32
3.3	Other Feedwater Subsystems	$3,312	$1,086	$1,031	$0	$5,429	$950	$0	$957	$7,336	$11
3.4	Service Water Systems	$2,789	$5,325	$17,244	$0	$25,358	$4,438	$0	$5,959	$35,755	$55
3.5	Other Boiler Plant Systems	$820	$298	$745	$0	$1,864	$326	$0	$328	$2,518	$4

	Case:	PA3	– SC PC and 49% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
3.6	Natural Gas Pipeline and Start-Up System	$4,173	$179	$135	$0	$4,487	$785	$0	$791	$6,064	$9
3.7	Waste Water Treatment Equipment	$17,631	$0	$10,806	$0	$28,437	$4,976	$0	$6,683	$40,096	$62
3.8	Spray Dryer Evaporator	$14,273	$0	$8,199	$0	$22,472	$3,933	$0	$5,281	$31,686	$49
3.9	Miscellaneous Plant Equipment	$253	$33	$128	$0	$414	$72	$0	$97	$584	$1
	Subtotal	**$56,176**	**$14,963**	**$46,827**	**$0**	**$117,967**	**$20,644**	**$0**	**$26,153**	**$164,764**	**$254**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$283,468	$0	$161,519	$0	$444,987	$77,873	$0	$78,429	$601,289	$925
4.10	Selective Catalytic Reduction System	$31,267	$0	$17,816	$0	$49,083	$8,589	$0	$8,651	$66,323	$102
4.11	Boiler Balance of Plant	$2,412	$0	$1,374	$0	$3,786	$663	$0	$667	$5,116	$8
4.12	Primary Air System	$1,954	$0	$1,113	$0	$3,068	$537	$0	$541	$4,145	$6
4.13	Secondary Air System	$2,625	$0	$1,496	$0	$4,121	$721	$0	$726	$5,568	$9
4.14	Induced Draft Fans	$5,826	$0	$3,319	$0	$9,145	$1,600	$0	$1,612	$12,357	$19
4.15	Major Component Rigging	$127	$0	$72	$0	$199	$35	$0	$35	$269	$0
4.16	Boiler Foundations	$0	$545	$479	$0	$1,024	$179	$0	$180	$1,383	$2
	Subtotal	**$327,679**	**$545**	**$187,188**	**$0**	**$515,412**	**$90,197**	**$0**	**$90,841**	**$696,450**	**$1,072**
5	Flue Gas Cleanup										
5.1	Cansolv Carbon Dioxide (CO_2) Removal System	$212,956	$91,254	$191,634	$0	$495,844	$86,773	$84,293	$116,709	$783,619	$1,206
5.2	WFGD Absorber Vessels & Accessories	$83,531	$0	$17,860	$0	$101,391	$17,743	$0	$17,870	$137,005	$211
5.3	Other FGD	$375	$0	$422	$0	$797	$139	$0	$140	$1,077	$2
5.4	Carbon Dioxide (CO_2) Compression & Drying	$44,186	$6,628	$14,773	$0	$65,587	$11,478	$0	$15,413	$92,478	$142
5.5	Carbon Dioxide (CO_2) Compressor Aftercooler	$497	$79	$213	$0	$788	$138	$0	$185	$1,112	$2
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	$2,823	$621	$2,776	$0	$6,220	$1,088	$0	$1,096	$8,404	$13
5.9	Particulate Removal (Bag House & Accessories)	$1,633	$0	$1,029	$0	$2,662	$466	$0	$469	$3,597	$6

Case:		PA3	– SC PC and 49% Biomass (w/ CO_2 Capture)					Estimate Type:		Conceptual	
Plant Size (MWnet):		650						Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
5.12	Gas Cleanup Foundations	$0	$282	$247	$0	$529	$93	$0	$93	$715	$1
5.13	Gypsum Dewatering System	$670	$0	$113	$0	$782	$137	$0	$138	$1,057	$2
	Subtotal	**$346,670**	**$98,864**	**$229,067**	**$0**	**$674,601**	**$118,055**	**$84,293**	**$152,115**	**$1,029,064**	**$1,583**
7						Ductwork & Stack					
7.3	Ductwork	$0	$851	$591	$0	$1,442	$252	$0	$254	$1,949	$3
7.4	Stack	$8,799	$0	$5,113	$0	$13,912	$2,435	$0	$2,452	$18,799	$29
7.5	Duct & Stack Foundations	$0	$216	$256	$0	$472	$83	$0	$111	$665	$1
	Subtotal	**$8,799**	**$1,066**	**$5,960**	**$0**	**$15,826**	**$2,770**	**$0**	**$2,817**	**$21,413**	**$33**
8						Steam Turbine & Accessories					
8.1	Steam Turbine Generator & Accessories	$76,724	$0	$8,550	$0	$85,274	$14,923	$0	$15,030	$115,227	$177
8.2	Steam Turbine Plant Auxiliaries	$1,741	$0	$3,707	$0	$5,448	$953	$0	$960	$7,361	$11
8.3	Condenser & Auxiliaries	$11,876	$0	$4,029	$0	$15,905	$2,783	$0	$2,803	$21,491	$33
8.4	Steam Piping	$45,285	$0	$18,354	$0	$63,638	$11,137	$0	$11,216	$85,991	$132
8.5	Turbine Generator Foundations	$0	$272	$450	$0	$722	$126	$0	$170	$1,018	$2
	Subtotal	**$135,625**	**$272**	**$35,089**	**$0**	**$170,987**	**$29,923**	**$0**	**$30,179**	**$231,088**	**$356**
9						Cooling Water System					
9.1	Cooling Towers	$21,376	$0	$6,611	$0	$27,986	$4,898	$0	$4,933	$37,816	$58
9.2	Circulating Water Pumps	$3,050	$0	$224	$0	$3,274	$573	$0	$577	$4,424	$7
9.3	Circulating Water System Auxiliaries	$17,538	$0	$2,314	$0	$19,852	$3,474	$0	$3,499	$26,824	$41
9.4	Circulating Water Piping	$0	$8,107	$7,342	$0	$15,449	$2,704	$0	$2,723	$20,876	$32
9.5	Make-up Water System	$1,330	$0	$1,709	$0	$3,039	$532	$0	$536	$4,107	$6
9.6	Component Cooling Water System	$1,263	$0	$969	$0	$2,233	$391	$0	$393	$3,017	$5
9.7	Circulating Water System Foundations	$0	$751	$1,247	$0	$1,998	$350	$0	$470	$2,817	$4
	Subtotal	**$44,557**	**$8,858**	**$20,416**	**$0**	**$73,831**	**$12,920**	**$0**	**$13,130**	**$99,882**	**$154**
10						Ash & Spent Sorbent Handling Systems					
10.6	Ash Storage Silos	$1,083	$0	$3,314	$0	$4,397	$769	$0	$775	$5,942	$9
10.7	Ash Transport & Feed Equipment	$3,684	$0	$3,652	$0	$7,336	$1,284	$0	$1,293	$9,912	$15
10.9	Ash/Spent Sorbent Foundation	$0	$753	$927	$0	$1,680	$294	$0	$395	$2,369	$4

	Case:	PA3	– SC PC and 49% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650							Cost Base:	Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
	Subtotal	**$4,767**	**$753**	**$7,893**	**$0**	**$13,413**	**$2,347**	**$0**	**$2,463**	**$18,223**	**$28**
11	**ACCESSORY ELECTRIC PLANT**										
11.1	Generator Equipment	$2,771	$0	$2,090	$0	$4,861	$851	$0	$857	$6,568	$10
11.2	Station Service Equipment	$8,977	$0	$770	$0	$9,747	$1,706	$0	$1,718	$13,171	$20
11.3	Switchgear & Motor Control	$13,936	$0	$2,418	$0	$16,354	$2,862	$0	$2,882	$22,099	$34
11.4	Conduit & Cable Tray	$0	$1,812	$5,221	$0	$7,033	$1,231	$0	$1,239	$9,503	$15
11.5	Wire & Cable	$0	$4,798	$8,576	$0	$13,374	$2,340	$0	$2,357	$18,071	$28
11.6	Protective Equipment	$55	$0	$191	$0	$246	$43	$0	$43	$332	$1
11.7	Standby Equipment	$851	$0	$786	$0	$1,637	$286	$0	$288	$2,212	$3
11.8	Main Power Transformers	$7,332	$0	$150	$0	$7,481	$1,309	$0	$1,319	$10,109	$16
11.9	Electrical Foundations	$0	$233	$592	$0	$825	$144	$0	$194	$1,163	$2
	Subtotal	**$33,922**	**$6,842**	**$20,793**	**$0**	**$61,558**	**$10,773**	**$0**	**$10,898**	**$83,228**	**$128**
12	**Instrumentation & Control**										
12.1	Pulverized Coal Boiler Control Equipment	$847	$0	$151	$0	$998	$175	$0	$176	$1,349	$2
12.3	Steam Turbine Control Equipment	$759	$0	$85	$0	$844	$148	$0	$149	$1,140	$2
12.5	Signal Processing Equipment	$962	$0	$171	$0	$1,133	$198	$0	$200	$1,531	$2
12.6	Control Boards, Panels & Racks	$294	$0	$180	$0	$474	$83	$24	$87	$668	$1
12.7	Distributed Control System Equipment	$8,302	$0	$1,480	$0	$9,782	$1,712	$489	$1,797	$13,780	$21
12.8	Instrument Wiring & Tubing	$581	$465	$1,860	$0	$2,907	$509	$145	$534	$4,095	$6
12.9	Other Instrumentation & Controls Equipment	$715	$0	$1,655	$0	$2,370	$415	$118	$435	$3,338	$5
	Subtotal	**$12,460**	**$465**	**$5,582**	**$0**	**$18,507**	**$3,239**	**$777**	**$3,378**	**$25,901**	**$40**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$481	$10,204	$0	$10,685	$1,870	$0	$2,511	$15,066	$23
13.2	Site Improvements	$0	$2,376	$3,140	$0	$5,517	$965	$0	$1,296	$7,779	$12
13.3	Site Facilities	$2,716	$0	$2,848	$0	$5,564	$974	$0	$1,308	$7,845	$12
	Subtotal	**$2,716**	**$2,857**	**$16,193**	**$0**	**$21,765**	**$3,809**	**$0**	**$5,115**	**$30,689**	**$47**
14	**Buildings & Structures**										

	Case:	PA3	– SC PC and 49% Biomass (w/ CO_2 Capture)				Estimate Type:			Conceptual	
	Plant Size (MWnet):	650					Cost Base:			Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
14.2	Boiler Building	$0	$11,598	$10,193	$0	$21,791	$3,813	$0	$3,841	$29,445	$45
14.3	Steam Turbine Building	$0	$16,121	$15,014	$0	$31,136	$5,449	$0	$5,488	$42,072	$65
14.4	Administration Building	$0	$1,047	$1,107	$0	$2,154	$377	$0	$380	$2,911	$4
14.5	Circulation Water Pumphouse	$0	$201	$159	$0	$360	$63	$0	$63	$486	$1
14.6	Water Treatment Buildings	$0	$494	$450	$0	$945	$165	$0	$167	$1,277	$2
14.7	Machine Shop	$0	$553	$371	$0	$923	$162	$0	$163	$1,247	$2
14.8	Warehouse	$0	$416	$416	$0	$832	$146	$0	$147	$1,124	$2
14.9	Other Buildings & Structures	$0	$290	$247	$0	$537	$94	$0	$95	$726	$1
14.10	Waste Treating Building & Structures	$0	$647	$1,959	$0	$2,606	$456	$0	$459	$3,521	$5
	Subtotal	**$0**	**$31,367**	**$29,917**	**$0**	**$61,284**	**$10,725**	**$0**	**$10,801**	**$82,809**	**$127**
	Total	**$1,037,126**	**$169,373**	**$622,135**	**$0**	**$1,932,426**	**$338,175**	**$85,070**	**$380,897**	**$2,736,568**	**$4,152**

Exhibit A-67. Case PA3 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$15,422	$24
1 Month Maintenance Materials	$2,576	$4
1 Month Non-Fuel Consumables	$3,474	$5
1 Month Waste Disposal	$866	$1
25% of 1 Months Fuel Cost at 100% CF	$5,638	$9
2% of TPC	$54,731	$84
Total	**$82,707**	**$127**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$51,158	$79
0.5% of TPC (spare parts)	$13,683	$21
Total	**$64,841**	**$100**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,864	$4
Land	$900	$1
Other Owner's Costs	$410,485	$632
Financing Costs	$73,887	$114
Total Overnight Costs (TOC)	**$3,372,252**	**$5,130**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$3,892,968**	**$5,990**

Exhibit A-68. Case PA3 initial and annual O&M costs

Case:	**PA3**	**– SC PC and 49% Biomass (w/ CO_2 Capture)**			**Cost Base:**	**Dec-18**
Plant Size (MWnet):	**650**	**Heat Rate-net (Btu/kWh):**		**11,668**	**Capacity Factor (%):**	**85.0**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	11.3	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**16.3**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,161,008	$11.018
Maintenance Labor:					$17,514,037	$26.947
Administrative & Support Labor:					$6,168,761	$9.491
Property Taxes and Insurance:					$54,731,367	$84.210
Total:					**$85,575,173**	**$131.666**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$26,271,056	$5.42852
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,725	$1.90	$0	$4,553,474	$0.94091
Makeup and Waste Water Treatment Chemicals (ton):	0	23.0	$550.00	$0	$3,926,467	$0.81135
Brominated Activated Carbon (ton):	0	1.70	$1,600.00	$0	$844,527	$0.17451
Enhanced Hydrated Lime (ton):	0	43.1	$240.00	$0	$3,212,340	$0.66378
Limestone (ton):	0	558	$22.00	$0	$3,810,212	$0.78732
Ammonia (19 wt%, ton):	0	74.6	$300.00	$0	$6,939,385	$1.43392
SCR Catalyst (ft^3):	19,090	17.4	150.00	$2,863,526	$811,332	$0.16765
CO_2 Capture System Chemicals[A]:		**Proprietary**			$10,063,174	$2.07940
Triethylene Glycol (gal):	w/equip.	605	$6.80	$0	$1,276,496	$0.26377
Subtotal:				**$2,863,526**	**$35,437,408**	**$7.32261**
Waste Disposal						
Fly Ash (ton)	0	572	$38.00	$0	$6,749,117	$1.39460
Bottom Ash (ton)	0	125	$38.00	$0	$1,472,930	$0.30436
SCR Catalyst (ft^3):	0	17.4	$2.50	$0	$13,522	$0.00279
Triethylene Glycol (gal):		605	$0.35	$0	$65,702	$0.01358
Thermal Reclaimer Unit Waste (ton)	0	3.91	$38.00	$0	$46,055	$0.00952
Prescrubber Blowdown Waste (ton)	0	41.3	$38.00	$0	$486,608	$0.10055
Subtotal:				**$0**	**$8,833,935**	**$1.82540**
By-Products						
Gypsum (ton)	0	848	$0.00	$0	$0	$0.00000
Subtotal:				$0	$0	$0.00000
Variable Operating Costs Total:				**$2,863,526**	**$70,542,399**	**$14.57652**
Fuel Cost						
Illinois Number 6 (ton):	0	5,789	$51.96	$0	$93,323,213	$19.28383
Hybrid Poplar (ton):	0	5,562	$79.21	$0	$136,698,902	$28.24677
Total:				**$0**	**$230,022,115**	**$47.53060**

[A]CO_2 Capture System Chemicals includes NaOH and Cansolv Solvent

Exhibit A-69. Case PA3 LCOE breakdown

Component	Value, $/MWh	Percentage
Capital	56.9	39%
Fixed	17.7	12%
Variable	14.6	10%
Fuel	47.5	32%
Total (Excluding T&S)	**136.7**	**N/A**
CO_2 T&S	10.0	7%
Total (Including T&S)	**146.6**	**N/A**

APPENDIX B: 100 PERCENT BIOMASS SCENARIO RESULTS

Technical and environmental life cycle analysis was performed for two additional scenarios: 100 percent biomass fuel without CCS (PN100) and 100 percent biomass fuel with an amine-based CCS system (PA100). Plant equipment was resized to deal with the increased fuel flow, and the flue gas desulphurization system was removed due to the negligible sulfur content of biomass fuel. The plant performance characteristics of these cases are shown in Exhibit B-1, with SC PC with and without CCS (B12B and B12A), and 49 percent biomass cases with and without CCS (PA3 and PN3) for comparison.

Exhibit B-1. Plant performance characteristics for SC PC, 49 wt% BECCS, and 100% biomass scenarios

	Case B12A*	Case PN3	Case PN100	Case B12B*	Case PA3	Case PA100
Nominal CO_2 Capture	**0%**	**0%**	**0%**	**90%**	**90%**	**90%**
Capacity Factor	**85%**	**85%**	**85%**	**85%**	**85%**	**85%**
Gross Power Output (MWe)	685	716	820	770	821	997
Auxiliary Power Requirement (MWe)	35	66	170	120	171	347
Net Power Output (MWe)	650	650	650	650	650	650
Coal Flow Rate (lb/hr)	472,037	368,334	0	603,246	482,441	0
Biomass Flow Rate (lb/hr)	0	353,889	1,597,799	0	463,521	2,252,158
HHV Thermal Input (kW_t)	1,613,879	1,696,892	1,975,628	2,062,478	2,222,578	2,784,722
Net Plant HHV Efficiency (%)	40.3%	38.3%	32.9%	31.5%	29.2%	23.3%
Net Plant HHV Heat Rate (Btu/kWh)	8,473	8,909	10,363	10,834	11,668	14,619
Raw Water Withdrawal (gpm)	6,054	5,917	6,510	9,911	10,729	13,620
Process Water Discharge (gpm)	1,242	1,297	2,900	2,893	3,678	6,627
Raw Water Consumption (gpm)	4,811	4,620	3,610	7,018	7,051	6,993
CO_2 Emissions (lb/MWh-gross)	1,627	1,688	1,871	185	193	217
CO_2 Emissions (lb/MWh-net)	1,714	1,861	2,360	219	244	333
SO_2 Emissions (lb/MWh-gross)	0.648	0.482	0.569	0.000	0.000	0.000
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06	2.93E-06	3.00E-06

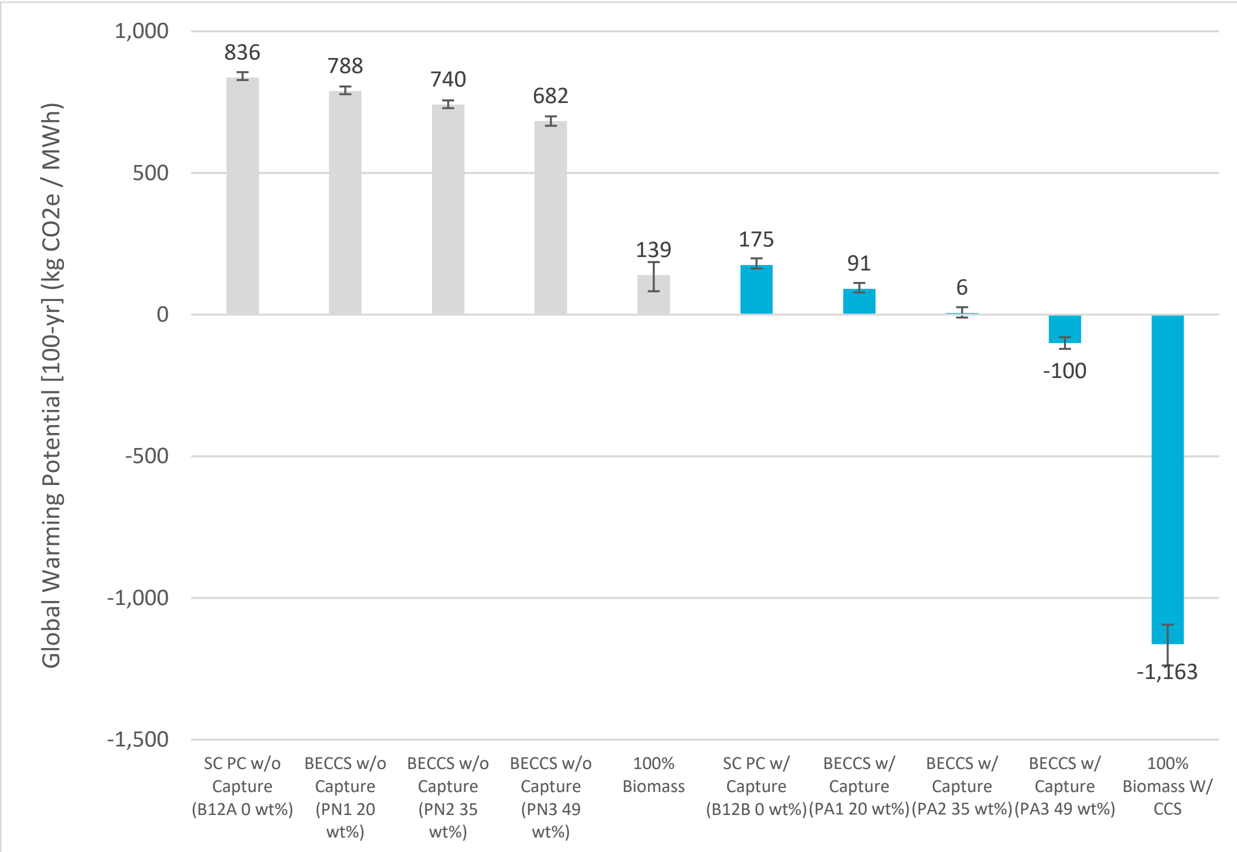
As Exhibit B-1 shows, moving to 100 percent biomass fueling results in a large increase in the total mass of fuel required and the auxiliary loads, as well as a significant decrease in the thermodynamic efficiency of the plant as whole. This is mainly due to the significant energy required to dry the biomass before combustion, as well as additional handling requirements. The increased biomass fuel requirements also exacerbate the biomass availability issues highlighted in the results section, as a correspondingly increased cultivation area will be required, as well as increased fuel transportation distances.

As shown in Exhibit B-2, increasing the level of biomass fuel increases environmental impacts other than greenhouse gas emissions, which decrease. Any analysis must, therefore, weigh the benefits of the decreasing greenhouse gas emissions at the expense of other environmental burdens. Despite tradeoffs, BECCS is one of the few existing technologically proven carbon-negative sources of power. Full environmental impacts are shown in Exhibit B-2 and GHG results are shown in Exhibit B-3 for the 100 percent biomass cases relative to SC PC and BECCS results. Additional concerns about plant size and biomass availability for a 100 percent biomass-powered thermoelectric plant are real but not directly addressed in this analysis.

Exhibit B-2. Heat map demonstrating scenarios with the highest environmental impacts (red) and lowest impacts (green) across each of the impact

Indicator	Unit	SC PC w/o Capture (B12A 0 wt%)	SC PC w/ Capture (B12B 0 wt%)	BECCS w/o Capture (PN1 20 wt%)	BECCS w/ Capture (PA1 20 wt%)	BECCS w/o Capture (PN2 35 wt%)	BECCS w/ Capture (PA2 35 wt%)	BECCS w/o Capture (PN3 49 wt%)	BECCS w/ Capture (PA3 49 wt%)	100% Biomass	100% Biomass W/ CCS
Acidification Potential	kg SO_2e	7.28E-01	5.04E-01	8.68E-01	7.18E-01	9.98E-01	9.19E-01	1.16E+00	1.17E+00	2.99E+00	3.71E+00
Eutrophication Potential	kg N e	2.25E-02	2.87E-02	5.33E-02	6.87E-02	8.41E-02	1.09E-01	1.22E-01	1.60E-01	4.74E-01	6.68E-01
Global Warming Potential [100 yr]	kg CO_2e	8.36E+02	1.75E+02	7.88E+02	9.09E+01	7.40E+02	5.66E+00	6.82E+02	-1.00E+02	1.39E+02	-1.16E+03
Ozone Depletion Potential	kg CFC-11e	4.57E-09	5.87E-09	2.11E-08	2.73E-08	3.79E-08	4.95E-08	5.90E-08	7.76E-08	2.62E-07	3.75E-07
Particulate Matter Formation Potential	kg PM2.5e	1.30E-01	1.42E-01	1.34E-01	1.50E-01	1.37E-01	1.57E-01	1.41E-01	1.66E-01	2.01E-01	2.55E-01
Photochemical Smog Formation Potential-	kg O_3e	1.12E+01	1.31E+01	1.31E+01	1.57E+01	1.51E+01	1.83E+01	1.75E+01	2.16E+01	4.03E+01	5.51E+01
Water Consumption	kg	1.97E+03	2.82E+03	7.69E+03	1.02E+04	1.34E+04	1.77E+04	2.04E+04	2.70E+04	8.48E+04	1.20E+05

Exhibit B-3. Global warming potential results



Note: blue bars indicate the presence of 90% CCS

APPENDIX C: ALTERNATIVE CO_2 DISPOSITION SCENARIOS

To consider CO_2 utilization, the carbon capture scenarios were analyzed with the assumption that the captured CO_2 would be utilized for enhanced oil recovery (EOR). The plant CO_2 was considered to displace natural dome CO_2 extraction, which is the most common source of industrial quantities of CO_2. This was modeled using the National Energy Technology Laboratory (NETL) natural dome CO_2 processes for well construction and installation, well operation, and CO_2 dehydration and compression. The compressed natural dome CO_2 could, therefore, be directly compared to the compressed CO_2 produced by the power plant. Pipeline transport and boosting was not considered, as transport distances are location and project dependent.

The results shown in Exhibit C-2 through Exhibit C-7 show declines in environmental impact compared to the sequestration scenarios, demonstrating that using captured CO_2 to replace natural dome CO_2 is environmentally preferable to sequestering captured CO_2 while still extracting natural dome CO_2 for industrial use.

Exhibit C-1. Global warming potential [100-yr] for BECCS and biomass-to-EOR scenarios

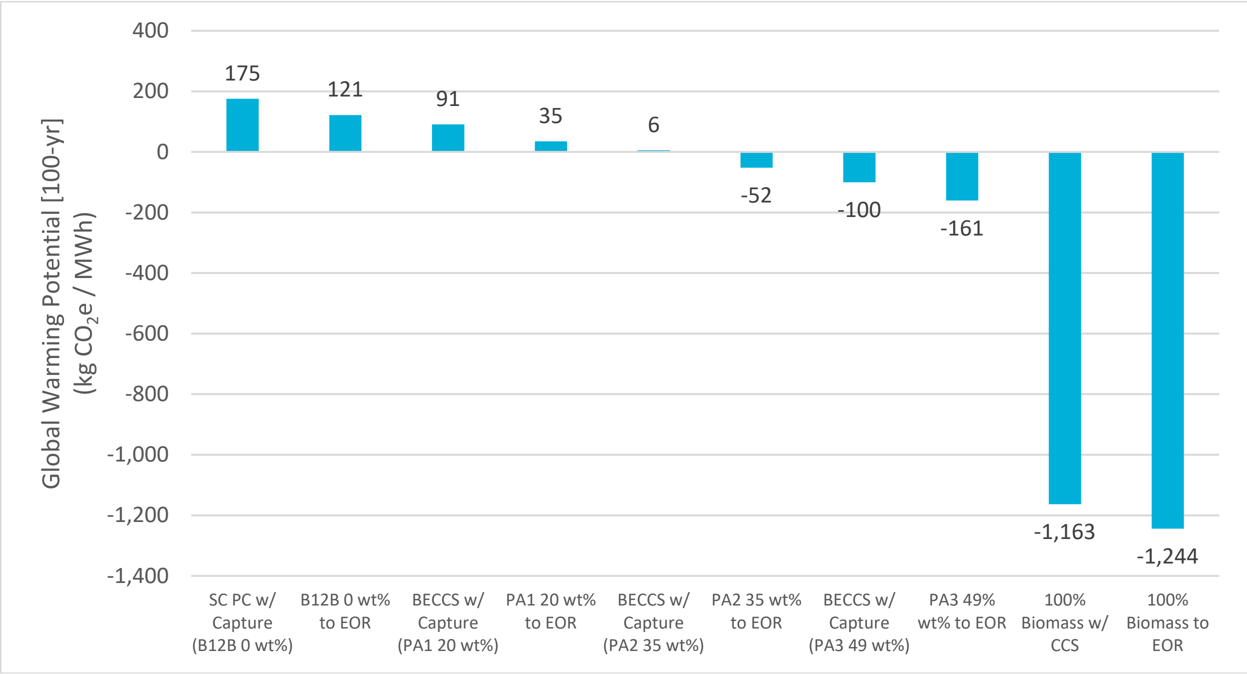


Exhibit C-2. Acidification potential for BECCS and biomass-to-EOR scenarios

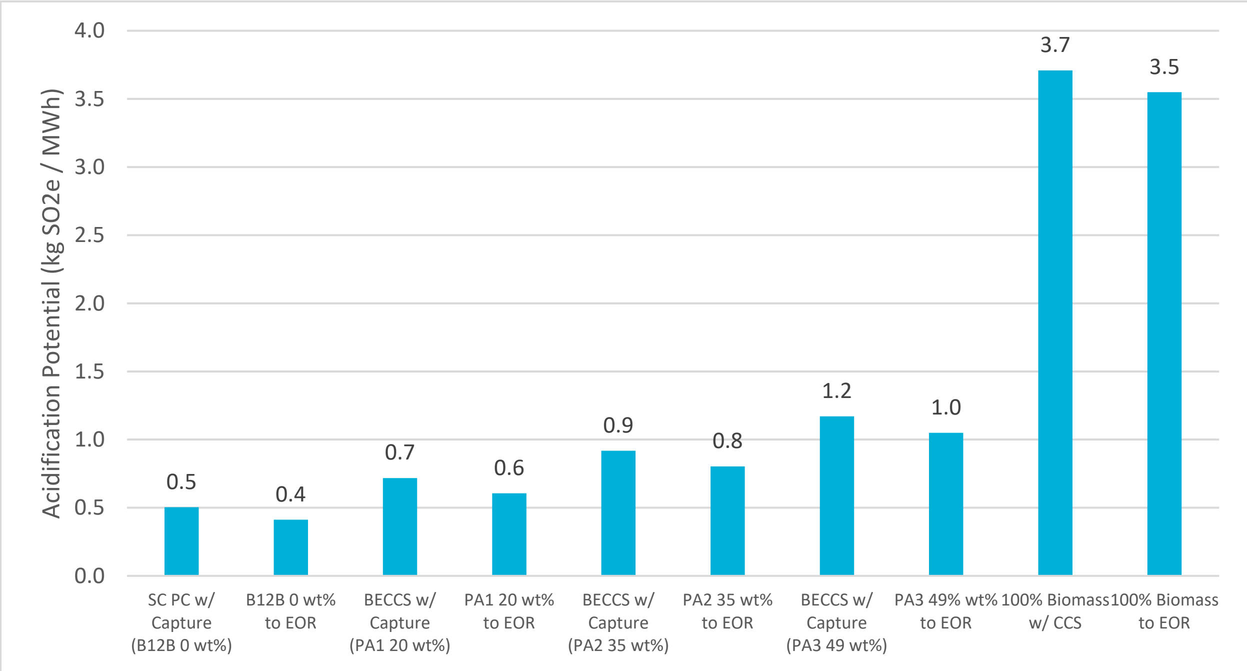


Exhibit C-3. Eutrophication potential for BECCS and biomass-to-EOR scenarios

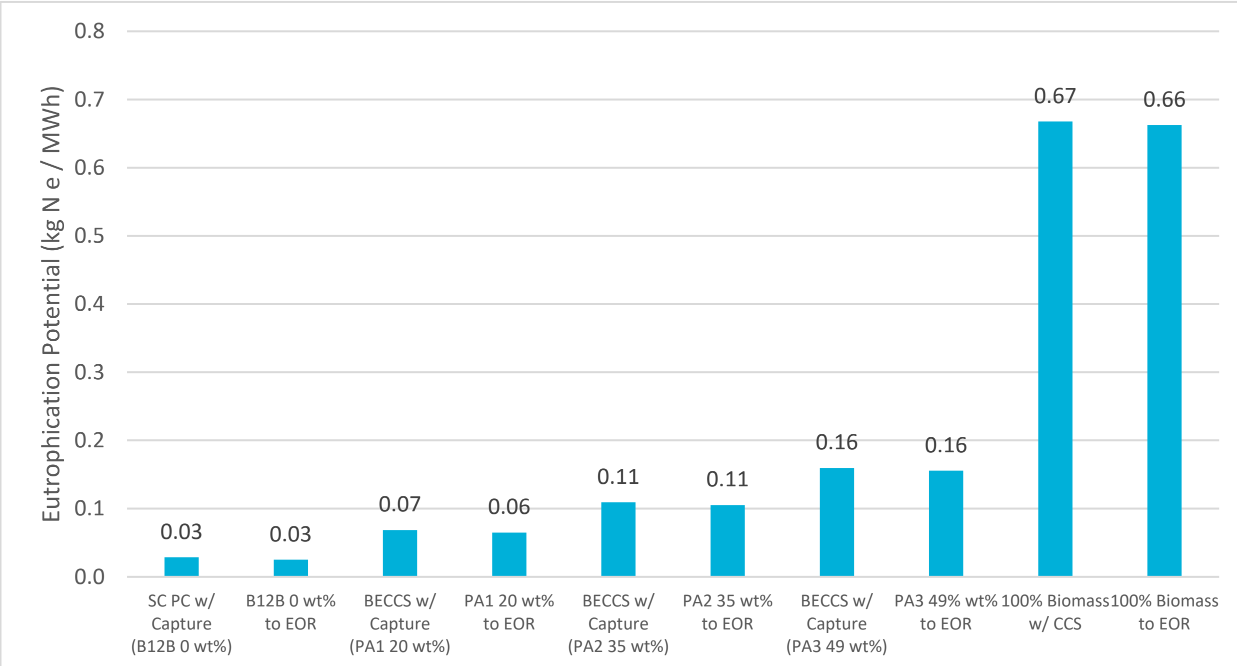


Exhibit C-4. Particulate matter formation potential for BECCS and biomass-to-EOR scenarios

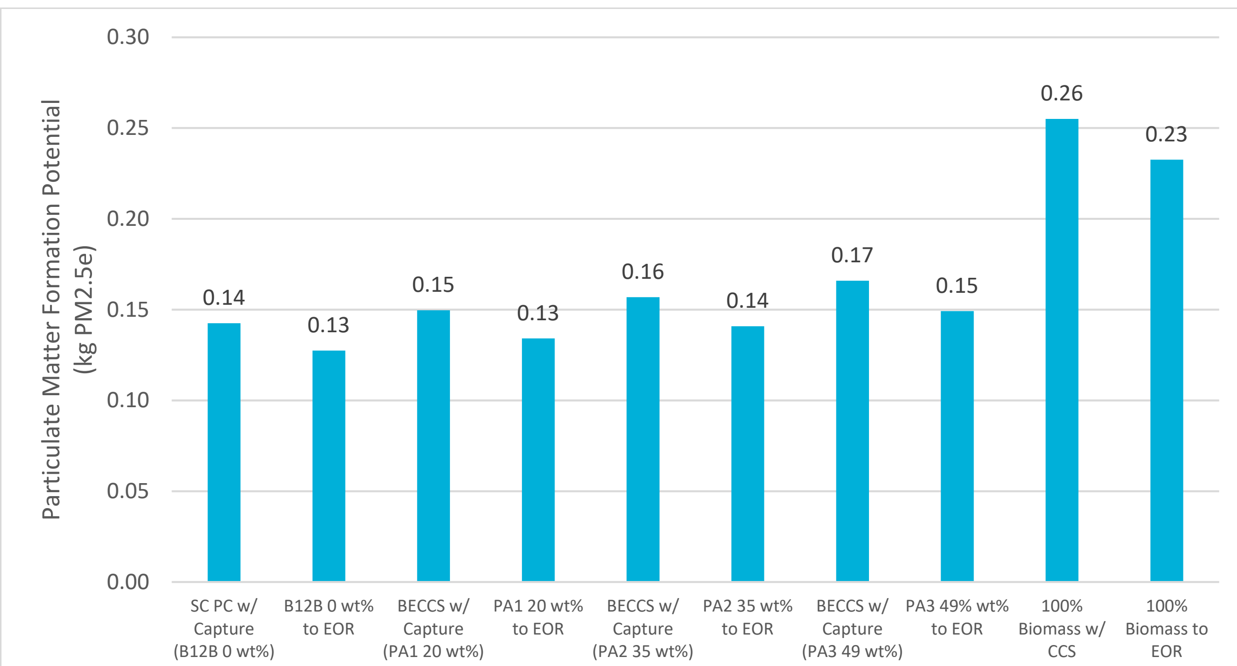


Exhibit C-5. Ozone depletion potential for BECCS and biomass-to-EOR scenarios

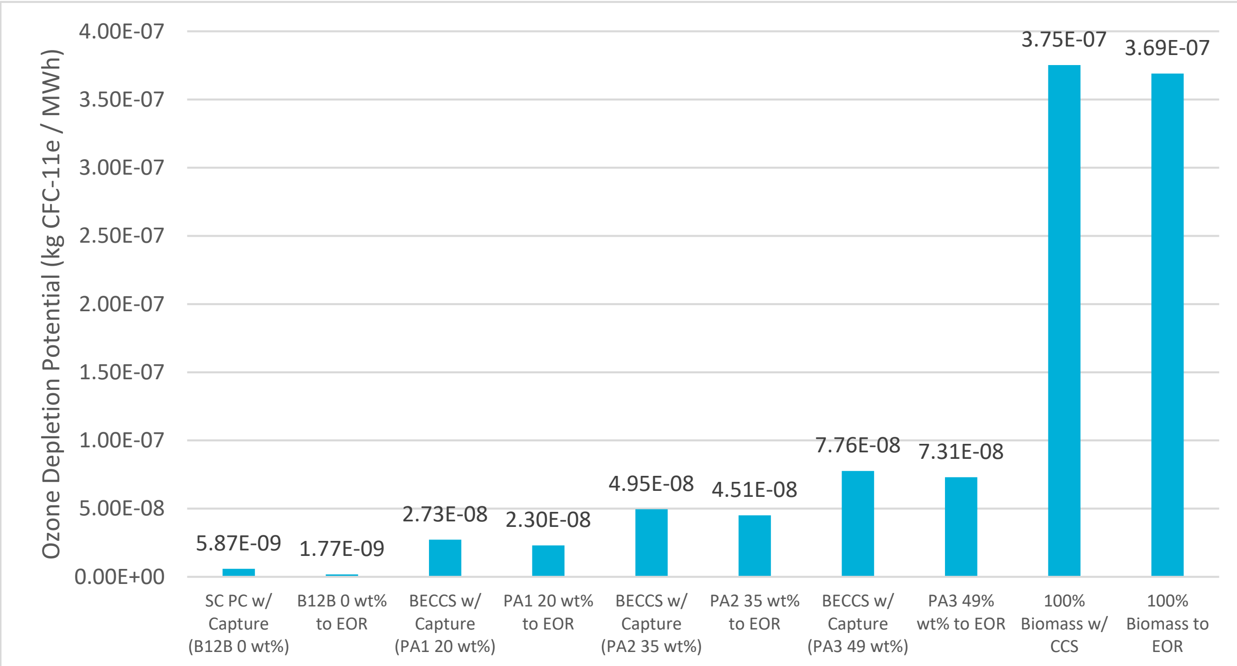


Exhibit C-6. Photochemical smog formation potential for BECCS and biomass-to-EOR scenarios

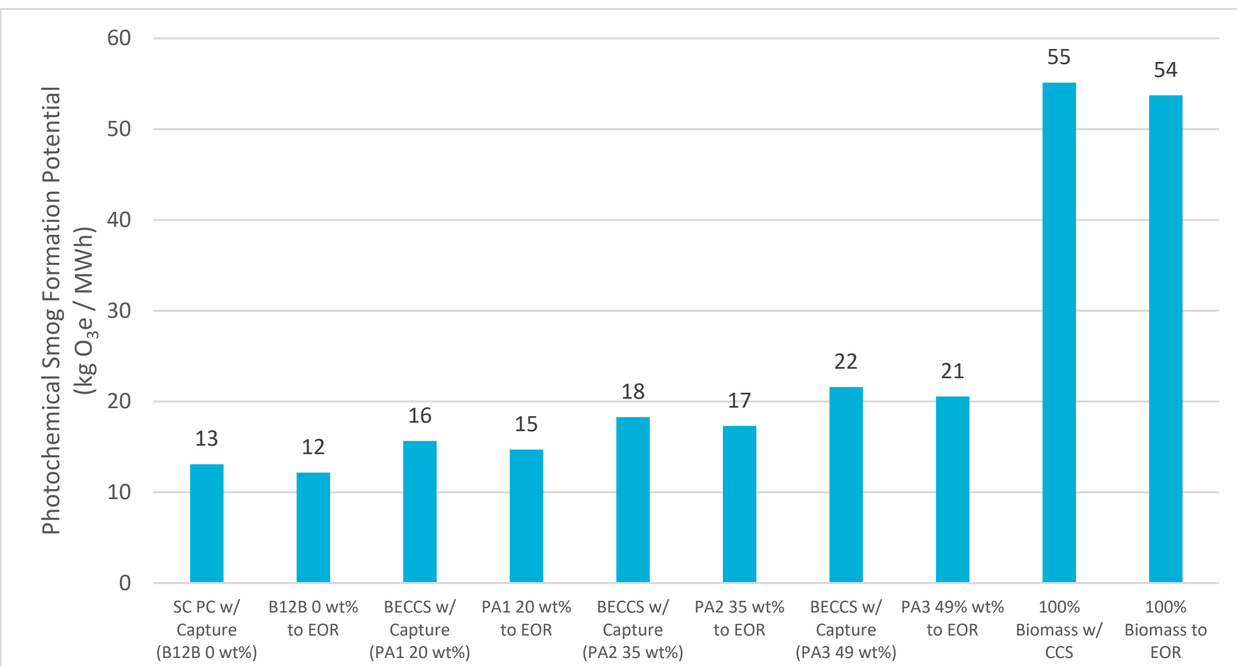
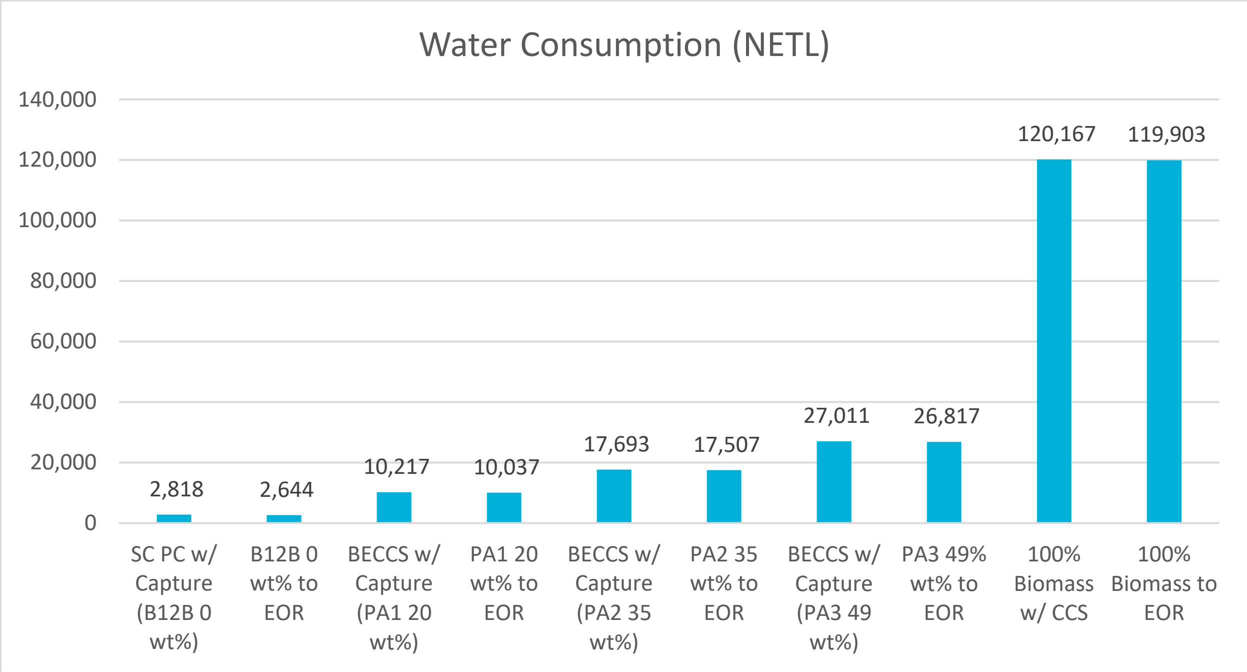


Exhibit C-7. Water consumption for BECCS and Biomass-to-EOR scenarios



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