Advanced Pressurized Fluidized Bed Coal Combustion with Carbon Capture

Pre-FEED Study Final Report

Concept Area: With Carbon Capture/Carbon Capture Ready

Contract: 89243319CFE000020

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May 6, 2020

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DOE-NETL Contract Number 89243319CFE000020

Acronyms and Abbreviations

AACE	American Association of Cost Engineering
acfm	Actual cubic feet per minute
AC	Alternating Current
AQC	Air Quality Control
Ar	Argon
ASME	American Society of Mechanical Engineers
BEC	Bare erected cost
BFD	Block flow diagram
BOD	Measurement of consumed oxygen by aquatic microorganisms to decompose or oxidize organic matter
BOP	Balance of Plant
Btu	British thermal unit
Btu/h, Btu/hr	British thermal units per hour
Btu/kWh	British thermal units per kilowatt hour
Btu/lb	British thermal units per pound
BTU/scf	British Thermal Unit per standard cubic feet
CCS	carbon dioxide capture system
cf	Cubic feet
cfm	Cubic feet per minute
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
COD	Requirement of dissolved oxygen for both the oxidation of organic and inorganic constituents
COE	Cost of electricity
cy/cu yd	Cubic yards
DCS	Distributed Control System
dia	Diameter
DL	Design Load
DOE	Department of Energy
DP	Differential Pressure
EPA	Environmental Protection Agency
EPCM	Engineering, Procurement and Construction Management
FEED	Front-End Engineering Design
FGD	Flue gas desulfurization
FO	Fuel Oil
FO&M	Fixed operations and maintenance
ft	Foot, Feet
FRP	Fiber-reinforced plastic
gal	Gallon
GIS	Gas Insulated Switchgear
GPM	Gallons per minute
h, hr	Hour
H_2	Hydrogen
H_2O	Water
H&MB	Heat and Mass Balance
HAP	Hazardous Air Pollutants
Hg	Mercury
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
Hz	Hertz
ID	Interior diameter (of pipe)
in. W.G.	Inch water gauge
IO	input/output
kV	Kilovolt
kVA	Kilovolt-ampere
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
kWt	Kilowatt thermal
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/ft	
lb/h, lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
LHV	Lower heating value
LNTP	Limited Notice to Proceed
LOI	Loss on ignition
LP	Low pressure
LSB	Last stage bucket
MATS	Mercury and Toxics Standard
MCC	Motor Control Center
mil	One-thousandth of an inch
mm	millimeter
MM	Million
MMBtu	Million British thermal units
MMBtu/h	Million British thermal units per hour
MP	Medium pressure

MVA	Mega volt-ampere
MW, MWe	Megawatt electric
MWh	Megawatt-hour
MW_t	Megawatt thermal
N_2	Nitrogen
N_2O	Nitrous oxide
N/A, NA	Not applicable
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NO_2	Nitrogen Dioxide
NO_X	Oxides of nitrogen
NPDES	National Pollution Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
NTP	Notice to Proceed
OEM	Original Equipment Manufacturer
O_2	Oxygen
O_3	Ozone
O&M	Operation and Maintenance
OWS	Operator Work Station
PC	Personal Computer
PFBC	Pressurized Fluid Bed Combustion
PFD	Process flow diagram
pH	potential hydrogen
PLC	Programmable Logic Controller
PM	Particulate matter
POTW	Publicly Owned Treatment Works
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
ppmw	Parts per million weight
PSD	Prevention of Significant Deterioration of Air Quality
psf	Pounds per square foot
psi	Pounds per square inch
psia	Pound per square inch absolute
psid	Pound per square inch differential
psig	Pound per square inch gage
Qty	Quantity
RF	Radio Frequency
sbbl	Standard barrel
scf	Standard cubic feet
scf/hr	Standard cubic feet per hour
scfm	Standard cubic feet per minute
SNCR	Selective non-catalytic reduction (NOx control)
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SO_X	Oxides of sulfur
SS	Stainless steel
TG	Turbine Generator
mt, tonne	Metric ton (1,000 kg)
TPC	Total plant cost
tph	Tons per hour
tpy	tons per year
TSS	Total suspended solids
$\mu g/m^3$	Micrograms per cubic meter
UPS	Uninterruptible Power Supply
ULSD	Ultra-Low Sulfur Diesel oil
U.S., US	United States
V	Volt
VFD	Variable Frequency Drive
VOC	Volatile Organic Compound
wg	Water gauge
wt%	Weight percent
WWTP	Waste Water Treatment Plant
°C	Degrees Celsius
°F	Degrees Fahrenheit

1 Concept Background

This section presents the concept background including the following:

- Coal-fired power plant scope description
- Plant production/facility capacity
- Plant location consistent with the NETL QGESS
- Business case from conceptual design

We also provide a discussion of the ability to meet specific design criteria and the proposed PFBC target levels of performance to round out this discussion.

1.1 Coal-Fired Power Plant Scope Description

The Advanced PFBC project team has adopted an alternate configuration utilizing an amine-based CO_2 capture system instead of the UOP Benfield capture system utilized in the Conceptual Design Phase (Phase 1) work. As such, with the exception of Section 1.4 (Business Case from Conceptual Design), the plant description and performance presented in this report are now for an amine-based CO_2 capture configuration. We present the amine-based configuration performance results in Section 4.

The proposed Coal-Based Power Plant of the Future concept is based on a pressurized fluidized bubbling bed combustor providing heat of combustion to a gas turbomachine (Brayton Cycle) and a steam generator providing steam to a steam turbine generator (Rankine Cycle) in parallel operation. The plant described is configured to fire Illinois No. 6 coal or fine, wet waste coal derived from CONSOL's bituminous coal mining operations in southwest Pennsylvania. Plant performance and operating characteristics will be evaluated separately for each design fuel, and certain plant components, such as the ash handling system, will be uniquely sized and optimized to accommodate each design fuel.

The offered technology is unique and innovative in this major respect: it has inherent fuel flexibility with the capability of combusting steam coal, waste coal, biomass, and opportunity fuels and has the ability to incorporate carbon capture while maintaining relatively high efficiency. Carbon capture may be added to a capture-ready plant configuration without major rework and with little interruption to the operation of the capture-ready plant. The essential feature of the capture-ready plant is the provision of additional space for housing the additional components, along with space for supporting auxiliaries (electrical cabinets, piping, etc.) The Base Case plant will be designed to fire Illinois No. 6 coal, while the Business Case plant will be designed to fire waste coal while also being fully capable of accommodating typical thermal coal products as well as co-firing up to 10% biomass.

The complete scope of the proposed power plant includes a fuel preparation plant co-located with the power generating plant. The power generation process is described in Section 1.4 and includes all necessary features to receive prepared fuel/sorbent mixture and fire this mixture to generate electricity and carbon dioxide as a co-product. The electric power generated is conveyed on a branch transmission line to the grid. The CO_2 is compressed for pipeline transport for storage or utilization. Both the Illinois No. 6 coal case and the Business Case assume that the CO_2 is compressed to 2215 psig for geologic storage; however, compression to a lower pressure may be possible depending upon the ultimate disposition (i.e., storage or utilization) of the CO_2.

The fuel preparation plant includes coal receiving and storage, limestone sorbent receiving and storage, and, optionally, biomass receiving and storage. Each of these materials are sized and mixed to form a paste with controlled water content (~26%) for firing in the PFBC power generating plant.

The PFBC power generating plant (Base Case-Illinois No. 6 Coal) includes an evaporative cooling tower heat sink, a water treatment facility to prepare several different levels of water quality for use in various parts of the power generating process, a waste water treatment facility to treat waste water streams for beneficial reuse within the complete facility (power generating plant or fuel preparation plant), and necessary administrative and maintenance facilities. The Business Case plant utilizes a dry air-cooled condenser for the steam turbine generator, but also includes a conventional evaporative cooling tower of reduced capacity for other heat loads that are better suited to a lower cooling water temperature. Both configurations include a Zero Liquid Discharge system to eliminate liquid discharges from the plant.

1.2 Plant Production / Facility Capacity

The plant production capacity for the PFBC plant is set primarily by the number of PFBC modules as the PFBC design is essentially fixed. The overall plant production capacity with four (4) PFBC modules firing Illinois No. 6 coal is set at a nominal 404 MWe net without CO_2 capture (but in complete capture ready configuration) and 308 MWe net with CO_2 capture operational at a rate of 97% of all CO_2 produced based on the amine capture system. When operating at this fully-rated capacity (308 MWe) the CO_2 available for delivery at the plant boundary is ~7700 tons/day of pure CO_2 mixed with small amounts of other gases.

The annual production of electricity for delivery to the grid is 2.34 million MWh at 85% capacity factor. The annual production of CO_2 for export at 85% capacity factor is 2.4 million tons/year.

The overall plant production capacity with four (4) PFBC modules firing waste coal and 5% biomass is set at a nominal 280 MWe net with CO_2 capture operational at a rate of 97% of all CO_2 produced based on the amine capture system. When operating at this fully-rated capacity (280 MWe) the CO_2 available for delivery at the plant boundary is ~7900 tons/day of pure CO_2 mixed with small amounts of other gases.

The annual production of electricity for delivery to the grid is 2.08 million MWh at 85% capacity factor. The annual production of CO_2 for export at 85% capacity factor is 2.4 million tons/year.

1.3 Plant Location Consistent with NETL QGESS

As discussed above, the Base Case PFBC plant was designed to fire Illinois No. 6 coal at a Midwestern site. However, the Business Case being considered by the project team would involve firing waste fuel available to CONSOL Energy in southwestern Pennsylvania. As such, we have developed separate designs for these two cases: (1) the Base Case based upon the Midwestern site and Illinois No. 6 coal and (2) the Business Case based upon the southwestern Pennsylvania (or northern West Virginia) site and wet, fine waste coal fuel and biomass. In documenting the site conditions and characteristics for plant location, we have followed the NETL QGESS [**1**] and have presented the site information in Section 3 of the Design Basis Report. Wherever possible, we have utilized available site information in lieu of generic information.

1.4 Business Case from Conceptual Design

The business case and underlying performance estimates and economics presented in this section, Section 1.4, are based on the work performed during the Conceptual Design Study phase of the project, which was completed in April-July 2019 and assumed that the Benfield Process was used for CO_2 capture. The project team has updated this information during the current pre-FEED study to reflect the best overall plant design, which is based on an amine-based CO_2 capture process. The Business Case based on the current pre-FEED study is presented in Section 7.

This business case presents the following:

- Market Scenario
- Market Advantage of the Concept

- Estimated Cost of Electricity Establishing the Competitiveness of the Concept

1.4.1 Market Scenario

The overall objective of this project is to design an advanced coal-fueled power plant that can be commercially viable in the U.S. power generation market of the future and has the potential to be demonstrated in the next 5-10 years and begin achieving market penetration by 2030. Unlike the current U.S. coal fleet, which was largely installed to provide baseload generation at a time when coal enjoyed a wide cost advantage over competing fuels and when advances in natural gas combined cycle, wind, and solar technologies had not yet materialized, the future U.S. coal fleet must be designed to operate in a much more competitive and dynamic power generation landscape. For example, during 2005-2008, the years leading up to the last wave of new coal-fired capacity additions in the U.S., the average cost of coal delivered to U.S. power plants ($1.77/MMBtu) was $6.05/MMBtu lower than the average cost of natural gas delivered to U.S. power plants ($7.82/MMBtu), and wind and solar accounted for less than 1% of total U.S. power generation. By 2018, the spread between delivered coal and natural gas prices ($2.06 and $3.54/MMBtu, respectively) had narrowed to just $1.48/MMBtu, and renewables penetration had increased to 8% [**2**]. EIA projects that by 2030, the spread between delivered coal and natural gas prices ($2.22/MMBtu and $4.20/MMBtu, respectively, in 2018 dollars) will have widened marginally to $1.98/MMBtu, and wind and solar penetration will have approximately tripled from current levels to 24% [**3**].

In this market scenario, a typical new advanced natural gas combined cycle (NGCC) power plant without carbon dioxide capture would be expected to dispatch with a delivered fuel + variable operating and maintenance (O&M) cost of $28.52/MWh (assuming a 6,300 Btu/kWh HHV heat rate and $2.06/MWh variable cost) and could be built for a total overnight cost of <$1,000/kWe (2018$) [**4**]. By comparison, a new ultra-supercritical pulverized coal-fired power plant would be expected to dispatch at a lower delivered fuel + variable O&M cost of ~$24.14/MWh (assuming an 8,800 Btu/kWh HHV heat rate and $4.60/MWh variable cost), but with a capital cost that is about four times greater than that of the NGCC plant [**5**]. The modest advantage in O&M costs for the coal plant is insufficient to outweigh the large disparity in capital costs vs. the NGCC plant, posing a barrier to market entry for the coal plant. This highlights the need for advanced coal-fueled power generation technologies that can overcome this barrier and enable continued utilization of the nation's valuable coal reserve base to produce affordable, reliable, resilient electricity.

Against this market backdrop, we believe that the commercial viability of any new coal-fueled power generation technology depends strongly upon the following attributes: (1) excellent environmental performance, including very low air, water, and waste emissions (to promote public acceptance and alleviate permitting concerns), (2) lower capital cost relative to other coal technologies (to help narrow the gap between coal and natural gas capex), (3) significantly lower O&M cost relative to natural gas (to help offset the remaining capital cost gap vs. natural gas and ensure that the coal plant is favorably positioned on the dispatch curve across a broad range of natural gas price scenarios), (4) operating flexibility to cycle in a power grid that includes a meaningful share of intermittent renewables (to maximize profitability), and (5) ability to incorporate carbon capture with moderate cost and energy penalties relative to other coal and gas generation technologies (to keep coal as a competitive dispatchable generating resource in a carbon-constrained scenario). These are generally consistent with or enabled by the traits targeted under DOE's Coal-Based Power Plants of the Future program (e.g., high efficiency, modular construction, near-zero emissions, CO_2 capture capability, high ramp rates and turndown capability, minimized water consumption, integration with energy storage and plant value streams), although our view is that the overall cost competitiveness of the plant (capital and O&M) is more important than any single technical performance target. In addition, the technology must have a relatively fast timeline to commercialization, so that new plants can be brought online in time to enable a smooth transition from the existing coal fleet without compromising the sustainability of the coal supply chain.

Pressurized fluidized bed combustion (PFBC) provides a technology platform that is well-suited to meet this combination of attributes. A base version of this technology has already been commercialized, with units currently operated at three locations worldwide: (1) Stockholm, Sweden (135 MWe, 2 x P200, subcritical, 1991 start-up), (2) Cottbus, Germany (80 MWe, 1 x P200, subcritical, 1999 start-up), and (3) Karita, Japan (360 MWe, 1 x P800, supercritical, 2001 start-up). These installations provide proof of certain key features of the technology, including high efficiency (the Karita plant achieved 42.3% net HHV efficiency using a supercritical steam cycle), low emissions (the Vartan plant in Stockholm achieved 98% sulfur capture without a scrubber and 0.05 lb/MMBtu NOx emissions using only SNCR), byproduct reuse (ash from the Karita PFBC is used as aggregate for concrete manufacture), and modular construction. Several of these installations were combined heat and power plants. This also highlights the international as well as domestic market applicability of the technology.

The concept proposed here builds upon the base PFBC platform to create an advanced, state-of-the-art coal-fueled power generation system. Novel aspects of this advanced PFBC technology include: (1) integration of the smaller P200 modules with a supercritical steam cycle to maximize modular construction while maintaining high efficiency, (2) optimizing the steam cycle, turbomachine, and heat integration, and taking advantage of advances in materials and digital control technologies to realize improvements in operating flexibility and efficiency, (3) integrating carbon dioxide capture, and (4) incorporating a new purpose-designed gas turbomachine to replace the earlier ABB (Alstom, Siemens) GT35P machine.

In addition, while performance estimates and economics are presented here for a greenfield Midwestern U.S. plant taking rail delivery of Illinois No. 6 coal, as specified in the Common Design Basis for Conceptual Design Configurations, the most compelling business case for the PFBC technology arises from taking advantage of its tremendous fuel flexibility to use fine, wet waste coal as the fuel source. The waste coal, which is a byproduct of the coal preparation process, can be obtained either by reclaiming tailings from existing slurry impoundments or by diverting the thickener underflow stream (before it is sent for disposal) from actively operating coal preparation plants. It can be transported via pipeline and requires only simple mechanical dewatering to form a paste that can be pumped into the PFBC combustor. There is broad availability of this material, with an estimated 34+ million tons produced each year by currently operating prep plants located in 13 coal-producing states, and hundreds of millions of tons housed in existing slurry impoundments. CONSOL's Bailey Central Preparation Plant in Greene County, PA, alone produces close to 3 million tons/year of fine coal refuse with a higher heating value of ~7,000 Btu/lb (dry basis), which is much more than sufficient to fuel a 300 MW net advanced PFBC power plant with CO_2 capture. This slurry is currently disposed of at a cost. As a result, it has the potential to provide a low- or zero-cost fuel source if it is instead used to fuel an advanced PFBC power plant located in close proximity to the coal preparation plant. Doing so also eliminates an environmental liability (slurry impoundments) associated with the upstream coal production process, improving the sustainability of the overall coal supply chain.

1.4.2 Market Advantage of the Concept

The market advantage of advanced PFBC relative to other coal-fueled generating technologies, then, stems from its unique ability to respond to all five key attributes identified above, while providing a rapid path forward for commercialization. Specifically, based on work performed during the Conceptual Design Phase:

1. Excellent Environmental Performance – The advanced PFBC is able to achieve very low NOx (<0.05 lb/MMBtu) and SO_2 (<0.117 lb/MMBtu) emission rates by simply incorporating selective non-catalytic reduction and limestone injection at pressure within the PFBC vessel itself. After incorporation of an SO_2 polishing step before the CO_2 capture process, the SO_2 emissions will be <0.03 lb/MMBtu or <0.256 lb/MWh. As mentioned above, the PFBC can also significantly improve the environmental footprint of the upstream coal mining process if it uses fine, wet waste coal as a fuel source, and it produces a dry solid byproduct (ash) having potential commercial applications.
2. Low Capital Cost – The advanced PFBC in carbon capture-ready configuration can achieve >40% net HHV efficiency at normal supercritical steam cycle conditions, avoiding the capital expense associated with the exotic materials and thicker walls needed for higher steam temperatures and pressures. Significant capital savings are also realized because NOx and SO_2 emission targets can be achieved without the need for an SCR or FGD. Finally, the P200 is designed for modular construction and replication based on a single, standardized design, enabling further capital cost savings.
3. Low O&M Cost – By fully or partially firing fine, wet waste coal at low-to-zero fuel cost, the advanced PFBC can achieve dramatically lower fuel costs than competing coal and natural gas plants. This is especially meaningful for the commercial competitiveness of the technology, as fuel cost (mine + transportation) accounts for the majority (~2/3) of a typical pulverized coal plant's total O&M cost, and for an even greater amount (>80%) of its variable (dispatch) cost. [**6**]
4. Operating Flexibility – The advanced PFBC plant includes four separate P200 modules that can be run in various combinations to cover a wide range of loads. Each P200 module includes a bed reinjection vessel to provide further load-following capability, enabling an operating range from <20% to 100%. A 4%/minute ramp rate can be achieved using a combination of coal-based energy and natural gas co-firing.
5. Ability to Cost-Effectively Incorporate Carbon Capture – The advanced PFBC produces flue gas at 11 bar, resulting in a greater CO_2 partial pressure and considerably smaller gas volumes relative to atmospheric boilers. The smaller volume results in smaller physical sizes for equipment. The higher partial pressure of CO_2 provides a greater driving force for CO_2 capture and can enable the use of the commercially-available Benfield CO_2 capture process, which has the same working pressure as the PFBC boiler. However, during this pre-FEED study, it was determined that an amine-based system operating at atmospheric pressure to capture CO_2 from the flue gas provides a more cost-effective overall design, even considering the specific process advantages of the Benfield process, due to the unrecoverable losses in temperature and pressure encountered when integrating the Benfield process with the PFBC gas path. In addition, because of the fuel flexibility afforded by the advanced PFBC boiler, there is also an opportunity to co-fire biomass with coal to achieve carbon-neutral operation.

The timeline to commercialization for advanced PFBC is expected to be an advantage relative to other advanced coal technologies because (1) the core P200 module has already been designed and commercially proven and (2) the main technology gaps associated with the advanced PFBC plant, including integration of carbon capture, integration of multiple P200 modules with a supercritical steam cycle, and development of a suitable turbomachine for integration with the PFBC gas path, are considered to be well within the capability of OEMs using existing materials and technology platforms. The concept of firing a PFBC with fine, wet waste coal (thickener underflow) was demonstrated in a 1 MWt pilot unit at CONSOL's former Research & Development facility in South Park, PA, both without CO_2 capture (in 2006-2007) and with potassium carbonate-based CO_2 capture (in 2009-2010), providing evidence of its feasibility. We believe that the first-generation advanced PFBC plant, capable of achieving ≥40% HHV efficiency in CO_2 capture-ready configuration or incorporating 90% CO_2 capture (increased to 97% in the pre-FEED study) and compression with ≤22% energy penalty, would be technically ready for commercial-scale demonstration in the early 2020s. We propose to evaluate CONSOL's Bailey Central Preparation Plant as a potential source of fuel (fine, wet waste coal) and potential location for this demonstration plant. Additional R&D in the areas of process optimization, turbomachine design, and advanced materials could enable a ≥4% efficiency point gain in Nth-of-a-kind plants and an approximately four percentage point improvement in the energy penalty associated with CO_2 capture, although it will likely only make sense to pursue efficiency improvement pathways that can be accomplished while maintaining or reducing plant capital cost.

1.4.3 Estimated Cost of Electricity Establishing the Competitiveness of the Concept

A summary of the estimated COE for the base case advanced PFBC with CO_2 capture is presented in Exhibit 1-1, again based on work performed during the Conceptual Design Study. These estimates are preliminary in nature and will be revised via a much more detailed analysis as part of the pre-FEED study. As discussed above, our base case economic analysis assumes a first-generation advanced PFBC plant constructed on a greenfield Midwestern U.S. site that takes rail delivery of Illinois No. 6 coal, as specified in the Common Design Basis for Conceptual Design Configurations. Capital cost estimates are in mid-2019 dollars and were largely developed by Worley Group, Inc. by scaling and escalating quotes or estimates produced under previous PFBC studies and power plant projects. Costs for coal and other consumables are based on approximate current market prices for the Midwestern U.S.: the delivered coal cost of $50/ton includes an assumed FOB mine price of $40/ton plus a rail delivery charge of $10/ton. For purposes of this conceptual estimate, it was assumed that PFBC bed and fly ash are provided for beneficial reuse at zero net cost/benefit. Also, because our Conceptual Design base plant design includes 90% CO_2 capture, we have assumed that the captured CO_2 is provided for beneficial use or storage at a net credit of $35/ton of CO_2, consistent with the 2024 value of the Section 45Q tax credit for CO_2 that is stored through enhanced oil recovery (EOR) or beneficially reused. Otherwise, the cost estimating methodology used here is largely consistent with that used in DOE's "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 3, July 6, 2015 [**7**][a]." The first-year cost of electricity (COE) values presented in Exhibit 1-1 are based on an 85% capacity factor (see discussion below) and 12.4% capital charge factor (CCF), consistent with the DOE bituminous baseline report assumption for high-risk electric power projects with a 5-year capital expenditure period.

To better understand the potential competitiveness of the advanced PFBC technology, preliminary estimates for three other cases are also summarized in Exhibit 1-1: (1) a carbon capture-ready PFBC plant based on current technology firing Illinois No. 6 coal, (2) a carbon capture-ready PFBC plant based on advanced technology (4-point efficiency improvement + 15% reduction in capital cost) firing fine, wet waste coal, and (3) a PFBC plant with 90% CO_2 capture based on advanced technology (same as above, plus 4-point reduction in CO_2 capture energy penalty) firing fine, wet waste coal. Use of waste coal in cases (2) and (3) is assumed to result in a fuel cost of $10/ton as compared to $50/ton in the base case. (This cost could be even lower depending on proximity to the waste coal source, commercial considerations, etc.; a revised assumption will be developed as part of the pre-FEED phase.) The improvements in efficiency are assumed to be achieved through process optimization and resolution of the technology gaps identified above and later in this report. The improvements in capital cost are assumed to be achieved through process optimization, adoption of modular construction practices, and learning curve effects.

[a] The reference to the 2015 version of the NETL Bituminous Baseline report was the latest version at the time of the Phase I conceptual report. References to the 2019 Bituminous Baseline report are made for the current pre-FEED work.

Exhibit 1-1. Cost of Electricity Projections for Advanced PFBC Plant Cases from Conceptual Design Study – Benfield Process

	Base Case: IL No. 6 coal 90% capture current tech	Case #1 IL No. 6 coal capture-ready current tech	Case #2 fine waste coal capture-ready advanced tech	Case #3 fine waste coal 90% capture advanced tech
Net HHV efficiency	31%	40%	44%	36%
Total Overnight Cost ($/kW)	$5,725	$3,193	$2,466	$4,189
Total Overnight Cost ($/MWh)	$95.33	$53.17	$41.07	$69.76
Fixed O&M Cost ($/MWh)	$24.34	$18.08	$16.44	$20.96
Fuel Cost ($/MWh)	$23.57	$17.93	$3.26	$4.06
CO_2 Credit ($/MWh)	($36.48)	--	--	($31.42)
Variable O&M Cost ($/MWh)	$10.16	$7.73	$7.03	$8.75
TOTAL COE ($/MWh)	$116.92	$96.91	$67.80	$72.12

Note: Data above are based on the Benfield CO_2 capture process, as presented in Conceptual Design Report.

Based on the initial projections from the Conceptual Design Phase in Exhibit 1-1, it is possible to highlight several competitive advantages of the advanced PFBC technology vs. other coal-fueled power generation technologies. First, although capital costs are expected to present a commercial hurdle for all coal-based technologies relative to natural gas-based technologies, the total overnight cost (TOC) range of $2,466/kW to $3,193/kW presented above for a capture-ready PFBC plant compares favorably with the expected TOC of ~$3,600/kW for a less-efficient new supercritical pulverized coal plant [**8**]. Second, the fuel flexibility of the PFBC plant provides an opportunity to use fine, wet waste coal to achieve dispatch costs that are expected to be substantially lower than those of competing coal and natural gas-based plants. As illustrated by Cases #2-3, a PFBC plant firing $10/ton waste coal is expected to achieve total fuel + variable O&M costs of $10-13/MWh, far better than the $24-29/MWh range for ultra-supercritical coal and natural gas combined cycle plants cited in the 2030 market scenario above. This should allow a PFBC plant firing waste coal to dispatch at a very high capacity factor, improving its economic viability. Finally, with a $35/ton credit for CO_2, and assuming a net zero-cost CO_2 offtake opportunity can be identified, the COE for an advanced PFBC plant with 90% CO_2 capture is expected to be reasonably similar to the COE for a capture-ready plant. We anticipate that the economics and performance of a first-generation PFBC plant with 90% CO_2 capture will fall between those presented in the Base Case and Case #3 above. A major objective of the project team moving forward will be to drive down COE through value engineering utilizing a combination of (i) process design and technology optimization and (ii) optimization of fuel sourcing and CO_2 offtake.

1.5 Ability to Meet Specific Design Criteria

The ability of the proposed plant design to meet the specific design criteria (as spelled out on p. 116 of the original Solicitation document) is described below:

- The PFBC plant is capable of meeting a 4% ramp rate using a combination of coal-based energy and co-fired natural gas energy up to 30% of total Btu input. Higher levels of natural gas firing may be feasible and can be evaluated. The PFBC design incorporates a bed reinjection vessel inside the main pressure vessel that stores an inventory of bed material (fuel and ash solids) during steady state operation. When a load increase is called for, this vessel reinjects a portion of its inventory back into the active bed to supplement the bed inventory. Natural gas co-firing using startup lances, over-bed firing, or a combination thereof is used to supplement the energy addition to the fluid bed to support the additional steam generation that supports the increase in power generation during the up-ramp transient. During down-ramp excursions, the bed reinjection vessel can take in some of the bed inventory to assist in maintaining the heat transfer requirements. Coal flow is reduced during a down-ramp transient. Steam bypass to the condenser may also be used in modulating a down-ramp transient.
- The PFBC plant requires 8 hours to start up from cold conditions on coal. Startup from warm conditions requires from 3 to 6 hours, depending on the metal and refractory temperatures existing when a restart order is given. Startup from hot conditions (defined as bed temperature at or near 1500 °F, and main steam pipe temperature above approximately 800 °F) requires less than 2 hours on coal; this time is reduced to approximately 1 to 2 hours with natural gas co-firing. It should be noted that very short startup times are not compatible with use of a supercritical steam cycle with high main and reheat steam design temperatures. There are two compelling factors that work against very fast starts for this type of steam cycle: first are the severe secondary stresses induced in heavy wall piping and valves necessary for supercritical steam conditions. Longer warmup times are necessary to avoid premature material failures and life-limiting changes in the pressure part materials for the piping, valves, and high-pressure turbine components. The second limiting factor on rapid startup times is the feed water chemistry limitation inherent in supercritical steam cycles. After a complete shutdown, condensate and feed water chemistry typically requires some length of time to be returned to specification levels. Assuring long material life and preventing various kinds of corrosion mechanisms from becoming an issue requires that water chemistry be brought to the proper levels prior to proceeding with a full startup from cold, no-flow conditions. Resolution of this entire bundle of issues could be viewed as a “Technology Gap” of sorts, requiring investigation to determine if realistic, cost-effective remedies can be developed.
- The PFBC can turn down to the required 20% load and below by reducing the number of modules in operation. A 20% power level can be achieved by operating one of four P200 modules at approximately 80% load or two modules at about 40% load each. Operation is expected at full environmental compliance based on known previous operational experience.
- The PFBC technology described employs 97% CO_2 capture, but it can also be offered as fully CO_2 capture-ready without the capture equipment installed. The addition (construction) of the CO_2 capture equipment may be performed while the plant is in operation without interference, and the switch-over to CO_2 capture, after construction is completed, can be made by opening/closing specific valves to make the transition while at power. This is accomplished one PFBC module at a time to minimize any impacts on system operation.
- The proposed PFBC plant will incorporate a Zero Liquid Discharge system. The power plant portion of the facility will be integrated with the fuel preparation portion of the facility to incorporate internal water recycle and to reuse water to the maximum extent. This will minimize the capacity, and thereby the cost, of any required zero liquid discharge (ZLD) system.
- Solids disposal is characterized by two major streams of solids: bed ash and cyclone and filter ash. The ash material has mild pozzolanic properties, and it may be landfilled or used in a beneficial way to fabricate blocks or slabs for landscaping or light-duty architectural applications. The ash products are generally non-leachable as demonstrated by PFBC operations in Sweden and Japan.

- Dry bottom and fly ash discharge: PFBC ash (both bed and fly ash) is dry. Discharge is made through ash coolers that provide some heat recovery into the steam cycle condensate stream. The cooled ash is discharged into ash silos and then off-loaded into closed ash transport trucks for ultimate disposal or transport to a facility for use in manufacture of saleable end products, as noted above.
- Efficiency improvement technologies applicable to the PFBC will include neural network control features and learning models for plant controls balancing air supply against fuel firing rate (excess air), ammonia injection for SNCR, balancing bed performance against the performance of the caustic polishing scrubber for removing sulfur, and other opportunities to optimize overall performance.
- The limitation of air heater outlet temperatures is not applicable to PFBC technology.
- High-efficiency motors will be used for motor-driven equipment when and where applicable. Electric generators will be specified to be constructed to state-of-the-art efficiency standards.
- Excess air levels will be maintained at appropriate levels to optimize the operation of the overall PFBC Brayton and Rankine cycles, and the sulfur capture chemical reactions in the bubbling bed. A 12% excess air limit may or may not be applicable to this technology. Further evaluation is required. The excess air for the base design case is 16%. The PFBC technology does not include any component similar to a PC or CFB boiler air heater. However, attempts will be made to minimize leakage of hot gas that could result in loss of recoverable thermal energy.
- The consideration of sliding pressure vs. partial arc admission at constant throttle pressure will be made during the Phase 3 FEED study.
- A self-cleaning condenser has been employed for the steam cycle of Cases 1A and 1B. This is not applicable to the air cooled condenser used in Cases 2B and 2C. The attainment of consistent 1.5 in Hg backpressure is achievable on an annual average basis for the proposed Midwest site location. However, summer peak backpressures are likely to reach 2.0 inches or more. This is a consequence of the statistically highly probable occurrence of high ambient wet bulb temperatures above 70 °F. Using aggressive design parameters for the heat sink, including a 5 °F terminal temperature difference for the condenser, a 7 or 8 °F cooling tower approach, and a 17 or 18 °F range for the circulating water system results in a condensing temperature of at least 99 or 100 °F at 70 °F ambient wet bulb temperature, which corresponds to a backpressure of 2.0 in Hga. Therefore, any time ambient wet bulb temperatures exceed 70 °F, the back pressure will exceed 2.0 in Hga. A back pressure of 1.5 in Hga (in the summer above 70 °F wet bulb temperature) might be maintained by use of a sub-dew point cooling tower technology. This is a relatively new innovation that promises to reduce the cooling water temperature produced by an evaporative cooling tower by adding the necessary components of the sub-dew point system to a relatively conventional evaporative cooling tower. Although the efficacy of the system to reduce cold water temperatures produced by an evaporative tower appears theoretically sound, the full economics of employing this type of system remain to be demonstrated in a commercial setting.
- When CO_2 capture is employed, additional sulfur capture is required ahead of the capture process. This additional polishing step reduces sulfur emissions to a level characterized by greater than 99.75% removal.
- Other low-cost solutions are being evaluated as applicable during this pre-FEED study.

1.6 Proposed PFBC Target Level of Performance for the Base Case (Illinois No. 6)

This section presents information on the following topics.

- Expected Plant Efficiency Range at Full and Part Load
- Emissions Control Summary

- CO_2 Control Strategy

1.6.1 Expected Plant Efficiency Range at Full and Part Load

The expected plant efficiency at full load for a CO_2 capture-ready advanced PFBC plant is shown in Exhibit 1-2 as a function of total plant capacity. (Note that information is presented with the amine configuration for various plant sizes, which vary according to the number of P200 modules installed.) The proposed PFBC technology is modular and couples to steam turbine generators of varying size. The efficiency varies with the size of the plant, as the selected steam conditions will vary. For almost a century of progress in the development of steam turbine cycles and equipment, the selected steam turbine throttle and reheat conditions have shown a strong correlation to size, as expressed in the table below. This is based on well-established design principles arrived at by the collective experience of turbine generator manufacturers. The steam temperatures are selected to be somewhat aggressive to maximize efficiency.

Exhibit 1-2. Output and Efficiency for Modular PFBC Designs for Various Installed Capacity Plants (Capture Ready – Amine Configuration)

No. of P200 Modules Installed	Total Installed Unit Output, MWe, net	Efficiency, HHV	Steam Cycle Parameters
1	88	37.0	1600/1025/1025
2	185	39.0	2000/1050/1050
3	285	40.0	2400/1075/1075
4	404	42.5%	3500/1100/1100

Note: The 4-module plant is selected as the case described in the remainder of this report.

Part-load efficiency for the 4 x P200 advanced PFBC plant in CO_2 capture-ready configuration is presented in Exhibit 1-3. The values in the exhibit reflect the PFBC plant operating with the indicated number of P200 modules at the stated load.

Exhibit 1-3. Part Load Efficiency Table for 4 x P200 PFBC Plant (Capture Ready – Amine Configuration)

Percent Load	No. Modules in Operation	MWe, net	Estimated Efficiency %, net, HHV
100	4	404	42.5%
80	4	323	40.7
60	3	242	39.4
40	2	162	37.1
20	1	81	32.0

The reduction in efficiency at part load will vary depending on how the plant is operated. Detailed modeling is required to estimate accurate impacts on thermal efficiency at part load. For example, the impact with 4 x P200 modules operating at 50% load may be different from the result obtained with only 2 x P200 modules operating at 100% load for a total plant output of 50%. Detailed definition of plant performance under these conditions will be evaluated in the Phase 3 FEED study.

For cases involving the addition of CO_2 capture to the completely capture-ready plant, two scenarios are presented below. Exhibit 1-4 shows different levels of CO_2 capture for the 4 x P200 module plant. Each case is based on applying the amine technology at a 97% capture rate to one, two, three, or all four P200 PFBC modules (the Conceptual Design Report used 90% and Benfield technology). These cases are all at full load for each module and for the entire plant.

The first efficiency column ("Current State-of-the-Art") presents estimated efficiency values for the configuration described in the Block Flow Diagram (BFD) in Exhibit 4-4. This configuration is based on currently available materials of construction, design experience, and practices. The second efficiency column ("Advanced State-of-the-Art") is based on resolution of the Technology Gap (Section 6.5.2.2 Improved Steam Cycle Conditions) identified in Section 6.5 "Technology Development Pathway Description" in this Report. The principal advance that would contribute to the higher efficiency levels is the use of advanced steam cycle alloys allowing use of the higher steam temperatures, including the use of double reheat.

Exhibit 1-4. Efficiency with CO_2 Capture for 4 x P200 PFBC Plant (Amine Configuration)

No. of Modules with Capture	% Capture, Total Plant	Estimated Efficiency, %, HHV, Current State-of-the-Art	Estimated Efficiency, %, HHV, Advanced State-of-the-Art
0	0	42.5	>44%
1	24.25	40.0	42
2	48.5	37.5	40
3	72.75	34.9	38
4	97.0	32.4	36

1.6.2 Emissions Control Summary

Air emissions for the PFBC technology are dependent on the coal and/or supplementary fuels fired. For the Illinois No. 6 coal, targeted emissions are presented in Exhibit 1-5. For the waste coal/biomass case, targeted emissions are presented in Exhibit 1-6. For different fuels and different sites, which may have widely varying emissions limits, additional measures may be required to meet these more stringent limits. The control of emissions to the limits stated in the DOE solicitation is accomplished as follows.

SO_2 is controlled by capture of sulfur in the pressurized bubbling bed. Limestone sorbent is incorporated in the fuel paste feed. The calcium in the limestone reacts with the sulfur in the coal to form calcium sulfate; the high partial pressure of oxygen in the pressurized bed assures that the material is sulfate (fully oxidized form) instead of sulfite. The design will achieve 90% capture in the bed at a calcium to sulfur (Ca/S) ratio of 2.5. In addition, a polishing step is added to the gas path to achieve a nominal overall 99.8% reduction of sulfur in the gas. The SO_2 reacts with NaOH in the polishing scrubber to form sodium bisulfite ($NaHSO_3$). Some SO_2 can react to form sodium sulfite (Na_2SO_3). This waste stream will be ultimately routed to the ZLD. The addition of the caustic scrubbing polishing step is driven by the limitation of sulfur in the gas feed to the CO_2 capture process as well as for HCl removal in the capture ready case. This has the added advantage of reducing SO_2 in the stack gas which makes the air permitting process easier, and also reduces limestone consumption and costs. The optimal value of total costs for limestone and caustic is expected to be in the range of the parameters described.

Exhibit 1-5. Expected Emissions for P200 Module Firing Illinois No. 6 Coal (Cases 1A / 1B)

Pollutant	DOE Target, lb/MWh	Stack Effluent, lb/MWh	Control Technology / Comments
SO_2	1.00	0.07 (1A) 0.08 (1B)	Target is achievable with 90% capture in-bed and added NaOH polishing step (with 98% removal). No removal by the CO_2 capture system is reflected.
NOx	0.70	0.39 (1A) 0.45 (1B)	Catalyst not required. Target is achievable with SNCR. No removal by the CO_2 capture system is reflected.
PM (filterable)	0.09	0.02	Cyclones and metallic filter will achieve target. Metallic filter is required to protect the turbomachine.
Hg	3×10^{-6}	1.8×10^{-6} (1A) 2×10^{-6} (1B)	Particulate removal and caustic scrubber will meet target. GORE® mercury removal system can be added if required.
HCl	0.010	<0.005	Cl capture of 99.5% plus is required based on the high Illinois No. 6 Cl content. Target is achieved primarily by the caustic scrubber with some Cl retention in the ash.

Exhibit 1-6. Expected Emissions for P200 Module Firing Waste Coal/biomass (Case 2C)

Pollutant	DOE Target, lb/MWh	Stack Effluent, lb/MWh	Control Technology / Comments
SO_2	1.00	0.07	Target is achievable with 90% capture in-bed and added NaOH polishing step (with 98% removal). No removal by the CO_2 capture system is reflected.
NOx	0.70	0.47	Catalyst not required. Target is achievable with SNCR. No removal by the CO_2 capture system is reflected.
PM (filterable)	0.09	0.05	Cyclones and metallic filter will achieve target. Metallic filter is required to protect the turbomachine.
Hg	3×10^{-6}	2.1×10^{-6}	Particulate removal, wet caustic scrubbing and the GORE® mercury removal system will be utilized to meet the target.
HCl	0.010	<0.002	Cl capture of 99.5% plus is required based on the high Illinois No. 6 Cl content. Target is achieved primarily by the caustic scrubber with some Cl retention in the ash.

The bed functions at a constant 1550 °F temperature, a temperature at which the NOx forming reactions are very slow (kinetically) and do not lead to any meaningful thermal NOx production. NOx that is formed is largely a product of fuel-bound nitrogen, as thermal NOx creation is minimized. The use of selective non-catalytic reduction (SNCR) reduces any NOx to very low levels (< 0.05 lb/MM Btu). The small amount of ammonia (NH3) slip from the SNCR will be removed in the NaOH scrubber prior to reaching the amine scrubbing process and/or the plant stack

In this version of the PFBC technology, a metallic filter is used to capture particulate matter (PM). The gas path leaving the PFBC vessel first encounters two stages of cyclones, which remove approximately 98% of the PM. The metallic filter removes over 99.5% of the remaining PM, resulting in very low PM emissions. This also enables the gas to be expanded in conventional gas expanders, and then after heat recovery, to be reacted with CO_2 capture solvent. The use of special expander materials and airfoil profiles is not required.

The fate of Hg and Cl requires detailed evaluation in the Phase 3 FEED study. However, at this time, the following rationale is offered in support of our belief that these elements will be controlled to within regulatory limits particularly for the CO_2 capture-equipped case. A significant portion of the Hg and Cl will be reacted to form a solid compound and will be captured by the two stages of cyclones inside the PFBC vessel and the metallic gas filter (external to the vessel) operating at 99.5% plus efficiency. That leaves Hg and Cl in the vapor phase in solution or as elemental species. The gas will pass in succession through the following:

1. A sulfur polishing stage using an alkaline solvent such as sodium hydroxide
2. A mercury removal system for removal of elemental Hg
3. The CO_2 capture absorber vessel

It is believed that the two stages of scrubbing and the mercury removal system, in series, will capture a very high percentage of the Hg and Cl that remained in the gas after the cyclone/filter stages.

1.6.3 CO_2 Control Strategy

The initial CO_2 capture strategy employed for the proposed advanced PFBC plant was to couple the Benfield process with the P200 gas path to capture CO_2 at elevated pressure and reduced temperature. Regenerative reheating of the gas was utilized to recover most of the thermal energy in the gas to maximize energy recovery and improve thermal efficiency. However, it was determined during the performance results generation process that using an amine-based system operating at 1 atmosphere pressure on the back end of the flue gas path yielded higher plant efficiency with reduced impact on plant capital costs. The CO_2 capture is applied in a modular manner, so that the quantity of CO_2 captured may be tailored to the needs of each specific project. Performance is presented for a 97% capture case (again, the Conceptual Design Report used 90%). For this 97% capture case, each P200 PFBC module is coupled to a separate amine process train for CO_2 capture. The system for CO_2 compression and drying utilizes two 50% capacity (relative to 100% plant capacity) component trains; therefore, each train serves two P200 PFBC modules.

As mentioned above, the project team evaluated a PFBC configuration based on the amine process and has adopted this process for completion of the remaining scope of work.

2 PFBC Process Description

The PFBC process developed in this pre-FEED study was originally based on the UOP Benfield CO_2 capture system utilized in the work from the Conceptual Design Study phase. The project team also evaluated an alternate configuration utilizing an amine-based CO_2 capture system instead of the UOP Benfield capture system. The PFBC process description herein is presented for both the Benfield- and amine-based configurations. We briefly discuss both configurations and provide a high-level comparison. The PFBC project team has evaluated the pros and cons of these options during this Pre-FEED work and has selected the amine-based carbon capture system for project development.

2.1 Preliminary Benfield and Amine Comparison

Exhibit 2-1 presents the pros and cons of PFBC configurations based on either the Benfield CO_2 capture or the amine CO_2 capture systems.

Exhibit 2-1. Pros & Cons of Benfield vs Amine Capture-Based Configurations

Configuration	Pros	Cons
Benfield	• Lower regeneration energy requirement. • Lower Electric auxiliary load • Lower annual solvent cost • Slightly lower CO_2 compression power since CO_2 starts at a slightly higher pressure.	• Lost Gas Turbine generation due to reduced gas turbine inlet temperature (TIT) • Lost Steam Turbine generation due to reduced GT outlet temperature resulting from the reduced TIT (no heat recovery from the gas path after expansion). • Added gas path delta P (additional HX to drop gas T to ~720°F) • Loss of CO_2 expansion power in gas turbine • The CO_2 capture occurs at ~ 11 bar, while the CO_2 is stripped at 2 bar. Thus significant CO_2 compression power is still required in spite of starting with the high pressure combustion products. • Requires regenerative gas cooling prior to the SO_2 and CO_2 removal, and subsequent reheating prior to gas expansion.
Amine	• Increased Gas Turbine generation due to higher gas TIT • Increased GT outlet temperature resulting from the increased TIT. • Minimized added gas path delta P retains CO_2 expansion power in gas turbine • The CO_2 capture and liberation occurs at approximately atmospheric pressure. CO_2 pressure change losses are minimized. • Net Generation is expected to be 6 to 9% higher than the Benfield configuration for the capture-ready and capture-equipped cases respectively. This is partly the result of the CO_2 capture in the amine case being after the gas expander. Thus the CO_2 can produce power in the expander.	• Higher regeneration energy requirement. • Higher electric auxiliary load • Higher annual solvent cost • Slightly higher CO_2 compression power since CO_2 starts at slightly lower pressure.

The original concept evaluated for CO_2 capture with the PFBC was based on utilization of the UOP Benfield potassium carbonate solution. The use of an amine-based process had been viewed as potentially too detrimental to overall thermal efficiency. However, a number of recent developments have caused a reappraisal of the CO_2 capture process, including reduced amine regeneration duties as reflected by the latest DOE Baseline report [**16**], along with commercial availability of a high-temperature metallic filter, which appear to offer significant thermal performance benefits. In addition, more complete modeling of the PFBC gas path with the addition of the Benfield process indicated the compounding effects of the losses noted in the table above (lower TIT, higher gas path delta P, and loss of CO_2 expansion power). Work performed as part of the Phase 2 pre-FEED study confirmed that, absent additional technology advances, the amine-based approach appears to be best-suited for integration with PFBC after considering the performance differentials and the CAPEX and OPEX differences between the application of the two CO_2 capture processes.

2.2 Proposed Plant Process Description

This section summarizes the Amine-based configuration in Section 2.2.1 and the Benfield-based configuration in Section 2.2.2.

2.2.1 Amine-Based Configuration

An alternative configuration for the Coal-Based Power Plant of the Future uses an amine-based CO_2 capture technology. This system is also based on a pressurized fluidized bubbling bed combustor providing heat of combustion to a gas turbomachine (Brayton Cycle) and a steam generator providing steam to a steam turbine generator (Rankine Cycle) in parallel operation. The plant is configured to fire most coals, including Illinois No. 6 coal and virtually any other carbonaceous fuel, including bituminous coal waste and biomass.

The bubbling bed combustor operates at elevated pressure of approximately 12 bar in the P200 module. This pressure enhances the combustion and sulfur capture reactions in the fluidized bed due to the elevated partial pressure of the reactants. Earlier versions of this technology that are not carbon capture-ready incorporated some feed water heating for the Rankine cycle by utilizing waste heat from the turbomachine exhaust. This feature is retained in the amine-based carbon capture-equipped or capture-ready versions of the technology.

The pressurized fluid bed is contained inside a pressure vessel that also encloses steam generating boiler tube surfaces. The combustion gases provide heat transfer to the steam generating surfaces for feed water/steam heating in a once-through type steam generator. The heated gas exits the pressure vessel at elevated pressure and temperature (11 bar/1500 ºF) after two stages of cyclones to pass through a high-efficiency metallic filter, and then (in the capture-ready case) on to a gas turbomachine expander.

The system is presented in a series of three block diagrams. A block diagram of the gas path for the integrated PFBC system in CO_2 capture-ready configuration is presented in Exhibit 2-2. The system with CO_2 capture installed is shown in Exhibit 2-3. Exhibit 2-4 presents the steam cycle as it relates to the PFBC vessel and gas turbomachines.

Exhibit 2-2. PFBC without CO_2 Capture (Capture-Ready Configuration, Amine-Based)

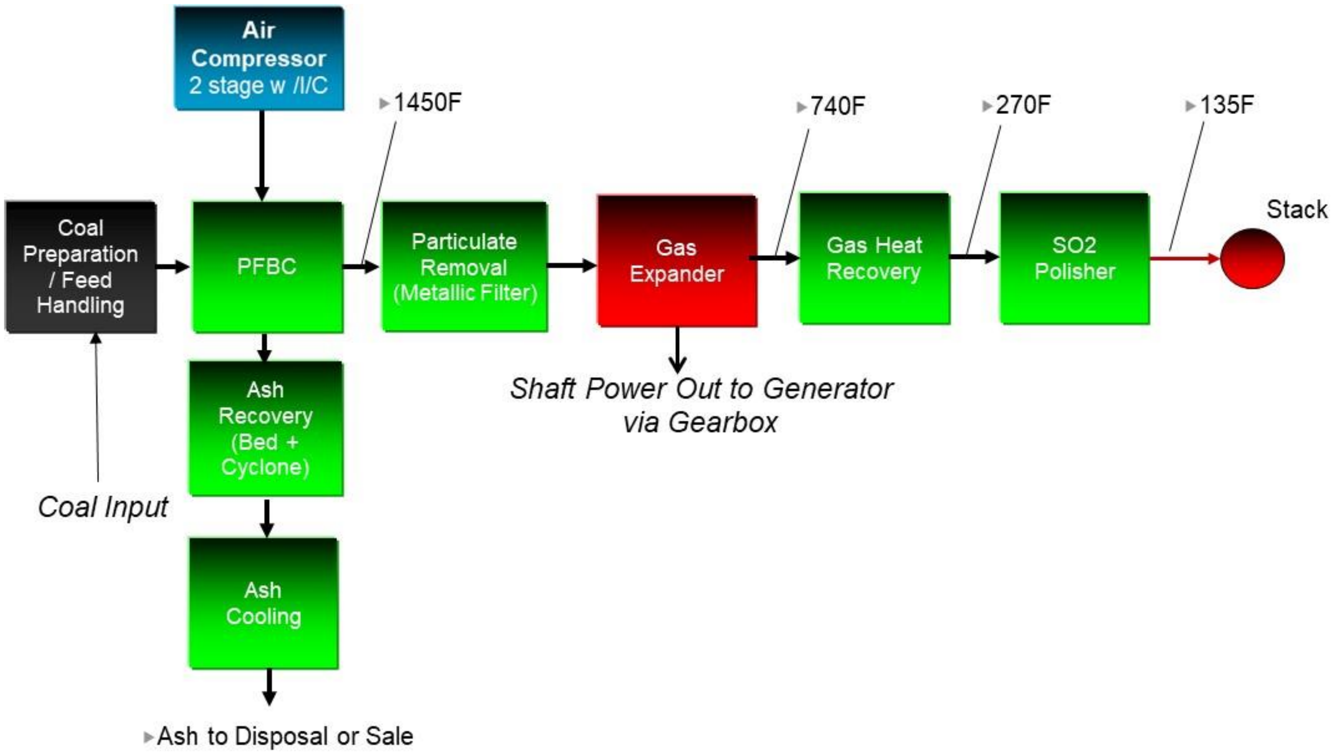


Exhibit 2-3. PFBC with CO_2 Capture (Amine-Based)

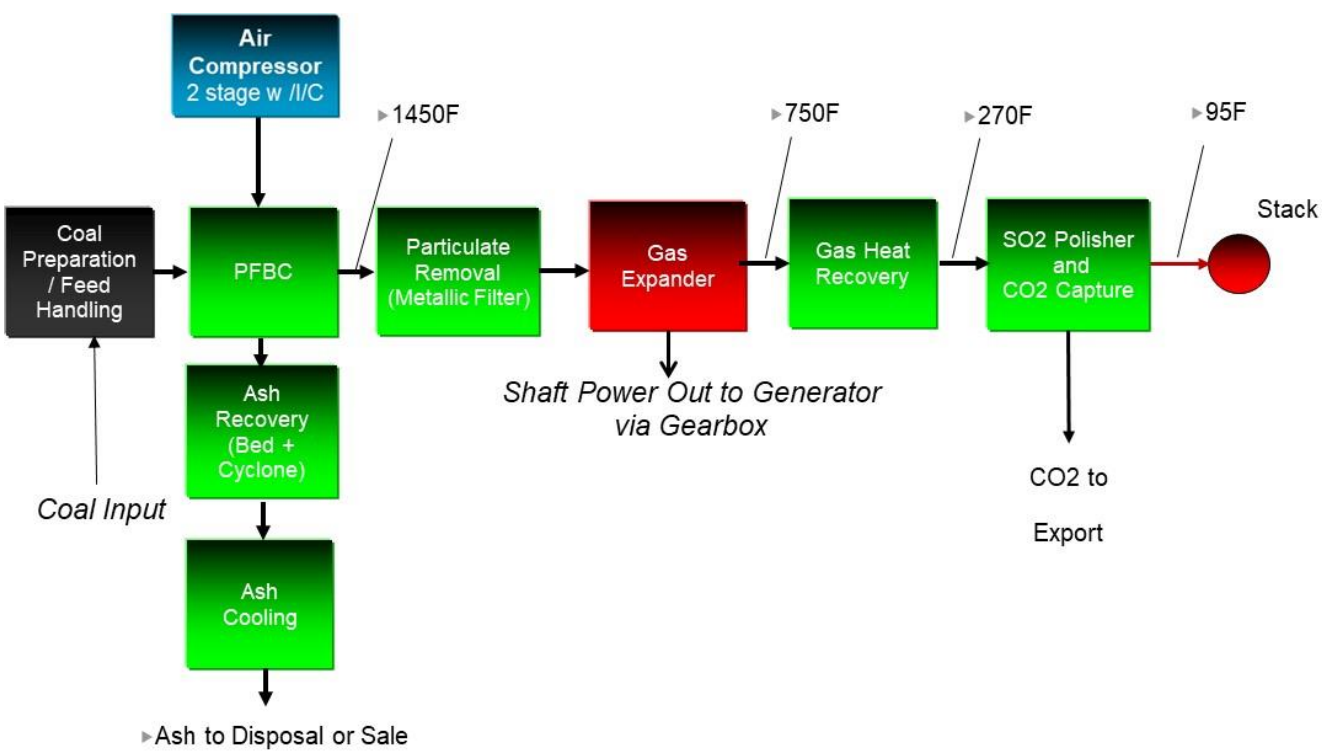
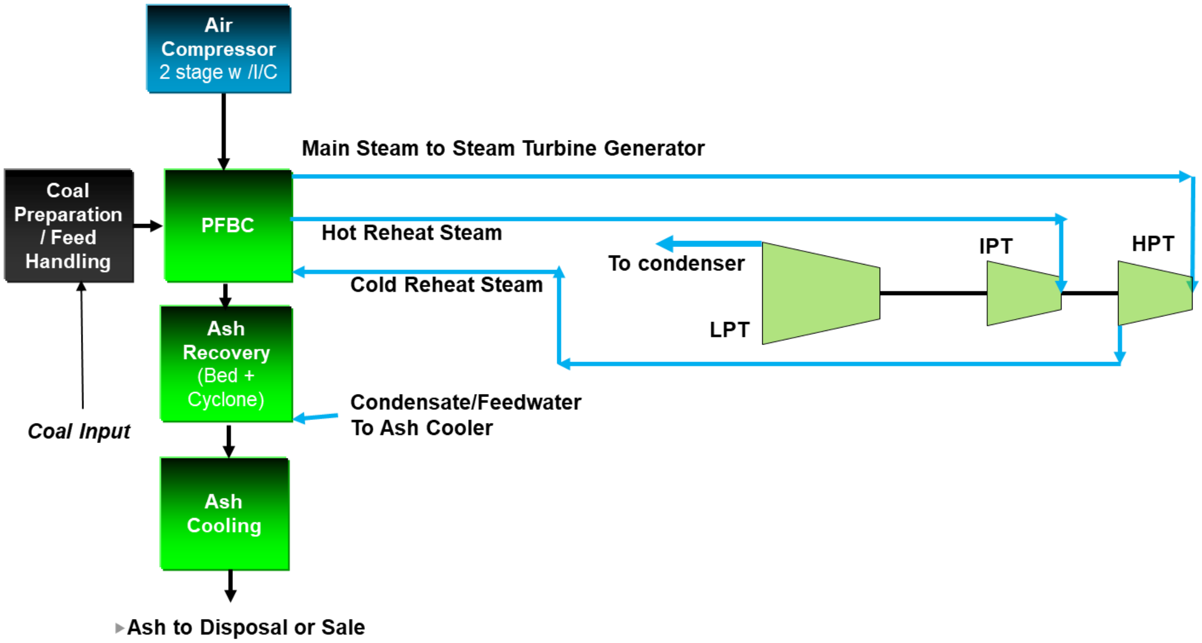


Exhibit 2-4. Steam Cycle Block Diagram Related to PFBC (simplified)



2.2.2 Benfield Based Configuration

The proposed Coal-Based Power Plant of the Future concept is based on a pressurized fluidized bubbling bed combustor providing heat of combustion to a gas turbomachine (Brayton Cycle) and a steam generator providing steam to a steam turbine generator (Rankine Cycle) in parallel operation. The plant described is configured to fire most coals, including Illinois No. 6 coal and virtually any other carbonaceous fuel, including bituminous coal waste and biomass.

The bubbling bed combustor operates at elevated pressure of approximately 12 bar in the P200 module. This pressure enhances the combustion and sulfur capture reactions in the fluidized bed due to the elevated partial pressure of the reactants. Earlier versions of this technology that are not carbon capture-ready incorporated some feed water heating for the Rankine cycle by utilizing waste heat from the turbomachine exhaust. This feature is not used in the carbon capture or capture-ready versions of the technology when the Benfield process is specified as the CO_2 capture system.

The pressurized fluid bed is contained inside a pressure vessel that also encloses steam generating boiler tube surfaces. The combustion gases provide heat transfer to the steam generating surfaces for feed water/steam heating in a once-through type steam generator. The heated gas exits the pressure vessel at elevated pressure and temperature (11 bar/1500 ºF) after two stages of cyclones to pass through a gas cooler, a high-efficiency metallic filter, and then (in the capture-ready case) on to a gas turbomachine expander.

The offered technology is unique and innovative in this major respect: it utilizes a carbon capture process that is capable of reducing the typical parasitic load (electric or steam) on the base thermal cycles. The well-known Benfield process using potassium carbonate as a solvent is used at elevated pressure in the gas path to capture CO_2.

The block diagram of the gas path for the integrated PFBC system in CO_2 capture-ready configuration is presented in Exhibit 2-5. The system with CO_2 capture installed is shown in Exhibit 2-6. Exhibit 2-4 presents the steam cycle as it relates to the PFBC vessel and gas turbomachines and is the same as for the amine-based case.

Exhibit 2-5. PFBC without CO_2 Capture (Capture-Ready Configuration, Benfield)

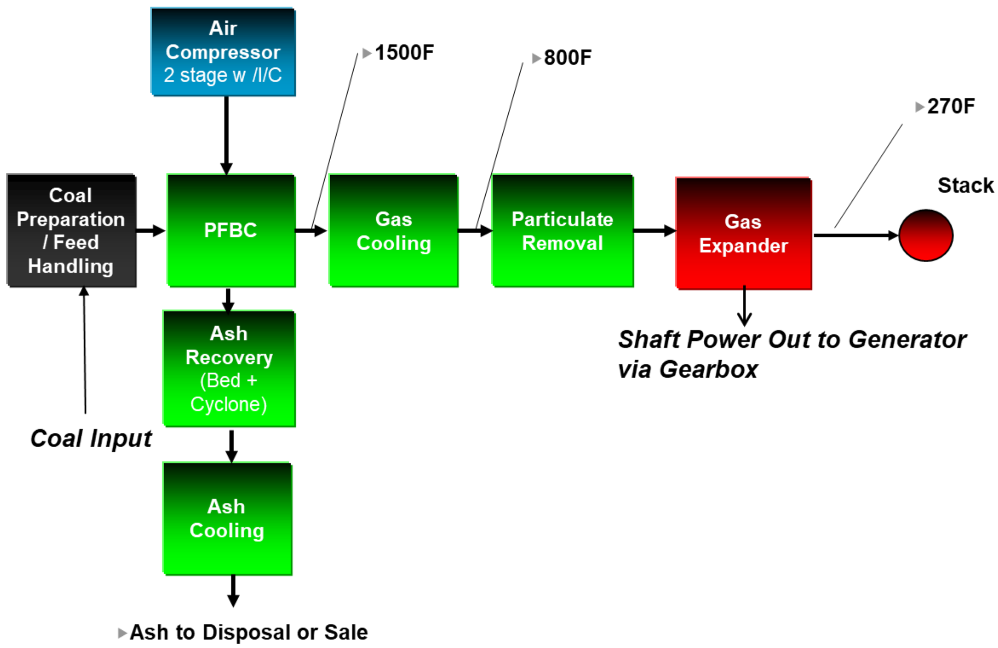
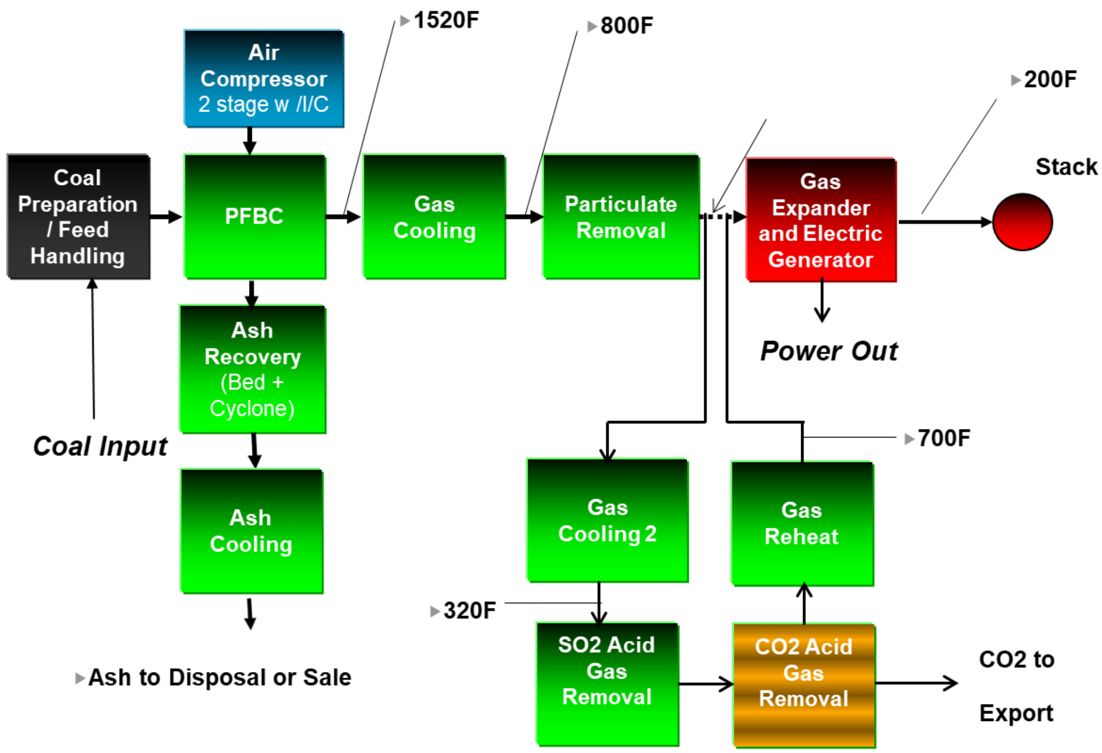


Exhibit 2-6. PFBC with CO_2 Capture (Benfield)



2.3 Description of Process Blocks – Amine-Based Configuration

This section presents descriptions of each process block in the Amine-based CO_2 capture-equipped configuration.

2.3.1 Coal Preparation and Handling

The coal preparation and feed process block incorporates necessary equipment to grind the coal and limestone to the required specifications, then mix the two solids and add sufficient water to form the pumpable paste for feeding to the PFBC fluidized bed. The water content of the paste will be ~26%. The primary sizing and storage of the coal and limestone are performed in the fuel and sorbent preparation facility included with the power plant. The coal and limestone are conveyed to a fuel preparation building where final grinding to size takes place. The sorbent sizing system uses a vibrating sizing screen that sends plus 1/8-in sorbent to a reversing hammermill crusher that discharges onto an oversize protection screen (vibrating). This screen will reject any material that is over 1/8-in, ensuring the sorbent product in the fuel prep system is 1/8-in x 0. The ground coal and sorbent (limestone) are mixed with water in the proper ratios and fed by special solids pumps (derived from concrete pumps) made by Putzmeister into the boiler bed. Each PFBC module is provided with a complement of 6 operating Putzmeister moving cavity pumps that pump the paste from the buffer silo at 1 bar to the 13+ bar pressure required for injection. (Each PFBC module has 2 spare Putzmeister pumps.) The paste fuel is introduced into the bed via a series of nozzles.

2.3.2 PFBC Vessel and Boiler

The next process block represents the PFBC pressure vessel and boiler. The paste fuel is injected into the fluidized bed and combusted (with ~16% excess air) to completely fire the fuel and release the heat of combustion. The sulfur dioxide produced from the coal also reacts with the limestone sorbent within the bubbling bed. The heat of combustion heats the gas temperature to ~1500 °F and also releases sufficient heat to power the supercritical once-through boiler tube surfaces, which also include economizer, superheat, and reheat surfaces. The rising column of combustion product gases passes through two stage of cyclones which remove about 98% (total) of the particulate matter entrained in the gas. The gas then exits the PFBC vessel.

2.3.3 Gas Cooling and Particulate Removal

At this point in the gas stream, a significant deviation occurs from prior PFBC applications. Instead of passing through the blade path of a specially designed gas turbine (the ABB GT35P, no longer in production), in the amine-based configuration, the gas is cooled from 1500 °F to 1450 °F in an external gas cooler (transferring heat to the steam cycle).

The 1450 °F gas then passes through a metallic filter (multiple filter baskets housed in a specially designed pressure vessel) to remove remaining PM to a level consistent with about 99.99% removal. The filtered gas passes to the gas expander.

2.3.4 Gas Expander and Gas Heat Recovery

The filtered gas enters the expander portion of the turbomachine to expand to 1 atmosphere to recover the available energy in the gas. This gas still contains all of the CO_2, which increases the gas expander generation compared to the Benfield configuration. The gas leaving the expander enters a gas heat recovery unit where it is cooled to approximately 270°F prior to being conveyed to the SO_2 polisher.

2.3.5 SO_2 Polishing, Hg Removal, CO_2 Removal and Stack

The cooled gas enters a caustic (NaOH) scrubber to remove residual SO_2 to the single digit ppmv level. At this point in the gas path, Hg capture by utilization of GORE surface contact elements can be installed in the duct to further reduce the gas Hg content, if required. The Hg removal is not anticipated in the Illinois no 6 case, as the significant Hg removal will be achieved with the bituminous coal ash removal, and the presence of a wet scrubber. The GORE system is anticipated in the waste coal case owing to the higher Hg level per MMBtus of fuel. The desulfurized and low Hg gas then enters the amine absorber unit to remove CO_2.

The gas enters the amine absorber vessel, which is a gas/liquid contact scrubber operating at near atmospheric nominal pressure. The absorber circulates the amine solvent solution through the absorber and then to a regenerator vessel.

The CO_2-rich solvent is stripped of its CO_2 burden in the regenerator vessel before recycling to the absorber vessel. The CO_2-rich gas is compressed for geologic storage or beneficial use.

The CO_2-lean gas (97% removal) is then conveyed to the stack and exhausted from the plant.

A CO_2 capture-ready configuration can also be configured, which would skip the CO_2 removal step and convey the cooled gas directly to the stack. The capture-ready configuration would provide space for the future addition of the CO_2 removal step.

2.3.6 Steam Cycle

Steam produced by the PFBC process is sent to the supercritical steam turbine cycle with throttle steam conditions of 3500 psig and 1100 °F. The high-pressure turbine (HPT) extracts mechanical energy for the generation of electric energy. Steam exiting the HPT is the cold reheat (CRH) steam that is returned to the PFBC boiler for reheating to 1105 °F. The hot reheat (HRH) steam is returned to the intermediate pressure steam turbine where the steam is further expanded and crosses over to the low-pressure turbine (LPT). The steam exiting the LPT is condensed by the condenser located at the exit of the LPT in a down draft configuration.

2.3.7 Water & Wastewater Treatment System

The following water & wastewater treatment system process description applies to all cases except as noted below.

The water treatment equipment includes all the necessary components to take water from a water supply source and condition it to meet the water quality requirements of the equipment to which it supplies makeup water. The water treatment system consists of two subsystems, which are a pretreatment system and a demineralized water system.

The pretreatment system provides makeup water to the cooling towers, service water system, SO_2 polishing scrubber and the ultrafiltration (UF) system that feeds the demineralizer system. The major components of the pretreatment system are a raw water storage tank, three 50% capacity raw water pumps, two 50% capacity clarifiers, two 100% capacity clarified water pumps and a clarified water storage tank. Any sludge generated in the clarifiers will be thickened, sent to a filter press system for dewatering, and then sent to a landfill for solids disposal. The filtrate from the sludge will be reused. The pretreatment system includes forwarding pumps to supply water to all equipment for which it is a water source unless gravity feed is possible. Chemical feed equipment is provided to inject coagulants and flocculants into the raw feed water to ensure the system effluent meets total suspended solids (TSS) water quality requirements of the downstream equipment.

The demineralized water system provides water for steam cycle makeup and for various other plant demineralized water needs. The major components of the UF system are a UF system feed tank, two 100% capacity UF trains each with two 100% capacity UF feed pumps, and a backwash and clean in place (CIP) system along with the required pumping skids. This system is needed to provide a water quality suitable for feeding the downstream reverse osmosis (RO) system. Two 100% capacity RO trains each with all required pumps and chemical feed systems and a common CIP system is provided. To ensure the demineralized water meets the stringent steam cycle makeup requirements, two 100% trains of ion exchange mixed bed polishing demineralizers are provided along with all pumps, tanks, and regeneration equipment needed for a complete working system. A demineralized water storage tank is included to provide a minimum of 24 hours of demineralized water storage.

The wastewater treatment system includes all the necessary components to take wastewater from a wastewater source and send it to a central wastewater equalization tank from which it can be directly reused in another process or sent for treatment after which it can be reused elsewhere. The wastewater treatment system consists of two subsystems which are a wastewater collection system and a zero liquid discharge (ZLD) system.

Plant-generated wastewater is collected, recycled and/or reused. Wastewater that can't be directly recycled and/or reused is sent to the onsite ZLD system for treatment and subsequent reuse. The system provides greater than 97% recovery (does not include water lost to evaporation or sludge disposal). A small highly concentrated purge stream is sent back to the fuel preparation system for use in formation of the coal/sorbent paste.

In the wastewater collection system, plant wastewater is collected in sumps located throughout the plant and then pumped from these sumps to a semi-buried concrete equalization tank. Some wastewater streams such as the cooling tower blowdown are sent directly to the wastewater equalization tank. As part of the wastewater collection system an oil water separator system is provided to condition any streams that may contain oil so that these wastewater streams can also be reused.

Any wastewater that cannot be directly recycled or reused is sent to the ZLD system for treatment. The ZLD system consists of a feed tank and two 50% capacity brine concentrator/crystallizer trains [except for the Illinois capture ready case (Case 1A) which includes only a single train] each with two 100% capacity brine concentrator feed pumps. The combined distillate from the brine concentrator(s) and crystallizer(s) is collected in a holding tank and sent back to the clarified water storage tank or alternately to the inlet of the demineralizer system (RO feed tank) for reuse. The purge stream from the crystallizer(s) is collected in a holding tank and also sent to the fuel preparation system for use in formation of the coal/sorbent paste. Any solids generated by the system will be sent to a landfill.

All tanks, pumps, and chemical feed equipment are supplied as required to provide a complete working system. For the ZLD system all process streams requiring pumps will be equipped with two 100% pumps.

2.3.8 Plant Control System Philosophy

The overall power plant will be monitored and controlled by a Distributed Control System (DCS). The DCS will provide for control of the PFBC modules, gas turbomachines, the CO_2 capture system, along with the complete balance of plant. The DCS control system will interface with the various island packaged control systems to provide routine operator control including start-up, shut down, synchronizing, and set point load control from the main control room consoles. The plant will be appropriately automated to reduce the manual actions required by operating personnel such that two operators can start-up, operate, and shut down the entire plant.

In addition to the control interface provided by the balance of plant control system, the primary equipment to produce electric power including the gas expanders, STG, and related auxiliaries will also be monitored, controlled, and protected via the main control room workstations and local workstations provided by the respective package suppliers.

The DCS processors will be centrally located in an electronics equipment room near the main control room. Remote I/O cabinets will be located in power distribution centers (PDC) and any other areas around the plant convenient to I/O. All remote I/O cabinets will be located indoors in controlled environmental conditions. Data links to remote I/O cabinets will be redundant.

Packaged systems will have stand-alone programmable logic controller (PLC) systems or OEM standard control systems. These PLCs will include an ethernet link to the DCS for transfer of process monitoring and status information only. All critical controls associated with PLC systems will be hard wired from the DCS to the PLC. Signals for start/stop, lead/lag, and status (running, trouble, etc.) will be hard wired to/from the DCS unless otherwise provided by the OEM.

Package systems with stand-alone (island) control systems will include the following;

- Gas expanders
- STG
- Coal preparation and feed
- Water treatment
- Waste water treatment
- Ash Handling

- CO_2 capture

A consistent control and instrumentation philosophy will apply throughout the plant to minimize diversity of equipment type and manufacturer.

There will be no hardwired discrete control and monitoring operator stations to back up the monitors and keyboards. However, individual emergency pushbuttons or switches will be provided for hardwired shutdown of major equipment including each PFBC, each gas expander, and the STG. These push buttons will be mounted in the main plant control room.

Control room operator workstations will be equipped with one keyboard and horizontally mounted color monitors. Each workstation will be located on desk type furniture with appropriate communication equipment mounted in the desk or integrated console. Custom angle pieces will be provided to create a horseshoe shaped Operator's console. The Operator's console will incorporate the gas expander and steam turbine OEM operator workstations.

A continuous emissions monitoring system (CEMS) shall be provided for each PFBC exhaust flue in the two stacks in accordance with the air permit. The CEMS shall have a plant data acquisition system (DAS). The CEMS shall consist of sampling devices connected via sample lines to emissions rack mounted measurement analytical devices and CEMS control equipment located in an enclosure near the base of the stacks.

This section discusses the instruments and controls required to operate the PFBC, gas expander, and steam turbine systems. The discussion will begin with an overview of normal system operation and the control functions associated with maintenance of stable operation, then discuss startup and shutdown.

Normal operation of the system at steady state will have the coal and limestone paste mixture pumped to each PFBC module by their respective Putzmeister pumps based on load demand. Pressure inside the PFBC is maintained by the air compressor section of the gas expander system. The DCS will send a load signal to each gas expander control system to control pressure at 176 psig. The load signal will be trimmed with O_2 measurement to maintain 16% excess air.

Steam is generated in each PFBC's supercritical boiler. A supercritical boiler does not have drum to separate the feedwater and steam. Above a pressure of 3200 psig and temperature of 705 °F the feedwater will phase transition into supercritical steam. Feedwater at a pressure of 3820 psig and 613 °F enters the economizer section of the boiler and exists as supercritical steam from the HP superheater section at 3500 psig and 1100 °F.

The HP steam temperature will be controlled through the DCS with a steam attemperator within each boilers HP steam sections using feedwater to control to a maximum HP steam temperature of 1100 °F.

Steam from each of the four PFBC boilers are headered together to flow to the HP section of the steam turbine. When producing steam and connected to the steam turbine, each PFBC will generally be at the same load demand as controlled by the DCS. The HP steam will enter the HP section of the steam turbine and exhaust into the cold reheat (CRH) steam header. The steam turbine control system will control the HP steam header with the HP throttle valves to a pressure of 3500 psig or a predetermined pressure according to the hybrid sliding pressure map. Electrical MWs produced by the steam turbine generator will not be controlled and will be a function of steam flow and pressure. The entire plant can however be controlled to meet a specific dispatch load or load set by any Power Purchase agreement that may apply.

Steam from the CRH header will flow back to each PFBC in operation. Flow control valves in each CRH to each boiler will equalize the flow between operating PFBCs. Hot reheat (HRH) steam will exit each boiler at a pressure of approximately 700 psig and 1100 °F and will be headered together before returning to the IP section of the steam turbine. HRH steam header pressure will normally not be controlled, and the IP STG throttle valves will be wide open.

The HRH steam temperature will be controlled through the DCS with a steam attemperator within each boilers HRH steam sections using feedwater to control to a maximum HRH steam temperature of 1105 °F.

Exhaust from the IP section will flow to the LP section of the steam turbine. LP steam pressure will normally not be controlled. LP steam turbine will exhaust into an air-cooled condenser (ACC) for the Business Case or water-cooled condenser for the Illinois No. 6 fired case.

Condensate pumps will deliver condensate from the ACC condensate tank or condenser hotwell through the LP heaters to the deaerator tank. Condensate pumps will be started and stopped through the DCS based on the number of PFBCs in operation. DCS controlled deaerator level control valve and condensate dump valve will control the water level in the deaerator tank.

Boiler feedwater (BFW) pumps will deliver feedwater from the common deaerator through each units HP feedwater heaters to the boilers. The BFW pumps will be started and stopped through the DCS based on the number of PFBC's in operation. Feedwater flow for each boiler will be controlled through the DCS by a feedwater flow control valve based on the load demand of the PFBC.

Gas exits the PFBC and flows through a heat recovery unit and filter then to the gas expander. The gas expander will reduce the pressure of the gas, where it will then flow through feedwater heaters, SO_2 polishing scrubbers, the mercury removal system for the Business Case, and the CO_2 capture system before exiting the stack. The gas expander control system will control the inlet pressure of the expander or have variable inlet guide vanes to maintain rotational speed and therefore power output. Electrical MW's produced by the gas expander generators will not be directly controlled and will thus be a function of gas flow and pressure.

Startup and shutdown of the PFBCs will be automated through the DCS.

For startup of a PFBC with other PFBCs online, as the PFBC is coming up on temperature, the HP steam produced in the HP section will be bypassed to the units CRH section and the HRH steam will be bypassed to the ACC or shell and tube condenser. The steam bypass valves will be controlled from the DCS. Once the PFBC being started up is up to temperature and HP and HRH steam equals the pressure and temperature of the running PFBCs, the HP and HRH steam stop valves can be opened. The bypass valves will be slowly closed as the load on the startup PFBC is increased to match the load of the running PFBCs until all steam being produced it flowing to the steam turbine.

For shutdown of a PFBC with other PFBCs online, the HP and HRH bypass valves will be opened as the load on the PFBC is decreased. Once pressure has decreased to the point that the steam check valves have closed, the PFBCs HP and HRH stop valves will be closed.

2.4 Description of Process Blocks – Benfield-Based Configuration

This section presents descriptions of each process block in the Benfield-based CO_2 capture-equipped configuration.

2.4.1 Coal Preparation and Handling

The coal preparation and handling system is unchanged by the Benfield-based configuration.

2.4.2 PFBC Vessel and Boiler

The PFBC vessel and boiler are unchanged by the Benfield-based configuration.

2.4.3 Gas Cooling, Particulate Removal and SO_2 Removal

In the Benfield-based configuration, the 1500 °F gas is cooled to 800 °F in a heat recovery unit to generate additional steam and/or provide some of the superheat and reheat duty of the steam cycle.

The 800°F gas then passes through a metallic filter (multiple filter baskets housed in a specially designed pressure vessel) to remove remaining PM to a level consistent with about 99.99% removal.

The filtered gas is then cooled further in the first of two heat exchangers that are part of a pair of regenerative units. The gas is cooled to approximately 300 °F and then passes through a caustic (NaOH) scrubber operating at the elevated pressure of the gas (~11 bar) to remove residual SO_2 to a level of approximately 15 ppmv. The desulfurized gas then enters the UOP Benfield absorber unit to remove CO_2.

2.4.4 CO_2 Removal, Expander, Hg Removal and Stack

The SO_2-free gas enters the UOP Benfield System for capture of the CO_2. The gas enters the Benfield absorber vessel, which is a gas/liquid contact scrubber operating at nominal 11 bar pressure. The Benfield absorber circulates the potassium carbonate solvent solution through the absorber and then to a regenerator vessel (the actual system utilizes four regenerator vessels for each absorber vessel).

The high-pressure CO_2-rich solvent is reduced in pressure in a hydraulic turbine to recover some power to offset the electrical loads of the Benfield system. The reduced pressure solvent is stripped of its CO_2 burden in the regenerator vessels before recycling to the absorber vessel. The CO_2-rich gas is compressed for geologic storage or beneficial use.

The CO_2-lean gas (97% removal) is then reheated in the second of the regenerative heat exchangers to about 700 °F. This cleaned, scrubbed gas then enters the expander portion of the turbomachine to expand to 1 bar to recover the available energy in the gas. The gas at the expander outlet is then conveyed to the mercury removal then the stack and exhausted from the plant.

A CO_2-capture ready configuration can also be configured, which would be identical to the one described above except that the second stage of gas cooling, the SO_2 removal step, the CO_2 removal step, and the gas reheat are bypassed.

2.4.5 SO_2 Polishing, CO_2 Removal and Stack

The cooled gas enters a caustic (NaOH) scrubber to remove residual SO_2 to the single digit ppmv level. At this point in the gas path, Hg capture by utilization of GORE surface contact elements can be installed in the duct to further reduce the gas Hg content, if required. The desulfurized gas then enters the amine absorber unit to remove CO_2.

The gas enters the amine absorber vessel, which is a gas/liquid contact scrubber operating at near atmospheric nominal pressure. The absorber circulates the amine solvent solution through the absorber and then to a regenerator vessel.

The CO_2-rich solvent is stripped of its CO_2 burden in the regenerator vessel before recycling to the absorber vessel. The CO_2-rich gas is compressed for geologic storage or beneficial use.

The CO_2-lean gas (97% removal) is then conveyed to the stack and exhausted from the plant.

A CO_2 capture-ready configuration can also be configured, which would skip the CO_2 removal step and convey the cooled gas directly to the stack. The capture-ready configuration would provide space for the future addition of the SO_2 removal step.

2.4.6 Steam Cycle

The steam cycle is relatively unaffected by the utilization of the Benfield-based configuration. There are minor changes in condensate and feedwater heating, steam extractions, and power generation levels.

2.4.7 Water & Wastewater Treatment System

The water & wastewater treatment systems are relatively unaffected by the utilization of the Benfield-based configuration.

2.4.8 Plant Control System Philosophy

The Plant control system philosophy is relatively unaffected by the utilization of the Benfield-based configuration.

2.5 Size of the Commercial Offering

2.5.1 Size of the Commercial Offering - Amine-Based Configuration

The base case (Illinois No. 6) advanced PFBC plant includes 4 x P200 modules with a net output of ~308 MWe with 97% CO_2 capture if the amine-based configuration is used (or ~404 MWe net without carbon capture in the amine-based carbon capture-ready configuration). However, the size of the commercial PFBC power plant can vary as explained above under Proposed PFBC Target Level of Performance. Exhibit 1-2 shows the performance for four different plant sizes (in the CO_2 capture-ready configuration) using different numbers of P200 modules. (Total unit output does not increase linearly in proportion to the number of modules as the efficiency of the steam cycle increases as the unit size is increased. More aggressive steam throttle pressures and temperatures are selected as plant size increases to take advantage of different steam cycle parameters.)

2.5.2 Size of the Commercial Offering - Benfield-Based Configuration

The base case (Illinois no 6) advanced PFBC plant includes 4 x P200 modules with a net output of ~286 MWe with 97% CO_2 capture if the Benfield-based configuration is used (or ~386 MWe net without carbon capture in the Benfield-based carbon capture-ready configuration). However, the size of the commercial PFBC power plant can vary as explained above under Proposed PFBC Target Level of Performance.

2.6 Advanced Technology Aspects

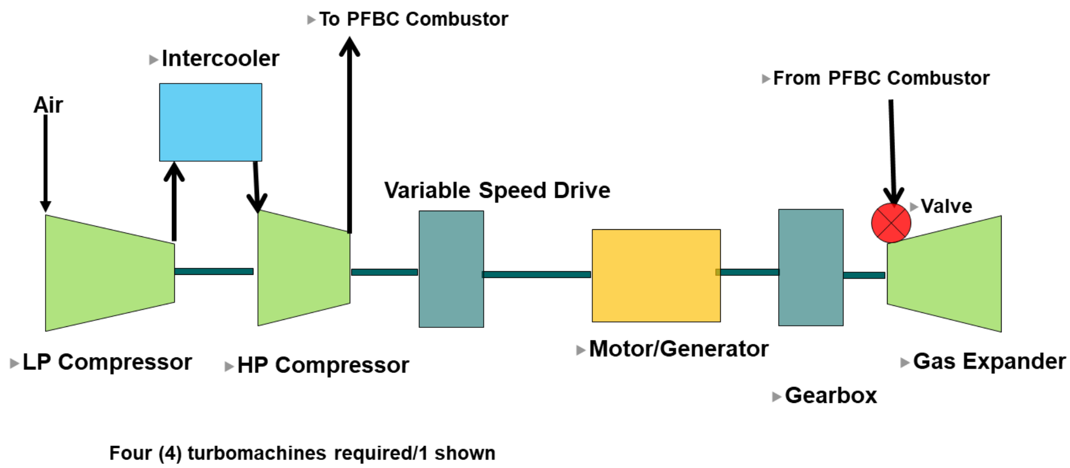
2.6.1 Advanced Technology Aspects – Amine-Based Configuration

The advanced technology aspects of the amine-based configuration reside in (1) the coupling of the pressurized fluidized bed with a high-temperature metallic filter, new gas turbomachine, and post-combustion amine-based CO_2 capture system and (2) the use of multiple P200 modules with a supercritical steam cycle. The P200 module has only been coupled with subcritical steam cycles. The supercritical PFBC plant in Japan (Karita) utilizes a single P800 module. The pressurized fluidized bed combustor has been demonstrated in several commercial plants constructed in Europe, the USA, and Japan. No existing PFBC plant has been equipped with a carbon capture system. The utilization of an amine-based carbon capture system results in a different and potentially more efficient configuration than that based on a Benfield-based carbon capture system.

However, the previous plants have used a specific gas turbine (GT35P) that was designed expressly for ingestion of particulate laden combustion products leaving the PFBC cyclones. The new turbo-compressor machine has not been specifically designed to accommodate particulate matter without damage, and a metallic filter is now required.

The design concept envisioned utilizes a new gas turbomachine that will be tailored to the process temperature, pressure and flow requirements of the advanced PFBC plant. The new gas turbomachine is shown schematically in Exhibit 2-7. Discussions are in progress with Baker Hughes and Siemens to obtain performance and estimated costs for this new machine.

Exhibit 2-7. Schematic Diagram of New Turbomachine for P200 Module (one required per module)



2.6.2 Advanced Technology Aspects – Benfield-Based Configuration

The advanced technology aspects of the Benfield-based configuration reside in (1) the coupling of the pressurized fluidized bed with a new gas turbomachine and carbon capture at elevated pressure in the UOP Benfield process and (2) the use of multiple P200 modules with a supercritical steam cycle. The P200 module has only been coupled with subcritical steam cycles. The supercritical PFBC plant in Japan (Karita) utilizes a single P800 module. The pressurized fluidized bed combustor has been demonstrated in several commercial plants constructed in Europe, the USA, and Japan. However, the previous plants have used a specific gas turbine that was designed expressly for integration with the pressurized fluidized bed combustor in a configuration that was not designed for CO_2 capture or to be CO_2 capture-ready.

The design concept presented utilizes a new gas turbomachine that will be tailored to the process requirements of the gas path that includes the CO_2 capture step. The new gas turbomachine is shown schematically in Exhibit 2-7 applies to the Benfield-based configuration as well as the amine-based configuration, although design conditions (i.e., inlet and outlet temperatures, gas volumes, etc.) will differ between the two configurations as described earlier in this Section 2.

Another advanced technology aspect of this offering is the coupling of the pressurized fluidized bed with the UOP Benfield process for CO_2 capture at elevated pressure. While the pressurized fluidized bed combustor and the UOP Benfield process have each been demonstrated separately, the entire combination of fluidized bed combustor, Benfield process, and turbomachine with regenerative heat transfer in the gas path has not been demonstrated as a complete integrated system in prior applications.

2.7 List of Components that are not Commercially Available

Components that are not available commercially at this writing are the gas turbomachine and the control system with confirmed algorithms to operate the integrated system. The gas turbomachine will be a new design with specific components (compressors, expanders, motor/generators, and controls) to operate to meet the gas path requirements of the P200 with integrated CO_2 capture**.** Discussions are underway with Siemens and Baker Hughes for this gas turbomachine design.

2.8 Extent and Manner of Use of Fuels Other than Coal

The PFBC, whether for the Illinois No. 6 fuel case or the waste coal fuel case, utilizes either natural gas (if available) or No. 2 fuel oil for startup. This auxiliary fuel may also be used to assist in rapid startups and to fuel a small auxiliary boiler that provides heating steam for the rare cases when the entire plant must be shut down.

The PFBC can fire a wide range of carbonaceous fuels, including various types of biomass. A key capability of the PFBC module lies in its ability to fire wet biomass. As long as sufficient heating value is available, the PFBC bubbling bed can extract that energy for gas and steam heating to drive the interconnected cycles. Past experience and testing with the PFBC have included firing diverse materials, such as olive pits, oil shale, and various types of coal. Each fuel must be evaluated for economic potential, recognizing the varying ash, sulfur, Hg, and Cl contents.

2.9 Thermal Storage

The PFBC system contains thermal (and some chemical in the form of potential heat of combustion) storage for the purpose of smoothing transient operation. The bed reinjection vessels (two per PFBC vessel) accumulate an inventory of bed material during power reduction transients and provide a corresponding inventory during power increase transients. The reinjection vessel inventory is available to the bed in a very short period of time. This assists in enabling the PFBC to provide thermal power smoothly during these transients and assists in enabling relatively rapid ramp rates compared to conventional fossil fueled power plants. This PFBC design feature does not provide assistance for longer-term operations (beyond several minutes).

2.10 Techniques to Reduce Design, Construction, and Commissioning Schedules

2.10.1 Modularization Potential

The modular nature of the PFBC system provides opportunities to reduce costs and schedules for multi-module plants and for plants ordered after the first one. These cost and schedule reductions are based on the fact that construction typically involves mobilization (Mob) and demobilization (DeMob) time and costs in field construction. When multiple modules are constructed in sequence (same site and same time sequence) the Mob/DeMob costs are only incurred once.

A second benefit of modular design and construction is a learning curve effect when more than one module is constructed at the same site and in the same time frame. This learning curve effect may carry over to subsequent sites if documented or if the same constructor and crews are employed for follow-on plants.

To some extent, off-site fabrication of complete systems or subsystems can also offer cost and schedule savings. Besides the obvious methods of creating shippable prefabricated modules of components, piping, wiring, etc., it can also be possible to fabricate and ship an entire PFBC vessel if the following conditions are present:

- Availability of a suitable shipyard or fabrication site where the PFBC vessel and contents can be assembled under controlled conditions with cost-effective and productive labor.
- Site locations (for completed power plant) affording the potential for barge shipment. The PFBC vessel and contents, as well as other large assemblies, can be fabricated in cost-effective locations and shipped by barge or other waterborne means to the ultimate site.

2.11 Advanced Process Engineering

The individual processes incorporated into the present PFBC offering do not by themselves represent "advanced" process engineering. However, the integration of all of the incorporated processes into a complete functional system that produces electric power, generates CO_2 for storage or utilization, and reduces air emissions to meet or beat current regulatory limits represents an advanced process. The control techniques and system hardware necessary for effective process control also represent advanced engineering from a controls perspective.

3 Design Basis Information

The following sections form the design basis for the advanced PFBC coal-based power plant. As discussed above, separate design bases are presented for the two cases that will be evaluated: (1) the Base Case based upon the Midwest site and Illinois No. 6 fuel, and (2) the Business Case based upon the southwestern Pennsylvania (or northern West Virginia) site and wet, fine waste coal fuel.

3.1 Site and Ambient Conditions

Site characteristics for the Base Case (Midwest site) are presented in Exhibit 3-1.

Exhibit 3-1. Site Characteristics – Base Case (Midwest)

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size, acres	300
Transportation	Rail or Truck
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water
Waste water	Zero Liquid Discharge
Coal Delivery	Rail Delivery of Typical Washed Coal Product

Ref. [**9**]

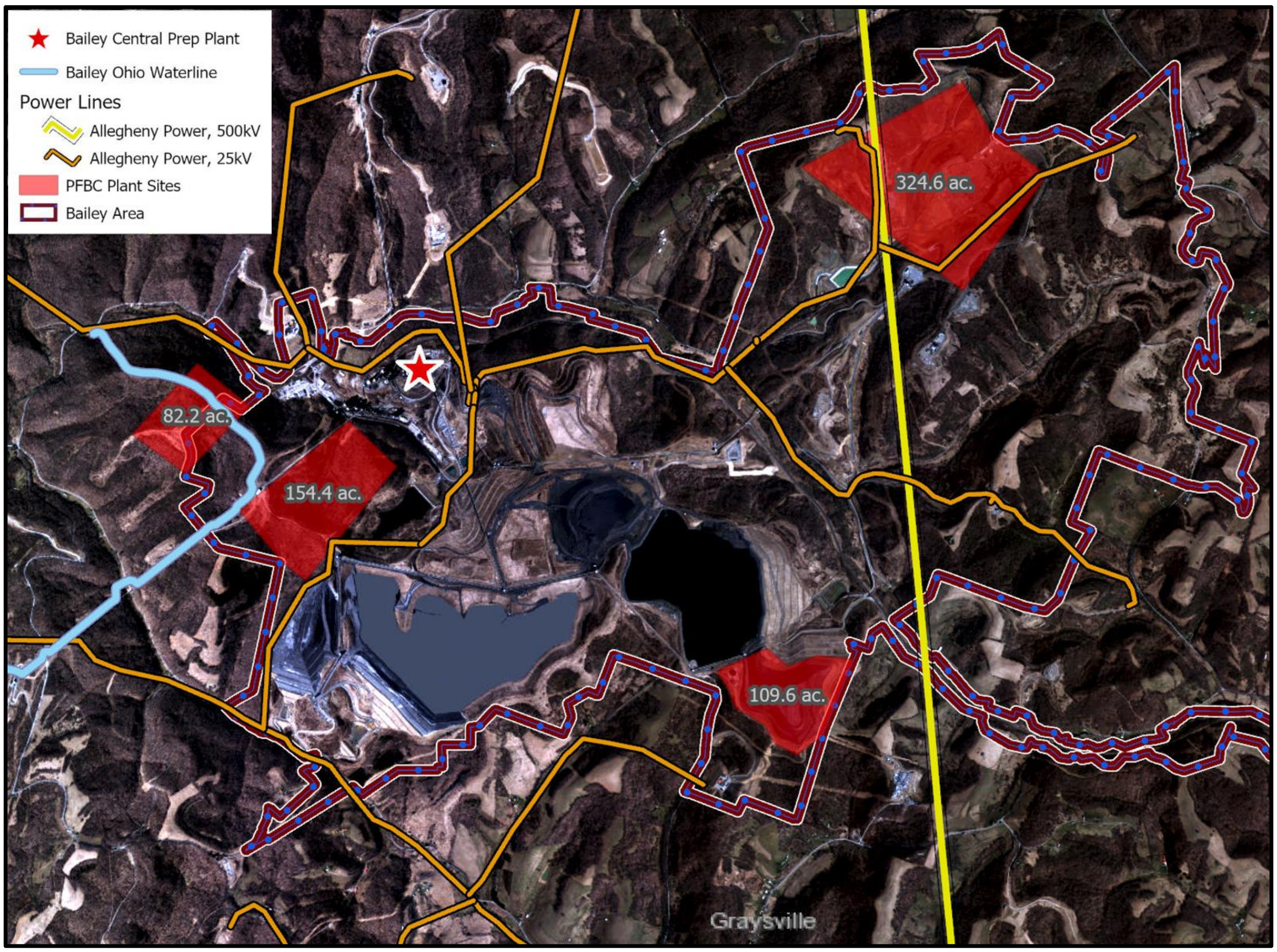
The site for the Business Case will be taken as a brownfield site in the vicinity of CONSOL's Bailey Central Preparation Plant at its Pennsylvania Mining Complex (PAMC) in southwestern Pennsylvania. Site characteristics for this Business Case are presented in Exhibit 3-2. Selection of a specific site, which would likely be located in either southwestern Pennsylvania or northern West Virginia, will occur during the Phase 3 FEED study.

Candidate sites in the vicinity of the CONSOL's PAMC are shown in Exhibit 3-3.

Exhibit 3-2. Site Characteristics – Business Case (Southwest Pennsylvania)

Parameter	Value
Location	Brownfield, Southwest Pennsylvania U.S.
Topography	Some leveling/earthwork required
Size, acres	80 to 300$^+$
Transportation	Rail or Truck
Ash Disposal	Off-Site within nearby PAMC property
Water	Ohio River Water
Waste water	Zero Liquid Discharge (or partial utilization in neighboring coal mining/processing operations)
Coal Delivery	Pipeline Delivery of Waste Coal Slurry

Exhibit 3-3. Potential Sites Aerial Photo – Business Case (Southwest Pennsylvania)



The design for the Base Case (Midwest site) will be based on site conditions as presented in Exhibit 3-4, and the design for the Business Case (southwest Pennsylvania site) will be based on site conditions as presented in Exhibit 3-5.

Exhibit 3-4. Site Ambient Conditions- Base Case (Midwest)

Parameter	Midwest Value
Elevation, (ft)	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

Ref. [**9**] for Midwest site parameter values. [**1**] p. 8ff for Air composition.

A The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 8.5 °F above ambient wet bulb conditions in ISO cases.

Exhibit 3-5. Site Ambient Conditions – Business Case (Southwest Pennsylvania)

Parameter	SW PA Value	Note
Elevation, (ft)	1185	[**10**]
Barometric Pressure, MPa (psia)	0.097 (14.078)	
Average Ambient Dry Bulb Temperature, °C (°F)	10.1 (50.2)	[**10**]
Average Ambient Wet Bulb Temperature, °C (°F)	6.5 (43.7)	60% RH
Design Ambient Relative Humidity, %	60	
Cooling Water Temperature, °C °(F)[A]	11.2 (52.2)	
Air composition based on published psychrometric data, mass % [B]		
N_2	75.15	
O_2	23.03	
Ar	1.29	
H_2O	0.48	
CO_2	0.05	
Total	100.00	

Ref [**10**] for Pennsylvania site elevation taken as Washington County Airport, PA.
The assumed PAMC site is about 13 miles from the Washington County Airport, with an elevation of approximately 1200 ft amsl.

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

[B] The Air Composition per the Performance Work Statement (PWS) appears INCORRECT at: N_2 (72.429%), O_2 (25.352%), Argon (1.761%), H_2O (0.382%) and CO_2 (0.076%) by mass. We have utilized N_2 (75.47%), O_2 (23.20%), Argon (1.28%), and CO_2 (0.06%), adjusted for moisture per the psychrometric chart.

The following design considerations are site-specific and have not been quantified for this pre-FEED study. Allowances for normal conditions and construction are included in the cost estimates. Typically, the consideration of these factors does not have a significant impact on the cost unless the site-specific situation is unusual or extreme.

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

3.2 Fuel Characteristics

This section documents the coal analysis for the Base Case (Illinois No. 6 coal) and the Business Case (wet, fine bituminous waste coal), the biomass analysis for the Business Case, and the natural gas analysis for both cases.

3.2.1 Coal – Illinois #6

This section presents the coal analysis in Exhibit 3-6, ash analysis in Exhibit 3-7, and coal trace element analysis in Exhibit 3-8 for the Illinois No. 6 coal for the Base Case (Midwest Site).

Exhibit 3-6. Design Coal – Illinois No. 6 (Bituminous)

Rank	**Bituminous**	
Seam	**Illinois No. 6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate Analysis (weight %)		
	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, Btu/lb	11,666	13,126
LHV, Btu/lb	11,252	12,712
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen	6.88	7.75
Total	100.00	100.00
	As Received	**Dry**
Sulfur Analysis (weight %)		
Pyritic		1.14
Sulfate		0.22
Organic		1.46

Ref: [**9**], [**11**] for sulfur.

Exhibit 3-7. Illinois No. 6 Coal Ash Analysis and Data

Coal name	**Illinois No. 6**	
Typical Ash Mineral Analysis[2]		
Silica	SiO_2	45.0%
Aluminum Oxide	Al_2O_3	18.0%
Titanium Dioxide	TiO_2	1.0%
Iron Oxide	Fe_2O_3	20.0%
Calcium Oxide	CaO	7.0%
Magnesium Oxide	MgO	1.0%
Sodium Oxide	Na_2O	0.6%
Potassium Oxide	K_2O	1.9%
Phosphorus Pentoxide	P_2O_5	0.2%
Sulfur Trioxide	SO_3	3.5%
Undetermined		1.8%
Total		100.0%

Typical Ash Fusion Temperatures (°F)[3]

Reducing		
Initial – Limited deformation		2,194 ºF
Softening	H=W	2,260 ºF
Hemispherical	H=1/2W	2,345 ºF
Fluid		2,415 ºF
Oxidizing		
Initial – Limited deformation		2,250 ºF
Softening	H=W	2,300 ºF
Hemispherical	H=1/2W	2,430 ºF
Fluid		2,450 ºF

Ref [**12**], pp. 36 & 37

Exhibit 3-8. Illinois No. 6 Trace Elements

Average trace element composition of coal shipped by Illinois mines, dry basis, ppm [4]

		Arithmetic Mean	Standard Deviation
Arsenic	As	7.5	8.1
Boron	B	90	45
Beryllium	Be	1.2	0.7
Cadmium	Cd	0.5	0.9
Chlorine	Cl	1671	1189
Cobalt	Co	3.5	1.3
Chromium	Cr	14	6
Copper	Cu	9.2	2.5
Fluorine	F	93	36
Mercury[5]	Hg	0.09	0.06
Lithium	Li	9.4	7.1
Manganese	Mn	38	32
Molybdenum	Mo	8.4	5.7
Nickel	Ni	14	5
Phosphorus	P	87	83
Lead	Pb	24	21
Tin	Sn	0.9	0.7
Selenium	Se	1.9	0.9
Thorium	Th	1.5	0.4
Uranium	U	2.2	1.9
Vanadium	V	31	16
Zinc	Zn	84.4	84.2

Ref: [**12**], pp. 36-37

Notes from above reference:

1. *Calculated Dulong HHV, As-Received - 11,634 Btu/lb, Dry - 13,089 Btu/lb*
2. *Typical ash mineral analysis is based on Combustion Technologies Composition Source Book, May 2005.*
3. *Reducing condition ash fusion temperature data are from source [12], and oxidizing condition typical ash fusion temperature data are based on the Combustion Technologies Composition Source Book, May 2005.*
4. *Average trace element composition of coal shipped by Illinois mines is based on 34 samples, 2004 Keystone Coal Industry Manual [7].*
5. *A mercury value of 0.15 ppm was used for Illinois No. 6 in previous system studies, which is the mean plus one standard deviation.*

A mercury value of 0.15 ppm (dry basis) is assumed as the design basis for the emissions analysis for Illinois No. 6 coal in this pre-FEED study, consistent with Note 5 above.

Fuel costs are specified according to the 2019 QGESS document "Fuel Prices for Selected Feedstocks in NETL Studies." [**13]** The current levelized coal price is $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 on-line year of 2023.

3.2.2 Coal – Waste Coal – Biomass

The proposed Business Case plant will fire waste coal that exists in great abundance in CONSOL's existing slurry impoundments and is produced routinely by CONSOL's preparation plant (thickener underflow stream) at the Pennsylvania Mining Complex. This section presents the coal analysis in

Exhibit 3-9 and ash analysis in Exhibit 3-11 for the wet, fine bituminous waste coal for the Business Case (southwest Pennsylvania site), based on preliminary sampling and analysis results. This design fuel specification for the Business Case will continue to be refined as additional sampling/analysis is completed during the project. Testing results for samples collected during the pre-FEED study are presented in Exhibit 3-10. Twelve samples were analyzed covering the time period of November 7, 2019 through March 26, 2019. For fine refuse samples, they show a remarkable consistency. This is likely because they are from a plant cleaning single coal seam.

Exhibit 3-9. Design Coal – Waste Coal Slurry (Bituminous)

Rank	**Bituminous**	
Seam	**Pittsburgh No. 8**	
Source	**Fine Waste Coal Slurry**	
Proximate Analysis (weight %)		
	As Received	**Dry**
Moisture	25.00	0.00
Ash	33.34	44.45
Volatile Matter	17.78	23.70
Fixed Carbon	23.90	31.86
Total	100.00	100.00
Sulfur	1.18	1.58
HHV, Btu/lb	5,852	7,803
LHV, Btu/lb		
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	25.00	0.00
Carbon	33.53	44.71
Hydrogen	2.23	2.97
Nitrogen	0.66	0.88
Chlorine	0.08	0.10
Sulfur	1.18	1.58
Ash	33.34	44.45
Oxygen[B]	3.98	5.31
Total	100.00	100.00
	As Received	**Dry**
Sulfur Analysis (weight %)		
Pyritic		0.97
Sulfate		0.03
Organic		0.58

Note: The 25% fuel moisture is distinct from the 26% fuel limestone paste moisture.

Exhibit 3-10. Pre-FEED Coal Sampling Analysis Results—Waste Coal*

Rank	**Bituminous**		
Seam	**Pittsburgh No. 8**		
Source	**Fine Waste Coal Slurry**		
Proximate Analysis (weight %)			
	Design Basis (Dry)	**Average (Dry)**	**Range (Dry)**
Moisture	0.00	0.00	NA
Ash	44.45	43.36	39.48-49.37
Volatile Matter	23.70	24.28	21.91-26.43
Fixed Carbon	31.86	32.36	28.60-34.66
Total	100.00	100.00	NA
Sulfur	1.58	1.68	1.26-1.91
HHV, Btu/lb	7,803	7,989	7,024-8,645
Ultimate Analysis (weight %)			
	Design Basis (Dry)	**Average (Dry)**	**Range (Dry)**
Moisture	0.00	0.00	NA
Carbon	44.71	45.55	40.56-49.02
Hydrogen	2.97	3.02	2.72-3.17
Nitrogen	0.88	0.88	0.78-0.97
Chlorine	0.10	0.10	0.068-0.114
Sulfur	1.58	1.68	1.26-1.91
Ash	44.45	43.36	39.48-49.37
Oxygen[B]	5.31	5.52	5.08-6.06
Total	100.00	100.00	NA
Sulfur Analysis (weight %)			
	Design Basis (Dry)	**Average (Dry)**	**Range (Dry)**
Pyritic	0.97	1.01	0.64-1.14
Sulfate	0.03	0.02	0.00-0.07
Organic	0.58	0.64	0.47-0.87

*Average and range for twelve samples of thickener underflow at CONSOL's Pennsylvania Mining Complex.

Exhibit 3-11. Waste Coal Slurry (Bituminous) Ash Analysis and Data

Coal name	Waste Coal Slurry	
Typical Ash Mineral Analysis		%
Silicon Dioxide	SiO_2	58.27
Aluminum Oxide	Al_2O_3	24.78
Titanium Dioxide	TiO_2	1.02
Iron Oxide	Fe_2O_3	5.71
Calcium Oxide	CaO	2.89
Magnesium Oxide	MgO	0.96
Sodium Oxide	Na_2O	0.75
Potassium Oxide	K_2O	2.70
Phosphorus Pentoxide	P_2O	0.26
Sulfur Trioxide	SO_3	2.93
Undetermined		-0.27
Total		100.0

Typical Ash Fusion Temperatures (°F)

Reducing		
Initial – Limited deformation		2525 ºF
Softening	H=W	2618 ºF
Hemispherical	H=1/2W	2657 ºF
Fluid		2770 ºF
Oxidizing		
Initial – Limited deformation		2602 ºF
Softening	H=W	2690 ºF
Hemispherical	H=1/2W	2725 ºF
Fluid		2782 ºF

An average mercury value of 0.10 ppm (dry basis) was determined from the twelve thickener underflow samples collected. Calculations for mercury capture are based on 0.15 ppm Hg to be conservative.

Biomass can easily be utilized as a fuel feedstock along with the coal or waste coal up to 10% or more by weight in the PFBC. The available biomass species will vary throughout the year for the proposed southwestern Pennsylvania site. Switchgrass has been selected as a representative biomass feedstock for the Business Case design basis. The project has developed a Business Case heat and mass balance with carbon capture based on 5% switchgrass and 95% waste coal by weight.

Exhibit 3-12 presents the switchgrass proximate and ultimate analyses, while Exhibit 3-13 presents the switchgrass ash analysis.

Exhibit 3-12. Design Biomass – Switchgrass

Biomass	**Switchgrass**		
Source	**Virginia (representative)**		
Proximate Analysis (weight %)			
	As Received	**Dry**	**Air Dry**
Moisture	17.42	0.00	3.90
Ash	4.34	5.25	5.05
Volatile Matter	68.07	82.43	79.22
Fixed Carbon	10.17	12.32	11.83
Total	100.00	100.00	100.00
Sulfur	0.058	0.070	0.067
HHV, Btu/lb	6,565	7,949	7,639
LHV, Btu/lb	5,955		
Ultimate Analysis (weight %)			
	As Received	**Dry**	**Air Dry**
Moisture	17.42	0.00	3.90
Carbon	39.71	48.09	46.21
Hydrogen	4.63	5.61	5.39
Nitrogen	0.54	0.66	0.63
Sulfur	0.06	0.07	0.07
Ash	4.34	5.25	5.05
Oxygen	33.30	40.32	38.75
Total	100.00	100.00	100.00
Chlorine	0.006	0.007	0.007
	As Received	**Dry**	**Air Dry**
Mercury (mg/kg)	0.01	0.01	0.01

Ref: [**14**].

Exhibit 3-13. Switchgrass Elemental Analysis of Ash

Coal name	**Illinois No. 6**	
Typical Ash Mineral Analysis[2]		
Silica	SiO_2	67.55%
Aluminum Oxide	Al_2O_3	1.59%
Titanium Dioxide	TiO_2	0.09%
Iron Oxide	Fe_2O_3	0.76%
Calcium Oxide	CaO	11.30%
Magnesium Oxide	MgO	3.85%
Sodium Oxide	Na_2O	0.23%
Potassium Oxide	K_2O	4.39%
Phosphorus Pentoxide	P_2O_5	2.60%
Sulfur Trioxide	SO_3	1.06%
Chlorine	Cl	0.28%
Carbon Dioxide	CO2	2.60%
Undetermined		3.70%
Total		100.00%

Typical Ash Fusion Temperatures (°F)[3]

Reducing		
Initial – Limited deformation		2,700$^+$ ºF
Softening	H=W	
Hemispherical	H=1/2W	
Fluid		
Oxidizing		
Initial – Limited deformation		2,700$^+$ ºF
Softening	H=W	
Hemispherical	H=1/2W	
Fluid		

Ref [**14**]

The assumed switchgrass price is $50/ton delivered to the Business Case site in 2019 dollars.

3.2.3 Natural Gas Characteristics

Natural gas characteristics for both the Base Case and Business Case are given in Exhibit 3-14.

Exhibit 3-14. Natural Gas Characteristics

Natural Gas Composition		
Component		**Volume Percentage**
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
Methanethiol[A]	CH_4S	$5.75x10^{-6}$
	Total	100.00
	LHV	**HHV**
kJ/kg (Btu/lb)	47,454 (20,410)	52,581 (22,600)
MJ/scm (Btu/scf)	34.71 (932)	38.46 (1,032)

A The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH_4S) with trace levels of H_2S.

Note: Fuel composition is normalized and heating values are calculated.

Ref. **[9]**

The delivered price of natural gas is assumed to be $3.35/MMBtu, on an HHV basis and in 2019 U.S. dollars, per the discussion in the Business Case (Section 7) of this report.

3.3 Limestone Characteristics

The limestone analysis for both the Base Case and Business Case is presented in Exhibit 3-15.

Greer limestone is sourced near Morgantown, WV, and utilized by power plants along the Ohio River. This is a reasonable limestone source for the Business Case plant, which is anticipated to be located within reasonable trucking distance from Morgantown.

Exhibit 3-15. Greer Limestone Analysis

Component	Dry Basis %
Calcium Carbonate, $CaCO_3$	80.40
Magnesium Carbonate, $MgCO_3$	3.50
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43
Total	100.00

Ref [**11**]

Limestone sand is available at $24.25/ton delivered via tractor trailer.

We have determined that the Greer limestone can be received as limestone sand that can have an occasional minus ½" top size. As such a sorbent sizing building will be required.

3.4 Environmental Targets

Exhibit 3-16 provides the air emission limits assumed for both cases and a brief description of the control technology utilized to satisfy the limits.

Exhibit 3-16. MATS and NSPS Emission Limits for PM, HCl, SO_2, NOx, and Hg

Pollutant	Limit (lb/MWh-gross)	Control Technology
SO_2	1.00	In-situ PFBC bed capture via limestone, polishing FGD
NOx	0.70	Low Temperature of PFBC, SNCR
PM (Filterable)	0.09	Cyclones, metallic filters
Hg	$3x10^{-6}$	Co-beneficial capture with ash, GORE mercury removal system
HCl	0.010	Polishing FGD

Ref. [**9**]

Exhibit 3-17 provides the water discharge limits assumed for both cases.

Exhibit 3-17. Water Discharge Targets

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

Ref. [**15**, **16**]

Note A: Monthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

3.5 Capacity

The PFBC coal-based power plant capacity is based on four (4) P200 modules consistent with the Cottbus P200 design. Thus, for the pre-FEED study performance analysis, the PFBC bed velocities are consistent with those of the Cottbus P200 design. The fuel heat input in all the cases is similar but reflects differences in the fuel composition (particularly ash). The PFBC coal-based power plant net capacity target depends on the ultimate plant configuration. The net capacity for the Illinois No. 6 fueled PFBC plant equipped with the amine-based CO_2 capture system is approximately 308 MW net with 97% CO_2 capture based on 4 x P200 PFBC modules (about 404 MW net in capture-ready mode). The net capacity for the waste coal / 5% biomass fueled PFBC plant equipped with the amine-based CO_2 capture system is approximately 280 MW net with 97% CO_2 capture based on 4 x P200 PFBC modules. The four modules will allow the plant to turn down to low levels, and to ramp up quickly if all four modules are operating.

3.6 Capacity Factor

The PFBC power plant analysis for the Base Case (Illinois No. 6 coal) is based on a capacity factor of 85%. This value is assumed to support the carbon capture investment and proposed revenue generated from CO_2 tax credits and/or sales.

The PFBC Power plant analysis for the Business Case (waste coal) is also based on a capacity factor of 85%, as the plant is likely to be baseloaded when fired on the very inexpensive waste coal and capturing carbon dioxide for storage or utilization with a corresponding tax credit/revenue stream. The Business Case is configured to operate with CO_2 capture operating most if not all of the time.

3.7 Raw Water

The makeup water composition reported in Exhibit 3-18 for the Base Case (Midwest site) is based on water qualities from actual operations as reported in QGESS Process Modeling Design Parameters [**1**]. POTW is the "Publicly Owned Treatment Works" from the reference document.

The makeup water composition for the Business Case (southwest Pennsylvania site) is reported in Exhibit 3-18 and is based on Ohio River makeup water compositions based on internal Worley Data. Water samples were taken from points between Wheeling, WV and Syracuse, WV. These data are based on Worley internal data accumulated from various projects and other information collected between 2005 and 2018. The maximum values are the high numbers that were associated with the projects. The data cover seasonal variations and should be representative of sites selected in the area with Ohio River water supply.

Exhibit 3-18. Design Makeup Water Quality – Base Case (Midwest Site)

Parameter	Ground Water (Range)	POTW Water (Range)	Makeup Water (Design Basis)
pH	6.6–7.9	7.1–8.0	7.4
Specific Conductance, µS/cm	1,096–1,484	1,150–1,629	1312
Turbidity, NTU		<50	<50
Total Dissolved Solids, ppm			906
M-Alkalinity as $CaCO_3$, ppm[a]	200–325	184–596	278
Sodium as Na, ppm	102–150	172–336	168
Chloride as Cl, ppm	73–100	205–275	157
Sulfate as SO	100–292	73–122	153
Calcium as Ca, ppm	106–160	71–117	106
Magnesium as Mg, ppm	39–75	19–33	40
Potassium as K, ppm	15–41	11–21	18
Silica as SiO	5–12	21–26	16
Nitrate as N, ppm	0.1–0.8	18–34	12
Total Phosphate as PO	0.1–0.2	1.3–6.1	1.6
Strontium as Sr, ppm	2.48–2.97	0.319–0.415	1.5
Fluoride as F, ppm	0.5–1.21	0.5–0.9	0.8
Boron as B, ppm	0.7–0.77		0.37
Iron as Fe, ppm	0.099–0.629	0.1	0.249
Barium as Ba, ppm	0.011–0.52	0.092–0.248	0.169
Aluminum as Al, ppm	0.068–0.1	0.1–0.107	0.098
Selenium as Se, ppm	0.02–0.15	0.0008	0.043
Lead as Pb, ppm	0.002–0.1		0.026
Arsenic as As, ppm	0.005–0.08		0.023
Copper as Cu, ppm	0.004–0.03	0.012–0.055	0.018
Nickel as Ni, ppm	0.02–0.05		0.018
Manganese as Mn, ppm	0.007–0.015	0.005–0.016	0.009
Zinc as Zn, ppm	0.005–0.024		0.009
Chromium as Cr, ppm	0.01–0.02		0.008
Cadmium as Cd, ppm	0.002–0.02		0.006
Silver as Ag, ppm	0.002–0.02		0.006
Mercury as Hg, ppm	0.0002–0.001		3E-04

[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.

Ref: [**1**], Exhibit 2-3.

Exhibit 3-19. Design Makeup Water Quality – Business Case (Southwest Pennsylvania Site)

Constituent / Parameter	Value Range	Units
Aluminum (Total) as Al	<0.2 - 0.21	mg/L
Ammonia as N	<1	mg/L
Bromide as Br	16 - 57	µg/L
Calcium as Ca	7 - 50	mg/L
Chloride as Cl	14 - 60	mg/L
Conductivity (Specific)	300 - >1000	µmhos/cm @ 25°C
Copper (Total) as Cu	5 - 30	µg/L
Hardness (Total) as CaCO3	45 - 210	mg/L
Iron (Total) as Fe	0.15 – 5.0	mg/L
Magnesium as Mg	4 - 17	mg/L
Manganese (Total) as Mn	<0.5	mg/L
Nitrite + Nitrate-Nitrogen	0.5 – 1.09	mg/L
Phosphorus as P	0.02 – 0.24	mg/L
Phenols (Total)	non-detect	µg/L
pH	5.98 – 9.1	S.U.
Potassium as K	2 - 4	mg/L
Silica as SiO_2	0.7 – 6.3	mg/L
Sodium as Na	11 - 35	mg/L
Sulfate as SO_4	56 - 169	mg/L
Temperature (Low)	33	°F
Temperature (High)	92	°F
TKN as N	0.2 – 1.41	mg/L
TOC	2 - 17	mg/L
Total Dissolved Solids	96 - >500	mg/L
Total Suspended Solids (normal river conditions)	1 - 30	mg/L
Total Suspended Solids (abnormal river events)	30 - 2000	mg/L

3.8 PFBC Air / Gas Path Configuration Basis (Single Shaft Configuration)

For this design, an integrated turbomachine employing an air compressor, a gas expander, and a motor/generator, all on a common shaft, has been specified. This configuration provides an approximate 0.4% (percentage points) improvement in plant efficiency relative to separating the components into separate machines. Component efficiencies used in this analysis are based on current equipment available from major manufacturers. The expectation is that future applications can see improvements by applying the most current aerodynamic and flow path sealing techniques. That is, industrial turbomachinery has not been developed to the same level as the larger gas turbine machines, and potential performance improvements exist.

3.9 Rankine Cycle Parameters

The Rankine cycle steam conditions at the steam turbine inlet connections are presented in Exhibit 3-20.

Exhibit 3-20. Steam Turbine Cycle Steam Conditions

Steam Parameter	Supercritical
Main Pressure, psig	3,500
Main Temperature, °F	1,100
Reheat Temperature, °F	1,100

3.10 Other Major Equipment Performance Assumptions

3.10.1 PFBC Sulfur Removal

The PFBC will retain sulfur in the bed and cyclone ash depending upon the Ca/S ratio of the added sorbent (limestone). For conservatism, we have assumed that the PFBC will only remove 90% S with a Ca/S ratio of 2.5 when operating on either waste coal or Illinois No. 6 coal for all cases. .

For both the capture-equipped and capture-ready cases, the overall plant process will also utilize a caustic scrubber in a packed tower to polish the SO_2 and HCl. The scrubber will remove 98% of the incoming SO_2. Total sulfur removal is estimated at 99.8%.

3.10.2 PFBC Feed System

The PFBC design is based on a paste feed system as opposed to a dry solids injection system.

3.10.3 Ash Handling Equipment

Ash handling and storage equipment will be based on the ash distribution presented in Exhibit 3-21.

Exhibit 3-21. PFBC Ash Distribution

Ash Stream	Ash Split (weight %)	Ash Split for Design (weight %)	Median Size
Bed Ash	30	40%	~1 mm
Cyclone 1	70	90%	20-50 µm
Cyclone 2	<3	With C1 above	3-4 µm
Filter	<2	With C1 above	2-3 µm

Ref: [**17**]

The cyclones will remove approximately 98% of the influent ash. The metallic filter will remove approximately 99.5% of the influent ash. The combined processes will remove 99.99% of the influent ash.

3.11 Plant Performance Targets

The energy efficiency target for the PFBC coal-based power plant is ≥40% on a net higher heating value basis when configured without carbon capture.

The plant will employ efficiency improvement technologies that maintain greater than 40% plant efficiency for a maximum load range (identified) without carbon capture. Examples of such technologies may include:

- Install high efficiency motors
- Limit excess air to 16%
- Sliding pressure for high efficiency at low load
- Self-cleaning condenser design with backpressure of 1.5” Hg to be achieved consistently
- Neural network
- Intelligent soot-blowers
- Other low-cost solutions to improve efficiency

3.12 Plant Flexibility Traits and Targets

The pre-FEED design meets the following Specific Design Criteria:

1. Greater than or equal to 4% ramp rate
   (up to 30% heat input from natural gas can be used)
2. 5:1 turndown with full environmental compliance
3. CO_2 capture-ready steam cycle
4. Zero liquid discharge
5. Solids disposal – limited landfill required
6. Dry bottom and fly ash discharge can be sold for beneficial use

The Coal FIRST target of achieving a cold/warm start in less than two hours is not achievable on a cold start basis. For warm starts, the startup time is a function of the temperature values maintained in specific key components, such as main steam piping and the HP turbine casing, etc.

Cold starts may be defined as starts commencing after the power plant has been offline for at least 120 hours. A traditional supercritical pulverized coal unit may require at least 12 hours to approach full power operation. Should the PFBC power plant need to startup in less than 2 hours, it may be decided that the plant should be maintained in a warm or hot state. Such an operational philosophy may be the most effective solution for the plant to meet a 2-hour start following an extended shutdown.

Start-up times are related to refractory temperature in the PFBC pressure vessel, as well as turbine casing and pipe wall temperatures for the main steam and hot reheat piping. Each of these has its own limitations on the speed at which warm-up can be imposed without compromising life of the component. A schedule of start times as a function of wall temperature will be developed during the Phase 3 FEED study.

3.13 Sparing Philosophy

The sparing philosophy for the major process components is presented in Exhibit 3-22.

Exhibit 3-22. PFBC Process Configuration and Design Redundancy

System	Description	Quantity/Capacity
Fuel Feed (per PFBC)	Putzmeister pump	24x4.17% [6 per PFBC module] Note 1
Air Compressor-Gas Expander	LP/Intercooler/LP Compressor/Expander	4 x 25% [1/PFBC]
PFBC	Pressurized Fluid Bed Combustor	4 x 25% [1/PFBC] Note 2
External reheater	Heat Exchanger	4 x 25% [1/PFBC]
Particulate Filter	Metal filter bank (1 per PFBC) Each bank is 6 or 7 filter vessels	4 x 25% [1/PFBC]
Polishing Scrubber	Flue Gas Desulfurization	4 x 25% [1/PFBC]
Acid Gas Removal	Amine-based system	4 x 25% [1/PFBC] Note 3
Flues and Stacks	Four Flues. Two Stacks	4 x 25% [1/PFBC]

Notes:

1. Two (2) spare Putzmeister feed pump are provided per P200 module.
2. Overall design redundancy is inherent in the 4 x P200 modular design, wherein the plant is capable of operating on any combination of PFBC modules.
3. The amine capture regeneration system is based on 2 x 50%, [i.e., 1 regenerator/ 2 absorbers].

The sparing philosophy of the traditional Rankine Cycle Power Island equipment will follow the established Good Engineering Practice (GEP) in the power plant design to achieve high availability /reliability. Except for the prime movers, large electrical equipment, and a few select units, adequate sparing will be provided.

General guidelines on sparing are presented below:

1. Prime Movers (Steam Turbine Generators): 1 x 100%
2. Step Up and Auxiliary Transformers: 1 x 100%
3. Cooling Tower: 1 x 100%,
   (multiple cells; loss of 1 cell will not limit power generating capacity)
4. Boiler Feed Pumps: 2 x 65%

5. Condensate Pumps: 3 x 50%
6. Closed Cooling Water Pumps: 2 x 100%
7. Circulating Water Pumps: 2 x 50%
8. Miscellaneous Other Pumps: 2 x 100%

3.14 CO_2 Gas Stream Conditions and Purity Requirements

Exhibit 3-23 lists the recommended maximum (or minimum when noted) CO_2 impurities for EOR, saline reservoir storage, and pipeline transport based on the NETL QGESS document [**18**]. The exhibit also presents the preliminary requirements specific to the PFBC project. Our PFBC specific requirements is based on the most restrictive entry for the EOE, saline reservoir storage and pipeline transport for all parameter, except for a minor relaxation on oxygen as discussed in Section 3.14.2.

Additional information on specific contaminants is provided below. Much of this input is taken from reference [**18**].

3.14.1 Water (H_2O)

Moisture content requirements vary widely and depend mostly on the amount of sulfur and other impurities in the gas stream. The lower range is typically for higher sulfur contents and the higher range is for lower sulfur contents. Sulfur and H_2O can combine to form sulfuric acid (H_2SO_4), which corrodes standard piping. The PFBC project CO_2 will have low sulfur levels as the carbon capture system requires a low level of sulfur in the feed to preclude high solvent blowdown. Many moisture content specifications in the literature were derived from instrument air standards producing an unnecessarily stringent requirement. Multiple design parameters mention a maximum of 30 lbs/MMSCF (650 ppmv). The NETL GQESS guidelines have chosen 500 ppmv as a compromise among the multiple sources ranging from 20 ppm to 30 lbs/MMSCF (650 ppmv) with many in the higher range. Moisture content, however, is very site-specific depending on the other impurities such as oxides of nitrogen (NOx) and sulfur dioxide (SOx), which can form acids in the presence of H_2O. H_2O in the presence of CO_2, NOx, and SOx can form equipment-damaging hydrates, depending on the pressure and temperature. Therefore, dehydration may be required at frequent intervals, particularly in the compression stages. In carbon steel pipelines, "rigorously dry CO_2" does not cause corrosion. However, the introduction of H_2O has compounding effects on other impurities, such as O_2 and SO_2.

Exhibit 3-23. CO_2 Stream Compositions Recommended Limits

Component	Unit (Max unless noted)	Carbon Steel Pipeline: Conceptual Design	Carbon Steel Pipeline: Range in Literature	Enhanced Oil Recovery: Conceptual Design	Enhanced Oil Recovery: Range in Literature	Saline Reservoir Sequestration: Conceptual Design	Saline Reservoir Sequestration: Range in Literature	PFBC Project: Pre-FEED Design	Venting Concerns
CO_2	vol% (Min)	95	90–99.8	95	90–99.8	95	90–99.8	**95**	Yes-IDLH 40,000 ppm_v
H_2O	ppm_v	500	20–650	500	20–650	500	20–650	**500**	
N_2	vol%	4	- 7	1	0.01 - 2	4	- 7	**1**	
O_2	vol%	0.001	0.001–4	0.001	0.001–1.3	0.001	0.001–4	**0.003**	
Ar	vol%	4	0.01–4	1	0.01–1	4	0.01–4	**1**	
CH_4	vol%	4	0.01–4	1	0.01–2	4	0.01–4	**1**	Yes- Asphyxiate, Explosive
H_2	vol%	4	- 4	1	- 1	4	- 4	**1**	Yes- Asphyxiate, Explosive
CO	ppmv	35	10–5000	35	10–5000	35	10–5000	**35**	Yes-IDLH 1,200 ppmv
H_2S	vol%	0.01	0.002–1.3	0.01	0.002–1.3	0.01	0.002–1.3	**0.01**	Yes-IDLH 100 ppmv
SO_2	ppmv	100	10–50000	100	10–50000	100	10–50000	**100**	Yes-IDLH 100 ppmv
NOX	ppmv	100	20–2500	100	20–2500	100	20–2500	**100**	Yes-IDLH NO- 100 ppmv, NO2 -200 ppmv
NH_3	ppmv	50	0–50	50	0–50	50	0–50	**50**	Yes-IDLH 300 ppmv
COS	ppmv	trace	trace	5	0–5	trace	trace	**Trace**	Lethal @ High Concentrations (>1,000 ppmv)
C_2H_6	vol%	1	0–1	1	0–1	1	0–1	**1**	Yes- Asphyxiant, Explosive
C_3+	vol%	<1	0–1	<1	0–1	<1	0–1	**<1**	
Part.	ppmv	1	0–1	1	0–1	1	0–1	**1**	
HCl	ppmv	N.I.*	N.I.*	N.I.*	N.I.*	N.I.*	N.I.*	**N.I.***	Yes-IDLH 50 Ppmv
HF	ppmv	N.I.*	N.I.*	N.I.*	N.I.*	N.I.*	N.I.*	**N.I.***	Yes-IDLH 30 Ppmv
HCN	ppm_v	trace	trace	trace	trace	trace	trace	**trace**	Yes-IDLH 50 ppm_v
Hg	ppm_v	N.I.*	N.I.*	N.I.*	N.I.*	N.I.*	N.I.*	**N.I.***	Yes-IDLH 2 mg/m^3 (organo)
Glycol	ppb_v	46	0–174	46	0–174	46	0–174	**46**	

** Not enough information is available to determine the maximum allowable amount*

Note: Components not expected in the CO_2 stream from the post-combustion capture process for the PFBC plant are shaded above.

Ref: **[18]**

3.14.2 Oxygen (O_2)

The O_2 level recommended by the NETL QGESS for conceptual design is 0.001 % by volume. Literature references for O_2 levels in captured CO_2 range up to 1.3 and 4% volume for EOR and carbon steel pipeline, respectively. For this pre-FEED PFBC power plant project, we have relaxed the design basis O_2 level from 0.001% to 0.003% volume (30 ppmv). This is only nominally higher than the QGESS conceptual value and well within the reference projects. This slight relaxation is judged acceptable in view of the low SO_2 levels. Additional background, largely from the QGESS document [**18**] is presented below.

O_2 is another non-condensable species requiring additional compression work and a concentration limit of less than 4 % by volume for most applications. The German Federal Institute for Materials Research and Testing in Berlin conducted testing on pipe material with O_2 concentrations up to 6,600 ppm (0.66 percent by volume) and found no negative pipeline effects when SO_2 concentration was kept to a minimum. However, O_2 in the presence of H_2O can increase cathodic reactions causing thinning in the CO_2 pipeline. Because of this, the typical standard found for pipeline designs is 0.01 percent by volume (100 ppmv); however, operating pipelines tend to be even more conservative in the 0.001 to 0.004 percent by volume (10 to 40 ppmv) range. Preliminary conclusions from an ongoing National Energy Technology Laboratory (NETL) study indicate that the cost of a CO_2 purification system used to lower O_2 content doesn't vary significantly based on final O_2 concentration (10,100 or 1,000 ppm_v).

The introduction of O_2 can inhibit the formation of iron carbonate ($FeCO_3$), which is a protective layer that works to prevent corrosion. O_2 also provides cathodic reaction paths that lead to corrosion of carbon steel pipes.

O_2 can also cause the injection points for EOR to overheat due to exothermic reactions with the hydrocarbons in the oil well. In addition, high O_2 content can cause aerobic bacteria to grow in the reservoir and at the injection points.

3.14.3 CO_2 Gas Stream Product Conditions

The CO_2 gas stream product will be compressed to a pressure of 2215 psia. [**16**, p 448]

The NETL quality guidelines do not specify the CO_2 gas stream product temperature that should be targeted. For this pre-FEED study, the CO_2 gas stream product will be cooled to 95°F. The FEED study will evaluate whether the product temperature can be raised to the 120 to 160°F range to minimize the cooling water requirement. CO_2 product cooling from the slightly elevated temperature to approximately 50°F can be accomplished within a short distance in the underground pipeline.

3.15 Balance of Plant Inputs

The balance of plant assumptions are presented in Exhibit 3-24.

Exhibit 3-24. Balance of Plant Assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower (Case 1, for BOP Case 2*) Air Cooled Condenser (for Steam Turbine – Case 2*)
Fuel and Other Storage	
Coal (Waste coal)	>30 days (via existing slurry impoundments at the prep plant)
Coal (Illinois No 6)	>30 days
Coal - Day Bin (Waste coal or IL No. 6)	1 day
Limestone	30 days
Ash (at Power Plant only)	24 to 36 hours
Caustic (NaOH)	7 days
Ammonia (for SNCR)	7 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV (Case 1*) 500 kV (Case 2*)
Water and Wastewater	
Makeup Water (Midwest Plant)	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Makeup Water (PA Plant)	The water supply is the Ohio River.
Stormwater	Storm water that does not contact equipment is collected through the stormwater system and discharged to its natural drainage course. system.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	The proposed PFBC plant will incorporate a Zero Liquid Discharge system. The plant design will be integrated with the fuel preparation facility to incorporate internal water recycle and to reuse water to the maximum extent to minimize the capacity of any required ZLD system

Note: * Case 1 is the Illinois No 6 base case. Case 2 is the waste coal/biomass business case.

We note that the business case location has the following transmission lines/substation infrastructure near-by.

The main 138kV substation at the mine/prep plant site is called “Enon” and has a supply capacity of about 200 MVA. The mine complex utilizes about 110 MVA, with a nearby residential demand of approximately another 10 MVA. There is about 80 MVA of spare capacity. The Pennsylvania power plant will need a grid connection of approximately 350 - 400 MVA, or less if the mine complex can be directly fed from the plant.

An existing 500 kV transmission line passes within a few miles of the assumed PAMC site. For this pre-FEED phase, we will assume an interconnection at 345 kV similar to the NETL baseline report for Case 1 and 500kV for Case 2.

4 Performance Results

The following sections present performance results for the advanced PFBC coal-fueled power plant with CO_2 capture. These results are based on a PFBC plant that is designed to use an amine-based CO_2 capture process (as opposed to the Benfield process, which was considered in the Conceptual Design Report).

Results were developed for two cases:

1) **Case 1:** The **Base Case** based on the **Midwestern site** and **Illinois No. 6 coal**, and
2) **Case 2:** The **Business Case** based upon the **southwestern Pennsylvania** site and **wet, fine waste coal**.

Each case has three (3) possible subcases (A, B, and C), as follows:

A – Capture-Ready

B – Carbon Capture-Equipped

C – Carbon Capture-Equipped with 5% biomass fuel by weight.

The six (6) potential cases are summarized in Exhibit 4-1. However, CONSOL has decided to only pursue the capture-equipped waste coal business cases (2B and 2C). Therefore, we fully present only Cases 1A, 1B, 2B, and 2C. We do not present Case 2A. Case 2C is essentially Case 2B with 5% biomass cofiring. The Case 2B and 2 C heat and mass balance diagrams, and performance tables show nearly identical performance. This is as expected since the biomass and waste coal have similar dry basis heating values. Thus a single water balance is presented for Case 2B/2C. Additional remarks regarding Case 2 performance firing 10% biomass are presented at the end of Section 4.3.2.

Exhibit 4-1. PFBC Case Matrix

Case Definition	Capture-Ready (Subcase A)	Capture-Equipped (Subcase B)	Capture-Equipped & Biomass (Subcase C)
Illinois No. 6 (Case 1)	Case 1A	Case 1B	Case 1C (Not developed)
Waste Coal (Case 2)	Case 2A (Not developed)	Case 2B	Case 2C

All of the cases are based on the relevant information from the Design Basis Report for this project. The steam turbine cycle has been optimized for each case. That is, the steam turbine for the capture-equipped case is not based on the capture-ready case but has been optimized and limited in its capacity in view of the steam demands of the carbon capture system.

4.1 Plant Performance Model

The primary software used to perform the heat and mass balance (H&MB) calculations for this study is Thermoflex V28. Thermoflex is a modular program with a graphical interface developed by Thermoflow, Inc. of Southborough, MA, USA. The program covers both design and off-design simulation and models all types of power plants, including combined cycles, conventional steam cycles, and renewables. It can also model steam plants, chilled water plants, general thermal systems, and steam networks.

The PFBC power plant is modeled using the standard equipment icons available in the Thermoflex model, including the following major equipment:

- PFBC boiler
- Combustion air compressor
- Gas expander & generator
- Steam turbine & generator
- Condenser
- Cooling tower
- Emission control systems, including CO_2 capture
- Heat exchangers
- Pumps
- Interconnection piping

In order to simplify the set up and use of the model, Thermoflex software was used to create one complete PFBC train, including the boiler, air compressor, gas expander, heat recovery and emission control equipment. The steam/water flows to and from the one PFBC train are multiplied by a factor to represent the total flow to/from all four PFBC trains. The design parameters for each piece of equipment are based on vendors' inputs, public references, and industry standard practice. The following are the major references and assumptions used in the H&MB modeling:

1) PFBC Performance: Based on original ABB H&MB for the P200 PFBC.
2) Steam Turbine and Generator: Based on GE's quotation and adjusted accordingly for the required steam flow.
3) Compressor & Expander: Assuming 88% polymetric efficiency for both compressor and expander.
4) Condenser and cooling tower: Optimized based on industry practice for improved overall plant efficiency. The Business Case (waste coal-fired) plant utilizes a dry air-cooled condenser for the steam turbine heat rejection to reduce plant makeup water consumption by approximately 60% for the assumed PAMC site, while using a reduced size wet cooling tower for other heat rejection. Other potential sites for the Business Case plant may use an evaporative cooling tower and shell and tube condenser like the Base Case (Illinois 6 coal-fired) plant.
5) CO_2 capture system: Energy consumption for CO_2 capture is based on the DOE baseline study for bituminous coal power plants [**16**] and adjusted for 97% CO_2 capture efficiency. The energy requirement was modeled based on the Cansolv data shown in the NETL baseline report.
6) Caustic Scrubber: the SO_2 and HCl removal efficiency are modeled based on vendor input and industry experience.

4.2 Illinois No. 6 PFBC Plant Cases 1A & 1B

This section presents both Illinois No. 6 cases, Case 1A (Capture-Ready) and Case 1B (Capture-Equipped).

4.2.1 Process Description

4.2.1.1 Case 1A Process Description

In this section, the Case 1A PFBC process in capture-ready configuration (i.e., without CO_2 capture installed) is described. The description follows the block flow diagram (BFD) in Exhibit 4-2 and the stream numbers reference the same exhibit. Exhibit 4-3 provides the process data for the numbered streams in the BFD.

Compressed air (Stream 2) and coal and limestone paste (Streams 3 & 4) are introduced into the PFBC vessel and into the PFBC bed. Note that the coal and limestone paste feed streams are shown separately for information. In the actual feed to the PFBC vessel and bed, the coal and limestone paste feed is a single stream. Prior to the power plant, the coal preparation and feeding systems consist of conventional coal receiving and unloading equipment, also incorporating a stacker-reclaimer and primary coal crushing equipment. The crushed, reclaimed coal is then milled to final size and mixed with ground limestone to form a pumpable paste with nominal 26% moisture by weight. PFDs of the fuel and sorbent handling system and other plant systems are presented in Appendix D.

Feedwater (Stream 10) enters the PFBC where supercritical main steam is produced (Stream 11) and is fed to the supercritical HP steam turbine. Cold reheat steam (Stream 12) returns to the PFBC vessel where it is reheated and is fed to the IP Steam turbine as hot reheat steam (Stream 13). The steam expands in the IP turbine before crossing over (Stream 14) to the LP steam turbine. Turbine exhaust steam (Stream 15) is condensed before continuing to the condensate and feed water heating train. The reader should note that there are four PFBC modules and one steam turbine. As such, some of the stream quantities are presented on a per PFBC basis, while others are presented on an overall plant basis. A row in the stream table indicates the flow basis of each stream (i.e., per PFBC or overall plant basis).

Flue gas exits the PFBC bed and cyclones (Stream 5) prior to being cooled to 1450 °F (Stream 6). The slightly cooled flue gas passes through the high temperature metallic filters prior to entering the turbo-expander (Stream 7). Fly ash from the cyclones (Stream 18) and metallic filters (Stream 19) is forwarded to the fly ash silos for short-term storage. The gas leaving the gas expander (Stream 8) passes through HP and LP economizers (Stream 9) before entering the caustic scrubber to remove SO_2 and HCl (Stream 20). The gas enters a mercury removal process and then exits the plant stack (Stream 21). The mercury removal system may not be required in light of the configuration's filters and wet scrubbers. Nevertheless, space provision will be provided for the mercury removal.

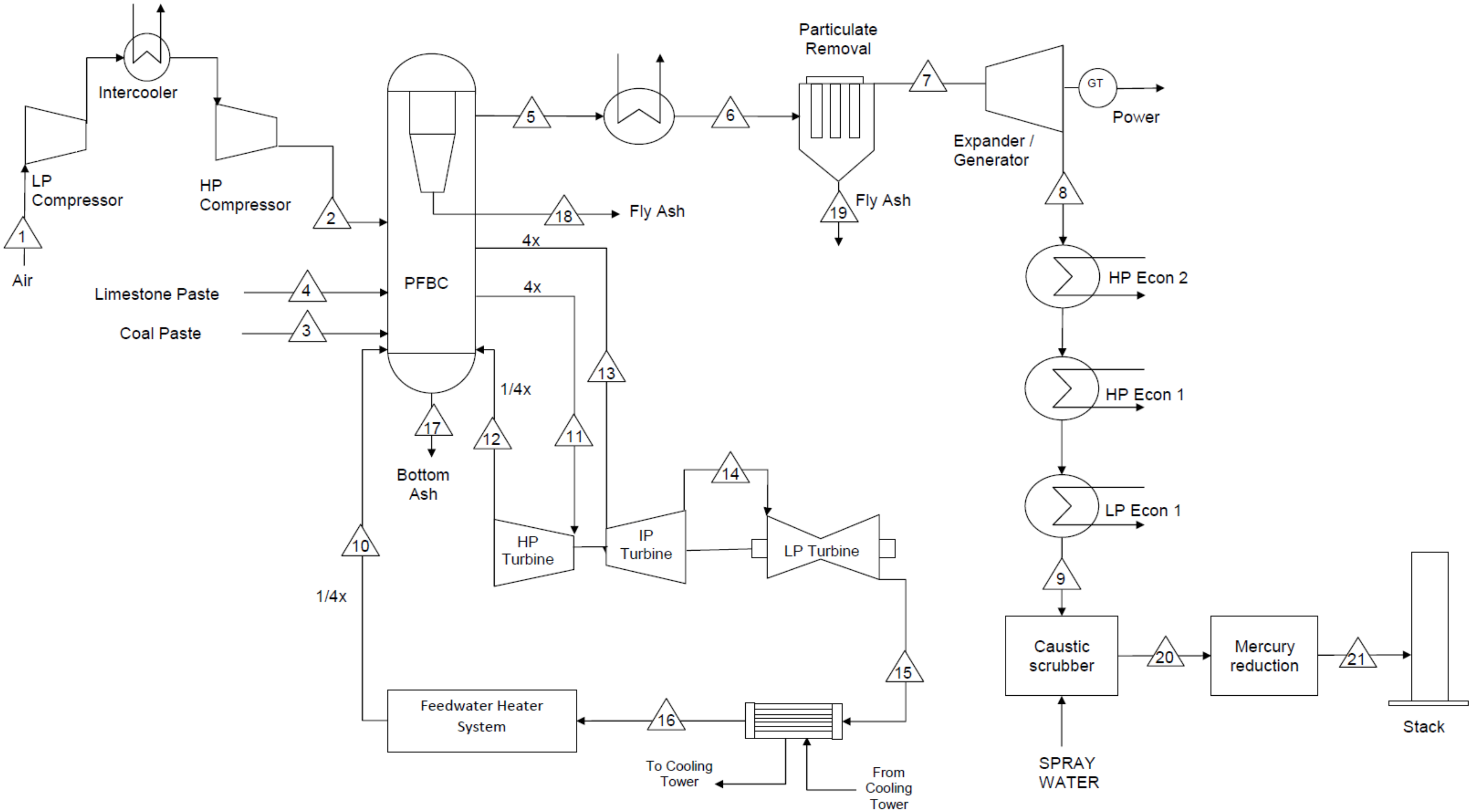
4.2.1.2 Case 1B Process Description

In this section, the Case 1B PFBC process with CO_2 capture is described. The description follows the BFD in Exhibit 4-4 and the stream numbers reference the same exhibit. Exhibit 4-5 provides the process data for the numbered streams in the BFD.

Compressed air (Stream 2) and coal and limestone paste (Streams 3 & 4) are introduced into the PFBC vessel and into the PFBC bed. (As indicated above, the coal and limestone paste feed streams are shown separately for information. In the plant, the coal and limestone paste feed is a single stream.) Feedwater (Stream 10) enters the PFBC where supercritical main steam is produced (Stream 11) and is fed to the supercritical HP steam turbine. Cold reheat steam (Stream 12) returns to the PFBC vessel where it is reheated and is fed to the IP Steam turbine as hot reheat steam (Stream 13). The steam expands in the IP turbine before crossing over (Stream 14) to the LP steam turbine. Turbine exhaust steam (Stream 15) is condensed before continuing to the condensate and feed water heating train. The reader should note that there are four PFBC modules and one steam turbine. As such, some of the stream quantities are presented on a per PFBC basis, while others are presented on an overall plant basis. A row in the stream table indicates the flow basis of each stream (i.e., per PFBC or overall plant basis).

Flue gas exits the PFBC bed and cyclones (Stream 5) prior to being cooled to 1450 °F (Stream 6). The slightly cooled flue gas passes through the high temperature metallic filters prior to entering the turbo-expander (Stream 7). Fly ash from the cyclones (Stream 18) and metallic filters (Stream 19) is forwarded to the fly ash silos for short-term storage. The gas leaving the gas expander (Stream 8) passes through HP and LP economizers. The stream leaving the LP economizer (Stream 9) enters the caustic scrubber to remove residual SO_2 and HCl to achieve emissions targets and minimize amine solvent degeneration. The polished flue gas (Stream 20) passes through a mercury removal system. At this point, the carbon capture configuration begins to differ from the carbon capture-ready configuration. The gas leaving the mercury removal system passes through a gas pre-cooler and then to the amine carbon dioxide scrubber (Stream 21). The mercury removal system may not be required in light of the configuration's filters and wet scrubbers. Nevertheless, space provision will be provided for the mercury removal. The scrubbed flue gas exits the plant stack (Stream 24), while the captured CO_2 (Stream 22) is compressed in a multi-stage intercooled compressor and dried in preparation for transport for geologic storage or beneficial use (Stream 23).

Exhibit 4-2. Case 1A Block Flow Diagram (BFD), PFBC without CO_2 Capture



Note: There are four PFBC units and one steam turbine in the plant. Streams for PFBC are for each unit.

Exhibit 4-3. Case 1A Stream Table, PFBC without CO_2 Capture

V-L Mole Fraction										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Ar	0.0093	0.0093	0.0000	0.0000	0.0085	0.0085	0.0085	0.0085	0.0085	0.0000
CO_2	0.0003	0.0003	0.0000	0.0000	0.1385	0.1385	0.1385	0.1385	0.1385	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0101	0.0101	1.0000	1.0000	0.1232	0.1232	0.1232	0.1232	0.1232	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0002	0.0002	0.0002	0.0002	0.0002	0.0000
N_2	0.7729	0.7729	0.0000	0.0000	0.7034	0.7034	0.7034	0.7034	0.7034	0.0000
O_2	0.2074	0.2074	0.0000	0.0000	0.0260	0.0260	0.0260	0.0260	0.0260	0.0000
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	229.5	229.5	229.5	229.5	229.5	0.0
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	24,641	24,641	1205.2	330.2	27,117	27,117	27,117	27,117	27,117	27,094
V-L Flowrate (lb/hr)	711,000	711,000	21,713	5,948	792,100	792,100	792,100	792,100	792,100	488,100
Solids Flowrate (lb/hr) [B]	-	-	61,797	16,930	298	298	2	2	2	
Flow Basis per PFBC/Plant	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	59.0	576.3	77.0	77.0	1500.0	1450.0	1448.1	739.2	270.0	613.5
Pressure (psia)	14.70	186.95	160.50	160.50	160.50	160.42	152.83	16.09	15.46	3837.0
Steam Table Enthalpy (Btu/lb) [A]	-	-	-	-	-	-	-	-	-	625.2
Density (lb/ft^3)	0.076	0.485	-	-	0.223	0.229	0.218	0.037	0.058	43.700
V-L Molecular Weight	28.855	28.855	18.015	18.015	29.210	29.210	29.210	29.210	29.210	18.015

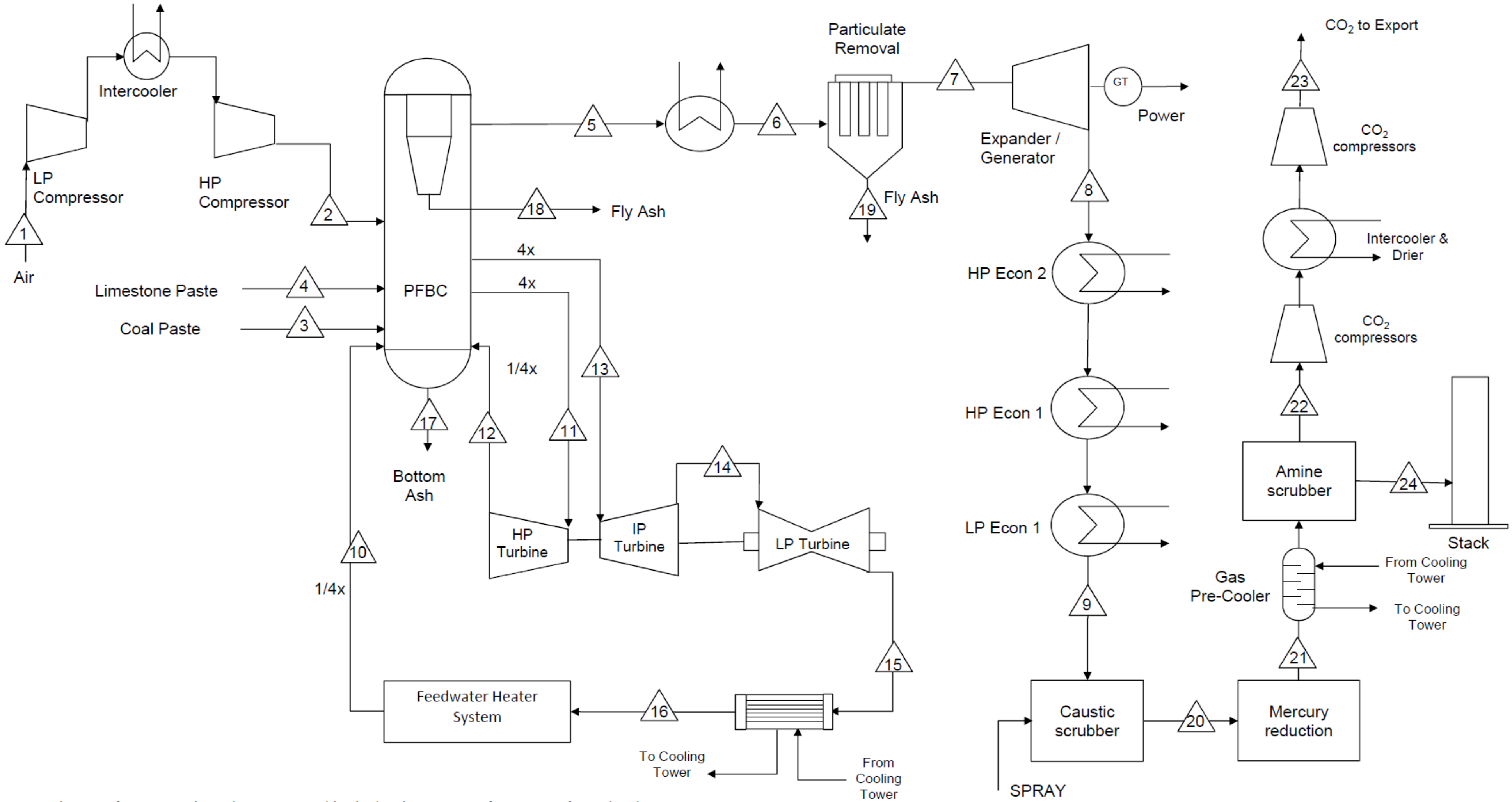
[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

[B] Solid flowrate is for dry solids.

V-L Mole Fraction											
	11	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0080	0.0080
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1317	0.1317
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	0.1665	0.1665
HCl	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	0.6691	0.6691
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0247	0.0247
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6	4.6
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	108,380	96,995	96,995	83,618	76,457	85,905	-	-	-	28,517	28,517
V-L Flowrate (lb/hr)	1,952,500	1,747,400	1,747,400	1,506,400	1,377,400	1,547,600	-	-	-	817,000	817,000
Solids Flowrate (lb/hr)	-	-	-	-	-	-	6,390	14,612	297	0	0
Flow Basis per PFBC/Plant	Plant	Plant	Plant	Plant	Plant	Plant	PFBC	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	1100.0	679.7	1100.0	545.2	91.7	92.8	-	-	-	134.7	134.6
Pressure (psia)	3515.0	781.0	711.3	82.0	0.74	2.53	-	-	-	15.03	14.85
Steam Table Enthalpy (Btu/lb) [A]	1496.7	1326.9	1570.2	1303.6	985.7	60.8	-	-	-	-	-
Density (lb/ft^3)	4.319	1.275	0.784	0.139	0.0025	62.080	-	-	-	0.068	0.067
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015	18.015	-	-	-	28.650	28.650

[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

Exhibit 4-4. Case 1B Block Flow Diagram (BFD), PFBC with CO_2 Capture



Note: There are four PFBC units and one steam turbine in the plant. Streams for PFBC are for each unit.

Exhibit 4-5. Case 1B Stream Table, PFBC with CO_2 Capture

V-L Mole Fraction										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Ar	0.0093	0.0093	0.0000	0.0000	0.0085	0.0085	0.0085	0.0085	0.0085	0.0000
CO_2	0.0003	0.0003	0.0000	0.0000	0.1385	0.1385	0.1385	0.1385	0.1385	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0101	0.0101	1.0000	1.0000	0.1232	0.1232	0.1232	0.1232	0.1232	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0002	0.0002	0.0002	0.0002	0.0002	0.0000
N_2	0.7729	0.7729	0.0000	0.0000	0.7034	0.7034	0.7034	0.7034	0.7034	0.0000
O_2	0.2074	0.2074	0.0000	0.0000	0.0260	0.0260	0.0260	0.0260	0.0260	0.0000
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	229.5	229.5	229.5	229.5	229.5	0.0
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	1.1	1.1	1.1	1.1	1.1	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	24,641	24,641	1,205	330	27,115	27,115	27,117	27,117	27,117	27,166
V-L Flowrate (lb/hr)	711,000	711,000	21,713	5,948	792,100	792,100	792,100	792,100	792,100	489,400
Solids Flowrate (lb/hr) [B]	-	-	61,797	16,930	298	298	2	2	2	-
Flow Basis per PFBC/Plant	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	59	576.2	77	77	1500	1450.0	1448.1	749.2	270.0	615.5
Pressure (psia)	14.70	186.96	160.46	160.46	160.46	160.42	152.83	16.50	15.88	3839.0
Steam Table Enthalpy (Btu/lb) [A]	-	-	-	-	-	-	-	-	-	627.9
Density (lb/ft^3)	0.076	0.485	-	-	0.223	0.229	0.218	0.037	0.059	43.551
V-L Molecular Weight	28.85	28.85	18.015-	18.015	29.212	29.212	29.210	29.210	29.210	18.015

[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

[B] Solid flowrate for is for dry solids.

V-L Mole Fraction										
	11	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1318
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	0.1662
HCl	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	0.6693
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0247
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000
V-L Flowrate (lbmol/hr)	108,669	97,240	97,240	48,065	47,182	56,025	-	-	-	28,505
V-L Flowrate (lb/hr)	1,957,700	1,751,800	1,751,800	865,900	850,000	1,009,300	-	-	-	816,800
Solids Flowrate (lb/hr)	-	-	-	-	-	-	6,390	14,612	297	0
Flow Basis per PFBC/Plant	Plant	Plant	Plant	Plant	Plant	Plant	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	1100.0	680.3	1100.0	559.6	91.7	96.2				135.6
Pressure (psia)	3515.0	784.0	714.1	87.5	0.74	5.94				15.31
Steam Table Enthalpy (Btu/lb) [A]	1496.7	1327.7	1570.2	1310.3	986.5	64.3	-	-	-	-
Density (lb/ft^3)	4.319	1.280	0.787	0.146	0.0025	62.039	-	-	-	0.069
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015	18.015	-	-	-	28.655

A Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

V-L Mole Fraction										
	21	22	23	24	25	26	27	28	29	30
Ar	0.0081	0.0000	0.0000	0.0108						
CO_2	0.1318	0.9722	1.0000	0.0053						
H_2	0.0000	0.0000	0.0000	0.0000						
H_2O	0.1662	0.0278	0.0000	0.0555						
HCl	0.0000	0.0000	0.0000	0.0000						
N_2	0.6693	0.0000	0.0000	0.8954						
O_2	0.0247	0.0000	0.0000	0.0331						
SO_2 (ppmvd)	4.6	0.0	0.0	0.0						
SO_3 (ppmvd)	0.0	0.0	0.0	0.0						
Total	1.0000	1.0000	1.0000	1.0000						
V-L Flowrate (lbmol/hr)	28,505	3,747	3,642	21,307						
V-L Flowrate (lb/hr)	816,800	162,200	160,300	592,400						
Solids Flowrate (lb/hr)	0	0	0	0						
Flow Basis per PFBC/Plant	PFBC	PFBC	PFBC	PFBC						
Temperature (°F)	135.6	95.0	95.0	95.0						
Pressure (psia)	15.13	29.30	2215.0	14.69						
Steam Table Enthalpy (Btu/lb) [A]	-	-	-	-						
Density (lb/ft^3)	0.068	0.213	16.420	0.069						
V-L Molecular Weight	28.655	43.287	44.010	27.803						

[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

4.2.2 Plant Performance Summary

The Case 1A (Capture-Ready) plant produces 403.97 MW net at a net plant HHV efficiency of 42.49%. The Case 1B (Capture-Equipped) plant produces 307.72 MW net at a net plant HHV efficiency of 32.37%.

The overall plant performance is summarized in Exhibit 4-6. A breakdown of the auxiliary loads is provided in Exhibit 4-7 for both Cases 1A and 1B. These exhibits present the performance both with and without the inclusion of a ZLD system to comply with the requirements of the Coal FIRST program (which include the use of a ZLD system), and to facilitate performance comparisons to other plant configurations that do not include the use of a ZLD. It is noted that the pulverized coal cases (i.e., Cases 11A, 11B, 12A, and 12B) in the NETL Cost and Performance Baseline report do not include ZLD [**16**].

Exhibit 4-6. Cases 1A & 1B Plant Performance Summary

	CASE 1A	CASE 1B
Total Gross Power, MWe	421.29	362.87
CO_2 Capture/Removal Auxiliaries, kWe	0	11,600
CO_2 Compression, kWe	0	23,600
Zero Liquid Discharge System (ZLD), kWe	1,700	2,500
Balance of Plant, kWe	15,618	17,448
Total Auxiliaries [excluding ZLD], MWe	15.62	52.65
Total Auxiliaries [including ZLD], MWe	17.32	55.15
Net Power [excluding ZLD], MWe	**405.67**	**310.22**
Net Power [including ZLD], MWe	**403.97**	**307.72**
HHV Net Plant Efficiency [excluding ZLD], %	**42.76%**	**32.63%**
HHV Net Plant Efficiency [including ZLD], %	**42.49%**	**32.37%**
HHV Net Plant Heat Rate [excluding ZLD], Btu/kWh	7,997	10,457
HHV Net Plant Heat Rate [including ZLD], Btu/kWh	8,030	10,542
Condenser Duty, MMBtu/hr	1,368	881
Amine-based AGR Cooling Duty, MMBtu/hr	0	1,085
As-Received Coal Feed, lb/hr	278,077	278,079
Limestone Sorbent Feed, lb/hr	67,720	67,720
HHV Thermal Input, kWt	950,692	950,700
Raw Water Withdrawal, gpm/MW_{net}	6.2	9.5
Raw Water Consumption, (gpm/MW_{net})	3.6	4.6
Excess Air, %	16.0	16.0

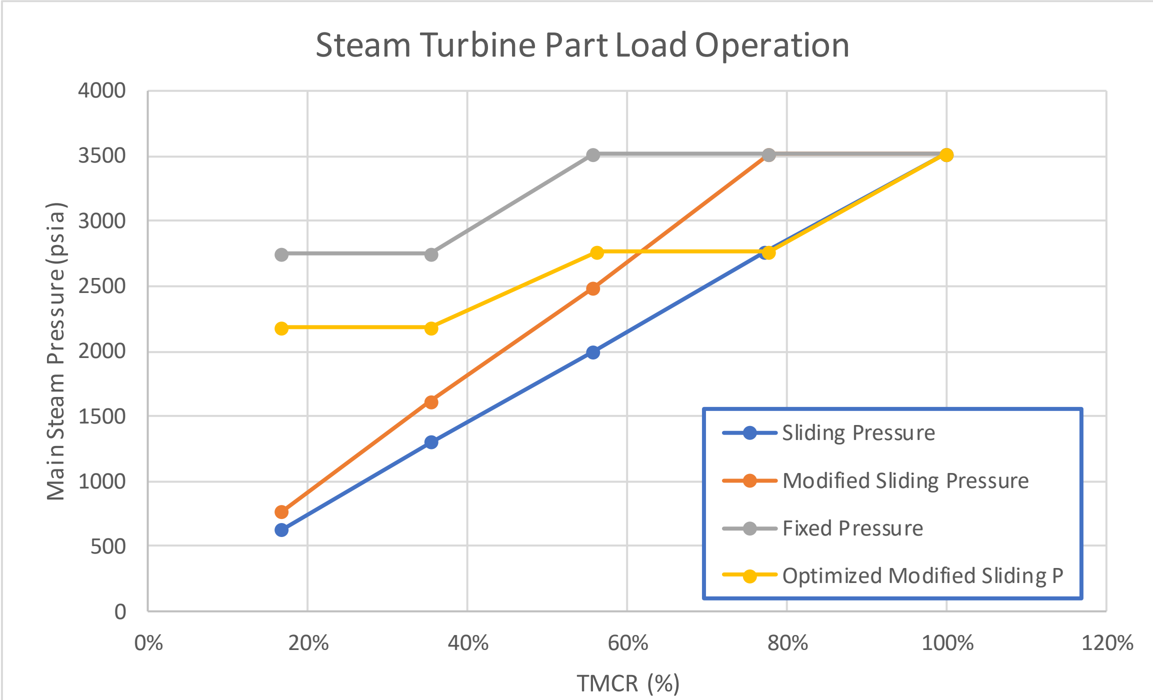
Exhibit 4-7. Case 1 Plant Power Summary

Power Summary		
	CASE 1A	**CASE 1B**
Steam Turbine Power, MWe	357.28	301.23
Turbomachine Power, MWe	64.01	61.64
Total Gross Power, MWe	421.29	362.87
Auxiliary Load Summary		
	CASE 1A	**CASE 1B**
Ash Handling, kWe	400	400
Circulating Water Pumps, kWe	2,400	3,700
CO_2 Capture/Removal Auxiliaries, kWe	-	11,600
CO_2 Compression, kWe	-	23,600
Condensate Pumps, kWe	800	480
Cooling Tower Fans, kWe	1,600	2,200
Fuel & Sorbent Preparation, kWe	4,000	4,000
Metallic Filter, kWe	40	40
Miscellaneous Balance of Plant[A,B], kWe	1,200	1,200
PFBC loads	1,500	1,500
Polishing Flue Gas Desulfurizer, kWe	1,328	1,328
Steam Turbine Auxiliaries, kWe	150	150
Transformer Losses, kWe	1,100	950
Water Treatment System, kWe	1,100	1,500
Zero Liquid Discharge (ZLD) loads, kWe	1,700	2,500
Total Auxiliaries [excluding ZLD], MWe	**15.62**	**52.65**
Total Auxiliaries [including ZLD], MWe	**17.32**	**55.15**
Net Power [excluding ZLD], MWe	**405.67**	**310.22**
Net Power [including ZLD], MWe	**403.97**	**307.72**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads
[C]Includes raw water, demineralized water, and waste water systems.

Part load performance will be presented in the Phase 3 FEED study for the selected configuration. We do note that the steam cycle used for this 4-unit PFBC plant is based on a hybrid of constant pressure and sliding pressure operation. A schedule of main steam pressure vs. load has been proposed by GE and has been adopted for the purposes of this Phase 2 pre-FEED study. The schedule that will be followed is the yellow line labeled “Optimized modified sliding pressure” in Exhibit 4-8.

Exhibit 4-8. Steam Turbine Part Load Operation



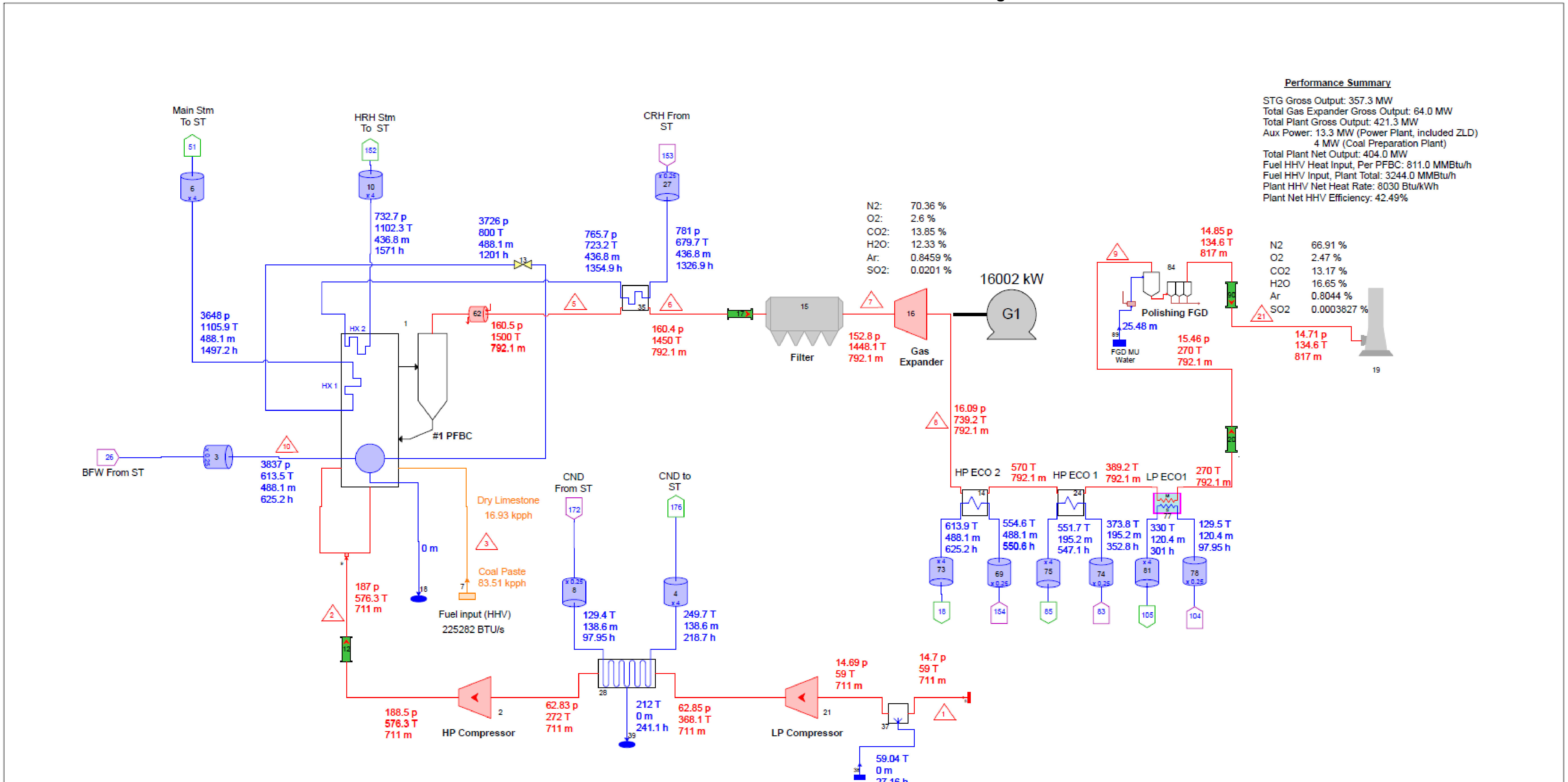
4.2.3 Heat and Mass Balances

In this section the Heat and Mass Balances (H&MB) are presented in two process sheets:

- PFBC Process
- Rankine Cycle

The PFBC H&MB covers the fuel, sorbent, boiler feed water, and air feed into the PFBC, steam generation and reheating, combustion gas cleanup and expansion, and economization of the feed water. The Rankine cycle H&MB covers the complete steam cycle. The Case 1A H&MB diagrams are presented in Exhibit 4-9 and Exhibit 4-10 for the PFBC and Rankine cycles, respectively. The Case 1B H&MB diagrams are presented in Exhibit 4-11 and Exhibit 4-12 for the PFBC and Rankine cycles, respectively.

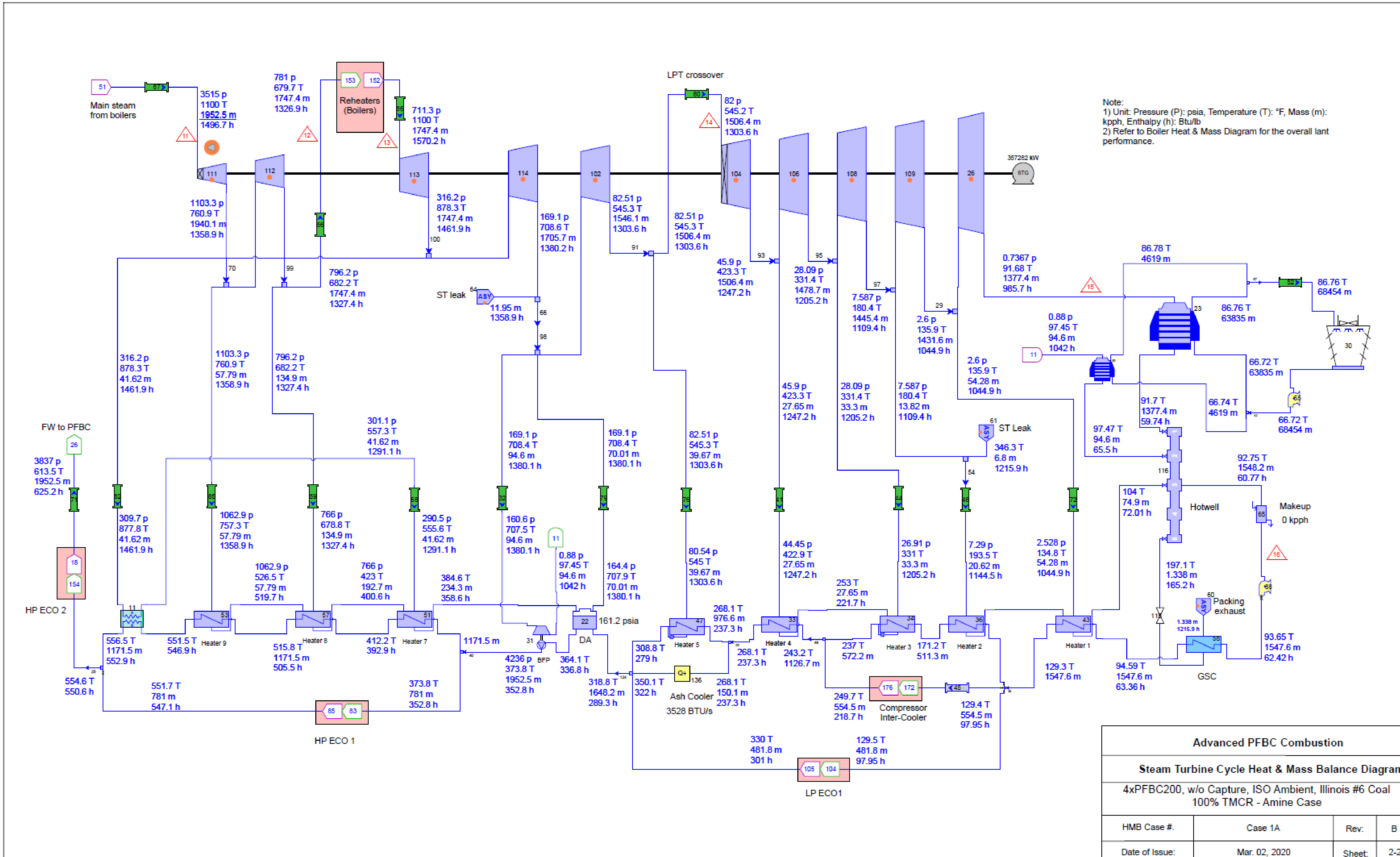
Exhibit 4-9. Case 1A PFBC Process H&MB Diagram



Advanced PFBC Combustion			
Boiler Heat & Mass Balance Diagram			
4xPFBC200, w/o Capture, ISO Ambient, Illinois #6 Coal 100% TMCR - Amine Case			
HMB Case #.	Case 1A	Rev:	B
Date of Issue:	Mar 02, 2020	Sheet:	1-2

Legend
P – psia
T – F
m – kpph
h – Btu/lb

Exhibit 4-10. Case 1A Rankine Cycle H&MB Diagram



Advanced PFBC Combustion			
Steam Turbine Cycle Heat & Mass Balance Diagram			
4xPFBC200, w/o Capture, ISO Ambient, Illinois #6 Coal 100% TMCR - Amine Case			
HMB Case #.	Case 1A	Rev:	B
Date of Issue:	Mar. 02, 2020	Sheet:	2-2

Exhibit 4-11. Case 1B PFBC Process H&MB Diagram

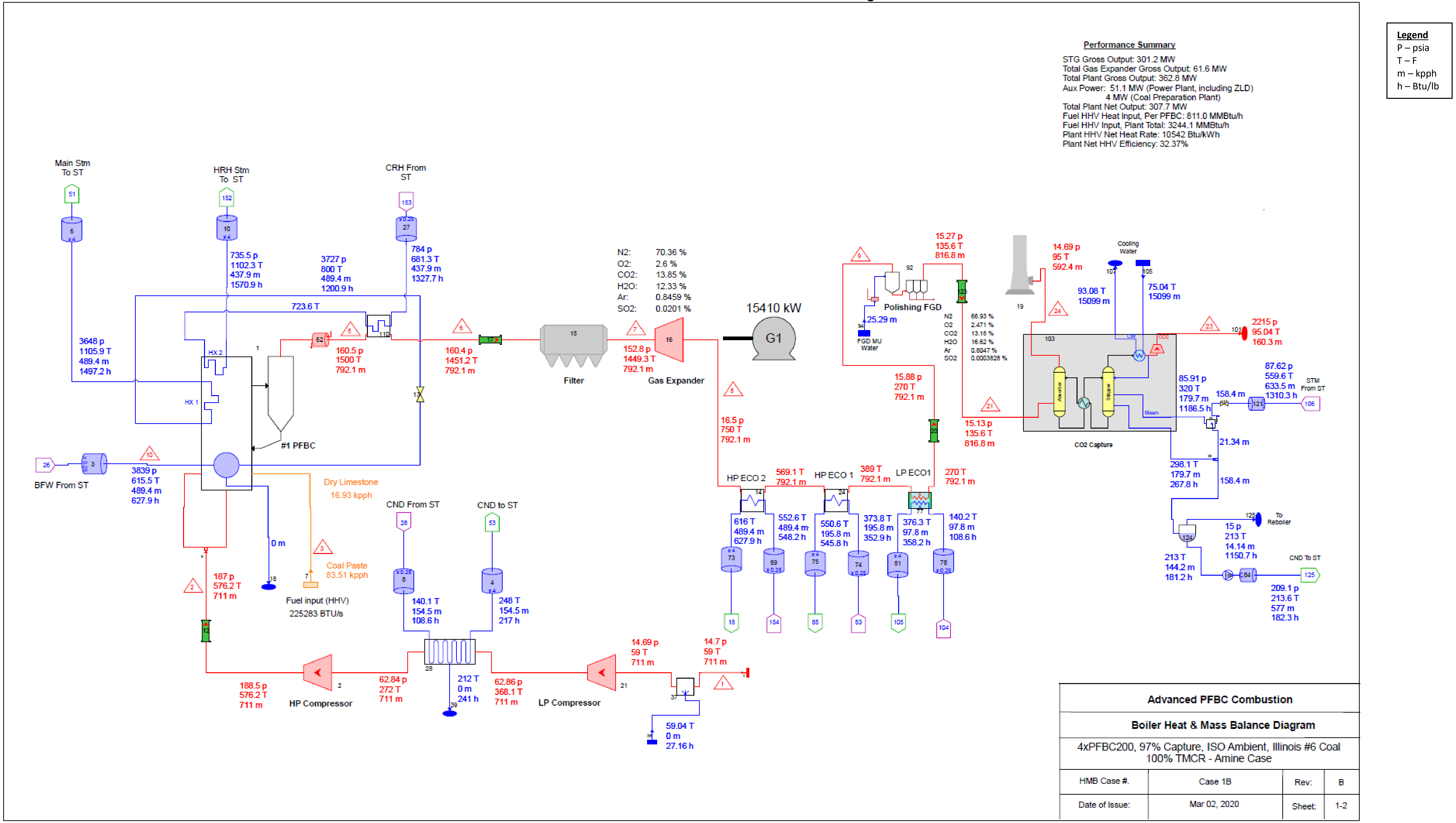
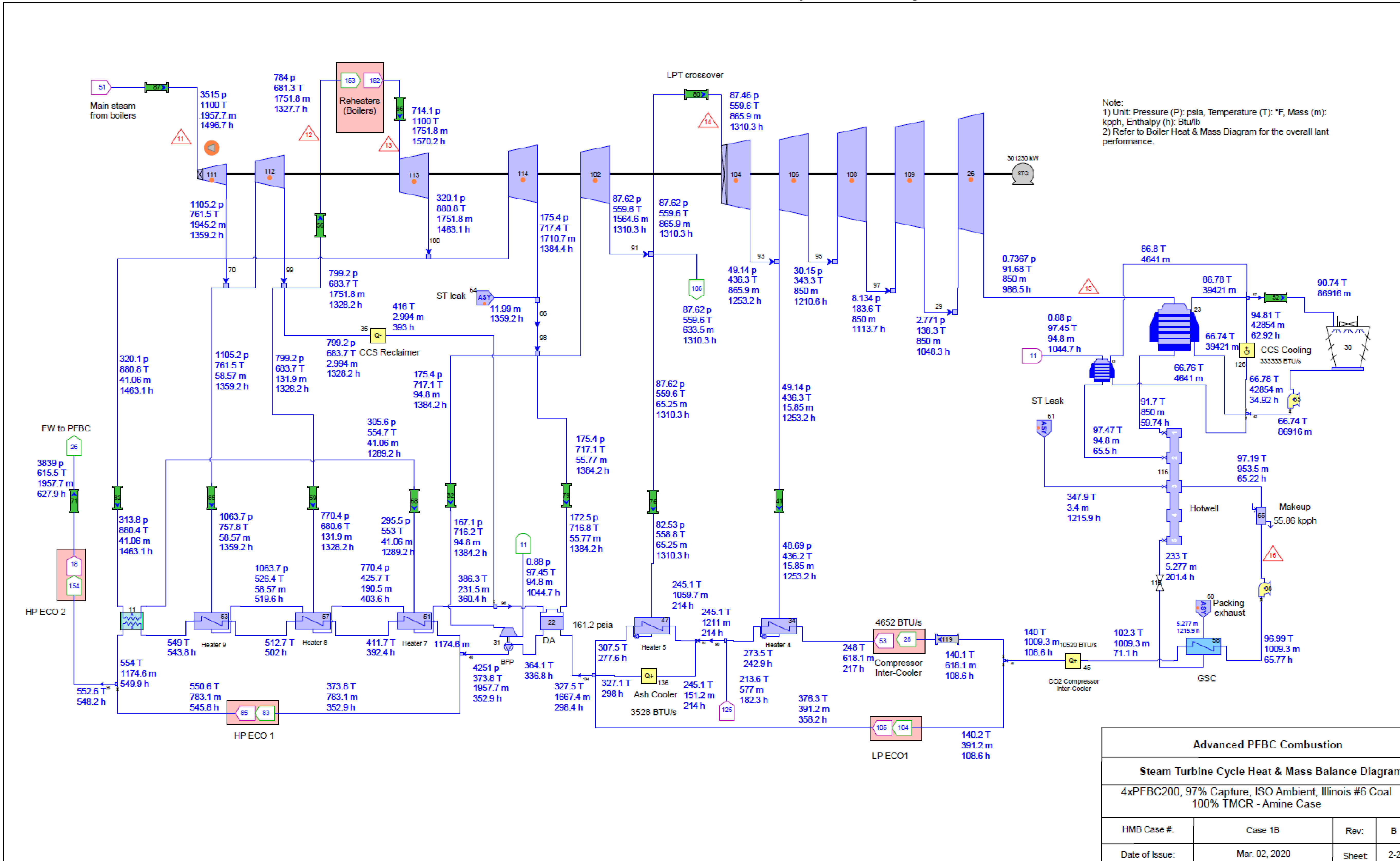


Exhibit 4-12. Case 1B Rankine Cycle H&MB Diagram



An overall plant energy balance for Case 1A is provided in tabular form in Exhibit 4-13. An overall plant energy balance for Case 1B is provided in tabular form in Exhibit 4-14. The power out is the steam turbine and the gas turbomachine power prior to generator losses.

Exhibit 4-13. Case 1A Overall Energy Balance (32 °F reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	3,244.0	4.4	–	3,248.5
Air	–	37.0	–	37.0
Raw Water Makeup	–	44.8	–	44.8
Limestone	–	1.6	–	1.6
Caustic (NaOH) solution (50%)	–	0.1	–	0.1
Auxiliary Power	–	–	41.7	41.7
TOTAL	**3,244.0**	**87.9**	**41.7**	**3,373.6**
Heat Out (MMBtu/hr)				
Bed Ash	–	1.4	–	1.4
Fly Ash	–	3.2	–	3.2
Stack Gas	–	441.9	–	441.9
$NaHS0_3$	–	0.1	–	0.1
Motor Losses and Design Allowances	–	–	15.0	15.0
Cooling Tower Load[A]	–	1,367.8	–	1,367.8
CO_2 Product Stream	–	–	–	0.0
Blowdown Streams and Deaerator Vent	–	4.4	–	4.4
Ambient Losses[B]	–	81.1	–	81.1
Gross Power	–	–	1,459.5	1,459.5
TOTAL	–	**1,899.9**	**1,474**	**3,374.3**
Unaccounted Energy[C]	–	–	–	-0.8

[A] Includes condenser 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 4-14. Case 1B Overall Energy Balance (32 °F reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	3,244.1	4.4	–	3,248.5
Air	–	37.0	–	37.0
Raw Water Makeup	–	68.4	–	68.4
Limestone	–	1.6	–	1.6
Caustic (NaOH) solution (50%)	–	0.1	–	0.1
Auxiliary Power	–	–	171.3	171.3
TOTAL	**3,244.1**	**111.5**	**171.3**	**3,526.9**
Heat Out (MMBtu/hr)				
Bed Ash	–	1.4	–	1.4
Fly Ash	–	3.2	–	3.2
Stack Gas	–	108.7	–	108.7
$NaHSO_3$	–	0.1	–	0.1
Motor Losses and Design Allowances	–	–	35.0	35.0
Cooling Tower Load[A]	–	2,004.8	–	2,004.8
CO_2 Product Stream	–	-35.1	–	-35.1
Blowdown Streams and Deaerator Vent	–	4.5	–	4.5
Ambient Losses[B]	–	113.5	–	113.5
Gross Power	–	–	1,257.1	1,257.1
TOTAL	0	2,201.0	1,292.1	3,493.1
Unaccounted Energy[C]	–	–	–	33.8

[A] Includes condenser 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

4.2.4 Environmental Emission

The environmental limits for emissions of SO_2, NOx, particulate, Hg, and HCl were presented in the Design Basis section. A summary of the plant air emissions for Case 1A is presented in Exhibit 4-16 and for Case 1B in Exhibit 4-17.

For the purpose of this pre-FEED study, these air emission limits have been utilized as the only emission constraints. In the implementation phase of the project, the determination of the emissions limits will require more detailed knowledge of the emissions attainment status of the region in which the plant is located and the applicability of Best Available Control Technology (BACT) and/or

Lowest Achievable Emissions Rate (LAER) emission standards on a pollutant-by-pollutant basis. LAER standards are required when a new stationary source is located in a nonattainment air quality region. BACT is required on major new or modified sources in attainment areas. The selection of BACT control technologies and limits allows the consideration of costs and specific costs (i.e., cost/ton). The selection of LAER control technologies does not allow for the consideration of cost. BACT and LAER are determined on a case-by-case basis, usually by state or local permitting agencies. This determination will be part of the FEED phase activities. For the emission estimate herein, the pre-FEED design basis environmental limits have been treated as the relevant environmental targets.

The control technologies utilized to achieve the emission targets are presented in Exhibit 4-15.

Exhibit 4-15. Air Emissions Control Technologies

Pollutant	Control Technology
SO_2	In-situ PFBC bed capture via limestone (90% capture), and caustic polishing FGD (98% removal)
NOx	Low temperature of PFBC bed, SNCR (60% removal)
CO	High partial pressure of O_2 in PFBC combustor yields low CO levels
PM (Filterable)	Cyclones (98% removal), metallic filter (99.5% removal)
Hg	Co-beneficial capture with ash (98% capture), GORE adsorber elements in gas path if required
HCl	Caustic scrubber (99.8% removal)
CO_2	97% capture in amine-based scrubber

Exhibit 4-16. Case 1A Air Emissions

Pollutant	Stack Emissions lb/MMBtu	Stack Emissions ton/year [A]	Stack Emissions lb/MWh [B]	DOE Target lb/MWh [B]
SO_2 [D]	0.0086	104	0.07	1.00
NOx	0.050	604	0.39	0.70
CO	0.050	604	0.39	
Particulate	0.002	25	0.02	0.09
Hg	$2.3x10^{-7}$	0.0028	$1.8x10^{-6}$	$3x10^{-6}$
HCL	0.001	6.2	0.004	0.010
CO_2	200.2	2,417,980	1,542	
CO_2 [C]		-	1,608	

[A] Calculations based on an 85 percent capacity factor
[B] Emissions based on gross power except where otherwise noted
[C] CO_2 emissions based on net power (Excluding ZLD) instead of gross power
[D] The SO_2 and HCl emissions conservatively ignore capture by the CO_2 system.

Exhibit 4-17. Case 1B Air Emissions

	Stack Emissions lb/MMBtu	Stack Emissions ton/year [A]	Stack Emissions lb/MWh [B]	DOE Target lb/MWh [B]
SO_2	0.0086	104	0.08	1.00
NOx	0.050	604	0.45	0.70
CO	0.050	604	0.45	
Particulate	0.002	25	0.02	0.09
Hg	2.3×10^{-7}	0.0028	2.0×10^{-6}	3×10^{-6}
HCL	0.001	6.2	0.005	0.010
CO_2	6.01	72,539	54	
CO_2 [C]		-	63	

Notes A-C are per Exhibit 4-16 above.

The SO_2 emissions are controlled using limestone in the PFBC bed and a caustic polishing scrubber. The PFBC bed achieves an SO_2 removal efficiency of 90% with a Ca/S molar ratio of 2.5, while the polishing scrubber achieves an additional 98% SO_2 removal efficiency. Together the PFBC bed and polishing scrubber have an overall SO_2 removal efficiency of 99.8%.

For Cases 1A and 1B, NOx emissions from the PFBC are controlled to about 0.38 and 0.45 lb/MWh, respectively, using the inherently low combustion temperature of the PFBC bed and SNCR.

Particulate emissions are controlled using cyclones within the PFBC vessel and external metallic filters. The two stages of cyclones remove approximately 98% of the particulates. The metallic filter removes over 99.5% of the remaining particulates. Overall, the cyclones and metallic filters operate at an efficiency of approximately 99.99%. Cases 1A and 1B will also likely receive an additional modest reduction in non-condensable particulate loading based on the operation of the SO_2 polishing caustic scrubber. Case 1B (capture case) may receive an additional modest reduction in non-condensable particulate loading based on the operation of the amine-based capture system.

Reduction in mercury emissions is achieved via process conditions (creating oxidized mercury) and combined control equipment (PFBC, cyclones, metallic filters, and wet caustic FGD). The PFBC is expected to provide excellent mercury control due to the solids-gas contact and mixing in the fluidized bed. The anticipated mercury removal for Case 1 precludes the need for the GORE mercury system employed in Case 2.

It is anticipated that the caustic scrubber will remove most of the HCl in addition to the sulfur oxides.

For Case 1A, the CO_2 emissions represent the uncontrolled discharge from the process.

For Case 1B, 97% of the CO_2 in the flue gas is removed in the amine-based carbon dioxide capture system.

The carbon balances for the Case 1A and 1B plants are shown in Exhibit 4-18 and Exhibit 4-19, respectively. The carbon input to the plant consists of carbon in the coal, carbon in the air, and carbon in the limestone reagent used in the PFBC. Carbon in the air is not neglected here since the Thermoflex model accounts for air components throughout the gas path. Carbon leaves the plant mostly as CO_2 through the stack in Case 1A, and through the captured CO_2 stream in Case 1B; however, a small amount of unburned carbon (minimal for the PFBC) remains in the bed ash.

Exhibit 4-18. Case 1A Carbon Balance

Carbon In		Carbon Out	
	lb/hr		lb/hr
Coal	177,274	Stack Gas	180,319
Air (CO_2)	387.8	Fly Ash	2,950
Limestone	6,871	Bed Ash	1,264
		CO_2 Product	0
		CO_2 Dryer Vent	0
		CO_2 Knockout	0
Total	**184,533**	**Total**	**184,533**

Exhibit 4-19. Case 1B Carbon Balance

Carbon In		Carbon Out	
	lb/hr		lb/hr
Coal	177,276	Stack Gas	5,410
Air (CO_2)	387.9	Fly Ash	2,965
Limestone	6,870	Bed Ash	1,271
		CO_2 Product	174,873
		CO_2 Dryer Vent	17
		CO_2 Knockout	0.4
Total	**184,535**	**Total**	**184,535**

Exhibit 4-20 and Exhibit 4-21 show the sulfur balance for the Case 1A and 1B plants, respectively. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered as calcium sulfate ($CaSO_4$) in the PFBC bed ash and fly ash and as sodium bisulfate ($NaHSO_3$) in the polishing scrubber, as well as sulfur emitted in the stack gas. For the Case 1B plant, the amine scrubber will further polish SO_2 out of the flue gas along with the removal of CO_2.

Exhibit 4-20. Case 1A Sulfur Balance

Sulfur In		Sulfur Out	
	lb/hr		**lb/hr**
Coal	6,980	PFBC & Filter Ash	6,282
		Polishing Scrubber Product	684
		Amine AGR	0
		Stack Gas	14.0
Total	**6,980**	**Total**	**6,980**

Exhibit 4-21. Case 1B Sulfur Balance

Sulfur In		Sulfur Out	
	lb/hr		**lb/hr**
Coal	6,980	PFBC & Filter Ash	6,282
		Polishing Scrubber Product	684
		Amine AGR	14.0
		Stack Gas	0.0
Total	**6,980**	**Total**	**6,980**

4.2.5 Water Use and Balance

Exhibit 4-22 and Exhibit 4-23 show the overall water balance tables for the Case 1A and 1B plants, respectively. Detailed water balance diagrams are presented in Appendix E.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used in internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a Publicly Owned Treatment Works (POTW) for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Exhibit 4-22. Case 1A Water Balance Table

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Fuel & Sorbent Prep	184	184		(184)	184
FGD Process Makeup	208		208	8	200
ZLD				(350)	350
Condenser Makeup	**72**		**72**		**72**
BFW Makeup	72		72		72
Miscellaneous	84		84	27	57
Cooling Tower	**2,496**	**365**	**2,131**	**499**	**1,632**
Total	**3,044**	**549**	**2,495**	**0**	**2,495**

Note: Process water discharge excludes ZLD.

Exhibit 4-23. Case 1B Water Balance Table

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	Gpm	Gpm	gpm	gpm
Fuel & Sorbent Prep	159	159		(159)	159
FGD Process Makeup	208		208	8	200
ZLD				(618)	618
CO_2 Capture	(511)	(511)			
Condenser Makeup	**72**		**72**	**0**	**72**
BFW Makeup	72		72	0	72
Miscellaneous	84		84	33	51
Cooling Tower	**3,683**	**1,111**	**2,572**	**736**	**1,836**
Total	**3,695**	**759**	**2,936**	**0**	**2,936**

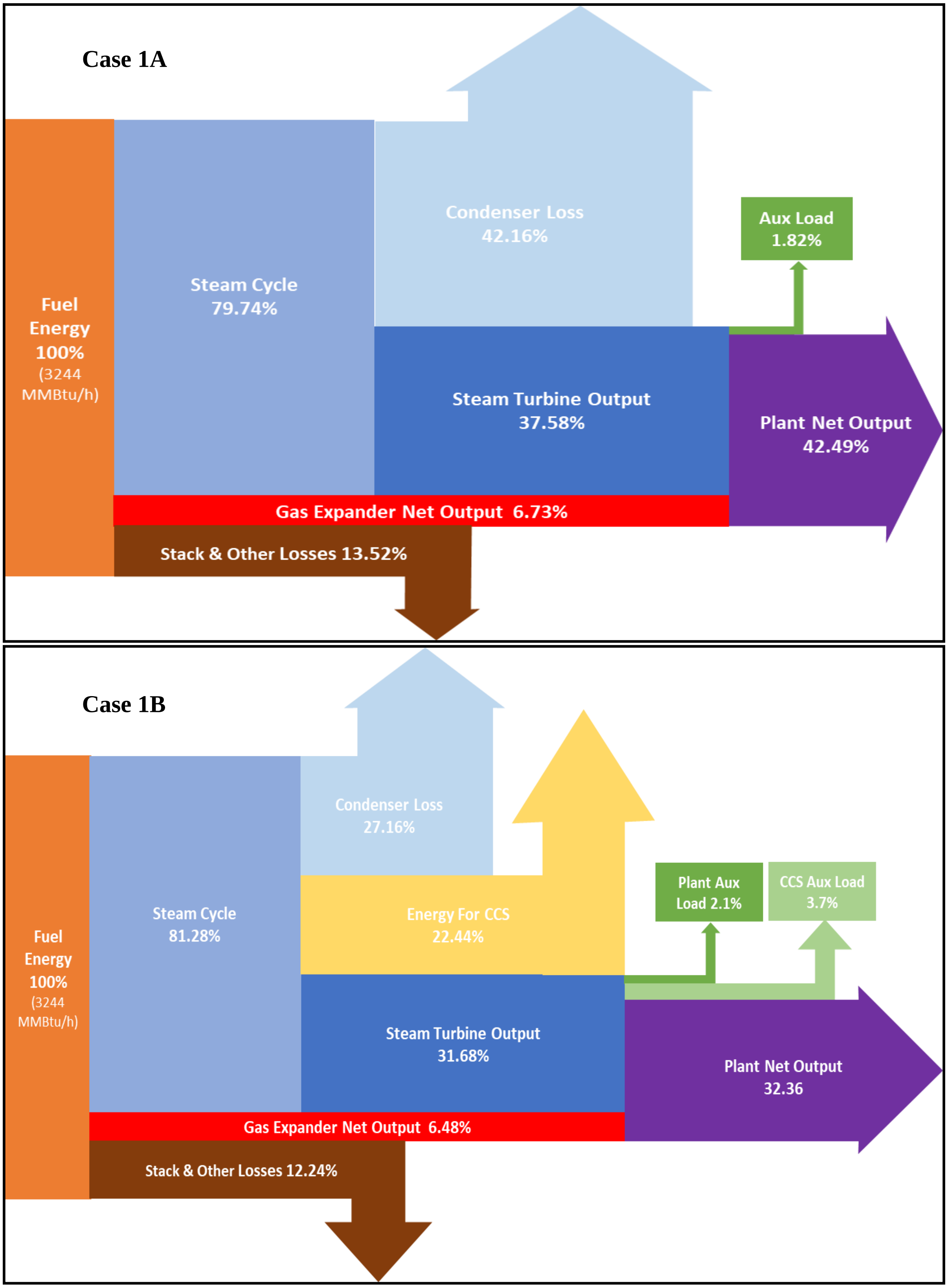
Note: Process water discharge excludes ZLD.

The sludge or solids from the ZLD are disposed of with the ash from the PFBC bed and cyclones as a solid.

4.2.6 Sankey Diagrams

Sankey diagrams for the Case 1A (capture-ready) and 1B (capture-equipped) plants are presented in Exhibit 4-24. These Sankey diagrams include the ZLD auxiliary loads.

Exhibit 4-24. Sankey Diagram for PFBC Cases 1A & 1B



4.3 Waste Coal PFBC Plant Cases 2B & 2C

This section presents both waste coal business cases, Case 2B (Capture-Equipped fueled) and Case 2C (Capture-Equipped and 5% biomass).

4.3.1 Process Description

4.3.1.1 Case 2B Process Description

In this section, the Case 2B PFBC process with CO_2 capture is described. The description follows the block flow diagram (BFD) in Exhibit 4-25 and the stream numbers reference the same exhibit. Exhibit 4-26 provides the process data for the numbered streams in the BFD.

Prior to the power plant, the waste coal slurry is pumped to the fuel prep site where it is dewatered in plate presses prior to being combined with the limestone sorbent into a pumpable paste. Compressed air (Stream 2) and coal and limestone paste (Streams 3 & 4) are introduced into the PFBC vessel and into the PFBC bed. Note that the coal and limestone paste feed streams are shown separately for information. In the actual feed to the PFBC vessel and bed, the coal and limestone paste feed is a single stream. PFDs of the fuel and sorbent handling system and other plant systems are presented in Appendix D.

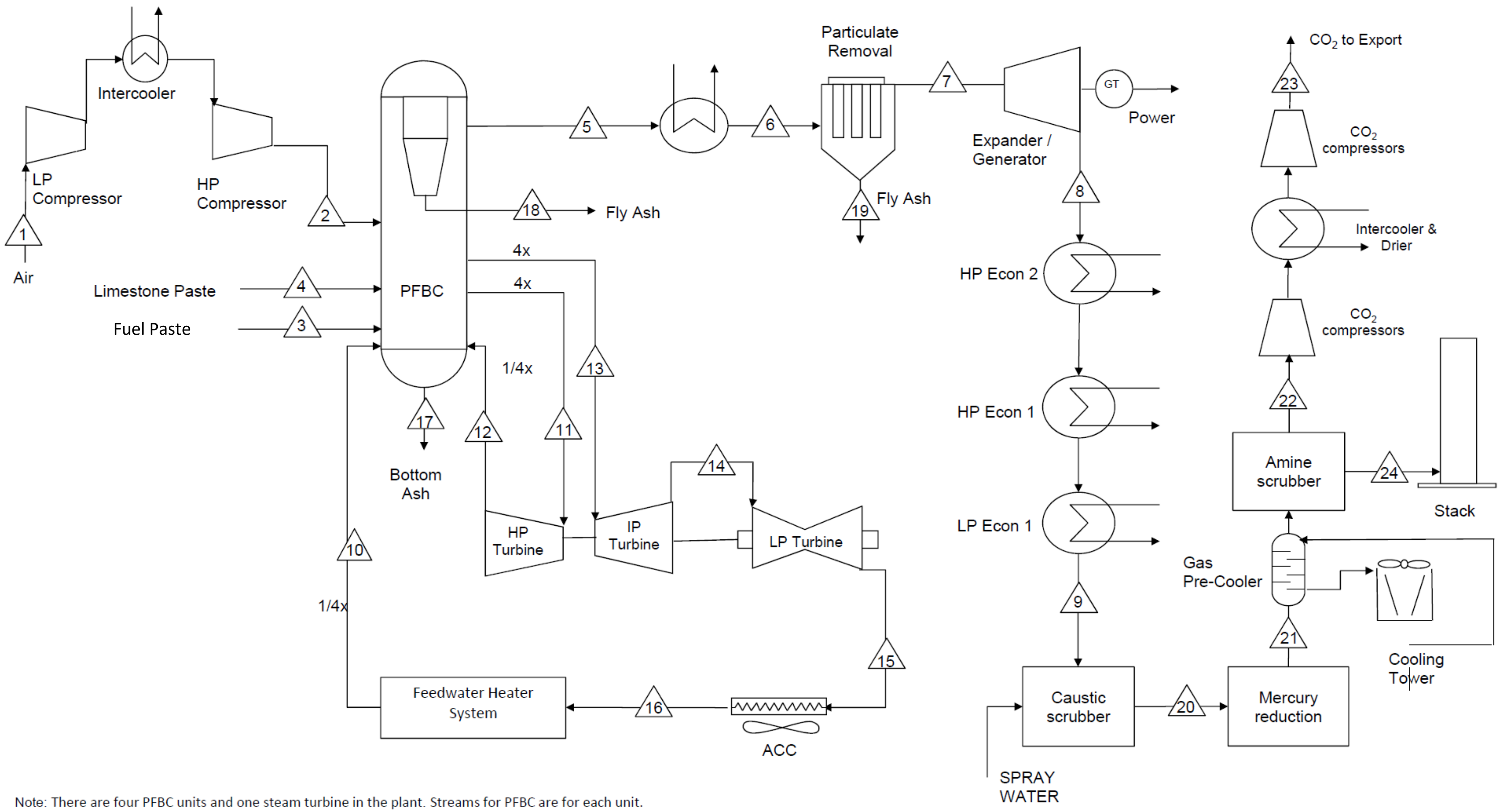
Feedwater (Stream 10) enters the PFBC where supercritical main steam is produced (Stream 11) and is fed to the supercritical HP steam turbine. Cold reheat steam (Stream 12) returns to the PFBC vessel where it is reheated and is fed to the IP Steam turbine as hot reheat steam (Stream 13). The steam expands in the IP turbine before crossing over (Stream 14) to the LP steam turbine. Turbine exhaust steam (Stream 15) is condensed in the air-cooled condenser (ACC) before continuing to the condensate and feedwater heating train. The reader should note that there are four PFBC modules and one steam turbine. As such, some of the stream quantities are presented on a per PFBC basis, while others are presented on an overall plant basis. A row in the stream table indicates the flow basis of each stream (i.e., per PFBC or overall plant basis).

Flue gas exits the PFBC bed and cyclones (Stream 5) prior to being cooled to 1450 °F (Stream 6). The slightly cooled flue gas passes through the high temperature metallic filters prior to entering the turbo-expander (Stream 7). Fly ash from the cyclones (Stream 18) and metallic filters (Stream 19) is forwarded to the fly ash silos for short-term storage. The gas leaving the gas expander (Stream 8) passes through HP and LP economizers. The stream leaving the LP economizer (Stream 9) enters the caustic scrubber to remove residual SO_2 and HCl to achieve emissions targets and minimize amine solvent degeneration. The polished flue gas (Stream 20) passes through mercury removal elements installed in the gas duct. The gas leaving the mercury removal elements passes through a gas pre-cooler and then to the amine carbon dioxide scrubber (Stream 21). The gas pre-cooler and other balance of plant heat loads continue to utilize a small wet cooling tower. The scrubbed flue gas exits the plant stack (Stream 24), while the captured CO_2 (Stream 22) is compressed in a multi-stage intercooled compressor and dried in preparation for transport for geologic storage or beneficial use (Stream 23).

4.3.1.2 Case 2C Process Description

The Case 2C process is identical to that for Case 2B described above. The only difference is that 5% of the fuel is now based on switchgrass biomass. The BFD is presented in Exhibit 4-25 and the stream table is presented in Exhibit 4-27.

Exhibit 4-25. Case 2B/2C Block Flow Diagram (BFD), PFBC with CO_2 Capture



Note: There are four PFBC units and one steam turbine in the plant. Streams for PFBC are for each unit.

Exhibit 4-26. Case 2B Stream Table, PFBC with CO_2 Capture

V-L Mole Fraction										
	1	2	3	4	5	6	7	8	9	10
Ar	0.0093	0.0093	0.0000	0.0000	0.0083	0.0083	0.0083	0.0083	0.0083	0.0000
CO_2	0.0003	0.0003	0.0000	0.0000	0.1372	0.1372	0.1372	0.1372	0.1372	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0101	0.0101	1.0000	1.0000	0.1420	0.1420	0.1420	0.1420	0.1420	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000
N_2	0.7729	0.7729	0.0000	0.0000	0.6869	0.6869	0.6869	0.6869	0.6869	0.0000
O_2	0.2074	0.2074	0.0000	0.0000	0.0254	0.0254	0.0254	0.0254	0.0254	0.0000
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	207.9	207.9	207.9	207.9	207.9	0.0
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	24,641	24,641	1,969	301	27,811	27,811	27,811	27,811	27,811	24,290
V-L Flowrate (lb/hr)	711,000	711,000	35,477	5,421	806,400	806,400	806,400	806,400	806,400	437,600
Solids Flowrate (lb/hr) [B]	-	-	100,973	15,430	814	814	4	4	4	-
Flow Basis per PFBC/Plant	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	59	586.1	77	77	1500	1450.0	1448.1	744.4	270.0	614.6
Pressure (psia)	14.08	186.63	158.79	158.79	158.79	158.43	151.17	15.91	15.27	3825.5
Steam Table Enthalpy (Btu/lb) [A]	-	-	-	-	-	-	-	-	-	626.8
Density (lb/ft^3)	0.074	0.480	-	-	0.219	0.224	0.214	0.036	0.057	43.618
V-L Molecular Weight	28.85	28.85	18.015	18.015	28.996	28.996	28.996	28.996	28.996	18.015

A Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

B Solid flowrate for dry solids.

V-L Mole Fraction										
	11	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0079
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1307
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	0.1834
HCl	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	0.6540
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0241
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.2
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000
V-L Flowrate (lbmol/hr)	97,162	85,039	85,039	41,065	42,386	49,613	-	-	-	29,216
V-L Flowrate (lb/hr)	1,750,400	1,532,000	1,532,000	739,800	763,600	893,800	-	-	-	831,500
Solids Flowrate (lb/hr)	-	-	-	-	-	-	17,450	39,902	810	0
Flow Basis per PFBC/Plant	Plant	Plant	Plant	Plant	Plant	Plant	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	1100.0	672.6	1100.0	560.5	98.1	96.6				137.9
Pressure (psia)	3515.0	759.9	697.1	84.5	0.90	11.27				14.69
Steam Table Enthalpy (Btu/lb) [A]	1496.7	1323.9	1570.6	1311.0	1002.7	64.6	-	-	-	-
Density (lb/ft^3)	4.319	1.248	0.768	0.141	0.0030	62.036	-	-	-	0.065
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015	18.015	-	-	-	28.460

[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

V-L Mole Fraction										
	21	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
Ar	0.0079	0.0000	0.0000	0.0107						
CO_2	0.1307	0.9722	1.0000	0.0054						
H_2	0.0000	0.0000	0.0000	0.0000						
H_2O	0.1834	0.0278	0.0000	0.0579						
HCl	0.0000	0.0000	0.0000	0.0000						
N_2	0.6540	0.0000	0.0000	0.8930						
O_2	0.0241	0.0000	0.0000	0.0330						
SO_2 (ppmvd)	4.6	0.0	0.0	0.0						
SO_3 (ppmvd)	0.0	0.0	0.0	0.0						
Total	1.0000	1.0000	1.0000	1.0000						
V-L Flowrate (lbmol/hr)	29,216	3,807	3,701	21,394						
V-L Flowrate (lb/hr)	831,500	164,800	162,900	594,300						
Solids Flowrate (lb/hr)	0	0	0	0						
Flow Basis per PFBC/Plant	PFBC	PFBC	PFBC	PFBC						
Temperature (°F)	137.9	95.0	95.0	95.0						
Pressure (psia)	14.51	29.30	2215.0	14.08						
Steam Table Enthalpy (Btu/lb) [A]	-	-	-	-						
Density (lb/ft^3)	0.064	0.213	16.420	0.066						
V-L Molecular Weight	28.460	43.287	44.010	27.779						

[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

Exhibit 4-27. Case 2C Stream Table, PFBC with CO_2 Capture

V-L Mole Fraction										
	1	2	3	4	5	6	7	8	9	10
Ar	0.0093	0.0093	0.0000	0.0000	0.0083	0.0083	0.0083	0.0083	0.0083	0.0000
CO_2	0.0003	0.0003	0.0000	0.0000	0.1380	0.1380	0.1380	0.1380	0.1380	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0101	0.0101	1.0000	1.0000	0.1443	0.1443	0.1443	0.1443	0.1443	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001	0.0001	0.0001	0.0001	0.0000
N_2	0.7729	0.7729	0.0000	0.0000	0.6838	0.6838	0.6838	0.6838	0.6838	0.0000
O_2	0.2074	0.2074	0.0000	0.0000	0.0254	0.0254	0.0254	0.0254	0.0254	0.0000
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	199.5	199.5	199.5	199.5	199.5	0.0
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0	1.0	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (lbmol/hr)	24,575	24,575	1,969	287	27,814	7,814	27,814	27,814	27,814	24,290
V-L Flowrate (lb/hr)	709,100	709,100	35,469	5,168	806,200	806,200	806,200	806,200	06,200	437,600
Solids Flowrate (lb/hr) [B]	-		100,951	14,710	777	777	4	4	4	-
Flow Basis per PFBC/Plant	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	50.2	585.7	77	77	1500	1450.1	1448.1	745.0	270.9	614.9
Pressure (psia)	14.08	186.64	158.8	158.8	158.80	158.44	151.17	15.91	15.27	3825.5
Steam Table Enthalpy (Btu/lb) [A]	-	-	-	-	-	-	-	-	-	627.1
Density (lb/ft^3)	0.074	0.480	-	-	0.219	0.224	0.214	0.036	0.056	43.587
V-L Molecular Weight	28.85	28.85	18.015	18.015	28.986	28.986	28.986	28.986	28.986	18.015

A Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

B Solid flowrate for dry solids.

V-L Mole Fraction										
	11	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0079
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1314
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	0.1857
HCl	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	0.6509
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0242
SO_2 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0
SO_3 (ppmvd)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000
V-L Flowrate (lbmol/hr)	97,162	85,039	85,033	40,710	42,031	49,269	-	-	-	29,224
V-L Flowrate (lb/hr)	1,750,400	1,532,000	1,531,900	733,400	757,200	887,600	-	-	-	831,400
Solids Flowrate (lb/hr)	-	-	-	-	-	-	16,660	38,096	774	0
Flow Basis per PFBC/Plant	Plant	Plant	Plant	Plant	Plant	Plant	PFBC	PFBC	PFBC	PFBC
Temperature (°F)	1100.0	672.5	1100.0	558.6	97.4	95.9				138.4
Pressure (psia)	3515.0	759.8	696.9	83.7	0.88	11.25				14.69
Steam Table Enthalpy (Btu/lb) [A]	1496.7	1323.9	1570.6	1310.1	1001.8	64.0	-	-	-	-
Density (lb/ft^3)	4.319	1.248	0.768	0.140	0.0029	62.044	-	-	-	0.065
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015	18.015	-	-	-	28.449

[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

V-L Mole Fraction										
	21	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**
Ar	0.0079	0.0000	0.0000	0.0108						
CO_2	0.1314	0.9722	1.0000	0.0054						
H_2	0.0000	0.0000	0.0000	0.0000						
H_2O	0.1857	0.0278	0.0000	0.0579						
HCl	0.0000	0.0000	0.0000	0.0000						
N_2	0.6509	0.0000	0.0000	0.8928						
O_2	0.0242	0.0000	0.0000	0.0331						
SO_2 (ppmvd)	4.0	0.0	0.0	0.0						
SO_3 (ppmvd)	0.0	0.0	0.0	0.0						
Total	1.0000	1.0000	1.0000	1.0000						
V-L Flowrate (lbmol/hr)	29,224	3,830	3,724	21,306						
V-L Flowrate (lb/hr)	831,400	165,800	163,900	591,900						
Solids Flowrate (lb/hr)	0	0	0	0						
Flow Basis per PFBC/Plant	PFBC	PFBC	PFBC	PFBC						
Temperature (°F)	138.4	95.0	95.0	95.0						
Pressure (psia)	14.51	29.30	2215.0	14.08						
Steam Table Enthalpy (Btu/lb) [A]	-	-	-	-						
Density (lb/ft^3)	0.064	0.213	16.420	0.066						
V-L Molecular Weight	28.449	43.287	44.010	27.781						

[A] Steam table enthalpy is referenced to zero at 32 °F (0 °C) with H_2O as liquid.

4.3.2 Plant Performance Summary

The Case 2B (waste coal) plant produces 279.69 MW net at a net plant HHV efficiency of 30.27%. The Case 2C (waste coal & biomass) plant produces 279.61 MW net at a net plant HHV efficiency of 30.23%. The net generation for Cases 2B and 2C are less than that for Case 1B because the water used to transport the high ash coal into the PFBC results in higher latent heat losses. The high ash content in the waste coal also contributes to higher sensible heat losses in the ash.

The overall plant performance is summarized in Exhibit 4-28. A breakdown of the auxiliary loads is provided in Exhibit 4-29 for both Cases 2B and 2C. These exhibits present the performance both with and without the inclusion of a ZLD system to comply with the requirements of the Coal FIRST program (which include the use of a ZLD system), and to facilitate performance comparisons to other plant configurations that do not include the use of a ZLD. It is noted that the pulverized coal cases (i.e., Cases 11A, 11B, 12A, and 12B) in the NETL Cost and Performance Baseline report do not include ZLD [**16**].

Exhibit 4-28. Cases 2B & 2C Plant Performance Summary

	CASE 2B	CASE 2C
Total Gross Power, MWe	333.49	333.63
CO_2 Capture/Removal Auxiliaries, kWe	11,850	11,850
CO_2 Compression, kWe	24,000	24,150
Zero Liquid Discharge System (ZLD), kWe	1,700	1,700
Balance of Plant, kWe	16,319	16,519
Total Auxiliaries [excluding ZLD], MWe	52.17	52.52
Total Auxiliaries [including ZLD], MWe	53.87	54.22
Net Power [excluding ZLD], MWe	**281.33**	**281.09**
Net Power [including ZLD], MWe	**279.63**	**279.39**
HHV Net Plant Efficiency [excluding ZLD], %	**30.45%**	**30.41%**
HHV Net Plant Efficiency [including ZLD], %	**30.26%**	**30.22%**
HHV Net Plant Heat Rate [excluding ZLD], Btu/kWh	11,207	11,211
HHV Net Plant Heat Rate [including ZLD], Btu/kWh	11,275	11,287
Air-cooled Condenser Duty, MMBtu/hr	808	802
Amine-based AGR Cooling Duty, MMBtu/hr	1,142	1,154
Paste Fuel Feed, lb/hr	546,015	545,720
Limestone Sorbent Feed, lb/hr	61,720	58,880
HHV Thermal Input, kWt	923,971	924,380
Raw Water Withdrawal, gpm/MW_{net}	4.9	4.9
Raw Water Consumption, (gpm/MW_{net})	0.6	0.6
Excess Air, %	16.0	16.0

Exhibit 4-29. Case 2B & 2C Plant Power Summary

Power Summary		
	CASE 2B	CASE 2C
Steam Turbine Power, MWe	266.64	266.44
Turbomachine Power, MWe	66.86	67.17
Total Gross Power, MWe	333.49	333.61
Auxiliary Load Summary		
	CASE 2B	CASE 2C
Ash Handling, kWe	400	400
Circulating Water Pumps, kWe	1,601	1,601
CO_2 Capture/Removal Auxiliaries, kWe	11,850	11,850
CO_2 Compression, kWe	24,000	24,150
Condensate Pumps, kWe	400	400
Cooling Tower Fans, kWe	950	950
ACC Fans, kWe	1,800	1,800
Fuel & Sorbent Preparation, kWe	5,000	5,200
Metallic Filter, kWe	40	40
Miscellaneous Balance of Plant[A,B], kWe	1,200	1,200
PFBC loads	1,500	1,500
Polishing Flue Gas Desulfurizer, kWe	1,328	1,328
Steam Turbine Auxiliaries, kWe	150	150
Transformer Losses, kWe	850	850
Water Treatment System, kWe	1,100	1,100
Zero Liquid Discharge (ZLD) loads, kWe	1,700	1,700
Total Auxiliaries [excluding ZLD], MWe	**52.17**	**52.52**
Total Auxiliaries [including ZLD], MWe	**53.87**	**54.22**
Net Power [excluding ZLD], MWe	**281.33**	**281.09**
Net Power [including ZLD], MWe	**279.63**	**279.39**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads
[C]Includes raw water, demineralized water, and waste water systems.

Part load performance will be presented in the Phase 3 FEED study for the selected configuration. The steam cycle used for this 4-unit PFBC plant is based on a hybrid of constant pressure and sliding pressure operation. A schedule of main steam pressure vs. load has been proposed by GE and has been adopted for the purposes of this Phase 2 pre-FEED study. The schedule that will be followed is the yellow line labeled "Optimized modified sliding pressure" in Exhibit 4-8.

Performance with up to 10% Biomass

The Business Case plant (Case 2B/2C) is designed to handle between 0 and 10% biomass and 100 to 90% waste coal (by weight) in the fuel feed. Case 2B utilizes 100% waste coal / 0% biomass. Case 2C utilizes 95% waste coal / 5% biomass. The overall performance is essentially the same (e.g., net efficiencies of 30.26% and 30.22% for Cases 2B and 2C, respectively). Minimal changes from Case 2C would be expected for 10% biomass feed. This is based on the dry Btu content for biomass (7,949 Btu/lb HHV design basis, per Exhibit 3-12) being very close to that for the dry waste coal (7,803 Btu/lb HHV design basis). Samples of waste coal (thickener underflow) collected during the pre-FEED study suggest that the Btu content of the waste coal fuel is expected to remain fairly consistent; the twelve samples collected exhibited a range of 7,024-8,645 Btu/lb HHV dry.

4.3.3 Heat and Mass Balances

In this section the Heat and Mass Balances (H&MB) are presented in two process sheets:

- PFBC Process
- Rankine Cycle

The PFBC H&MB covers the fuel, sorbent, boiler feed water, and air feed into the PFBC, steam generation and reheating, combustion gas cleanup and expansion, and economization of the feed water. The Rankine cycle H&MB covers the complete steam cycle. The Case 2B H&MB diagrams are presented in Exhibit 4-30 and Exhibit 4-31 for the PFBC and Rankine cycles, respectively. The Case 2C H&MB diagrams are presented in Exhibit 4-32 and Exhibit 4-33 for the PFBC and Rankine cycles, respectively.

Exhibit 4-30. Case 2B PFBC Process H&MB Diagram

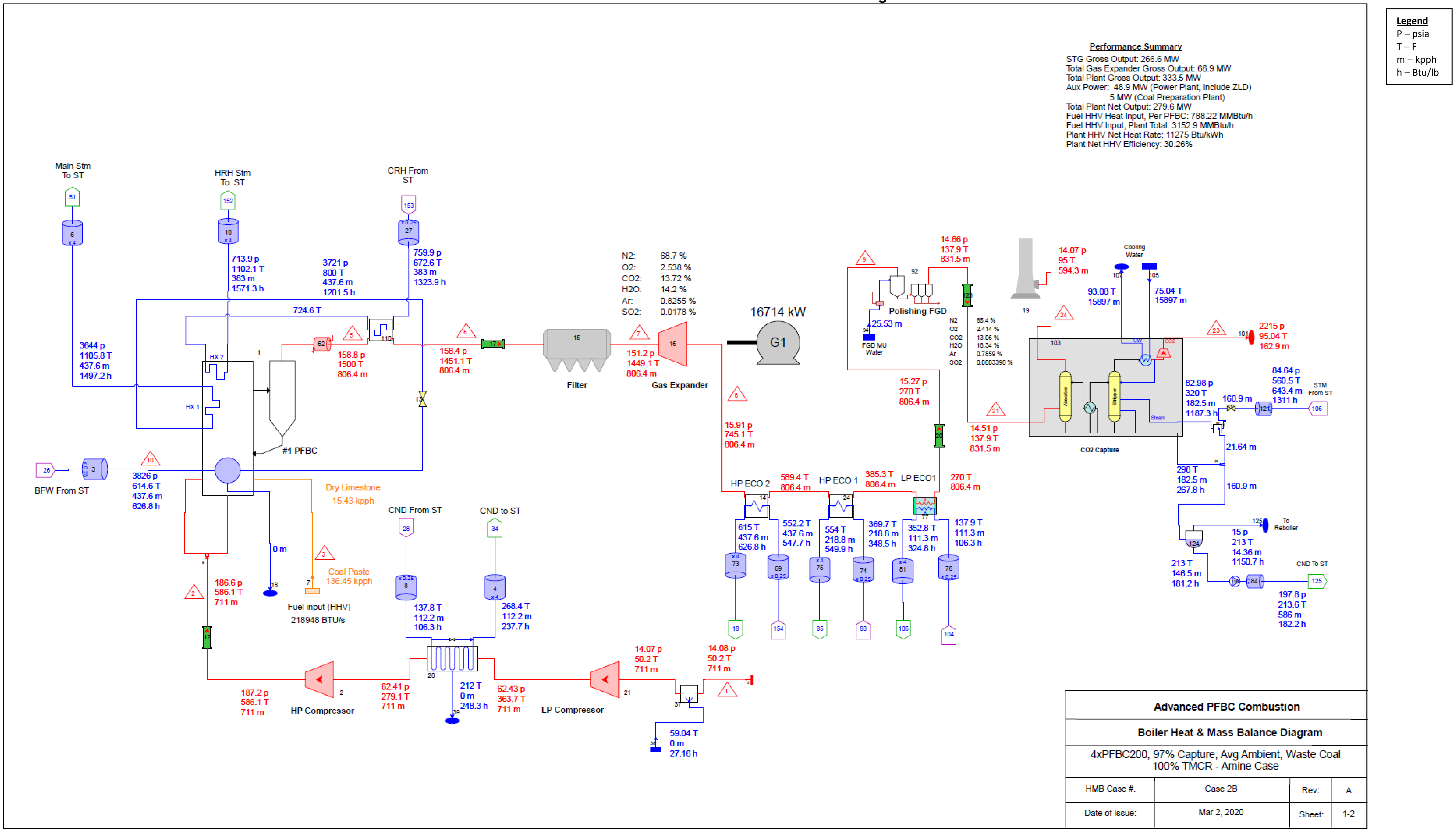


Exhibit 4-31. Case 2B Rankine Cycle H&MB Diagram

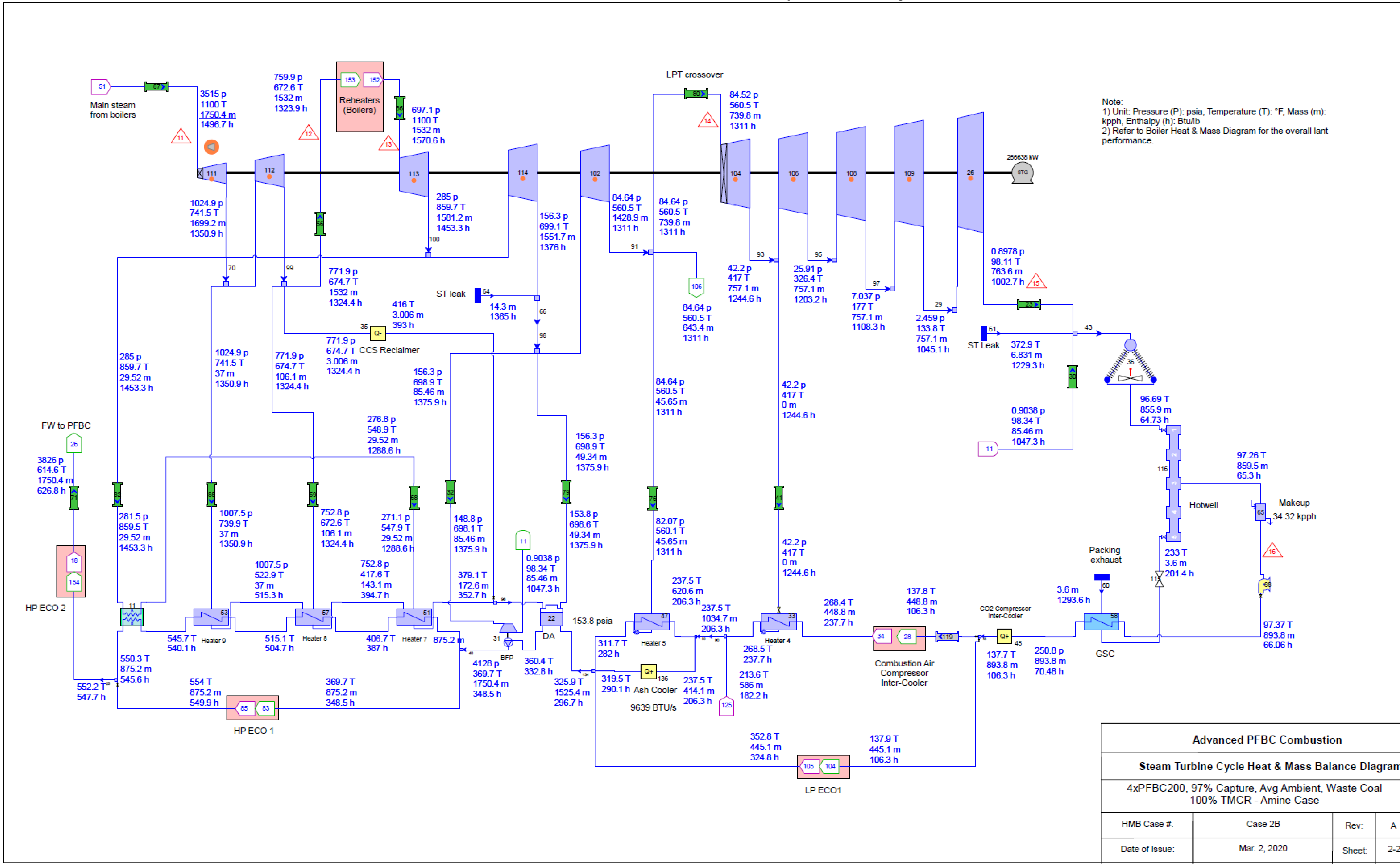


Exhibit 4-32. Case 2C PFBC Process H&MB Diagram

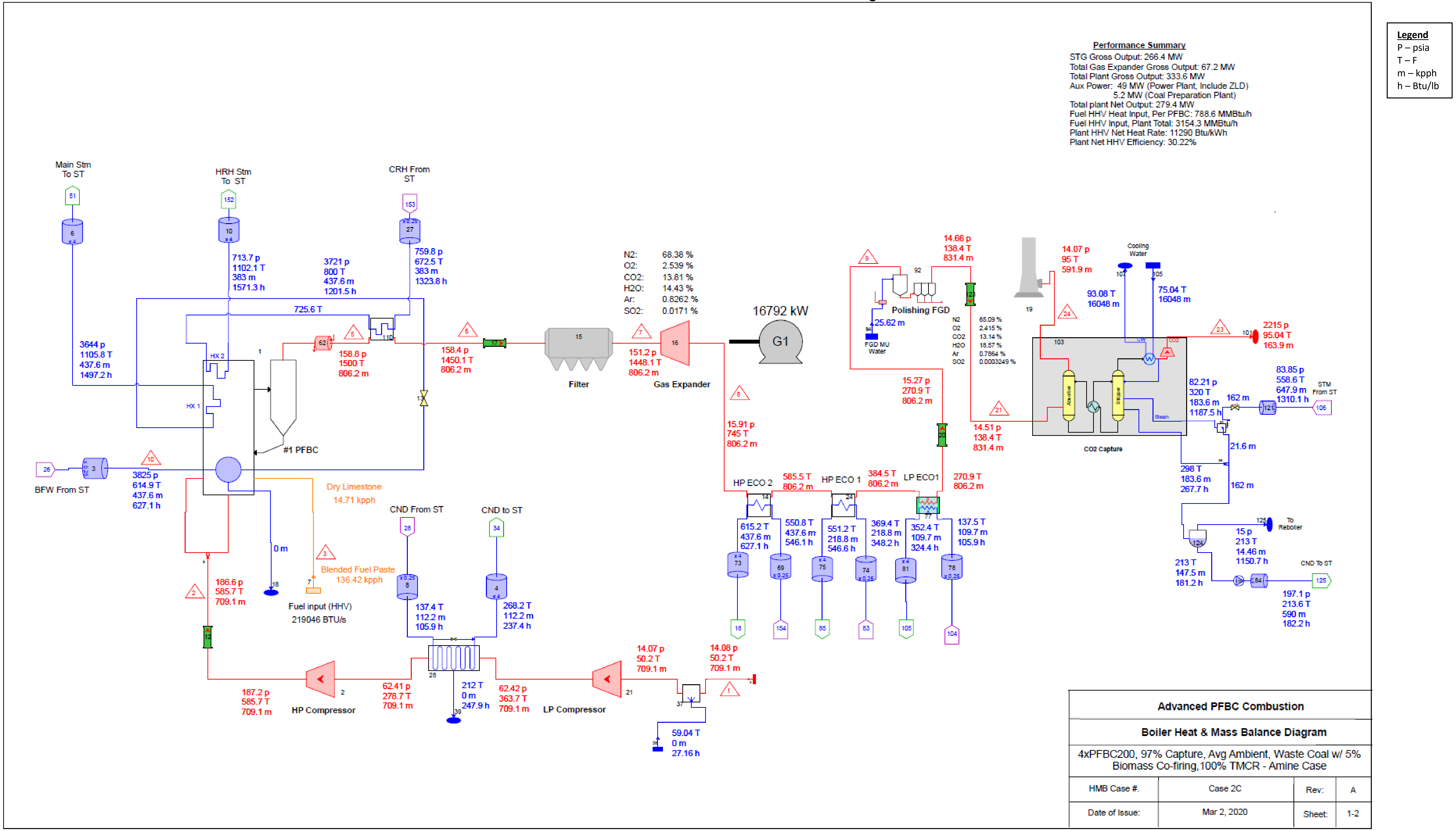
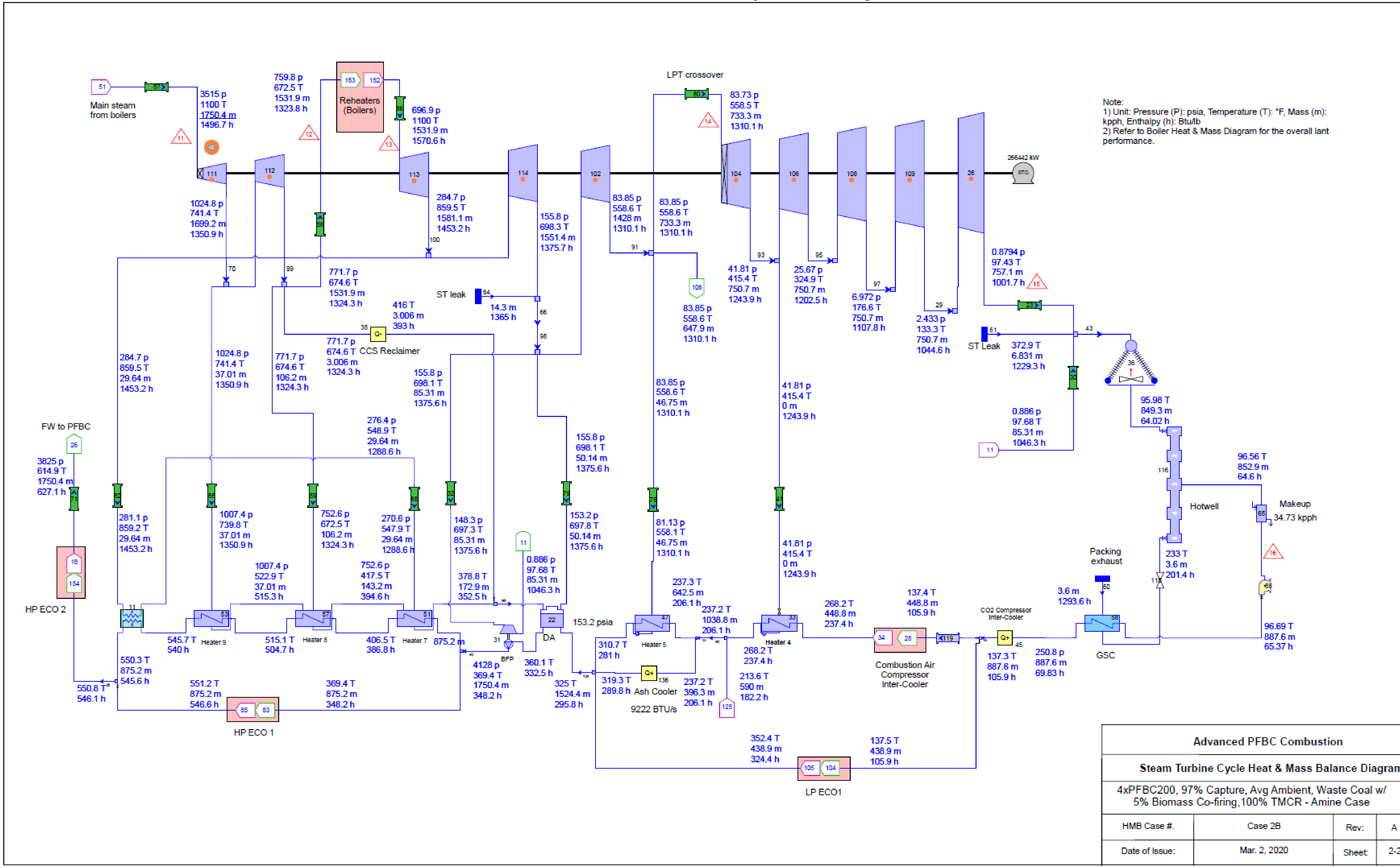


Exhibit 4-33. Case 2C Rankine Cycle H&MB Diagram



An overall plant energy balance for Case 2B is provided in tabular form in Exhibit 4-34. An overall plant energy balance for Case 2C is provided in tabular form in Exhibit 4-35. An overall plant energy balance for Case 2C will not be provided as Cases 2B and 2C are very similar. The power out is the steam turbine and the gas turbomachine power prior to generator losses.

Exhibit 4-34. Case 2B Overall Energy Balance (32 °F reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal	3,152.9	8.7	–	3,161.6
Air	–	31.0	–	31.0
Raw Water Makeup	–	37.6	–	37.6
Limestone	–	1.5	–	1.5
Caustic (NaOH) solution (50%)	–	0.1	–	0.1
Auxiliary Power	–	–	163.9	163.9
TOTAL	**3,152.9**	**78.9**	**163.9**	**3,395.6**
Heat Out (MMBtu/hr)				
Bed Ash	–	3.7	–	3.7
Fly Ash	–	8.6	–	8.6
Stack Gas	–	113.5	–	113.5
$NaHS0_3$	–	0.1	–	0.1
Motor Losses and Design Allowances	–	–	35.0	35.0
Cooling Tower Load[A]	–	1,989.2	–	1,989.2
CO_2 Product Stream	–	-35.8	–	-35.8
Blowdown Streams and Deaerator Vent	–	4.0	–	4.0
Ambient Losses[B]	–	110.4	–	110.4
Gross Power	–	–	1,155.3	1,155.3
TOTAL	–	**2,193.6**	**1,190.5**	**3,383.9**
Unaccounted Energy[C]	–	–	–	11.7

[A] Includes condenser 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 4-35. Case 2C Overall Energy Balance (32 °F reference)

	HHV	Sensible + Latent	Power	Total
Heat In (MMBtu/hr)				
Coal & Biomass	3,154.3	8.7	–	3,163
Air	–	30.9	–	30.9
Raw Water Makeup	–	38	–	38
Limestone	–	1.4	–	1.4
Caustic (NaOH) solution (50%)	–	0.1	–	0.1
Auxiliary Power	–	–	164.4	164.4
TOTAL	**3,154.3**	**79.1**	**164.4**	**3,397.8**
Heat Out (MMBtu/hr)				
Bed Ash	–	3.5	–	3.5
Fly Ash	–	8.2	–	8.2
Stack Gas	–	113.0	–	113.0
$NaHS0_3$	–	0.1	–	0.1
Motor Losses and Design Allowances	–	–	35.0	35.0
Cooling Tower Load[A]	–	1,994.5	–	1,994.5
CO_2 Product Stream	–	-36.1	–	-36.1
Blowdown Streams and Deaerator Vent	–	3.9	–	3.9
Ambient Losses[B]	–	110.4	–	110.4
Gross Power	–	–	1,156	1,155.7
TOTAL	–	**2,197.7**	**1,191**	**3,388.4**
Unaccounted Energy[C]	–	–	–	9.4

[A] Includes condenser 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

4.3.4 Environmental Emission

The environmental limits for emissions of SO_2, NOx, particulate, Hg, and HCl were presented in the Design Basis section. A summary of the plant air emissions for Case 2B is presented in Exhibit 4-37 and for Case 2C in Exhibit 4-38.

For the purpose of this pre-FEED study, these air emission limits have been utilized as the only emission constraints. In the implementation phase of the project, the determination of the emissions limits will require more detailed knowledge of the emissions attainment status of the region in which the plant is located and the applicability of Best Available Control Technology (BACT) and/or Lowest Achievable Emissions Rate (LAER) emission standards on a pollutant-by-pollutant basis. LAER standards are required when a new stationary source is located in a nonattainment air quality region. BACT is required on major new or modified sources in attainment areas. The selection of BACT control technologies and limits allows the consideration of costs and specific costs (i.e., cost/ton). The selection of LAER control technologies does not allow for the consideration of cost. BACT and LAER are determined on a case-by-case basis, usually by state or local permitting agencies. This determination will be part of the FEED phase activities. For the emission estimate herein, the pre-FEED design basis environmental limits have been treated as the relevant environmental targets.

The control technologies utilized to achieve the emission targets are presented in Exhibit 4-36. The control technologies are the same as used with the Case 1B except for the addition of the GORE mercury removal system.

Exhibit 4-36. Case 2B & 2C Air Emissions Control Technologies

Pollutant	Control Technology
SO_2	In-situ PFBC bed capture via limestone (90% capture), and caustic polishing FGD (98% removal)
NOx	Low temperature of PFBC bed, SNCR (60% removal)
CO	High partial pressure of O_2 in the PFBC yields low CO levels
PM (Filterable)	Cyclones (98% removal), metallic filter (99.5% removal)
Hg	Co-beneficial capture with ash (98% capture), GORE mercury removal system
HCl	Caustic scrubber (99.8% removal)
CO2	97% capture in amine-based scrubber

Exhibit 4-37. Case 2B Air Emissions

Pollutant	Stack Emissions lb/MMBtu	Stack Emissions ton/year [A]	Stack Emissions lb/MWh [B]	DOE Target lb/MWh [B]
SO_2 [D]	0.0081	95	0.08	1.00
NOx	0.050	587	0.47	0.70
CO	0.050	587	0.47	
Particulate	0.006	69	0.06	0.09
Hg	$2.3x10^{-7}$	0.0027	$2.2x10^{-6}$	$3x10^{-6}$
HCL	0.000	3.1	0.002	0.010
CO_2	6.30	73,932	60	
CO_2 [C]		-	71	

[A] Calculations based on an 85 percent capacity factor

[B] Emissions based on gross power except where otherwise noted

[C] CO_2 emissions based on net power (Excluding ZLD) instead of gross power
[D] The SO_2 and HCl emissions conservatively ignore capture by the CO_2 system.

Exhibit 4-38. Case 2C Air Emissions

	Stack Emissions lb/MMBtu	Stack Emissions ton/year [A]	Stack Emissions lb/MWh [B]	DOE Target lb/MWh [B]
SO_2	0.0077	91	0.07	1.00
NOx	0.050	587	0.47	0.70
CO	0.050	587	0.47	
Particulate	0.006	66	0.05	0.09
Hg	2.2x10-7	0.0026	2.1×10^{-6}	3×10^{-6}
HCL	0.000	3.0	0.002	0.010
CO_2	6.33	74,325	60	
CO_2 (with biomass credit)	(4.97)	(58,395)	(47)	
CO_2[C]		-	71	

Notes A-D are per Exhibit 4-37 above.

The SO_2 emissions are controlled using limestone injection into the PFBC bed and a caustic polishing scrubber. The PFBC bed achieves an SO_2 removal efficiency of 90% with a Ca/S molar ratio of 2.5. The byproduct calcium sulfate is removed with the PFBC bed ash and fly ash. Subsequently the polishing scrubber achieves an additional 98% SO_2 removal efficiency for an overall SO_2 removal efficiency of 99.8%.

For Cases 2B and 2C, NOx emissions from the PFBC are controlled to about 0.47 lb/MWh using the inherently low combustion temperature of the PFBC bed and SNCR.

Particulate emissions are controlled using cyclones within the PFBC vessel and external metallic filters. The two stages of cyclones remove approximately 98% of the particulates. The metallic filter removes over 99.5% of the remaining particulates. Overall, the cyclones and metallic filters operate at an efficiency of approximately 99.99%. Cases 2B and 2C will also likely receive an additional modest reduction in non-condensable particulate loading based on the operation of the SO_2 polishing caustic scrubber and amine-based CO_2 capture system.

Reduction in mercury emissions is achieved via process conditions (creating oxidized mercury) and combined control equipment (PFBC, cyclones, metallic filter, and wet caustic FGD). The PFBC is expected to provide excellent mercury control due to the solids-gas contact and mixing in the fluidized bed. The GORE® mercury removal system located in the flue gas duct in route to the stack is capable of removing both oxidized and elemental mercury, eliminating concerns related to the effects of changing process conditions and mercury speciation. This Hg removal device is modular, and the number of modules can be adjusted to attain the specified removal efficiency.

It is anticipated that the caustic scrubber will remove most of the HCl in addition to the sulfur oxides.

For Cases 2B and 2C, 97% of the CO_2 in the flue gas is removed in the amine-based carbon dioxide capture system.

The carbon balances for the Case 2B and 2C plants are shown in Exhibit 4-39 and Exhibit 4-40, respectively. The carbon input to the plant consists of carbon in the coal, carbon in the air, and carbon in the limestone reagent used in the PFBC. Carbon in the air is not neglected here since the Thermoflex model accounts for air components throughout the gas path. Carbon leaves the plant mostly through the captured CO_2 stream in Case 2B and 2C; however, a small amount of unburned carbon remains in the bed ash.

Exhibit 4-39. Case 2B Carbon Balance

Carbon In		Carbon Out	
	lb/hr		lb/hr
Coal	180,686	Stack Gas	5,497
Air (CO_2)	387.8	Fly Ash	2,879
Limestone	6,262	Bed Ash	1,234
		CO_2 Product	177,709
		CO_2 Dryer Vent	17
		CO_2 Knockout	0.4
Total	**187,336**	**Total**	**187,336**

Exhibit 4-40. Case 2C Carbon Balance

Carbon In		Carbon Out	
	lb/hr		lb/hr
Fuel	181,234	Stack Gas	5,533
Air (CO_2)	386.9	Fly Ash	2,195
Limestone	5,974	Bed Ash	941
		CO_2 Product	178,909
		CO_2 Dryer Vent	17
		CO_2 Knockout	0.4
Total	**187,595**	**Total**	**187,595**

Exhibit 4-41 and Exhibit 4-42 show the sulfur balance for the Case 2B and 2C plants, respectively. Sulfur input comes primarily from the sulfur in the coal with a small amount in the biomass. Sulfur output includes the sulfur recovered as calcium sulfate ($CaSO_4$) in the PFBC bed ash and fly ash and as sodium bisulfate ($NaHSO_3$) in the polishing scrubber, as well as sulfur emitted in the stack gas. The amine scrubber will further polish SO_2 out of the flue gas along with the removal of CO_2.

Exhibit 4-41. Case 2B Sulfur Balance

Sulfur In		Sulfur Out	
	lb/hr		lb/hr
Coal	6,389	PFBC & Filter Ash	5,750
		Polishing Scrubber Product	626
		Amine AGR	12.8
		Stack Gas	0.0
Total	**6,389**	**Total**	**6,389**

Exhibit 4-42. Case 2C Sulfur Balance

Sulfur In		Sulfur Out	
	lb/hr		lb/hr
Fuel (Coal & Biomass)	6,057	PFBC & Filter Ash	5,452
		Polishing Scrubber Product	594
		Amine AGR	12.1
		Stack Gas	0.0
Total	**6,057**	**Total**	**6,057**

4.3.5 Water Use and Balance

Exhibit 4-43 shows the overall water balance table for the Case 2B/2C plant. Detailed water balance diagrams are presented in Appendix E.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used in internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the Ohio River for use in the plant. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Exhibit 4-43. Case 2B Water Balance Table

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Fuel & Sorbent Prep	43	43		(43)	43
FGD Process Makeup	208		208	8	200
ZLD				(532)	532
CO_2 Capture	(592)	(592)			
Condenser Makeup	**72**		**72**		**72**
BFW Makeup	72		72		72
Miscellaneous	84		84	34	50
Cooling Tower	**2,133**	**1,114**	**1,019**	**533**	**486**
Total	**1,948**	**565**	**1,383**	**0**	**1,383**

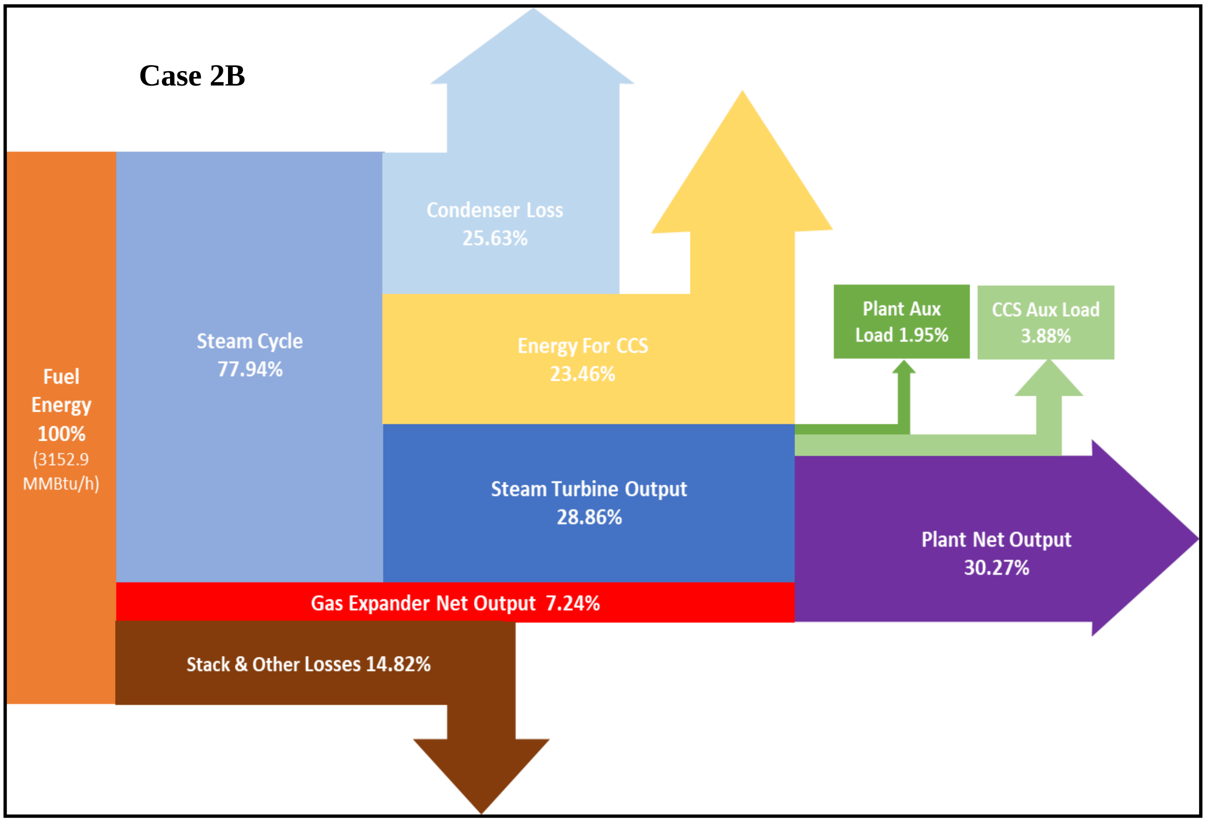
Note: Process water discharge excludes ZLD.

The sludge or solids from the ZLD are disposed of with the ash from the PFBC bed and cyclones as a solid.

4.3.6 Sankey Diagrams

The Sankey diagram for Case 2B is presented in Exhibit 4-44. This Sankey diagram includes the ZLD auxiliary loads. The Sankey diagram for Case 2C is nearly identical to that for Case 2B and is not presented. The efficiency difference between Case 2B and 2C is only 0.04% and this difference is attributed to the additional biomass handling auxiliary load.

Exhibit 4-44. Sankey Diagram for PFBC Cases 2B



4.4 Performance Relative to Flexibility Metrics

This section presents the flexibility metrics of ramp rate, startup times, and turndown.

4.4.1 Ramping

The advanced PFBC plant includes four separate P200 modules that can be operated in various combinations to cover a wide range of loads. Each P200 module includes a bed reinjection vessel to provide further load-following capability, enabling an operating range from <20% to 100%. A 4%/minute ramp rate can be achieved using a combination of coal-based energy and natural gas co-firing.

The PFBC plant is capable of meeting a 4% ramp rate using a combination of coal-based energy and co-fired natural gas energy up to 30% of total Btu input. Higher levels of natural gas firing may be feasible and can be evaluated. The PFBC design incorporates a bed reinjection vessel inside the main pressure vessel that stores an inventory of bed material (fuel and ash solids) during steady state operation. When a load increase is called for, this vessel reinjects a portion of its inventory back into the active bed to supplement the bed inventory. Natural gas co-firing using startup lances, over-bed firing, or a combination thereof is used to supplement the energy addition to the fluid bed to support the additional steam generation that supports the increase in power generation during the up-ramp transient. During down-ramp excursions, the bed reinjection vessel can take in some of the bed inventory to assist in maintaining the heat transfer requirements. Coal flow is reduced during a down-ramp transient. Steam bypass to the condenser may also be used in modulating a down-ramp transient.

With respect to the turbomachine, the compressor train (comprised of low- and high-pressure units) is likely to operate at the same speed as the motor generator at full load. However, at reduced loads and during startup and ramp-up, the compressor speed may be reduced to ensure stable operation. Dynamic compression machines (axial flow and centrifugal flow) do not turn down (provide reduced flow rates) very well, and other solutions such as bleeds and blow-offs are required to manage the machine. The provision of a variable speed device potentially resolves this problem and will be evaluated in the Phase 3 FEED study.

Detailed modeling studies in Phase 3 will confirm the ramp rate capability of the 4XP200 plus supercritical steam turbine generator system, and the contribution of the bed reinjection vessel vs. the use of the startup gas lances to enhance ramp up capability.

4.4.2 Cold Start

The PFBC plant requires 8 hours to start up from cold conditions on coal. Startup from warm conditions requires from 3 to 6 hours, depending on the metal and refractory temperatures existing when a restart order is given. Startup from hot conditions (defined as bed temperature at or near 1500 °F, and main steam pipe temperature above approximately 800 °F) requires less than 2 hours on coal; this time is reduced to approximately 1 to 2 hours with natural gas co-firing. It should be noted that very short startup times are not compatible with use of a supercritical steam cycle with high main and reheat steam design temperatures. There are two compelling factors that work against very fast starts for this type of steam cycle: first are the severe secondary stresses induced in heavy wall piping and valves necessary for supercritical steam conditions. Longer warmup times are necessary to avoid premature material failures and life-limiting changes in the pressure part materials for the piping, valves, and high-pressure turbine components. The second limiting factor on rapid startup times is the feed water chemistry limitation inherent in supercritical steam cycles. After a complete shutdown, condensate and feed water chemistry typically requires some length of time to be returned to specification levels. Assuring long material life and preventing various kinds of corrosion mechanisms from becoming an issue requires that water chemistry be brought to the proper levels prior to proceeding with a full startup from cold, no-flow conditions.

Start-up times are related to refractory temperature in the PFBC pressure vessel, as well as turbine casing and pipe wall temperatures for the main steam and hot reheat piping. Each of these has its own limitations on the speed at which warm-up can be imposed without compromising life of the component. A schedule of start times as a function of wall temperature will be developed during the Phase 3 FEED study.

4.4.3 Turndown

The four separate P200 modules can be run in various combinations to cover a wide range of loads, allowing the PFBC plant to be turned down quickly to a low level.

For example, a single P200 module operating at 80% can allow the complete four module PFBC plant to operate at 20% load. Multiple configurations can be envisioned for higher load points. For example, the 40% load point can be achieved by 2 x P200 modules each operating at 80% load, or three P200 modules each operating at 53.3% load.

A summary of estimated plant performance under various operating conditions was presented in Section 1.6.1; more detailed modeling results will be developed and presented in the Phase 3 FEED study.

The minimum plant turndown will be mostly limited by the steam turbine. With the carbon dioxide capture system (CCS) steam extraction in operation, the minimum stable steam turbine load is 20%

without LP exhaust spray (condenser hood spray) in operation. With LP exhaust spray in operation the minimum steam turbine stable load would be about 17%. However, it is not recommended to operate in this mode continuously due to risk of Last Stage Blade (LSB) erosion. For the Capture Ready Case (Case 1A) without CCS steam extraction, the minimum stable load is 16% without LP exhaust spray in operation. With LP exhaust spray in operation, the minimum stable load is about 10% for Case 1A, but it is not recommended to operate in this mode continuously due to risk of LSB erosion.

4.5 Equipment Summary (Commercial vs that Requiring R&D)

Major equipment and systems for the supercritical PFBC plant are shown in the following tables. A single list is used for both the capture-ready and capture-equipped configurations. Items that only relate to the capture-equipped configuration are highlighted in light green in Account 5 (Flue Gas Cleanup). The accounts used in the equipment list correspond to the account numbers used in the cost estimates being generated for the project. The commercial status for the major equipment/systems has been identified with one of following three designations:

1. Commercial
2. Custom Design
3. R&D needed

Equipment designated as “Custom Design” equipment requires customization of the commercial offering.

Exhibit 4-45. Case 1A & 1B – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Commercial Status
	DRY FUEL HANDLING/SIZING		
1	Rail Car/Bottom Dump/Hopper Unloader	Field Erect	Commercial
2	Hopper Unloading Feeders	Vibrating	Commercial
3	Rail Unloading Conveyor to Stacking Tube	Belt	Commercial
4	Cross Belt Sampler	Swing Hammer	Commercial
5	Stacker Transfer Conveyor #1	Belt	Commercial
6	Stacking Tubes (2) Reclaim Tunnel with Escape	Open	Commercial
7	Reclaim Feeders (4)	Vibratory	Commercial
8	Reclaim Conveyor with Scale Magnet	Belt	Commercial
9	Reclaim Transfer Conveyor	Belt	Commercial
10	Sizing Station Feed Conveyor	Belt	Commercial
11	Sizing Building	Enclosed	Commercial
12	Sizing Screens	8x16 DD Incline	Commercial
13	Rreversible Hammermill Crusher		Commercial
14	Oversize Protection Screens	8x16 DD inclined	Commercial
15	Sizing Station Discharge Conveyor/Scale	Belt	Commercial
16	Fuel Prep Feed Conveyor	Belt	Commercial
	SORBENT HANDLING		
1	Truck Scale	72' x 11' Sorbent	Commercial
2	Sorbent Truck Dump/Hopper	Field Erect	Commercial
3	Truck Dump Feeders	Vibrating	Commercial
4	Truck Dump Collecting Conveyor		Commercial
5	Conveyor to Sorbent Storage Stacker	Belt	Commercial
6	Sorbent Storage Reclaim Hoppers/Feeders	Augers	Commercial
7	Sorbent Reclaim Conveyor to Sizing Bldg with Scale	Belt	Commercial
8	Sorbent Sizing Bldg	Enclosed	Commercial
9	Bulk Material Bin with Gates (2)	Enclosed	Commercial
10	Bin Rotary Airlock/Feeders		Commercial
11	Sizing Screens		Commercial
12	Crusher Hammermill		Commercial
13	Oversize Protection Screen		Commercial
14	Fuel Prep Feed Conveyor/Scale		Commercial
15	Process Bag Filter	Dust Collecting	Commercial
16	Process Bag Filter	At Fuel Prep Bldg	Commercial

Exhibit 4-46. Case 1A, 1B, 2B & 2C– Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Commercial Status
	FUEL PREPARATION & DELIVERY SYSTEM (Equipment Per Pumpaction Quote PRJ20-0023		
1	Fuel Prep Building	Enclosed	Commercial
2	Floor Sump Pump	Vertical	Commercial
3	Fuel Receiving Bins	Field Erect	Commercial
4	Sliding Frames	Hydraulic Power Pack	Commercial
5	Auger Feeders	Auger	Commercial
6	Fuel Weigh Feeders	Belt	Commercial
7	Sorbent Receiving Bins	Field Erect	Commercial
8	Inlet Rotary Airlocks/Feeders		Commercial
9	Outlet Rotary Airlocks/Feeders		Commercial
10	Sorbent Weigh Feeders	Belt	Commercial
11	Paste Sumps/ Mixers/Moisture Control	Mixers	Commercial
12	Prepared Fuel Sumps/ Agitators		Commercial
13	Prepared Fuel Transfer Pumps	Hydraulic Power Pack	Commercial
	FUEL PREP LOCATION AT POWER PLANT BOILER		Commercial
14	Buffer Silos/Level Detectors	Platework	Commercial
15	Buffer Silo Agitators	Mixer	Commercial
16	Fuel Injection Pumps	Hydraulic	Commercial

Exhibit 4-47. Case 2B & 2C – Account 1: Waste Coal and Sorbent Handling

Equipment No.	Description	Type	Commercial Status
	WASTE FUEL STORAGE EQUIPMENT		
1	Thickeners	Static	Commercial
2	Thickener Rakes Rotation	Structural	Commercial
3	Thickener Rakes Lift	Vibrating	Commercial
4	Thickener Underflow Pumps	Centrifugal	Commercial
5	Clarified Water Pumps	Centrifugal	Commercial
	WASTE FUEL DRYING SYSTEM		
6	Waste Fuel Drying Building	Structural	Commercial
7	Plate Press Feed Sumps/ Mixers		Commercial
8	Plate Press Feed Pumps Stage 1		Commercial
9	Plate Press Feed Pumps Stage 2		Commercial
10	Plate Press Hydraulic Pumps		Commercial
11	Plate Press Plate Shifter		Commercial
12	Plate Press Plate Shaker		Commercial
13	Plate Press Hydraulic Drip Trays		Commercial
14	Plate Press Washdown Pumps		Commercial
15	Plate Press Air Compressors		Commercial
16	Gland Water Pumps		Commercial
17	Plate Press Effluent/ Sumps/Pumps		Commercial
18	Plate Press Hoist/Tram		Commercial
19	Floor Sump Pumps		Commercial
20	Waste Fuel Conveyor	Belt	Commercial
21	Waste Fuel Collecting Conveyor with Belt Scale		Commercial
22	Waste Fuel Transfer Conveyor with Scale	Belt	Commercial
23	Waste Fuel Storage Conveyor	Belt	Commercial
24	Cross Belt Sampler	Swing Hammer	Commercial
25	Waste Fuel Storage Dome		Commercial
26	Dome Vibrafloor Reclaim System		Commercial
27	Waste Fuel Reclaim Conveyors	Belt	Commercial
28	Waste Fuel Transfer Conveyor with Scale	Belt	Commercial
29	Waste Fuel Fuel Prep Bldg Feed Conveyor	Belt; Enclosed	Commercial

Exhibit 4-47. Case 2B & 2C – Account 1: Waste Coal and Sorbent Handling (cont'd)

Equipment No.	Description	Type	Commercial Status
	SORBENT SIZING / HANDLING		
1	Truck Scale	Field Erect	Commercial
2	Sorbent Truck Dump/Hopper	Field Erect	Commercial
3	Truck Dump Feeders	Vibrating	Commercial
4	Truck Dump Conveyor to Sorbent Storage Stacker	Belt	Commercial
5	Sorbent Storage Reclaim Hoppers/Feeders	Augers	Commercial
6	Sorbent Reclaim Conveyor to Sizing Bldg with Scale	Belt	Commercial
7	Sorbent Sizing Bldg	Enclosed	Commercial
8	Bulk Material Bin with Gates (2)	Enclosed	Commercial
9	Bin Rotary Airlock/Feeders		Commercial
10	Sizing Screens		Commercial
11	Crusher Hammermill		Commercial
12	Oversize Protection Screens		Commercial
13	Fuel Prep Feed Conveyor/Scale		Commercial
14	Process Bag Filter	Dust Collecting	Commercial
15	Process Bag Filter	At Fuel Prep Bldg	Commercial
16	Trough Conveyors	At Fuel Prep Bldg	Commercial

Exhibit 4-48. Case 2C – Account 1: Biomass Handling & Sizing

Equipment No.	Description	Type	Commercial Status
	WASTE FUEL BIOMASS EQUIPMENT		
1	Storage	500 Ton Each	Commercial
2	Reclaim Feeder Apron		Commercial
3	Biomass Sizing Plant Feed Conveyeor	Belt / Scale / Magnet	Commercial
4	Biomass Sizing Building	Structural; Insulated	Commercial
5	Biomass Sizing Screen	Incline 8 x 16	Commercial
6	Biomass Crusher	Reversible Hammermill	Commercial
7	Biomass Sized Collection Bin / Feeder	20 Ton Bin; Vibratory Feeder	Commercial
8	Biomass Sizing Plant Discharge Conveyor with Scale	Belt	Commercial

Exhibit 4-49. Case 1A, 1B, 2B, 2C – Account 3: Feed Water and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Commercial Status
1	Condensate Pumps	Vertical canned	Commercial
2	Deaerator and Storage Tank	Horizontal spray type	Commercial
3	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	Commercial
4	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	Commercial
5	Emergency Diesel driven backup FWP	Barrel type, multi-stage, centrifugal	Commercial
6	LP Feedwater Heater 1	Horizontal U-tube	Commercial
7	LP Feedwater Heater 2	Horizontal U-tube	Commercial
8	LP Feedwater Heater 3	Horizontal U-tube	Commercial
9	LP Feedwater Heater 4	Horizontal U-tube	Commercial
10	LP Feedwater Heater 5	Horizontal U-tube	Commercial
11	HP Feedwater Heater 7	Horizontal U-tube	Commercial
12	HP Feedwater Heater 8	Horizontal U-tube	Commercial
13	HP Feedwater Heater 9	Horizontal U-tube	Commercial
14	Topping Feedwater Feeder	Horizontal U-tube	Commercial
15	Auxiliary Boiler	Shop fabricated, water tube	Commercial
16	Closed Cycle Cooling System	Shell and tube HX & Horizontal centrifugal Pumps	Commercial
17	Condensate Polisher System	Deep Bed Condensate Polisher System with three service vessels, cation separation/regeneration vessel, anion regeneration vessel, resin refill hopper, resin storage vessel, acid and caustic storage tanks, acid and caustic regeneration skids, mixing skids,design of neutralization tank, neutralization tank internals, PLC Controls	Commercial
18	Neutralization Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
19	Sluice/Regen Water Pumps	All 316 stainless steel construction, horizontal centrifugal	Commercial
20	Condensate Polisher Booster Pumps	316 Stainless Steel construction, horizontal centrifugal	Commercial
21	Raw Water Pretreatment Clarifier System	Two train clarifier system: Including clarifiers, sludge handling equipment, filter presses, sludge storage and forwarding tanks, sludge feed pumps, chemical feed systems and PLC Controls	Commercial
22	Raw Water System Pumps with VFD	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
23	Raw Water/ Fire water Storage Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
24	Clarified Water Storage Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
25	Clarified Water Pumps with VFD	Cast Iron construction, 316 stainless steel shaft & Impeller, vertical centrifugal	Commercial
26	Cooling Tower Makeup Water Pumps with VFD	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
27	Service Water Transfer Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, vertical centrifugal	Commercial
28	Service Water Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial

Equipment No.	Description	Type	Commercial Status
29	Service Water Storage Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
30	Sodium Hypochlorite Storage Tank	Vertical, cylindrical, outdoor, FRP construction, external UV protection	Commercial
31	SO_2 Polishing Makeup Water Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
32	Liquid Waste Treatment System	ZLDS two train Evaporator & Crystalizer System	Commercial
33	ZLD Primary Feed Tank	Vertical, cylindrical, indoors, AL6XN	Commercial
34	ZLD Distillate Tank	Vertical, cylindrical, indoors, 304L stainless steel	Commercial
35	ZLD Brine Holding Tank	Vertical, cylindrical, indoors, FRP	Commercial
36	ZLD WW Feed Pumps	316 Stainless Steel construction	Commercial
37	ZLD Fuel Prep Feedwater Transfer Pumps	316 Stainless Steel construction	Commercial
38	LP Economizer- Water Side	Horizontal Field Erected Waste Heat Recovery	Commercial
39	HP Economizer 1 - Water Side	Horizontal Field Erected Waste Heat Recovery	Commercial
40	HP Economizer 2 - Water Side	Horizontal Field Erected Waste Heat Recovery	Commercial
41	BFP Condenser	Single pass including vacuum pumps	Commercial
42	SO_2 Polishing Makeup Water Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
43	Motor Driven Fire Pump	Horizontal Centrifugal	Commercial
44	Diesel driven fire pump	Vertical Turbine	Commercial
45	Jockey fire pump	Horizontal Centrifugal	Commercial
46	Emergency Instrument Air Compressor	Oil Free Screw	Commercial
47	Instrument Air dryer	Duplex, regenerative	Commercial
48	Instrument Air Accumulator	Carbon Steel, Vertical	Commercial
49	Service Air Compressor	Flood Screw	Commercial
50	Service Air dryer	Heatless	Commercial
51	Service Air Accumulator	Carbon Steel, Vertical	Commercial
52	Raw Water Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
53	Clarifier Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
54	Demineralized Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
55	RO Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
56	Condensate Polisher Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
57	Transformer Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
58	Cooling Tower Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
59	Chemical Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
60	Evaporator Area Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
61	Crystallizer Area Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
62	ZLD Area Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
63	ZLD Waste Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
64	Oil Water Separator	Horizontal Cylindrical tank with pump out chamber and effluent pumps	Commercial

Exhibit 4-50. Case 1A, 1B, 2B, 2C – Account 3.1: Demineralized Water Systems

Equipment No.	Description	Type	Commercial Status
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor, 304L	Commercial
2	Demineralized Water Ultrafiltration (UF) System	Two train UF System with feed tank and pumps, CIP System, UF backwash System, PLC Controls	Commercial
3	UF Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
4	Demineralized Water Reverse Osmosis (RO) System	Two train, two stage RO System with feed tank and pumps, CIP system, RO feed pumps, chemical Feed Skids, PLC Controls	Commercial
5	First Pass RO Supply Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
6	First Pass RO Permeate Tank	Vertical, cylindrical, outdoor, 304L	Commercial
7	RO Product Tank	Vertical, cylindrical, outdoor, 304L	Commercial
8	Demineralized Water Mixed Bed (MB) System	Two train, MB System with feed tank and pumps, recirculation pumps, acid and caustic regeneration system, acid and caustic storage tanks, design of neutralization tank, neutralization tank internals, PLC Controls	Commercial
9	Mixed Bed Feed Pumps	All 316 stainless steel construction, horizontal centrifugal	Commercial
10	Neutralization Tank	Vertical, cylindrical, outdoors, carbon Steel, internal epoxy lining	Commercial
11	Demineralized Water Feed Pumps	All 316 stainless steel construction, horizontal centrifugal	Commercial

Exhibit 4-51. Case 1A, 1B, 2B, 2C – Account 4: PFBC Coal Boiler and Accessories

Equipment No.	Description	Type	Commercial Status
1	PFBC	P200, supercritical, SNCR	Custom Design (supercritical)
2	SNCR Ammonia Storage & Feed System	Horizontal tank, centrifugal pump, injection grid	Commercial
3	External Reheater	Shell & Tube Heat exchanger	Commercial
4	Process Air Compressors	Screw Type	Commercial
5	Process Air Receiver	Vertical	Commercial
6	Process Air Moisture Separator	Duplex	Commercial
7	Process Air Membrane Drier		Commercial
8	Nitrogen Storage Tank	Horizontal	Commercial
9	Nitrogen Vaporizer	Electrical Heating	Commercial
10	Nitrogen Buffer Tank	Horizontal	Commercial

Exhibit 4-52. Case 1A, 1B, 2B, 2C – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Commercial Status
1	Hot Gas Metallic Filter	Pressure vessel with replaceable filter elements, back-pulse cleaning	Custom Design
2	Mercury Control system	GORE® Sorbent Polymer Catalyst (SPC) composite material	Commercial
3	SO_2 Polisher Absorber Module	Counter-current packed column absorber, caustic solvent	Custom Design
4 Capture only	Gas Pre-cooler	Direct Contact	Custom Design
5 Capture only	CO_2 Absorber System	Amine-based CO_2 capture (e.g., CANSOLV capture technology)	Custom Design
6 Capture only	CO_2 Dryer	Triethylene glycol (TEG)	Custom Design
7 Capture only	CO_2 Compression system	Integrally geared, multi-stage centrifugal compressor	Custom Design
8 Capture only	CO_2 Intercooler	Shell and tube heat exchanger (Included w/MAN CO2 Compressor Quote)	Custom Design
9 Capture only	CO_2 Aftercooler	Shell and tube heat exchanger	Custom Design
10	CEMS	Standalone building	Commercial

Exhibit 4-53. Case 1A, 1B, 2B, 2C – Account 6: Turbomachines

Equipment No.	Description	Type	Commercial Status
1	Intake Air Filter/Silencer	Dry	Custom Design
2	Gas turbo machine	Integrated compressor, expander, and motor/generator	Custom Design
3	Gas turbo Intercooler	Shell Tube	Custom Design
4	Heat Recovery Unit	Fin Tube Heat Exchanger, See water side economizers in account 3	Custom Design

Exhibit 4-54. Case 1A, 1B, 2B, 2C – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Commercial Status
1	Stack	Reinforced concrete with FRP liner	Custom Design

Exhibit 4-55. Case 1A, 1B, 2B, 2C – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Commercial Status
1	Steam Turbine	Commercially available advanced steam turbine	Custom Design
2	Steam Turbine Generator	Hydrogen cooled, static excitation	Custom Design
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	Custom Design
4 Cases 2 Only	Air Cooled Condenser	"A" Frame Type	Custom Design

Exhibit 4-56. Case 1A, 1B, 2B, 2C – Account 9: Cooling Water System

Equipment No.	Description	Type	Commercial Status
1	Circulating Water Pumps	Vertical, wet pit	Commercial
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	Commercial

Exhibit 4-57. Case 1A, 1B, 2B, 2C – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Commercial Status
	Bed Ash Handling System	-	
1	L-Valve	non-mechanical	Commercial
2	Lock Hopper		Commercial
3	Atmospheric Bin		Commercial
4	Atmospheric Bin Filter	Pulse Jet	Commercial
5	Conveyor	Screw	Commercial
6	Conveyor	Belt	Commercial
7	Bucket Elevator		Commercial
8	Conveyor	Belt	Commercial
9	Bed Ash Storage Silo	Reinforced concrete, Vertical cylinder	Commercial
	Cyclone & Filter Ash Handling System		
1	Pressure Reducer		Commercial
2	Storage Hopper	Reinforced concrete, Vertical cylinder	Commercial
3	External Ash Cooler	Shell Tube	Commercial
4	External Cyclone	Cyclone with air ejector	Commercial
5	Wet Unloader		Commercial
6	telescoping unloading chute		Commercial
7	Fly Ash Silo	Reinforced concrete, Vertical cylinder	Commercial

Exhibit 4-58. Case 1A, 1B, 2B, 2C – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Commercial Status
1	STG Transformer	Oil-filled	Commercial
2	Turbo-machine Transformer	Oil-filled	Commercial
3	High Voltage Transformer	Oil-filled	Commercial
4	Medium Voltage Transformer	Oil-filled	Commercial
5	Low Voltage Transformer	Dry ventilated	Commercial
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	Commercial
7	Turbo-machine Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	Commercial
8	Medium Voltage Switchgear	Metal clad	Commercial
9	Low Voltage Switchgear	Metal enclosed	Commercial
10	Emergency Diesel Generator	Sized for emergency shutdown	Commercial
11	Station Battery and DC Bus		Commercial
12	120 AC Uninterruptible Power Support		Commercial

Exhibit 4-59. Case 1A, 1B, 2B, 2C – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Commercial Status
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Custom Design
2	DCS -Processor	Microprocessor with redundant input/output	Custom Design
3	DCS - Data Highway	Fiber optic	Custom Design

4.6 Assessment of Available Data for Commercial Equipment & Vendor Contacts

Exhibit 4-60 reviews the status of the available data for commercial equipment and vendors with whom the project team is collaborating or having discussions for the major equipment unique to the PFBC Power cycle.

Exhibit 4-60. Assessment of Available Data for Commercial Equipment

Equipment	Vendor / OEM	Collabo-ration	Notes
P200 PFBC Module	• PFBC-EET • Nooter/Eriksen • GE (Alstom)	✓ ✓ ✓	PFBC-EET is providing PFBC knowledge and design information. Nooter/Eriksen (N/E) is providing cost for the supercritical PFBC module for everything inside and including the PFBC pressure vessel. The N/E design is based on the Cottbus bed and cyclone design parameters. GE (now the owner of the Alstom PFBC design) is onboard with the PFBC project.
High-temperature particulate filter	• Mott • PALL	✓ ✓	Contact made with both OEMS. Mott has provided performance and cost based on custom design. Mott design can accommodate 1450 °F.
Turbomachine	• Baker Hughes • Siemens	✓ ✓	Baker Hughes and Siemens have been engaged to provide performance and cost based on custom design.
Supercritical STG	• GE • Siemens	✓ ✓	GE and Siemens have provided performance and cost estimates.
SO_2 polishing scrubber (Caustic)	• Dürr Megtec	✓	Dürr Megtec has provided performance and costs for the caustic scrubber. It is possible that the SO_2 polisher can be combined with the CO_2 capture system, depending on the vendor.
Amine Carbon Capture	• CANSOLV • Linde • Air Liquide	✓	We used performance and cost information from the DOE Baseline study for the CANSOLV carbon capture system extended to 97% capture. We have received a valid quote from Linde and are utilizing cost estimate.
Mercury Capture	• GORE	✓	GORE has provided useful technical information, and costs depend on the integration with other AQC equipment and ducting.
Fuel Handling Mixer / Paste Pump	• Putzmeister	✓	Putzmeister is providing support for performance and cost data.

5 Cost Estimating Methodology and Cost Results

5.1 Capital Costs

5.1.1 General

Capital costs have been developed for a four-module PFBC power plant for each of the pre-FEED study configurations identified in Exhibit 4-1, including:

Case 1A – Illinois No. 6 Coal with 0% CO_2 Capture (Capture-Ready Configuration)

Case 1B – Illinois No. 6 Coal with 97% CO_2 Capture

Case 2B – Waste Coal with 97% CO_2 capture

Case 2C – 95% Waste Coal / 5% Biomass with 97% CO_2 Capture

The capital cost estimates are based on a blend of budget quotations from selected equipment vendors, some targeted material take-off data based on design information developed during the course of the Phase 2 pre-FEED study, and scaled or factored cost information for similar systems and equipment from the Worley experience base.

Capital costs are presented at the Bare Erected Cost (BEC), Total Plant Cost (TPC), Total Overnight Cost (TOC), and Total As-Spent Capital (TASC) levels. BEC includes the cost of equipment, construction materials, and associated installation labor (both direct and indirect). TPC includes BEC plus the cost of engineering, design, and construction management services and associated fees, as well as both process and project contingencies. TOC includes the TPC plus all other overnight costs, including pre-production costs, inventory capital, financing costs, and other owner's costs. TASC represents the total of all capital expenditures incurred during the capital expenditure period, including both escalation and interest during construction. TOC and TASC were estimated using the methodology set forth in the *Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance* [**20**].

Additional details of the capital costing approach are listed below.

- The estimates are based on an engineer, procure and construction management (EPCM) contracting approach, utilizing multiple subcontracts.
- All costs are presented in U.S. dollars and represent "overnight" costs for late 2019/early 2020. Forward escalation over the period of performance through FEED and Design and Construction to Commercial Operation is excluded.
- The estimated boundary limit is defined as the total plant facility within the "fence line," including fuel (Illinois No. 6 or waste coal and biomass) and limestone sorbent receiving and preparation to form the fuel/sorbent paste that is fed to the PFBC boiler. CO_2 compression and pipeline within the fence line are also included.
- A new switchyard is required, and an allowance for a 4-breaker ring bus configuration to connect to an existing transmission line (345 kV for Case 1 and 500 kV for Case 2) crossing the intended site has been included.
- The project site will be furnished in a clean, level condition.

- Costs are grouped according to a system-oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.

5.1.2 Equipment and Material Pricing

Vendor quotations were solicited and received for the following major subsystems and components:

• PFBC Vessels and Internals	Nooter/Eriksen
• CO_2 Capture System	BASF-Linde
• Hot Gas Filters	Mott Corporation and Pall Corp. (subsidiary of Danaher Corp.)
• Steam Turbine Generator	General Electric and Siemens
• Gas Turbomachines	Baker Hughes
• Fuel and Sorbent Prep and Feed	Farnham & Pfile

The above were supplemented by a limited number of project-specific quotations for some of the more minor equipment items as well as from Worley's database of quotations for similar equipment and systems from other recent or ongoing projects. All database quotations were scaled to reflect the project-specific design parameters and escalated as appropriate.

All quotations were adjusted as required to include freight to site, vendor technical direction during installation, incomplete or missing scope items, and/or changes in capacity, as well as conversion to U.S. dollars.

Where specifically identified, contingency was removed from the quotations and applied in a consistent manner in the cost summaries presented later in this section.

5.1.3 Labor Pricing

Installation labor costs for the Illinois No. 6 coal-fired cases (Cases 1A and 1B) are based on merit-shop rates for a Midwest U.S. location. Labor costs for the waste coal-fired Business Cases located in southwest Pennsylvania (Cases 2B and 2C) are based on union shop rates and associated productivities. All cases are based on a competitive bidding environment, with adequate skilled craft labor available locally to staff the projects.

Labor is based on a 50-hour workweek (5-10s). No additional incentives such as per-diems or bonuses have been included to attract craft labor.

The labor cost is considered all-inclusive and includes the following:

- Craft wages
- Burdens and benefits
- Payroll taxes and insurance
- Supervision, indirect craft, scaffolding
- Temporary facilities and utilities
- Field office
- Small tools and consumables
- Safety
- Mobilization/demobilization

- Construction rental equipment (with associated fuel, oil, and maintenance)
- Contractor's labor-related overhead and profit

5.1.4 Engineering

Engineering, procurement and construction management costs were generally estimated at 10 percent of the BEC. These costs included all home office engineering, design, and procurement services as well as field construction management staff. Site staffing generally included a construction manager, resident engineers, scheduling, project controls, document control, materials management, site safety, and field inspection.

The furnish and erect quotation for the PFBC vessels and the furnish and erect estimate for the complete fuel and sorbent preparation and feed system each included all required costs for design, engineering, procurement, and site supervision. As such, the engineering costs for these items were estimated at a reduced value of 3.5 percent to reflect the reduced scope of work for the project EPCM contractor.

5.1.5 Contingency

Contingencies are included in the estimate to account for unknown costs that are omitted or unforeseen due to a lack of complete project definition and engineering. Experience has shown that such costs are likely and expected to be incurred even though they cannot be explicitly determined at the time the estimate is prepared. It is expected that by the end of the project the entire contingency will be spent on either direct or indirect costs.

Process contingency is intended to compensate for uncertainty in cost estimates caused by performance and technology integration uncertainties associated with the development status of a particular system. While the overall project is in essence a first-of-a-kind plant, it is comprised of equipment and processes that are, in most cases, representative of mature commercial technologies. As such, process contingency has been applied to only two accounts:

- Turbomachines: 20% process contingency to address a custom design for this application
- Instrumentation and Controls: 15% process contingency to address integration issues

Project contingency has generally been applied at 15 percent of the sum of BEC, EPCM, and process contingency. This is based on the current level of design development and definition. Contingency has been reduced to 10% on the furnish and erect values for the fuel and sorbent preparation and feed system and the PFBC vessels. This is consistent with the estimate development process for these packages.

5.1.6 Exclusions

The following items are excluded from the capital cost estimate:

- Demolition/removal of existing facilities/structures
- Removal/remediation of hazardous or contaminated materials
- Removal/relocation of underground obstructions
- Infrastructure external to plant boundary (e.g. CO_2 pipeline)
- All taxes, with the exception of payroll and property taxes (property taxes are included with the fixed O&M costs)

5.1.7 Estimate Accuracy

AACE International estimate classifications identify both the level of project definition and the estimate approach associated with various degrees of estimate accuracy; the better the accuracy, the more stringent the requirements. However, estimate accuracy is somewhat subjective as it is a function of numerous variables. These include the level of project definition, the estimate approach, the extent and quality of supporting quotations, estimate preparation time, etc. A further consideration is maturity of the technologies and their integration into a process. In setting estimate accuracy, each of these must be taken into account and the associated risk evaluated.

Some key considerations regarding this estimate include:

- Project definition is currently in the very early stages; estimated to be in the range of 1% of total engineering and design definition.
- While the individual project components are mostly considered to be mature technologies, the overall plant is essentially a first-of-a-kind.
- Project-specific quotations were limited to individual equipment items or processes and likely do not reflect the full extent of the overall project process integration requirements.

Based on the level of design definition and the estimate methodology, the current estimate is best classified as falling between AACE Class 3 and Class 4.

5.2 Capital Cost Saving Concepts for FEED Study Implementation

The design configuration presented in the Phase 2 pre-FEED Study Final Report is comprised of 4 x P200 PFBC modules operating at nominal 12 bar pressure connected in parallel to a single supercritical steam turbine generator. The flue gas path employs CO_2 capture at low pressure and temperature, after expansion through the turbomachine and all economically feasible energy recovery from the gas have been completed.

This configuration is significantly different from what was employed at the beginning of the pre-FEED study. That configuration employed a reduction in gas temperature prior to gas filtration, followed by further gas cooling in a regenerative heat transfer arrangement, CO_2 capture at elevated pressure (nominal 12 bar) using the Benfield process, and reheating of the CO_2-lean gas in the regenerative heat transfer system prior to expansion through the turbomachine.

Thermodynamic cycle studies were performed to evaluate alternative arrangements, based on the somewhat disappointing performance results from the original configuration. These studies revealed that there were unrecoverable losses due to the following:

- Pressure drops on the gas side in the heat transfer processes, leading to loss of expander power,
- Reduction in final temperature at the gas expander inlet, due to realistic and finite approach temperatures in the various heat exchangers employed. This reduction in temperature also reduces available power generation, and
- Loss of expansion power from the CO_2 gas component of the total gas stream. Although the CO_2 is captured at pressure in the original configuration, it is stripped and released from the Benfield solvent at between 1 and 2 bar. This then requires recompression to the final desired pressure (2215 psi or 153 bar).

These cumulative losses do not compensate for the reduced parasitic loads incurred in operation of the Benfield CO_2 capture system (lower steam requirement for CO_2 stripping and lower auxiliary electrical loads) relative to the amine-based CO_2 capture process selected for inclusion in the final design configuration. It is likely that prior evaluations of the application of the Benfield process to CO_2 capture in a PFBC did not fully account for or underestimated the losses involved.

At the conclusion of the Phase 2 pre-FEED study, a review was conducted to identify further changes to the advanced PFBC concept that hold promise for further reducing costs and increasing efficiency. These modifications are described below; they may be evaluated separately in parallel and then combined for a final system evaluation. The potential cost savings may not be linearly additive, as there may be interactions between these proposed changes that are synergistic (cumulative effects may be greater than the simple sum); or, conversely, the net combined sum of the changes may be less than the total linear superposition sum.

The first initiative to be evaluated is to increase the operating pressure of each PFBC module from 12 bar to 16 bar. In theory, this can allow three PFBC modules operating at 16 bar to accomplish the same thermal duty and power generation as four modules operating at 12 bar. This is precisely what the Karita P800 design in Japan has accomplished (though in that case the three higher-pressure PFBC boilers are integrated into a single large pressure vessel, resulting in a less modular design). The increased pressure allows higher mass flow and heat transfer to occur at the same volumetric flow.

This concept requires modifications to the PFBC pressure vessel, gas piping, gas filters, and gas turbomachines. Other ancillary equipment is also impacted, and the combustor building can be redesigned with a smaller footprint. The net cost savings that may accrue from this change in operating pressure can range up to $100 MM or more on a bare erected overnight construction cost basis. Other projected cost savings presented below are also on the same overnight BEC basis.

The second initiative to reduce overall costs is to select a power plant site with direct river access. This will allow complete fabrication of the PFBC vessels at a favorable site with regard to labor costs and productivity. With the current inland site, significant additional disassembly and reassembly work and non-destructive examination (radiography of welds, possible post-weld heat treatment) is required. Net cost savings from this change can be in the range of $30 to 50 MM.

Another potential cost saving modification to the Business Case plant documented in the Phase 2 Pre-FEED Study Final Report is to perform additional pre-processing of the waste coal to be fired. Based on extensive modeling of the PFBC system with Thermoflex, it is known that power output and thermal efficiency (on an HHV basis) are impacted by the ash content of the as-fired fuel. More ash requires more water for transport into the PFBC boilers. The resulting increase in vapor phase water occupies volume inside the PFBC gas flow passages and impacts the gas velocity throughout the system. As gas velocity is limited through the fluidized bubbling bed, this constraint limits fuel input and, therefore, power output. This change by itself will not reduce PFBC module costs but can reduce some ancillary system costs such as ash handling system costs. It is expected that some or all of these cost savings may be offset by increased costs in the fuel preparation area to cover the costs of the additional coal processing. However, the primary capital cost benefit to be gained by this modification is that, by increasing net power output, it will reduce costs on a $/kWe basis. The difference in ash content and power output can be gauged roughly by comparing the Illinois No. 6 case with the waste coal case (assuming the same steam turbine conditions). This implies an increase in net output of about 28 MWe for a decrease in ash content from nominal 33% by weight for waste coal to 10% by weight for Illinois 6 No. coal, as well as an approximately 2+ percentage point increase in net plant HHV efficiency. Pilot testing conducted by OMNIS Bailey, LLC using the thickener underflow stream from CONSOL's Bailey Central Preparation Plant has demonstrated that the ash content of the waste coal stream can be reduced to even lower levels than this and that the resulting separated mineral matter stream (which is not ash because it has been separated from the fuel prior to combustion) may have applicability as a soil amendment in agricultural applications [**29**]. OMNIS is now building the first commercial-scale module at Bailey to process thickener underflow [**30**]; this option will be explored in depth as part of the FEED study.

Again, cost savings may be realized by subjecting the design of the entire PFBC power plant to a disciplined Value Engineering process. This process evaluates functions of the various systems and components, reliability and availability relative to the installed capacity of components (i.e., sparing and capacity selections - for example, two pumps at 100% vs. three pumps at 50%), mean time to failure and mean time to repair for essential components, materials of construction for all systems and components, selection of appropriate design codes and design margins, etc. The general arrangement drawings of the plant and the footprint of the major buildings and structures show potential for reduction in size and cost. There was insufficient time during the pre-FEED study to fully evaluate these measures. It is difficult to put a number on the potential savings that can be achieved by a disciplined, structured Value Engineering process. For the purposes of this narrative, it is suggested that a range of 3% to 6% of bare erected cost be used; therefore, a reduction in bare erected cost of between $45 to $90 MM can be assumed.

Another avenue of possible capital cost reduction is a reduction in the size of the ZLD system and the costs associated with it. The present configuration includes systems sized assuming the use of evaporative cooling towers for the Illinois No. 6 case (i.e., Case 1), and a smaller evaporative cooling tower for the waste coal-fired Business Case (i.e., Case 2, which uses a dry air-cooled condenser for the steam turbine generator).

Some of the remaining heat loads, in addition to the steam turbine condenser, can be cooled by a closed loop cooling system using a dry fin fan cooler. By further reducing the cooling tower duty, and thus reducing the evaporation and blowdown rates, the ZLD system size and cost can be reduced. This will be evaluated in the Phase 3 FEED study, with estimated savings of $5 to $10 million.

Yet another area of review for potential cost savings is the CO_2 capture and compression system. The cost for this system in the current estimate is based on a quote from a single vendor. (A total of five vendors were solicited for quotes. Four of the five declined to provide any information within the timeframe and scope of the pre-FEED study but noted that they would be more forthcoming in an actual procurement process). Besides competitive bidding, some reconfiguration of the system might be possible based on inputs from qualified vendors, leading to potential cost reductions. Cost reductions of 5% to 10% can be assumed as a placeholder for the purposes of this narrative. Therefore, cost savings of $ 10MM to $ 20MM are possible.

As more detailed analyses and design proceed during the Phase 3 FEED study, other potential initiatives to reduce costs may be revealed. The simple linear superposition of the initiatives described in this narrative total to a sum between $190 MM to $270 MM in bare erected cost. In addition, a gain in net power for sale on the order of 30 MWe may be achieved for the Business Case (Case 2) plant.

The net impact of successfully implementing the initiatives described above can produce a reduction in plant capital costs ranging from 20% to 30% on a $/kWe (net) basis. This represents a very significant improvement in the potential plant economic basis. These initiatives are very credible and can be implemented with a good likelihood of success. All will be pursued and fully vetted during the initial design studies planned for the first seven months of the Phase 3 FEED study.

5.3 Operation and Maintenance Costs

Operation and Maintenance (O&M) costs were estimated on a late-2019/early 2020 "overnight" cost basis consistent with the capital costs. The costs are presented on an average annual basis and do not include initial start-up costs. The O&M costs are split into two components: fixed and variable. Fixed costs are independent of capacity factor, while variable costs are proportional to the plant capacity factor. Annual costs for property taxes & insurance have been included at two percent of the TPC.

Operating labor cost was based on the anticipated staffing, by area, required to operate the plant. The corresponding hours were converted to equivalent around-the-clock (24/7) operating jobs.

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost for similar equipment items and processes. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section.

Fuel costs for Illinois No. 6 coal and biomass were based on the assumptions set forth in Sections 3.2.1 and 3.2.2, respectively. Waste coal for the Business Case (Case 2) was assumed to be supplied to the power plant gate at zero net cost, as this material is a waste stream having no current value (it is actually being disposed of at cost), and the cost to pump it via slurry pipeline to the assumed power plant site (within the footprint of the Bailey Central Preparation Plant Site) was estimated to be approximately the same as the current cost to pump it via slurry pipeline for disposal in slurry impoundments located within that same footprint.

Costs for consumables (water, chemicals, and supplemental fuels) were determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours. The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or capacity factor.

Similarly, waste disposal costs were determined on the basis of individual consumption / production rates, the unit costs for each item, and the plant annual operating hours. For purposes of this initial estimate, and based on the success achieved with beneficially utilizing PFBC ash produced at the Karita plant, it was assumed that PFBC bed and fly ash are provided for beneficial reuse at zero net cost/benefit.

Also, for those cases including CO_2 capture, we assumed that the captured CO_2 is injected for storage in a deep geologic formation in the vicinity of the plant. As described in the Business Case (Section 7), CO_2 that has been verified as geologically sequestered was assumed to have a credit value of $50/ton for the life of the plant, consistent with the value currently specified under Section 45Q of the U.S. tax code. DOE-NETL estimated the costs for CO_2 transport and storage to be approximately $10/tonne ($9/ton) of CO_2 in the midwestern U.S. [**16**]. As such, all of the costs presented in this report assumed that any captured CO_2 was credited at a value of $41/ton ($50/ton value of 45Q credit less $9/ton for transport and storage) at the power plant gate.

5.4 Cost Results

The total plant cost results initial and annual O&M Expense results for analyzed cases are presented in the following Exhibits.

Exhibit 5-1. Total Plant Cost Summary – Case 1A (Illinois No. 6 - Capture Ready)

Exhibit 5-2. Owner's Costs – Case 1A (Illinois No. 6 - Capture Ready)

Exhibit 5-1. Total Plant Cost Summary – Case 1A (Illinois No. 6 - Capture Ready)

Client: Consol
Project: Case 1A - PFBC Illinois Coal Based Power Plant **no** CO2 Capture
Report Date: 2020 May 04

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual
Plant Size: 404.0 MW,net
Labor Basis mid-West US - merit
Cost Base Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED	$88,700	$0	**$88,700**	$3,105	$0	$9,180	**$100,985**	$250
2	OPEN	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$97,276	$55,122	**$152,398**	$15,240	$0	$25,146	**$192,784**	$477
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	**$326,500**	$11,428	$0	$33,793	**$371,720**	$920
4.2-4.9	Other	$3,774	$4,976	**$8,750**	$875	$0	$1,444	**$11,069**	$0
	SUBTOTAL 4	**$330,274**	**$4,976**	**$335,250**	**$12,303**	**$0**	**$35,237**	**$382,790**	**$947**
5	FLUE GAS CLEANUP	$78,111	$16,466	**$94,577**	$9,458	$0	$15,605	**$119,639**	$296
5B	CO2 REMOVAL & COMPRESSION	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	TURBO MACHINES								
6.1	Turbo Machines	$54,192	$6,143	**$60,335**	$6,034	$12,067	$11,765	**$90,201**	$223
6.2-6.9	Other	$361	$949	**$1,311**	$131	$0	$216	**$1,658**	$4
	SUBTOTAL 6	**$54,553**	**$7,093**	**$61,646**	**$6,165**	**$12,067**	**$11,982**	**$91,859**	**$227**
7	DUCTING & STACK								
7.1	open	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	Ductwork and Stack	$28,941	$2,034	**$30,975**	$3,097	$0	$5,111	**$39,183**	$97
	SUBTOTAL 7	**$28,941**	**$2,034**	**$30,975**	**$3,097**	**$0**	**$5,111**	**$39,183**	**$97**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$36,060	$5,728	**$41,788**	$4,179	$0	$6,895	**$52,862**	$131
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$29,796	$18,251	**$48,047**	$4,805	$0	$7,928	**$60,779**	$150
	SUBTOTAL 8	**$65,856**	**$23,979**	**$89,835**	**$8,983**	**$0**	**$14,823**	**$113,641**	**$281**
9	COOLING WATER SYSTEM	$16,631	$12,292	**$28,922**	$2,892	$0	$4,772	**$36,587**	$91
10	ASH HANDLING SYSTEM	$28,785	$4,844	**$33,629**	$3,363	$0	$5,549	**$42,540**	$105
11	ACCESSORY ELECTRIC PLANT	$41,230	$32,908	**$74,138**	$7,414	$0	$12,233	**$93,784**	$232
12	INSTRUMENTATION & CONTROL	$10,583	$948	**$11,531**	$1,153	$1,730	$2,162	**$16,575**	$41
13	IMPROVEMENTS TO SITE	$2,175	$4,595	**$6,770**	$677	$0	$1,117	**$8,564**	$21
14	BUILDINGS & STRUCTURES	$52,735	$31,498	**$84,233**	$8,423	$0	$13,898	**$106,554**	$264
	TOTAL COST	**$895,849**	**$196,753**	**$1,092,602**	**$82,272**	**$13,797**	**$156,814**	**$1,345,485**	**$3,330**

Client:	Consol	**Report Date:**	2020 May 04
Project:	Case 1A - PFBC Illinois Coal Based Power Plant **no** CO2 Capture		

TOTAL PLANT COST SUMMARY

Estimate Type:	Conceptual	**Labor Basis**	mid-West US - merit
Plant Size:	404.0 MW,net	**Cost Base**	Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED								
1.1	Fuel Prep & Feed System - complete plant	$88,700	$0	$88,700	$3,105	$0	$9,180	$100,985	$250
1.8	Fuel Prep & Feed Buildings - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Fuel Prep & Feed Foundations - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$88,700**	**$0**	**$88,700**	**$3,105**	**$0**	**$9,180**	**$100,985**	**$250**
2	OPEN								
2.1	open	$0	$0	$0	$0	$0	$0	$0	$0
2.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS								
3.1	Feedwater System	$16,192	$6,471	$22,662	$2,266	$0	$3,739	$28,668	$71
3.2	Water Makeup & Pretreating - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.3	Other Feedwater Subsystems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.4	Service Water Systems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.5	Other Plant Systems	$43,780	$26,975	$70,755	$7,076	$0	$11,675	$89,505	$222
3.6	FO Supply System - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.7	Zero Liquid Discharge System	$36,250	$19,281	$55,531	$5,553	$0	$9,163	$70,247	$174
3.8	Misc. Equip.(cranes,AirComp.,Comm.) - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.8	BOP Foundations	$1,054	$2,396	$3,450	$345	$0	$569	$4,364	$11
	SUBTOTAL 3.	**$97,276**	**$55,122**	**$152,398**	**$15,240**	**$0**	**$25,146**	**$192,784**	**$477**
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	$326,500	$11,428	$0	$33,793	$371,720	$920
4.2	PFBC Auxilliary Systems	$252	$703	$955	$95	$0	$158	$1,208	$3
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	$0	$0	$0	$0	$0	$0	$0
4.9	PFBC Foundations	$3,522	$4,273	$7,796	$780	$0	$1,286	$9,861	$24
	SUBTOTAL 4.	**$330,274**	**$4,976**	**$335,250**	**$12,303**	**$0**	**$35,237**	**$382,790**	**$947**

Client: Consol **Report Date:** 2020 May 04
Project: Case 1A - PFBC Illinois Coal Based Power Plant **no** CO2 Capture

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual **Labor Basis** mid-West US - merit
Plant Size: 404.0 MW,net **Cost Base** Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP								
5.1	Gas Heating & Cooling	$0	$0	$0	$0	$0	$0	$0	$0
5.2	Gas Filtration	$68,040	$9,277	$77,317	$7,732	$0	$12,757	$97,806	$242
5.3	SO2 Removal	$6,000	$3,369	$9,369	$937	$0	$1,546	$11,851	$29
5.4	Mercury removal	$0	$0	$0	$0	$0	$0	$0	$0
5.5	Flue Gas Piping	$3,051	$3,531	$6,582	$658	$0	$1,086	$8,327	$21
5.6	CEMs	$1,020	$289	$1,309	$131	$0	$216	$1,656	$4
5.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$78,111**	**$16,466**	**$94,577**	**$9,458**	**$0**	**$15,605**	**$119,639**	**$296**
5B	CO2 REMOVAL & COMPRESSION								
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression	$0	$0	$0	$0	$0	$0	$0	$0
5B.9	CO2 Removal & Compression Foundations	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	TURBO MACHINES								
6.1	Turbo Machines	$54,192	$6,143	$60,335	$6,034	$12,067	$11,765	$90,201	$223
6.2	Intercooler for PFBC	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Turbo Machines Foundations	$361	$949	$1,311	$131	$0	$216	$1,658	$4
	SUBTOTAL 6.	**$54,553**	**$7,093**	**$61,646**	**$6,165**	**$12,067**	**$11,982**	**$91,859**	**$227**
7	DUCTING & STACK								
7.1	open	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$561	$994	$1,555	$156	$0	$257	$1,967	$5
7.4	Stack - furnish and erect	$27,600	$0	$27,600	$2,760	$0	$4,554	$34,914	$86
7.9	Duct & Stack Foundations	$780	$1,040	$1,820	$182	$0	$300	$2,302	$6
	SUBTOTAL 7.	**$28,941**	**$2,034**	**$30,975**	**$3,097**	**$0**	**$5,111**	**$39,183**	**$97**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$36,060	$5,728	$41,788	$4,179	$0	$6,895	$52,862	$131
8.2	Turbine Plant Auxiliaries	$1,955	$2,435	$4,390	$439	$0	$724	$5,553	$14
8.3	Condenser & Auxiliaries	$5,990	$2,493	$8,483	$848	$0	$1,400	$10,732	$27
8.4	Steam Piping	$19,933	$9,645	$29,578	$2,958	$0	$4,880	$37,417	$93
8.9	STG Foundations	$1,917	$3,678	$5,595	$559	$0	$923	$7,077	$18
	SUBTOTAL 8.	**$65,856**	**$23,979**	**$89,835**	**$8,983**	**$0**	**$14,823**	**$113,641**	**$281**
9	COOLING WATER SYSTEM								
9.1	Cooling Towers - furnish & erect	$6,720	$0	$6,720	$672	$0	$1,109	$8,501	$21
9.2	Circulating Water Pumps	$1,200	$104	$1,304	$130	$0	$215	$1,649	$4
9.3	Circ.Water System Auxiliaries	$194	$119	$313	$31	$0	$52	$396	$1
9.4	Circ.Water Piping	$5,435	$7,083	$12,518	$1,252	$0	$2,065	$15,835	$39
9.5	Make-up Water System	$0	$0	$0	$0	$0	$0	$0	$0
9.6	Component Cooling Water Sys	$657	$588	$1,245	$125	$0	$205	$1,575	$4
9.9	Circ.Water System Foundations & Structures	$2,425	$4,398	$6,822	$682	$0	$1,126	$8,630	$21
	SUBTOTAL 9.	**$16,631**	**$12,292**	**$28,922**	**$2,892**	**$0**	**$4,772**	**$36,587**	**$91**

Client: Consol
Project: Case 1A - PFBC Illinois Coal Based Power Plant **no** CO2 Capture
Report Date: 2020 May 04

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual
Plant Size: 404.0 MW,net
Labor Basis mid-West US - merit
Cost Base Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH HANDLING SYSTEM								
10.1	Ash Handling System	$18,115	$2,620	$20,735	$2,073	$0	$3,421	$26,230	$65
10.2	Ash Silos - furnish & erect	$8,920	$0	$8,920	$892	$0	$1,472	$11,284	$28
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash System Foundations	$1,750	$2,224	$3,974	$397	$0	$656	$5,027	$12
	SUBTOTAL 10.	**$28,785**	**$4,844**	**$33,629**	**$3,363**	**$0**	**$5,549**	**$42,540**	**$105**
11	ACCESSORY ELECTRIC PLANT								
11.1	Electrical Equipment	$25,225	$4,324	$29,549	$2,955	$0	$4,876	$37,380	$93
11.2	open	$0	$0	$0	$0	$0	$0	$0	$0
11.3	open	$0	$0	$0	$0	$0	$0	$0	$0
11.4	Raceway, wire & cable	$9,545	$23,496	$33,041	$3,304	$0	$5,452	$41,797	$103
11.5	open	$0	$0	$0	$0	$0	$0	$0	$0
11.6	Switchyard	$5,680	$3,131	$8,811	$881	$0	$1,454	$11,146	$28
11.7	open	$0	$0	$0	$0	$0	$0	$0	$0
11.8	open	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$780	$1,956	$2,736	$274	$0	$451	$3,461	$9
	SUBTOTAL 11.	**$41,230**	**$32,908**	**$74,138**	**$7,414**	**$0**	**$12,233**	**$93,784**	**$232**
12	INSTRUMENTATION & CONTROL								
12.1	PFBC Control Equipment - with PFBC	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Turbo Machine Control - with Turbo Machine	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control - with Steam Turbine	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control - with equipment	$0	$0	$0	$0	$0	$0	$0	$0
12.5	open	$0	$0	$0	$0	$0	$0	$0	$0
12.6	open	$0	$0	$0	$0	$0	$0	$0	$0
12.7	Distributed Control System Equipment	$10,000	w/ mat'l	$10,000	$1,000	$1,500	$1,875	$14,375	$36
12.8	Instrument Wiring & Tubing - with electrical	$0	$0	$0	$0	$0	$0	$0	$0
12.9	Other I & C Equipment	$583	$948	$1,531	$153	$230	$287	$2,200	$5
	SUBTOTAL 12.	**$10,583**	**$948**	**$11,531**	**$1,153**	**$1,730**	**$2,162**	**$16,575**	**$41**
13	IMPROVEMENTS TO SITE								
13.1	Site Preparation	$0	$0	$0	$0	$0	$0	$0	$0
13.2	Site Improvements	$2,175	$4,595	$6,770	$677	$0	$1,117	$8,564	$21
13.3	Site Facilities	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 13.	**$2,175**	**$4,595**	**$6,770**	**$677**	**$0**	**$1,117**	**$8,564**	**$21**
14	BUILDINGS & STRUCTURES								
14.1	Combustion Building	$25,894	$19,006	$44,900	$4,490	$0	$7,409	$56,799	$141
14.2	Turbine Building	$12,255	$10,302	$22,556	$2,256	$0	$3,722	$28,534	$71
14.3	Administration Building	$2,101	$175	$2,275	$228	$0	$375	$2,878	$7
14.4	Water Treatment Building	$2,694	$471	$3,166	$317	$0	$522	$4,004	$10
14.5	CO2 Regeneration & Compression Buildings	$9,028	$1,341	$10,369	$1,037	$0	$1,711	$13,116	$32
14.6	open	$0	$0	$0	$0	$0	$0	$0	$0
14.7	open	$0	$0	$0	$0	$0	$0	$0	$0
14.9	Other Buildings & Structures	$764	$203	$967	$97	$0	$160	$1,223	$3
	SUBTOTAL 14.	**$52,735**	**$31,498**	**$84,233**	**$8,423**	**$0**	**$13,898**	**$106,554**	**$264**
	TOTAL COST	**$895,849**	**$196,753**	**$1,092,602**	**$82,272**	**$13,797**	**$156,814**	**$1,345,485**	**$3,330**

Exhibit 5-2. Owner's Costs – Case 1A (Illinois No. 6 - Capture Ready)

Owner's Costs

Case 1A - PFBC Illinois Coal Based Power Plant no CO2 Capture

Description	$ x 1,000	$.kW
TPC	$1,345,485	$3,330
Pre-production		
6 Months All Labor	$9,764	$24
1 Month Maintenance Materials	$1,147	$3
1 Month Non-Fuel Consumables	$1,532	$4
1 Month Waste Disposal	$0	$0
25% of 1 Month's Fuel at 100% CF	$5,274	$13
2% of TPC	$26,910	$67
Total Preproduction	**$44,627**	$110
Inventory Capital		
60 Day Supply Fuel & Consumables at 100% CF	$13,426	$33
0.5% of TPC (spare parts)	$6,727	$17
Total Inventory Capital	**$20,153**	$50
Other Costs		
Initial Cost for Catalysts & Chemicals	$693	$2
Land	$900	$2
Finanacing Costs	$36,328	$90
Owner's Costs	$201,823	$500
Total Other Costs	**$239,744**	$593
Total OverNight Cost (TOC)	**$1,650,009**	$4,084
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Capital(TASC)	**$1,904,110**	$4,713

Exhibit 5-3. Initial and Annual O&M Expenses – Case 1A (Illinois No. 6 - Capture Ready)

INITIAL & ANNUAL O&M EXPENSES						
Case 1A - PFBC Illinois Coal Based Power Plant					Cost Basis:	Dec 2019
4 x 1 P200 **no** CO2 capture					Heat Rate-net (Btu/kWh):	8,030
					MWe-net:	404.0
					Capacity Factor (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	38.50	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Total Operators & Lab Techs	15					
(equivalent 24/7 positions)					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$6,445,039	$15.953
Maintenance Labor Cost					$9,177,858	$22.717
Administrative & Support Labor					$3,905,724	$9.668
Property Taxes and Insurance					$26,909,703	$66.608
TOTAL FIXED OPERATING COSTS					**$46,438,324**	**$114.946**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$13,766,788**	**$0.00458**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water (/1000 gallons)	-	3,593	1.90	$0	$2,117,984	$0.00070
Chemicals						
MU & WT Chem.(lbs)	121,747	8,696	0.28	$33,480	$741,950	$0.00025
Limestone (ton)	11,368	812	24.25	$275,674	$6,109,133	$0.00203
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	-	10,000.00	$0	$0	$0.00000
Ammonia (19% NH3) ton	81	5.8	300.00	$24,402	$540,766	$0.00018
NaOH - 50% (ton) for causitc scrubber	329	23.5	600.00	$197,568	$4,378,248	$0.00146
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$0	$0.00000
Triethylene Glycol (gal)	w/ capital	-	6.80	$0	$0	$0.00000
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	1	285.00	$0	$53,295	$0.00002
NaOH - 50% (ton) for demin/condensate	10	0.7	600.00	$6,266	$138,864	$0.00005
H2SO4 - 93% (ton) for demin/condensate	14	1.0	205.00	$2,937	$65,095	$0.00002
NaOH - 50% (ton) for ZLD	54	3.8	600.00	$32,227	$714,172	$0.00024
H2SO4 - 93% (ton) for ZLD	55	3.9	205.00	$11,243	$249,146	$0.00008
Anti-scale (ton) for ZLD	2	0.2	5,900.00	$14,233	$315,405	$0.00010
Anti-coagulant (ton) for ZLD	46	3	2,050.00	$94,655	$2,097,618	$0.00070
Subtotal Chemicals				**$692,685**	**$15,403,691**	**$0.00512**
Other						
Supplemental Fuel #2 Oil (MMBtu)	7,000	12	15.00	$105,000	$55,845	$0.00002
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00006
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$226,695**	**$0.00008**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	-	0.35	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
CO2 (ton)	-	-	41.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$797,685**	**$31,515,157**	**$0.01048**
Fuel - Coal (ton)	46,715	3,337	51.96	$2,427,299	$53,790,669	$0.01788
Fuel - Biomass (ton)	0	0	50.00	$0	$0	$0.00000
TOTAL FUEL COSTS				**$2,427,299**	**$53,790,669**	**$0.01788**

Exhibit 5-4. Total Plant Cost Summary – Case 1B (Illinois No. 6 - Capture Equipped)

Client: Consol
Project: Case 1B - PFBC Illinois Coal Based Power Plant **with** CO2 Capture
Report Date: 2020 May 04

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual
Plant Size: 307.7 MW,net

mid-West US - merit
Dec 2019 ($x1000) ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED	$88,700	$0	**$88,700**	$3,105	$0	$9,180	**$100,985**	$328
2	OPEN	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$93,790	$53,854	**$147,644**	$14,764	$0	$24,361	**$186,769**	$607
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	**$326,500**	$11,428	$0	$33,793	**$371,720**	$1,208
4.2-4.9	Other	$3,774	$4,976	**$8,750**	$875	$0	$1,444	**$11,069**	$0
	SUBTOTAL 4	**$330,274**	**$4,976**	**$335,250**	**$12,303**	**$0**	**$35,237**	**$382,790**	**$1,244**
5	FLUE GAS CLEANUP	$82,707	$17,646	**$100,353**	$10,035	$0	$16,558	**$126,947**	$413
5B	CO2 REMOVAL & COMPRESSION	$140,091	$88,071	**$228,161**	$22,816	$0	$37,647	**$288,624**	$938
6	TURBO MACHINES								
6.1	Turbo Machines	$53,012	$6,001	**$59,013**	$5,901	$11,803	$11,508	**$88,225**	$287
6.2-6.9	Other	$361	$949	**$1,311**	$131	$0	$216	**$1,658**	$5
	SUBTOTAL 6	**$53,373**	**$6,951**	**$60,324**	**$6,032**	**$11,803**	**$11,724**	**$89,883**	**$292**
7	DUCTING & STACK								
7.1	open	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	Ductwork and Stack	$25,341	$2,034	**$27,375**	$2,737	$0	$4,517	**$34,629**	$113
	SUBTOTAL 7	**$25,341**	**$2,034**	**$27,375**	**$2,737**	**$0**	**$4,517**	**$34,629**	**$113**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$32,250	$5,113	**$37,363**	$3,736	$0	$6,165	**$47,264**	$154
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$26,063	$16,214	**$42,277**	$4,228	$0	$6,976	**$53,481**	$174
	SUBTOTAL 8	**$58,313**	**$21,327**	**$79,640**	**$7,964**	**$0**	**$13,141**	**$100,744**	**$327**
9	COOLING WATER SYSTEM	$15,740	$11,917	**$27,657**	$2,766	$0	$4,563	**$34,986**	$114
10	ASH HANDLING SYSTEM	$28,785	$4,844	**$33,629**	$3,363	$0	$5,549	**$42,540**	$138
11	ACCESSORY ELECTRIC PLANT	$41,230	$32,908	**$74,138**	$7,414	$0	$12,233	**$93,784**	$305
12	INSTRUMENTATION & CONTROL	$10,583	$948	**$11,531**	$1,153	$1,730	$2,162	**$16,575**	$54
13	IMPROVEMENTS TO SITE	$2,175	$4,595	**$6,770**	$677	$0	$1,117	**$8,564**	$28
14	BUILDINGS & STRUCTURES	$52,735	$31,498	**$84,233**	$8,423	$0	$13,898	**$106,554**	$346
	TOTAL COST	**$1,023,837**	**$281,567**	**$1,305,404**	**$103,552**	**$13,532**	**$191,887**	**$1,614,375**	**$5,247**

Client: Consol **Report Date:** 2020 May 04
Project: Case 1B - PFBC Illinois Coal Based Power Plant **with** CO2 Capture

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual mid-West US - merit
Plant Size: 307.7 MW,net Dec 2019 ($x1000) ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED								
1.1	Fuel Prep & Feed System - complete plant	$88,700	$0	$88,700	$3,105	$0	$9,180	$100,985	$328
1.8	Fuel Prep & Feed Buildings - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Fuel Prep & Feed Foundations - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$88,700**	**$0**	**$88,700**	**$3,105**	**$0**	**$9,180**	**$100,985**	**$328**
2	OPEN								
2.1	open	$0	$0	$0	$0	$0	$0	$0	$0
2.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS								
3.1	Feedwater System	$14,694	$6,216	$20,910	$2,091	$0	$3,450	$26,451	$86
3.2	Water Makeup & Pretreating - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.3	Other Feedwater Subsystems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.4	Service Water Systems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.5	Other Plant Systems	$43,462	$26,842	$70,304	$7,030	$0	$11,600	$88,935	$289
3.6	FO Supply System - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.7	Zero Liquid Discharge System	$34,581	$18,399	$52,980	$5,298	$0	$8,742	$67,019	$218
3.8	Misc. Equip.(cranes,AirComp.,Comm.) - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.8	BOP Foundations	$1,054	$2,396	$3,450	$345	$0	$569	$4,364	$14
	SUBTOTAL 3.	**$93,790**	**$53,854**	**$147,644**	**$14,764**	**$0**	**$24,361**	**$186,769**	**$607**
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	$326,500	$11,428	$0	$33,793	$371,720	$1,208
4.2	PFBC Auxilliary Systems	$252	$703	$955	$95	$0	$158	$1,208	$4
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	$0	$0	$0	$0	$0	$0	$0
4.9	PFBC Foundations	$3,522	$4,273	$7,796	$780	$0	$1,286	$9,861	$32
	SUBTOTAL 4.	**$330,274**	**$4,976**	**$335,250**	**$12,303**	**$0**	**$35,237**	**$382,790**	**$1,244**

Client: Consol
Project: Case 1B - PFBC Illinois Coal Based Power Plant **with** CO2 Capture
Report Date: 2020 May 04

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual — mid-West US - merit
Plant Size: 307.7 MW,net — Dec 2019 ($x1000) ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP								
5.1	Gas Heating & Cooling	$4,596	$1,180	$5,777	$578	$0	$953	$7,307	$24
5.2	Gas Filtration	$68,040	$9,277	$77,317	$7,732	$0	$12,757	$97,806	$318
5.3	SO2 Removal	$6,000	$3,369	$9,369	$937	$0	$1,546	$11,851	$39
5.4	Mercury removal	$0	$0	$0	$0	$0	$0	$0	$0
5.5	Flue Gas Piping	$3,051	$3,531	$6,582	$658	$0	$1,086	$8,327	$27
5.6	CEMs	$1,020	$289	$1,309	$131	$0	$216	$1,656	$5
5.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$82,707**	**$17,646**	**$100,353**	**$10,035**	**$0**	**$16,558**	**$126,947**	**$413**
5B	CO2 REMOVAL & COMPRESSION								
5B.1	CO2 Removal System	$110,000	$80,977	$190,977	$19,098	$0	$31,511	$241,585	$785
5B.2	CO2 Compression	$29,160	$5,105	$34,265	$3,426	$0	$5,654	$43,345	$141
5B.9	CO2 Removal & Compression Foundations	$931	$1,990	$2,920	$292	$0	$482	$3,694	$12
	SUBTOTAL 5B.	**$140,091**	**$88,071**	**$228,161**	**$22,816**	**$0**	**$37,647**	**$288,624**	**$938**
6	TURBO MACHINES								
6.1	Turbo Machines	$53,012	$6,001	$59,013	$5,901	$11,803	$11,508	$88,225	$287
6.2	Intercooler for PFBC	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Turbo Machines Foundations	$361	$949	$1,311	$131	$0	$216	$1,658	$5
	SUBTOTAL 6.	**$53,373**	**$6,951**	**$60,324**	**$6,032**	**$11,803**	**$11,724**	**$89,883**	**$292**
7	DUCTING & STACK								
7.1	open	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$561	$994	$1,555	$156	$0	$257	$1,967	$6
7.4	Stack - furnish and erect	$24,000	$0	$24,000	$2,400	$0	$3,960	$30,360	$99
7.9	Duct & Stack Foundations	$780	$1,040	$1,820	$182	$0	$300	$2,302	$7
	SUBTOTAL 7.	**$25,341**	**$2,034**	**$27,375**	**$2,737**	**$0**	**$4,517**	**$34,629**	**$113**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$32,250	$5,113	$37,363	$3,736	$0	$6,165	$47,264	$154
8.2	Turbine Plant Auxiliaries	$1,944	$2,433	$4,377	$438	$0	$722	$5,537	$18
8.3	Condenser & Auxiliaries	$4,633	$1,878	$6,511	$651	$0	$1,074	$8,236	$27
8.4	Steam Piping	$17,766	$8,594	$26,360	$2,636	$0	$4,349	$33,345	$108
8.9	STG Foundations	$1,721	$3,309	$5,030	$503	$0	$830	$6,363	$21
	SUBTOTAL 8.	**$58,313**	**$21,327**	**$79,640**	**$7,964**	**$0**	**$13,141**	**$100,744**	**$327**
9	COOLING WATER SYSTEM								
9.1	Cooling Towers - furnish & erect	$6,000	$0	$6,000	$600	$0	$990	$7,590	$25
9.2	Circulating Water Pumps	$1,200	$104	$1,304	$130	$0	$215	$1,649	$5
9.3	Circ.Water System Auxiliaries	$194	$119	$313	$31	$0	$52	$396	$1
9.4	Circ.Water Piping	$5,435	$7,083	$12,518	$1,252	$0	$2,065	$15,835	$51
9.5	Make-up Water System	$0	$0	$0	$0	$0	$0	$0	$0
9.6	Component Cooling Water Sys	$737	$666	$1,403	$140	$0	$231	$1,774	$6
9.9	Circ.Water System Foundations & Structures	$2,175	$3,945	$6,120	$612	$0	$1,010	$7,741	$25
	SUBTOTAL 9.	**$15,740**	**$11,917**	**$27,657**	**$2,766**	**$0**	**$4,563**	**$34,986**	**$114**

	Client:	Consol					**Report Date:** 2020 May 04			
	Project:	Case 1B - PFBC Illinois Coal Based Power Plant **with** CO2 Capture								
		TOTAL PLANT COST SUMMARY								
	Estimate Type:	Conceptual					mid-West US - merit			
	Plant Size:	307.7 MW,net					Dec 2019 ($x1000)	($x1000)		
Acct No.	**Item/Description**	**Equipment & Material Cost**	**Labor Cost**	**Bare Erected Cost $**	**Eng'g CM H.O.& Fee**	**Contingencies Process**	**Contingencies Project**	**TOTAL PLANT COST $**	**TOTAL PLANT COST $/kW**	
10	ASH HANDLING SYSTEM									
10.1	Ash Handling System	$18,115	$2,620	$20,735	$2,073	$0	$3,421	$26,230	$85	
10.2	Ash Silos - furnish & erect	$8,920	$0	$8,920	$892	$0	$1,472	$11,284	$37	
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	
10.9	Ash System Foundations	$1,750	$2,224	$3,974	$397	$0	$656	$5,027	$16	
	SUBTOTAL 10.	**$28,785**	**$4,844**	**$33,629**	**$3,363**	**$0**	**$5,549**	**$42,540**	**$138**	
11	ACCESSORY ELECTRIC PLANT									
11.1	Electrical Equipment	$25,225	$4,324	$29,549	$2,955	$0	$4,876	$37,380	$121	
11.2	open	$0	$0	$0	$0	$0	$0	$0	$0	
11.3	open	$0	$0	$0	$0	$0	$0	$0	$0	
11.4	Raceway, wire & cable	$9,545	$23,496	$33,041	$3,304	$0	$5,452	$41,797	$136	
11.5	open	$0	$0	$0	$0	$0	$0	$0	$0	
11.6	Switchyard	$5,680	$3,131	$8,811	$881	$0	$1,454	$11,146	$36	
11.7	open	$0	$0	$0	$0	$0	$0	$0	$0	
11.8	open	$0	$0	$0	$0	$0	$0	$0	$0	
11.9	Electrical Foundations	$780	$1,956	$2,736	$274	$0	$451	$3,461	$11	
	SUBTOTAL 11.	**$41,230**	**$32,908**	**$74,138**	**$7,414**	**$0**	**$12,233**	**$93,784**	**$305**	
12	INSTRUMENTATION & CONTROL									
12.1	PFBC Control Equipment - with PFBC	$0	$0	$0	$0	$0	$0	$0	$0	
12.2	Turbo Machine Control - with Turbo Machine	$0	$0	$0	$0	$0	$0	$0	$0	
12.3	Steam Turbine Control - with Steam Turbine	$0	$0	$0	$0	$0	$0	$0	$0	
12.4	Other Major Component Control - with equipment	$0	$0	$0	$0	$0	$0	$0	$0	
12.5	open	$0	$0	$0	$0	$0	$0	$0	$0	
12.6	open	$0	$0	$0	$0	$0	$0	$0	$0	
12.7	Distributed Control System Equipment	$10,000	w/ mat'l	$10,000	$1,000	$1,500	$1,875	$14,375	$47	
12.8	Instrument Wiring & Tubing - with electrical	$0	$0	$0	$0	$0	$0	$0	$0	
12.9	Other I & C Equipment	$583	$948	$1,531	$153	$230	$287	$2,200	$7	
	SUBTOTAL 12.	**$10,583**	**$948**	**$11,531**	**$1,153**	**$1,730**	**$2,162**	**$16,575**	**$54**	
13	IMPROVEMENTS TO SITE									
13.1	Site Preparation	$0	$0	$0	$0	$0	$0	$0	$0	
13.2	Site Improvements	$2,175	$4,595	$6,770	$677	$0	$1,117	$8,564	$28	
13.3	Site Facilities	$0	$0	$0	$0	$0	$0	$0	$0	
	SUBTOTAL 13.	**$2,175**	**$4,595**	**$6,770**	**$677**	**$0**	**$1,117**	**$8,564**	**$28**	
14	BUILDINGS & STRUCTURES									
14.1	Combustion Building	$25,894	$19,006	$44,900	$4,490	$0	$7,409	$56,799	$185	
14.2	Turbine Building	$12,255	$10,302	$22,556	$2,256	$0	$3,722	$28,534	$93	
14.3	Administration Building	$2,101	$175	$2,275	$228	$0	$375	$2,878	$9	
14.4	Water Treatment Building	$2,694	$471	$3,166	$317	$0	$522	$4,004	$13	
14.5	CO2 Regeneration & Compression Buildings	$9,028	$1,341	$10,369	$1,037	$0	$1,711	$13,116	$43	
14.6	open	$0	$0	$0	$0	$0	$0	$0	$0	
14.7	open	$0	$0	$0	$0	$0	$0	$0	$0	
14.9	Other Buildings & Structures	$764	$203	$967	$97	$0	$160	$1,223	$4	
	SUBTOTAL 14.	**$52,735**	**$31,498**	**$84,233**	**$8,423**	**$0**	**$13,898**	**$106,554**	**$346**	
	TOTAL COST	**$1,023,837**	**$281,567**	**$1,305,404**	**$103,552**	**$13,532**	**$191,887**	**$1,614,375**	**$5,247**	

Exhibit 5-5. Owner's Costs – Case 1B (Illinois No. 6 - Capture Equipped)

Owner's Costs
Case 1B - PFBC Illinois Coal Based Power Plant with CO2 Capture

Description	$ x 1,000	$.kW
TPC	$1,614,375	$5,247
Pre-production		
6 Months All Labor	$11,512	$37
1 Month Maintenance Materials	$1,371	$4
1 Month Non-Fuel Consumables	$2,026	$7
1 Month Waste Disposal	$3	$0
25% of 1 Month's Fuel at 100% CF	$5,274	$17
2% of TPC	$32,287	$105
Total Preproduction	**$52,473**	$171
Inventory Capital		
60 Day Supply Fuel & Consumables at 100% CF	$14,400	$47
0.5% of TPC (spare parts)	$8,072	$26
Total Inventory Capital	**$22,471**	$73
Other Costs		
Initial Cost for Catalysts & Chemicals	$686	$2
Land	$900	$3
Finanacing Costs	$43,588	$142
Owner's Costs	$242,156	$787
Total Other Costs	**$287,330**	$934
Total OverNight Cost (TOC)	**$1,976,649**	$6,424
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Capital(TASC)	**$2,281,053**	$7,413

Exhibit 5-6. Initial and Annual O&M Expenses – Case 1B (Illinois No. 6 - Capture Equipped)

INITIAL & ANNUAL O&M EXPENSES						
Case 1B - PFBC Illinois Coal Based Power Plant					Cost Basis:	Dec 2019
4 x 1 P200 with CO2 capture					Heat Rate-net (Btu/kWh):	10,542
					MWe-net:	307.7
					Capacity Factor (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	38.50 $/hour					
Operating Labor Burden:	30.00 % of base					
Labor O-H Charge Rate:	25.00 % of labor					
Total Operators & Lab Techs	17					
(equivalent 24/7 positions)					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$7,453,446	$24.223
Maintenance Labor Cost					$10,965,390	$35.637
Administrative & Support Labor					$4,604,709	$14.965
Property Taxes and Insurance					$32,287,497	$104.932
TOTAL FIXED OPERATING COSTS					**$55,311,043**	**$179.756**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$16,448,085**	**$0.00718**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	-	4,228	1.90	$0	$2,492,300	$0.00109
Chemicals						
MU & WT Chem.(lbs)	143,264	10,233	0.28	$39,397	$873,076	$0.00038
Limestone (ton)	11,368	812	24.25	$275,674	$6,109,133	$0.00267
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	-	10,000.00	$0	$0	$0.00000
Ammonia (19% NH3) ton	81	5.8	300.00	$24,402	$540,766	$0.00024
NaOH - 50% (ton) for causitc scrubber	329	23.5	600.00	$197,568	$4,378,248	$0.00191
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$4,613,800	$0.00201
Triethylene Glycol (gal)	w/ capital	273	6.80	$0	$575,948	$0.00025
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	1	285.00	$0	$46,633	$0.00002
NaOH - 50% (ton) for demin/condensate	9	0.6	600.00	$5,146	$114,047	$0.00005
H2SO4 - 93% (ton) for demin/condensate	12	0.8	205.00	$2,412	$53,462	$0.00002
NaOH - 50% (ton) for ZLD	50	3.6	600.00	$29,925	$663,159	$0.00029
H2SO4 - 93% (ton) for ZLD	51	3.6	205.00	$10,440	$231,350	$0.00010
Anti-scale (ton) for ZLD	2	0.2	5,900.00	$13,216	$292,876	$0.00013
Anti-coagulant (ton) for ZLD	43	3	2,050.00	$87,894	$1,947,788	$0.00085
Subtotal Chemicals				**$686,075**	**$20,440,287**	**$0.00892**
Other						
Supplemental Fuel #2 Oil (MBtu)	7,000	12	15.00	$105,000	$55,845	$0.00002
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00007
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$226,695**	**$0.00010**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	273	0.35	$0	$29,644	$0.00001
Subtotal-Waste Disposal				**$0**	**$29,644**	**$0.00001**
By-products & Emissions						
CO2 (ton)	-	7,694	41.00	$0	-$97,869,604	-$0.04272
Subtotal By-Products				**$0**	**-$97,869,604**	**-$0.04272**
TOTAL VARIABLE OPERATING COSTS				**$791,075**	**-$58,232,592**	**-$0.02542**
Fuel - Coal (ton)	46,715	3,337	51.96	$2,427,299	$53,790,669	$0.02348
Fuel - Biomass (ton)	0	0	50.00	$0	$0	$0.00000
TOTAL FUEL COSTS				**$2,427,299**	**$53,790,669**	**$0.02348**

Exhibit 5-7. Total Plant Cost Summary – Case 2B (Waste Coal - Capture Equipped)

Client: Consol
Project: Case 2B - PFBC Waste Coal Based Power Plant with CO2 Capture
Report Date: 2020 May 04

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual
Plant Size: 279.6 MW,net
Labor Basis Southeast, PA - union
Cost Base Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED	$136,350	$0	**$136,350**	$4,772	$0	$14,112	**$155,234**	$555
2	OPEN	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$71,433	$56,421	**$127,854**	$12,785	$0	$21,096	**$161,735**	$578
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	**$326,500**	$11,428	$0	$33,793	**$371,720**	$1,329
4.2-4.9	Other	$3,774	$6,591	**$10,365**	$1,036	$0	$1,710	**$13,111**	$0
	SUBTOTAL 4	**$330,274**	**$6,591**	**$336,865**	**$12,464**	**$0**	**$35,503**	**$384,831**	**$1,376**
5	FLUE GAS CLEANUP	$88,767	$22,500	**$111,267**	$11,127	$0	$18,359	**$140,753**	$503
5B	CO2 REMOVAL & COMPRESSION	$140,091	$117,806	**$257,897**	$25,790	$0	$42,553	**$326,239**	$1,167
6	TURBO MACHINES								
6.1	Turbo Machines	$53,012	$8,191	**$61,203**	$6,120	$12,241	$11,935	**$91,498**	$327
6.2-6.9	Other	$361	$1,234	**$1,595**	$159	$0	$263	**$2,017**	$7
	SUBTOTAL 6	**$53,373**	**$9,424**	**$62,798**	**$6,280**	**$12,241**	**$12,198**	**$93,516**	**$334**
7	DUCTING & STACK								
7.1	open	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	Ductwork and Stack	$15,268	$2,531	**$17,799**	$1,780	$0	$2,937	**$22,516**	$81
	SUBTOTAL 7	**$15,268**	**$2,531**	**$17,799**	**$1,780**	**$0**	**$2,937**	**$22,516**	**$81**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$29,900	$6,583	**$36,483**	$3,648	$0	$6,020	**$46,151**	$165
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$40,006	$27,202	**$67,208**	$6,721	$0	$11,089	**$85,018**	$304
	SUBTOTAL 8	**$69,906**	**$33,786**	**$103,692**	**$10,369**	**$0**	**$17,109**	**$131,170**	**$469**
9	COOLING WATER SYSTEM	$11,359	$10,911	**$22,269**	$2,227	$0	$3,674	**$28,171**	$101
10	ASH HANDLING SYSTEM	$35,265	$6,780	**$42,045**	$4,205	$0	$6,937	**$53,187**	$190
11	ACCESSORY ELECTRIC PLANT	$41,230	$45,343	**$86,573**	$8,657	$0	$14,284	**$109,514**	$392
12	INSTRUMENTATION & CONTROL	$10,583	$1,383	**$11,966**	$1,197	$1,795	$2,244	**$17,201**	$62
13	IMPROVEMENTS TO SITE	$2,175	$5,532	**$7,707**	$771	$0	$1,272	**$9,749**	$35
14	BUILDINGS & STRUCTURES	$52,735	$41,142	**$93,876**	$9,388	$0	$15,490	**$118,753**	$425
	TOTAL COST	**$1,058,808**	**$360,149**	**$1,418,957**	**$111,810**	**$14,035**	**$207,768**	**$1,752,570**	**$6,268**

Client:	Consol	**Report Date:**	2020 May 04
Project:	Case 2B - PFBC Waste Coal Based Power Plant with CO2 Capture		

TOTAL PLANT COST SUMMARY

Estimate Type:	Conceptual	**Labor Basis**	Southeast, PA - union
Plant Size:	279.6 MW,net	**Cost Base**	Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED								
1.1	Fuel Prep & Feed System - complete plant	$136,350	$0	$136,350	$4,772	$0	$14,112	$155,234	$555
1.8	Fuel Prep & Feed Buildings - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Fuel Prep & Feed Foundations - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$136,350**	**$0**	**$136,350**	**$4,772**	**$0**	**$14,112**	**$155,234**	**$555**
2	OPEN								
2.1	open	$0	$0	$0	$0	$0	$0	$0	$0
2.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS								
3.1	Feedwater System	$12,858	$7,887	$20,745	$2,075	$0	$3,423	$26,242	$94
3.2	Water Makeup & Pretreating - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.3	Other Feedwater Subsystems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.4	Service Water Systems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.5	Other Plant Systems	$42,165	$34,160	$76,326	$7,633	$0	$12,594	$96,552	$345
3.6	FO Supply System - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.7	Zero Liquid Discharge System	$15,355	$11,298	$26,653	$2,665	$0	$4,398	$33,716	$121
3.8	Misc. Equip.(cranes,AirComp.,Comm.) - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.8	BOP Foundations	$1,054	$3,077	$4,130	$413	$0	$682	$5,225	$19
	SUBTOTAL 3.	**$71,433**	**$56,421**	**$127,854**	**$12,785**	**$0**	**$21,096**	**$161,735**	**$578**
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	$326,500	$11,428	$0	$33,793	$371,720	$1,329
4.2	PFBC Auxilliary Systems	$252	$998	$1,250	$125	$0	$206	$1,581	$6
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	$0	$0	$0	$0	$0	$0	$0
4.9	PFBC Foundations	$3,522	$5,593	$9,115	$912	$0	$1,504	$11,530	$41
	SUBTOTAL 4.	**$330,274**	**$6,591**	**$336,865**	**$12,464**	**$0**	**$35,503**	**$384,831**	**$1,376**

Client: Consol **Report Date:** 2020 May 04
Project: Case 2B - PFBC Waste Coal Based Power Plant with CO2 Capture

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual **Labor Basis** Southeast, PA - union
Plant Size: 279.6 MW,net **Cost Base** Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP								
5.1	Gas Heating & Cooling	$4,596	$1,750	$6,346	$635	$0	$1,047	$8,028	$29
5.2	Gas Filtration	$59,440	$10,823	$70,263	$7,026	$0	$11,593	$88,882	$318
5.3	SO2 Removal	$6,000	$4,509	$10,509	$1,051	$0	$1,734	$13,294	$48
5.4	Mercury removal	$14,660	$0	$14,660	$1,466	$0	$2,419	$18,545	$66
5.5	Flue Gas Piping	$3,051	$5,011	$8,062	$806	$0	$1,330	$10,198	$36
5.6	CEMs	$1,020	$407	$1,427	$143	$0	$235	$1,805	$6
5.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$88,767**	**$22,500**	**$111,267**	**$11,127**	**$0**	**$18,359**	**$140,753**	**$503**
5B	CO2 REMOVAL & COMPRESSION								
5B.1	CO2 Removal System	$110,000	$108,398	$218,398	$21,840	$0	$36,036	$276,274	$988
5B.2	CO2 Compression	$29,160	$6,833	$35,993	$3,599	$0	$5,939	$45,532	$163
5B.9	CO2 Removal & Compression Foundations	$931	$2,575	$3,505	$351	$0	$578	$4,434	$16
	SUBTOTAL 5B.	**$140,091**	**$117,806**	**$257,897**	**$25,790**	**$0**	**$42,553**	**$326,239**	**$1,167**
6	TURBO MACHINES								
6.1	Turbo Machines	$53,012	$8,191	$61,203	$6,120	$12,241	$11,935	$91,498	$327
6.2	Intercooler for PFBC	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Turbo Machines Foundations	$361	$1,234	$1,595	$159	$0	$263	$2,017	$7
	SUBTOTAL 6.	**$53,373**	**$9,424**	**$62,798**	**$6,280**	**$12,241**	**$12,198**	**$93,516**	**$334**
7	DUCTING & STACK								
7.1	open	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$561	$1,318	$1,879	$188	$0	$310	$2,376	$8
7.4	Stack - furnish and erect	$14,000	$0	$14,000	$1,400	$0	$2,310	$17,710	$63
7.9	Duct & Stack Foundations	$707	$1,214	$1,921	$192	$0	$317	$2,430	$9
	SUBTOTAL 7.	**$15,268**	**$2,531**	**$17,799**	**$1,780**	**$0**	**$2,937**	**$22,516**	**$81**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$29,900	$6,583	$36,483	$3,648	$0	$6,020	$46,151	$165
8.2	Turbine Plant Auxiliaries	$1,940	$3,446	$5,386	$539	$0	$889	$6,813	$24
8.3	Condenser & Auxiliaries	$20,052	$8,382	$28,434	$2,843	$0	$4,692	$35,969	$129
8.4	Steam Piping	$16,401	$11,258	$27,660	$2,766	$0	$4,564	$34,990	$125
8.9	STG Foundations	$1,612	$4,116	$5,729	$573	$0	$945	$7,247	$26
	SUBTOTAL 8.	**$69,906**	**$33,786**	**$103,692**	**$10,369**	**$0**	**$17,109**	**$131,170**	**$469**
9	COOLING WATER SYSTEM								
9.1	Cooling Towers - furnish & erect	$3,960	$0	$3,960	$396	$0	$653	$5,009	$18
9.2	Circulating Water Pumps	$1,200	$139	$1,339	$134	$0	$221	$1,694	$6
9.3	Circ.Water System Auxiliaries	$194	$166	$360	$36	$0	$59	$455	$2
9.4	Circ.Water Piping	$4,119	$6,960	$11,079	$1,108	$0	$1,828	$14,015	$50
9.5	Make-up Water System	$0	$0	$0	$0	$0	$0	$0	$0
9.6	Component Cooling Water Sys	$737	$897	$1,634	$163	$0	$270	$2,067	$7
9.9	Circ.Water System Foundations & Structures	$1,149	$2,749	$3,898	$390	$0	$643	$4,930	$18
	SUBTOTAL 9.	**$11,359**	**$10,911**	**$22,269**	**$2,227**	**$0**	**$3,674**	**$28,171**	**$101**

Client:	Consol	**Report Date:**	2020 May 04
Project:	Case 2B - PFBC Waste Coal Based Power Plant with CO2 Capture		

TOTAL PLANT COST SUMMARY

Estimate Type:	Conceptual	**Labor Basis**	Southeast, PA - union
Plant Size:	279.6 MW,net	**Cost Base**	Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH HANDLING SYSTEM								
10.1	Ash Handling System	$19,915	$3,870	$23,785	$2,378	$0	$3,925	$30,088	$108
10.2	Ash Silos - furnish & erect	$13,600	$0	$13,600	$1,360	$0	$2,244	$17,204	$62
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash System Foundations	$1,750	$2,910	$4,660	$466	$0	$769	$5,895	$21
	SUBTOTAL 10.	**$35,265**	**$6,780**	**$42,045**	**$4,205**	**$0**	**$6,937**	**$53,187**	**$190**
11	ACCESSORY ELECTRIC PLANT								
11.1	Electrical Equipment	$25,225	$6,089	$31,314	$3,131	$0	$5,167	$39,612	$142
11.2	open	$0	$0	$0	$0	$0	$0	$0	$0
11.3	open	$0	$0	$0	$0	$0	$0	$0	$0
11.4	Raceway, wire & cable	$9,545	$32,298	$41,843	$4,184	$0	$6,904	$52,932	$189
11.5	open	$0	$0	$0	$0	$0	$0	$0	$0
11.6	Switchyard	$5,680	$4,411	$10,091	$1,009	$0	$1,665	$12,765	$46
11.7	open	$0	$0	$0	$0	$0	$0	$0	$0
11.8	open	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$780	$2,544	$3,324	$332	$0	$548	$4,205	$15
	SUBTOTAL 11.	**$41,230**	**$45,343**	**$86,573**	**$8,657**	**$0**	**$14,284**	**$109,514**	**$392**
12	INSTRUMENTATION & CONTROL								
12.1	PFBC Control Equipment - with PFBC	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Turbo Machine Control - with Turbo Machine	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control - with Steam Turbine	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control - with equipment	$0	$0	$0	$0	$0	$0	$0	$0
12.5	open	$0	$0	$0	$0	$0	$0	$0	$0
12.6	open	$0	$0	$0	$0	$0	$0	$0	$0
12.7	Distributed Control System Equipment	$10,000	w/ mat'l	$10,000	$1,000	$1,500	$1,875	$14,375	$51
12.8	Instrument Wiring & Tubing - with electrical	$0	$0	$0	$0	$0	$0	$0	$0
12.9	Other I & C Equipment	$583	$1,383	$1,966	$197	$295	$369	$2,826	$10
	SUBTOTAL 12.	**$10,583**	**$1,383**	**$11,966**	**$1,197**	**$1,795**	**$2,244**	**$17,201**	**$62**
13	IMPROVEMENTS TO SITE								
13.1	Site Preparation	$0	$0	$0	$0	$0	$0	$0	$0
13.2	Site Improvements	$2,175	$5,532	$7,707	$771	$0	$1,272	$9,749	$35
13.3	Site Facilities	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 13.	**$2,175**	**$5,532**	**$7,707**	**$771**	**$0**	**$1,272**	**$9,749**	**$35**
14	BUILDINGS & STRUCTURES								
14.1	Combustion Building	$25,894	$24,866	$50,760	$5,076	$0	$8,375	$64,211	$230
14.2	Turbine Building	$12,255	$13,441	$25,696	$2,570	$0	$4,240	$32,506	$116
14.3	Administration Building	$2,101	$225	$2,326	$233	$0	$384	$2,942	$11
14.4	Water Treatment Building	$2,694	$611	$3,305	$331	$0	$545	$4,181	$15
14.5	CO2 Regeneration & Compression Buildings	$9,028	$1,737	$10,764	$1,076	$0	$1,776	$13,617	$49
14.6	open	$0	$0	$0	$0	$0	$0	$0	$0
14.7	open	$0	$0	$0	$0	$0	$0	$0	$0
14.9	Other Buildings & Structures	$764	$262	$1,025	$103	$0	$169	$1,297	$5
	SUBTOTAL 14.	**$52,735**	**$41,142**	**$93,876**	**$9,388**	**$0**	**$15,490**	**$118,753**	**$425**
	TOTAL COST	**$1,058,808**	**$360,149**	**$1,418,957**	**$111,810**	**$14,035**	**$207,768**	**$1,752,570**	**$6,268**

Exhibit 5-8. Owner's Costs – Case 2B (Waste Coal - Capture Equipped)

Owner's Costs

Case 2B - PFBC Waste Coal Based Power Plant with CO2 Capture

Description	Case 2B $ x 1,000	$.kW
TPC	$1,752,570	$6,268
Pre-production		
6 Months All Labor	$12,894	$46
1 Month Maintenance Materials	$1,490	$5
1 Month Non-Fuel Consumables	$1,836	$7
1 Month Waste Disposal	$0	$0
25% of 1 Month's Fuel at 100% CF	$0	$0
2% of TPC	$35,051	$125
Total Preproduction	**$51,272**	$183
Inventory Capital		
60 Day Supply Fuel & Consumables at 100% CF	$3,621	$13
0.5% of TPC (spare parts)	$8,763	$31
Total Inventory Capital	**$12,384**	$44
Other Costs		
Initial Cost for Catalysts & Chemicals	$540	$2
Land	$900	$3
Finanacing Costs	$47,319	$169
Owner's Costs	$262,886	$940
Total Other Costs	**$311,645**	$1,115
Total OverNight Cost (TOC)	**$2,127,871**	$7,610
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Capital(TASC)	**$2,455,563**	$8,782

Exhibit 5-9. Initial and Annual O&M Expenses – Case 2B (Waste Coal - Capture Equipped)

INITIAL & ANNUAL O&M EXPENSES						
Case 2B - PFBC Waste Coal Based Power Plant					Cost Basis:	Dec 2019
4 x 1 P200 with CO2 capture					Heat Rate-net (Btu/kWh):	11,275
					MWe-net:	279.6
					Capacity Factor (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	45.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Total Operators & Lab Techs (equivalent 24/7 positions)	17					
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$8,711,820	$31.158
Maintenance Labor Cost					$11,919,235	$42.630
Administrative & Support Labor					$5,157,764	$18.447
Property Taxes and Insurance					$35,051,406	$125.363
TOTAL FIXED OPERATING COSTS					**$60,840,226**	**$217.597**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$17,878,853**	**$0.00859**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	-	1,992	1.90	$0	$1,174,234	$0.00056
Chemicals						
MU & WT Chem.(lbs)	67,498	4,821	0.28	$18,562	$411,345	$0.00020
Limestone (ton)	10,416	744	24.25	$252,588	$5,597,531	$0.00269
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	0.4	10,000.00	$0	$1,224,000	$0.00059
Ammonia (19% NH3) ton	79	5.7	300.00	$23,730	$525,874	$0.00025
NaOH - 50% (ton) for causitc scrubber	302	21.5	600.00	$180,936	$4,009,671	$0.00193
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$4,688,600	$0.00225
Triethylene Glycol (gal)	w/ capital	277	6.80	$0	$584,387	$0.00028
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	0	285.00	$0	$43,605	$0.00002
NaOH - 50% (ton) for demin/condensate	8	0.6	600.00	$4,922	$109,084	$0.00005
H2SO4 - 93% (ton) for demin/condensate	11	0.8	205.00	$2,307	$51,135	$0.00002
NaOH - 50% (ton) for ZLD	20	1.4	600.00	$11,970	$265,264	$0.00013
H2SO4 - 93% (ton) for ZLD	20	1.5	205.00	$4,176	$92,540	$0.00004
Anti-scale (ton) for ZLD	1	0.1	5,900.00	$5,286	$117,150	$0.00006
Anti-coagulant (ton) for ZLD	17	1	2,050.00	$35,158	$779,115	$0.00037
Subtotal Chemicals				**$539,636**	**$18,499,301**	**$0.00889**
Other						
Supplemental Fuel #2 Oil (MBtu)	7,000	12	15.00	$105,000	$55,845	$0.00003
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00008
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$226,695**	**$0.00011**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	-	0.35	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
CO2 (ton)	-	7,819	41.00	$0	-$99,459,635	-$0.04777
Subtotal By-Products				**$0**	**-$99,459,635**	**-$0.04777**
TOTAL VARIABLE OPERATING COSTS				**$644,636**	**-$61,680,551**	**-$0.02963**
Fuel - Coal (ton)	90,509	6,465	0.00	$0	$0	$0.00000
Fuel - Biomass (ton)	0	0	50.00	$0	$0	$0.00000
TOTAL FUEL COSTS				**$0**	**$0**	**$0.00000**

Exhibit 5-10. Total Plant Cost Summary – Case 2C (Waste Coal & Biomass - Capture Equipped)

Client: Consol | Report Date: 2020 May 04
Project: Case 2C - PFBC Waste Coal & Biomass Based Power Plant with CO2 Capture

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual | Labor Basis: Southeast, PA - union
Plant Size: 279.4 MW,net | Cost Base: Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED	$136,350	$0	**$136,350**	$4,772	$0	$14,112	**$155,234**	$556
2	OPEN	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$71,433	$56,421	**$127,854**	$12,785	$0	$21,096	**$161,735**	$579
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	**$326,500**	$11,428	$0	$33,793	**$371,720**	$1,330
4.2-4.9	Other	$3,774	$6,591	**$10,365**	$1,036	$0	$1,710	**$13,111**	$0
	SUBTOTAL 4	**$330,274**	**$6,591**	**$336,865**	**$12,464**	**$0**	**$35,503**	**$384,831**	**$1,377**
5	FLUE GAS CLEANUP	$88,767	$22,500	**$111,267**	$11,127	$0	$18,359	**$140,753**	$504
5B	CO2 REMOVAL & COMPRESSION	$140,091	$117,806	**$257,897**	$25,790	$0	$42,553	**$326,239**	$1,168
6	TURBO MACHINES								
6.1	Turbo Machines	$53,012	$8,191	**$61,203**	$6,120	$12,241	$11,935	**$91,498**	$327
6.2-6.9	Other	$361	$1,234	**$1,595**	$159	$0	$263	**$2,017**	$7
	SUBTOTAL 6	**$53,373**	**$9,424**	**$62,798**	**$6,280**	**$12,241**	**$12,198**	**$93,516**	**$335**
7	DUCTING & STACK								
7.1	open	$0	$0	**$0**	$0	$0	$0	**$0**	$0
7.2-7.9	Ductwork and Stack	$15,268	$2,531	**$17,799**	$1,780	$0	$2,937	**$22,516**	$81
	SUBTOTAL 7	**$15,268**	**$2,531**	**$17,799**	**$1,780**	**$0**	**$2,937**	**$22,516**	**$81**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$29,900	$6,583	**$36,483**	$3,648	$0	$6,020	**$46,151**	$165
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$40,006	$27,202	**$67,208**	$6,721	$0	$11,089	**$85,018**	$304
	SUBTOTAL 8	**$69,906**	**$33,786**	**$103,692**	**$10,369**	**$0**	**$17,109**	**$131,170**	**$469**
9	COOLING WATER SYSTEM	$11,359	$10,911	**$22,269**	$2,227	$0	$3,674	**$28,171**	$101
10	ASH HANDLING SYSTEM	$35,265	$6,780	**$42,045**	$4,205	$0	$6,937	**$53,187**	$190
11	ACCESSORY ELECTRIC PLANT	$41,230	$45,343	**$86,573**	$8,657	$0	$14,284	**$109,514**	$392
12	INSTRUMENTATION & CONTROL	$10,583	$1,383	**$11,966**	$1,197	$1,795	$2,244	**$17,201**	$62
13	IMPROVEMENTS TO SITE	$2,175	$5,532	**$7,707**	$771	$0	$1,272	**$9,749**	$35
14	BUILDINGS & STRUCTURES	$52,735	$41,142	**$93,876**	$9,388	$0	$15,490	**$118,753**	$425
	TOTAL COST	**$1,058,808**	**$360,149**	**$1,418,957**	**$111,810**	**$14,035**	**$207,768**	**$1,752,570**	**$6,273**

Client:	Consol	**Report Date:**	2020 May 04
Project:	Case 2C - PFBC Waste Coal & Biomass Based Power Plant with CO2 Capture		

TOTAL PLANT COST SUMMARY

Estimate Type:	Conceptual	**Labor Basis**	Southeast, PA - union
Plant Size:	279.4 MW,net	**Cost Base**	Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	FUEL PREP & FEED								
1.1	Fuel Prep & Feed System - complete plant	$136,350	$0	$136,350	$4,772	$0	$14,112	$155,234	$556
1.8	Fuel Prep & Feed Buildings - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Fuel Prep & Feed Foundations - incl with system costs	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$136,350**	**$0**	**$136,350**	**$4,772**	**$0**	**$14,112**	**$155,234**	**$556**
2	OPEN								
2.1	open	$0	$0	$0	$0	$0	$0	$0	$0
2.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS								
3.1	Feedwater System	$12,858	$7,887	$20,745	$2,075	$0	$3,423	$26,242	$94
3.2	Water Makeup & Pretreating - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.3	Other Feedwater Subsystems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.4	Service Water Systems - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.5	Other Plant Systems	$42,165	$34,160	$76,326	$7,633	$0	$12,594	$96,552	$346
3.6	FO Supply System - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.7	Zero Liquid Discharge System	$15,355	$11,298	$26,653	$2,665	$0	$4,398	$33,716	$121
3.8	Misc. Equip.(cranes,AirComp.,Comm.) - incl with other	$0	$0	$0	$0	$0	$0	$0	$0
3.8	BOP Foundations	$1,054	$3,077	$4,130	$413	$0	$682	$5,225	$19
	SUBTOTAL 3.	**$71,433**	**$56,421**	**$127,854**	**$12,785**	**$0**	**$21,096**	**$161,735**	**$579**
4	PFBC								
4.1	PFBC - furnish & erect	$326,500	$0	$326,500	$11,428	$0	$33,793	$371,720	$1,330
4.2	PFBC Auxilliary Systems	$252	$998	$1,250	$125	$0	$206	$1,581	$6
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	$0	$0	$0	$0	$0	$0	$0
4.9	PFBC Foundations	$3,522	$5,593	$9,115	$912	$0	$1,504	$11,530	$41
	SUBTOTAL 4.	**$330,274**	**$6,591**	**$336,865**	**$12,464**	**$0**	**$35,503**	**$384,831**	**$1,377**

Client:	Consol
Project:	Case 2C - PFBC Waste Coal & Biomass Based Power Plant with CO2 Capture
Report Date:	2020 May 04

TOTAL PLANT COST SUMMARY

Estimate Type:	Conceptual
Plant Size:	279.4 MW,net
Labor Basis	Southeast, PA - union
Cost Base	Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP								
5.1	Gas Heating & Cooling	$4,596	$1,750	$6,346	$635	$0	$1,047	$8,028	$29
5.2	Gas Filtration	$59,440	$10,823	$70,263	$7,026	$0	$11,593	$88,882	$318
5.3	SO2 Removal	$6,000	$4,509	$10,509	$1,051	$0	$1,734	$13,294	$48
5.4	Mercury removal	$14,660	$0	$14,660	$1,466	$0	$2,419	$18,545	$66
5.5	Flue Gas Piping	$3,051	$5,011	$8,062	$806	$0	$1,330	$10,198	$37
5.6	CEMs	$1,020	$407	$1,427	$143	$0	$235	$1,805	$6
5.9	open	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	**$88,767**	**$22,500**	**$111,267**	**$11,127**	**$0**	**$18,359**	**$140,753**	**$504**
5B	CO2 REMOVAL & COMPRESSION								
5B.1	CO2 Removal System	$110,000	$108,398	$218,398	$21,840	$0	$36,036	$276,274	$989
5B.2	CO2 Compression	$29,160	$6,833	$35,993	$3,599	$0	$5,939	$45,532	$163
5B.9	CO2 Removal & Compression Foundations	$931	$2,575	$3,505	$351	$0	$578	$4,434	$16
	SUBTOTAL 5B.	**$140,091**	**$117,806**	**$257,897**	**$25,790**	**$0**	**$42,553**	**$326,239**	**$1,168**
6	TURBO MACHINES								
6.1	Turbo Machines	$53,012	$8,191	$61,203	$6,120	$12,241	$11,935	$91,498	$327
6.2	Intercooler for PFBC	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Open	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Turbo Machines Foundations	$361	$1,234	$1,595	$159	$0	$263	$2,017	$7
	SUBTOTAL 6.	**$53,373**	**$9,424**	**$62,798**	**$6,280**	**$12,241**	**$12,198**	**$93,516**	**$335**
7	DUCTING & STACK								
7.1	open	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$561	$1,318	$1,879	$188	$0	$310	$2,376	$9
7.4	Stack - furnish and erect	$14,000	$0	$14,000	$1,400	$0	$2,310	$17,710	$63
7.9	Duct & Stack Foundations	$707	$1,214	$1,921	$192	$0	$317	$2,430	$9
	SUBTOTAL 7.	**$15,268**	**$2,531**	**$17,799**	**$1,780**	**$0**	**$2,937**	**$22,516**	**$81**
8	STEAM TURBINE GENERATOR								
8.1	Steam TG & Accessories	$29,900	$6,583	$36,483	$3,648	$0	$6,020	$46,151	$165
8.2	Turbine Plant Auxiliaries	$1,940	$3,446	$5,386	$539	$0	$889	$6,813	$24
8.3	Condenser & Auxiliaries	$20,052	$8,382	$28,434	$2,843	$0	$4,692	$35,969	$129
8.4	Steam Piping	$16,401	$11,258	$27,660	$2,766	$0	$4,564	$34,990	$125
8.9	STG Foundations	$1,612	$4,116	$5,729	$573	$0	$945	$7,247	$26
	SUBTOTAL 8.	**$69,906**	**$33,786**	**$103,692**	**$10,369**	**$0**	**$17,109**	**$131,170**	**$469**
9	COOLING WATER SYSTEM								
9.1	Cooling Towers - furnish & erect	$3,960	$0	$3,960	$396	$0	$653	$5,009	$18
9.2	Circulating Water Pumps	$1,200	$139	$1,339	$134	$0	$221	$1,694	$6
9.3	Circ.Water System Auxiliaries	$194	$166	$360	$36	$0	$59	$455	$2
9.4	Circ.Water Piping	$4,119	$6,960	$11,079	$1,108	$0	$1,828	$14,015	$50
9.5	Make-up Water System	$0	$0	$0	$0	$0	$0	$0	$0
9.6	Component Cooling Water Sys	$737	$897	$1,634	$163	$0	$270	$2,067	$7
9.9	Circ.Water System Foundations & Structures	$1,149	$2,749	$3,898	$390	$0	$643	$4,930	$18
	SUBTOTAL 9.	**$11,359**	**$10,911**	**$22,269**	**$2,227**	**$0**	**$3,674**	**$28,171**	**$101**

Client: Consol **Report Date:** 2020 May 04
Project: Case 2C - PFBC Waste Coal & Biomass Based Power Plant with CO2 Capture

TOTAL PLANT COST SUMMARY

Estimate Type: Conceptual **Labor Basis** Southeast, PA - union
Plant Size: 279.4 MW,net **Cost Base** Dec 2019 ($x1000)

Acct No.	Item/Description	Equipment & Material Cost	Labor Cost	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH HANDLING SYSTEM								
10.1	Ash Handling System	$19,915	$3,870	$23,785	$2,378	$0	$3,925	$30,088	$108
10.2	Ash Silos - furnish & erect	$13,600	$0	$13,600	$1,360	$0	$2,244	$17,204	$62
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash System Foundations	$1,750	$2,910	$4,660	$466	$0	$769	$5,895	$21
	SUBTOTAL 10.	**$35,265**	**$6,780**	**$42,045**	**$4,205**	**$0**	**$6,937**	**$53,187**	**$190**
11	ACCESSORY ELECTRIC PLANT								
11.1	Electrical Equipment	$25,225	$6,089	$31,314	$3,131	$0	$5,167	$39,612	$142
11.2	open	$0	$0	$0	$0	$0	$0	$0	$0
11.3	open	$0	$0	$0	$0	$0	$0	$0	$0
11.4	Raceway, wire & cable	$9,545	$32,298	$41,843	$4,184	$0	$6,904	$52,932	$189
11.5	open	$0	$0	$0	$0	$0	$0	$0	$0
11.6	Switchyard	$5,680	$4,411	$10,091	$1,009	$0	$1,665	$12,765	$46
11.7	open	$0	$0	$0	$0	$0	$0	$0	$0
11.8	open	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$780	$2,544	$3,324	$332	$0	$548	$4,205	$15
	SUBTOTAL 11.	**$41,230**	**$45,343**	**$86,573**	**$8,657**	**$0**	**$14,284**	**$109,514**	**$392**
12	INSTRUMENTATION & CONTROL								
12.1	PFBC Control Equipment - with PFBC	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Turbo Machine Control - with Turbo Machine	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control - with Steam Turbine	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control - with equipment	$0	$0	$0	$0	$0	$0	$0	$0
12.5	open	$0	$0	$0	$0	$0	$0	$0	$0
12.6	open	$0	$0	$0	$0	$0	$0	$0	$0
12.7	Distributed Control System Equipment	$10,000	w/ mat'l	$10,000	$1,000	$1,500	$1,875	$14,375	$51
12.8	Instrument Wiring & Tubing - with electrical	$0	$0	$0	$0	$0	$0	$0	$0
12.9	Other I & C Equipment	$583	$1,383	$1,966	$197	$295	$369	$2,826	$10
	SUBTOTAL 12.	**$10,583**	**$1,383**	**$11,966**	**$1,197**	**$1,795**	**$2,244**	**$17,201**	**$62**
13	IMPROVEMENTS TO SITE								
13.1	Site Preparation	$0	$0	$0	$0	$0	$0	$0	$0
13.2	Site Improvements	$2,175	$5,532	$7,707	$771	$0	$1,272	$9,749	$35
13.3	Site Facilities	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 13.	**$2,175**	**$5,532**	**$7,707**	**$771**	**$0**	**$1,272**	**$9,749**	**$35**
14	BUILDINGS & STRUCTURES								
14.1	Combustion Building	$25,894	$24,866	$50,760	$5,076	$0	$8,375	$64,211	$230
14.2	Turbine Building	$12,255	$13,441	$25,696	$2,570	$0	$4,240	$32,506	$116
14.3	Administration Building	$2,101	$225	$2,326	$233	$0	$384	$2,942	$11
14.4	Water Treatment Building	$2,694	$611	$3,305	$331	$0	$545	$4,181	$15
14.5	CO2 Regeneration & Compression Buildings	$9,028	$1,737	$10,764	$1,076	$0	$1,776	$13,617	$49
14.6	open	$0	$0	$0	$0	$0	$0	$0	$0
14.7	open	$0	$0	$0	$0	$0	$0	$0	$0
14.9	Other Buildings & Structures	$764	$262	$1,025	$103	$0	$169	$1,297	$5
	SUBTOTAL 14.	**$52,735**	**$41,142**	**$93,876**	**$9,388**	**$0**	**$15,490**	**$118,753**	**$425**
	TOTAL COST	**$1,058,808**	**$360,149**	**$1,418,957**	**$111,810**	**$14,035**	**$207,768**	**$1,752,570**	**$6,273**

Exhibit 5-11. Owner's Costs – Case 2C (Waste Coal & Biomass - Capture Equipped)

Owner's Costs

Case 2C - PFBC Waste Coal & Biomass Based Power Plant with CO2 Capture

Description	$ x 1,000	$.kW
TPC	$1,752,570	$6,273
Pre-production		
6 Months All Labor	$12,894	$46
1 Month Maintenance Materials	$1,490	$5
1 Month Non-Fuel Consumables	$1,836	$7
1 Month Waste Disposal	$0	$0
25% of 1 Month's Fuel at 100% CF	$447	$2
2% of TPC	$35,051	$125
Total Preproduction	**$51,719**	$185
Inventory Capital		
60 Day Supply Fuel & Consumables at 100% CF	$4,504	$16
0.5% of TPC (spare parts)	$8,763	$31
Total Inventory Capital	**$13,266**	$47
Other Costs		
Initial Cost for Catalysts & Chemicals	$540	$2
Land	$900	$3
Finanacing Costs	$47,319	$169
Owner's Costs	$262,886	$941
Total Other Costs	**$311,645**	$1,115
Total OverNight Cost (TOC)	**$2,129,200**	$7,621
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Capital(TASC)	**$2,457,097**	$8,794

Exhibit 5-12. Initial and Annual O&M Expenses – Case 2C (Waste Coal & Biomass - Capture Equipped)

INITIAL & ANNUAL O&M EXPENSES					Cost Basis:	Dec 2019
Case 2C - PFBC Waste Coal & Biomass Based Power Plant					Heat Rate-net (Btu/kWh):	11,290
4 x 1 P200 with CO2 capture					MWe-net:	279.4
					Capacity Factor (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	45.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Total Operators & Lab Techs	17					
(equivalent 24/7 positions)					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$8,711,820	$31.180
Maintenance Labor Cost					$11,919,235	$42.660
Administrative & Support Labor					$5,157,764	$18.460
Property Taxes and Insurance					$35,051,406	$125.452
TOTAL FIXED OPERATING COSTS					**$60,840,226**	**$217.753**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$17,878,853**	**$0.00859**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	-	1,992	1.90	$0	$1,174,234	$0.00056
Chemicals						
MU & WT Chem.(lbs)	67,498	4,821	0.28	$18,562	$411,345	$0.00020
Limestone (ton)	10,416	744	24.25	$252,588	$5,597,531	$0.00269
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	0.4	10,000.00	$0	$1,224,000	$0.00059
Ammonia (19% NH3) ton	79	5.7	300.00	$23,730	$525,874	$0.00025
NaOH - 50% (ton) for causitc scrubber	302	21.5	600.00	$180,936	$4,009,671	$0.00193
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$4,688,600	$0.00225
Triethylene Glycol (gal)	w/ capital	277	6.80	$0	$584,387	$0.00028
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	0	285.00	$0	$43,605	$0.00002
NaOH - 50% (ton) for demin/condensate	8	0.6	600.00	$4,922	$109,084	$0.00005
H2SO4 - 93% (ton) for demin/condensate	11	0.8	205.00	$2,307	$51,135	$0.00002
NaOH - 50% (ton) for ZLD	20	1.4	600.00	$11,970	$265,264	$0.00013
H2SO4 - 93% (ton) for ZLD	20	1.5	205.00	$4,176	$92,540	$0.00004
Anti-scale (ton) for ZLD	1	0.1	5,900.00	$5,286	$117,150	$0.00006
Anti-coagulant (ton) for ZLD	17	1	2,050.00	$35,158	$779,115	$0.00037
Subtotal Chemicals				**$539,636**	**$18,499,301**	**$0.00889**
Other						
Supplemental Fuel #2 Oil (MBtu)	7,000	12	15.00	$105,000	$55,845	$0.00003
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00008
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$226,695**	**$0.00011**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	-	0.35	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
CO2 (ton)	-	7,819	41.00	$0	-$99,459,635	-$0.04781
Subtotal By-Products				**$0**	**-$99,459,635**	**-$0.04781**
TOTAL VARIABLE OPERATING COSTS				**$644,636**	**-$61,680,551**	**-$0.02965**
Fuel - Coal (ton)	86,116	6,151	0.00	$0	$0	$0.00000
Fuel - Biomass (ton)	4,116	294	50.00	$205,817	$4,561,047	$0.00219
TOTAL FUEL COSTS				**$205,817**	**$4,561,047**	**$0.00219**

5.5 O&M Expenses Sensitivity to Operational Flexibility

In Section 5.4, the O&M Expenses were developed at an 85% capacity factor and a load point of 100%. In this section we present O&M expenses for the alternate capacity factor and load point combinations presented per Exhibit 5-13 to illustrate the impact of the plant's operational flexibility.

Exhibit 5-13. O&M Expenses for Alternate Operating Parameters

Case Identifier	Capacity Factor	Load Point	Exhibit No.
Case 1B	85%	100%	Exhibit 5-6
Case 1B – Alt 1	75%	90%	Exhibit 5-14
Case 1B – Alt 2	65%	90%	Exhibit 5-15
Case 2B	85%	100%	Exhibit 5-9
Case 2B – Alt 1	75%	90%	Exhibit 5-16
Case 2B – Alt 2	65%	90%	Exhibit 5-17

Exhibit 5-14. Initial and Annual O&M Expenses – Case 1B Alt 1 (Illinois No. 6 - Capture Equipped, 75% Capacity Factor, 90% Load Point)

INITIAL & ANNUAL O&M EXPENSES						
Case 1B - PFBC Illinois Coal Based Power Plant					Cost Basis:	Dec 2019
4 x 1 P200 with CO2 capture					Heat Rate-net (Btu/kWh):	10,616
					MWe-net:	278.1
		Load Factor (%):	90		Capacity Factor (%):	75
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	38.50	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Total Operators & Lab Techs (equivalent 24/7 positions)	17					
					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$7,453,446	$26.801
Maintenance Labor Cost					$10,965,390	$39.430
Administrative & Support Labor					$4,604,709	$16.558
Property Taxes and Insurance					$32,287,497	$116.100
TOTAL FIXED OPERATING COSTS					**$55,311,043**	**$198.889**
VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost					**$16,448,085**	**$0.00814**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	-	3,932	1.90	$0	$2,262,831	$0.00112
Chemicals						
MU & WT Chem.(lbs)	143,264	9,313	0.28	$39,397	$775,711	$0.00038
Limestone (ton)	11,368	739	24.25	$275,674	$5,427,841	$0.00268
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	-	10,000.00	$0	$0	$0.00000
Ammonia (19% NH3) ton	81	5.3	300.00	$24,402	$480,459	$0.00024
NaOH - 50% (ton) for causitc scrubber	329	21.4	600.00	$197,568	$3,889,985	$0.00192
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$4,099,268	$0.00203
Triethylene Glycol (gal)	w/ capital	248	6.80	$0	$511,718	$0.00025
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	0	285.00	$0	$41,433	$0.00002
NaOH - 50% (ton) for demin/condensate	9	0.6	600.00	$5,146	$101,329	$0.00005
H2SO4 - 93% (ton) for demin/condensate	12	0.8	205.00	$2,412	$47,500	$0.00002
NaOH - 50% (ton) for ZLD	50	3.2	600.00	$29,925	$589,204	$0.00029
H2SO4 - 93% (ton) for ZLD	51	3.3	205.00	$10,440	$205,549	$0.00010
Anti-scale (ton) for ZLD	2	0.1	5,900.00	$13,216	$260,214	$0.00013
Anti-coagulant (ton) for ZLD	43	3	2,050.00	$87,894	$1,730,571	$0.00086
Subtotal Chemicals				**$686,075**	**$18,160,783**	**$0.00994**
Other						
Supplemental Fuel #2 Oil (MBtu)	7,000	11	15.00	$105,000	$49,617	$0.00002
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00008
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$220,467**	**$0.00011**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	248	0.35	$0	$26,338	$0.00001
Subtotal-Waste Disposal				**$0**	**$26,338**	**$0.00001**
By-products & Emissions						
CO2 (ton)	-	7,002	41.00	$0	-$86,955,171	-$0.04301
Subtotal By-Products				**$0**	**-$86,955,171**	**-$0.04301**
TOTAL VARIABLE OPERATING COSTS				**$791,075**	**-$49,836,666**	**-$0.02369**
Fuel - Coal (ton)	42,514	3,037	51.96	$2,209,032	$43,194,457	$0.02364
Fuel - Biomass (ton)	0	0	50.00	$0	$0	$0.00000
TOTAL FUEL COSTS				**$2,209,032**	**$43,194,457**	**$0.02364**

Exhibit 5-15. Initial and Annual O&M Expenses – Case 1B Alt 2 (Illinois No. 6 - Capture Equipped, 65% Capacity Factor, 90% Load Point)

INITIAL & ANNUAL O&M EXPENSES					Cost Basis:	Dec 2019
Case 1B - PFBC Illinois Coal Based Power Plant					Heat Rate-net (Btu/kWh):	10,616
4 x 1 P200 with CO2 capture					MWe-net:	278.1
		Load Factor (%):	90		Capacity Factor (%):	65
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	38.50	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Total Operators & Lab Techs	17					
(equivalent 24/7 positions)					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$7,453,446	$26.801
Maintenance Labor Cost					$10,965,390	$39.430
Administrative & Support Labor					$4,604,709	$16.558
Property Taxes and Insurance					$32,287,497	$116.100
TOTAL FIXED OPERATING COSTS					**$55,311,043**	**$198.889**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$16,448,085**	**$0.00939**
Consumables	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	-	3,932	1.90	$0	$1,961,120	$0.00112
Chemicals						
MU & WT Chem.(lbs)	143,264	9,313	0.28	$39,397	$672,283	$0.00038
Limestone (ton)	11,368	739	24.25	$275,674	$4,704,129	$0.00268
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	-	10,000.00	$0	$0	$0.00000
Ammonia (19% NH3) ton	81	5.3	300.00	$24,402	$416,398	$0.00024
NaOH - 50% (ton) for causitc scrubber	329	21.4	600.00	$197,568	$3,371,320	$0.00192
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$3,552,699	$0.00203
Triethylene Glycol (gal)	w/ capital	248	6.80	$0	$443,489	$0.00025
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	0	285.00	$0	$35,908	$0.00002
NaOH - 50% (ton) for demin/condensate	9	0.6	600.00	$5,146	$87,818	$0.00005
H2SO4 - 93% (ton) for demin/condensate	12	0.8	205.00	$2,412	$41,167	$0.00002
NaOH - 50% (ton) for ZLD	50	3.2	600.00	$29,925	$510,643	$0.00029
H2SO4 - 93% (ton) for ZLD	51	3.3	205.00	$10,440	$178,143	$0.00010
Anti-scale (ton) for ZLD	2	0.1	5,900.00	$13,216	$225,519	$0.00013
Anti-coagulant (ton) for ZLD	43	3	2,050.00	$87,894	$1,499,828	$0.00086
Subtotal Chemicals				**$686,075**	**$15,739,345**	**$0.00994**
Other						
Supplemental Fuel #2 Oil (MBtu)	7,000	11	15.00	$105,000	$43,002	$0.00002
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00010
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$213,852**	**$0.00012**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	248	0.35	$0	$22,827	$0.00001
Subtotal-Waste Disposal				**$0**	**$22,827**	**$0.00001**
By-products & Emissions						
CO2 (ton)	-	7,002	41.00	$0	-$75,361,148	-$0.04301
Subtotal By-Products				**$0**	**-$75,361,148**	**-$0.04301**
TOTAL VARIABLE OPERATING COSTS				**$791,075**	**-$40,975,919**	**-$0.02243**
Fuel - Coal (ton)	42,514	3,037	51.96	$2,209,032	$37,435,196	$0.02364
Fuel - Biomass (ton)	0	0	50.00	$0	$0	$0.00000
TOTAL FUEL COSTS				**$2,209,032**	**$37,435,196**	**$0.02364**

Exhibit 5-16. Initial and Annual O&M Expenses – Case 2B Alt 1 (Waste Coal - Capture Equipped, 75% Capacity Factor, 90% Load Point)

INITIAL & ANNUAL O&M EXPENSES					Cost Basis:	Dec 2019
Case 2B - PFBC Waste Coal Based Power Plant					Heat Rate-net (Btu/kWh):	11,383
4 x 1 P200 with CO2 capture					MWe-net:	252.2
		Load Factor (%):	90		Capacity Factor (%):	75

OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	45.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Total Operators & Lab Techs	17					
(equivalent 24/7 positions)					Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost					$8,711,820	$34.543
Maintenance Labor Cost					$11,919,235	$47.261
Administrative & Support Labor					$5,157,764	$20.451
Property Taxes and Insurance					$35,051,406	$138.983
TOTAL FIXED OPERATING COSTS					**$60,840,226**	**$241.238**

VARIABLE OPERATING COSTS	Consumption Initial Fill	Consumption /Day	Unit Cost	Initial Fill Cost	Annual Cost	$/kWh-net
Maintenance Material Cost					**$17,878,853**	**$0.00973**
Water (/1000 gallons)	-	1,838	1.90	$0	$1,059,878	$0.00058
Chemicals						
MU & WT Chem.(lbs)	67,498	4,449	0.28	$18,562	$371,285	$0.00020
Limestone (ton)	10,416	686	24.25	$252,588	$5,052,399	$0.00275
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	0.4	10,000.00	$0	$1,104,797	$0.00060
Ammonia (19% NH3) ton	79	5.2	300.00	$23,730	$474,660	$0.00026
NaOH - 50% (ton) for causitc scrubber	302	19.9	600.00	$180,936	$3,619,178	$0.00197
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$4,231,987	$0.00230
Triethylene Glycol (gal)	w/ capital	256	6.80	$0	$527,475	$0.00029
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	0	285.00	$0	$39,358	$0.00002
NaOH - 50% (ton) for demin/condensate	8	0.5	600.00	$4,922	$98,460	$0.00005
H2SO4 - 93% (ton) for demin/condensate	11	0.7	205.00	$2,307	$46,155	$0.00003
NaOH - 50% (ton) for ZLD	20	1.3	600.00	$11,970	$239,430	$0.00013
H2SO4 - 93% (ton) for ZLD	20	1.3	205.00	$4,176	$83,528	$0.00005
Anti-scale (ton) for ZLD	1	0.1	5,900.00	$5,286	$105,741	$0.00006
Anti-coagulant (ton) for ZLD	17	1	2,050.00	$35,158	$703,239	$0.00038
Subtotal Chemicals				**$539,636**	**$16,697,694**	**$0.01007734**
Other						
Supplemental Fuel #2 Oil (MBtu)	7,000	11	15.00	$105,000	$50,406	$0.00003
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00009
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$221,256**	**$0.00012**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	-	0.35	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
CO2 (ton)	-	7,215	41.00	$0	-$89,773,477	-$0.04887
Subtotal By-Products				**$0**	**-$89,773,477**	**-$0.04887**
TOTAL VARIABLE OPERATING COSTS				**$644,636**	**-$53,915,795**	**-$0.02836**
Fuel - Coal (ton)	83,514	5,965	0.00	$0	$0	$0.00000
Fuel - Biomass (ton)	0	0	50.00	$0	$0	$0.00000
TOTAL FUEL COSTS				**$0**	**$0**	**$0.00000**

Exhibit 5-17. Initial and Annual O&M Expenses – Case 2B Alt 2 (Waste Coal - Capture Equipped, 65% Capacity Factor, 90% Load Point)

INITIAL & ANNUAL O&M EXPENSES					Cost Basis:	Dec 2019
Case 2B - PFBC Waste Coal Based Power Plant					Heat Rate-net (Btu/kWh):	11,383
4 x 1 P200 with CO2 capture					MWe-net:	252.2
		Load Factor (%):	90		Capacity Factor (%):	65
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate (base):	45.00	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
Total Operators & Lab Techs	17					
(equivalent 24/7 positions)					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost					$8,711,820	$34.543
Maintenance Labor Cost					$11,919,235	$47.261
Administrative & Support Labor					$5,157,764	$20.451
Property Taxes and Insurance					$35,051,406	$138.983
TOTAL FIXED OPERATING COSTS					**$60,840,226**	**$241.238**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$17,878,853**	**$0.01123**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water (/1000 gallons)	-	1,838	1.90	$0	$918,561	$0.00058
Chemicals						
MU & WT Chem.(lbs)	67,498	4,449	0.28	$18,562	$321,781	$0.00020
Limestone (ton)	10,416	686	24.25	$252,588	$4,378,746	$0.00275
Activated Carbon (ton)	-	-	1,600.00	$0	$0	$0.00000
Mercury Removal Filter Modules	w/ capital	0.4	10,000.00	$0	$957,491	$0.00060
Ammonia (19% NH3) ton	79	5.2	300.00	$23,730	$411,372	$0.00026
NaOH - 50% (ton) for causitc scrubber	302	19.9	600.00	$180,936	$3,136,621	$0.00197
Amine Solvent (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 NaOH - 20% (gal) - $ incl w/ CO2 Capture Solvents	-	-	-	$0	$0	$0.00000
CO2 Capture Solvents - proprietary	w/ capital	-	-	$0	$3,667,722	$0.00230
Triethylene Glycol (gal)	w/ capital	256	6.80	$0	$457,145	$0.00029
Ion Exchange Resin (ft3) for demin/condensate	w/ capital	0	285.00	$0	$34,111	$0.00002
NaOH - 50% (ton) for demin/condensate	8	0.5	600.00	$4,922	$85,332	$0.00005
H2SO4 - 93% (ton) for demin/condensate	11	0.7	205.00	$2,307	$40,001	$0.00003
NaOH - 50% (ton) for ZLD	20	1.3	600.00	$11,970	$207,506	$0.00013
H2SO4 - 93% (ton) for ZLD	20	1.3	205.00	$4,176	$72,391	$0.00005
Anti-scale (ton) for ZLD	1	0.1	5,900.00	$5,286	$91,643	$0.00006
Anti-coagulant (ton) for ZLD	17	1	2,050.00	$35,158	$609,474	$0.00038
Subtotal Chemicals				**$539,636**	**$14,471,335**	**$0.01008**
Other						
Supplemental Fuel #2 Oil (MBtu)	7,000	11	15.00	$105,000	$43,686	$0.00003
Natural Gas for start-up (MMBtu)	-	164	3.35	$0	$170,850	$0.00011
Gases, N2 etc. (/100scf)	-	-	-	$0	$0	$0.00000
Subtotal Other				**$105,000**	**$214,536**	**$0.00013**
Waste Disposal						
Fly Ash (ton)	-	-	38.00	$0	$0	$0.00000
Bed Ash (ton)	-	-	38.00	$0	$0	$0.00000
Triethylene Glycol (gal)	-	-	0.35	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$0**	**$0.00000**
By-products & Emissions						
CO2 (ton)	-	7,215	41.00	$0	-$77,803,680	-$0.04887
Subtotal By-Products				**$0**	**-$77,803,680**	**-$0.04887**
TOTAL VARIABLE OPERATING COSTS				**$644,636**	**-$44,320,395**	**-$0.02685**
Fuel - Coal (ton)	83,514	5,965	0.00	$0	$0	$0.00000
Fuel - Biomass (ton)	0	0	50.00	$0	$0	$0.00000
TOTAL FUEL COSTS				**$0**	**$0**	**$0.00000**

5.6 COE Results and Sensitivities

The first year COE for the four cases is presented in Exhibit 5-18.

Exhibit 5-18. First Year COE for Cases 1A, 1B, 2B, 2C

Parameter / Case	Case 1A	Case 1B	Case 2B	Case 2C
COE ($/MWh)	88.55	92.59	82.99	85.29

Sensitivity analyses were performed for several parameters of interest for the various PFBC configurations described in this Report. These analyses evaluated the Cost of Electricity (COE) as the principal result using DOE methodology as prescribed in the September 2019 Quality Guidelines for Energy System Studies-Cost Estimation Methodology for NETL Assessments of Power Plant Performance [**19**].

With reference to Section 3.4.1 of the above referenced DOE Quality Guidelines, the COE has been calculated for ranges of variation for the following parameters of interest:

- **Cost of Fuel (Coal)**: this cost was varied between zero and $80.00/ton. The zero lower bound was used because the waste coal-fired Business Cases (Cases 2B and 2C in this report) will fire waste coal owned by CONSOL and is likely to be available to the plant at zero net cost. (Exhibit 5-19)
- **Capital Cost** (expressed as Total Plant Cost): the capital cost was varied over a range from 80 to 120% of nominal. (Exhibit 5-20)
- **Capacity Factor**: this parameter was varied from a low of 60% to a high of 90%. It was expected that the various cases described in this report, especially the waste coal-fired Cases 2B and 2C, will be operated as baseload plants, with high-priority dispatch. This assumption was based on their status as potentially very low-cost marginal producers of electricity, derived by firing very low-cost fuel and, therefore, being very high in the dispatch order. The very low or slightly negative carbon footprint will contribute to their high dispatch potential. (Exhibit 5-21)
- **CO_2 Credit Value**: this factor varied from zero to a maximum value of $50/ton of CO_2 captured. The CO_2 will be sequestered to capture the section 45Q tax credit or other credits as long as they are available or sold for beneficial end use. (Exhibit 5-22)

The results of the various sensitivity analyses are presented in the Exhibits below.

Exhibit 5-19. First Year COE vs Coal Cost Sensitivity

Exhibit 5-20. First Year COE vs TPC Sensitivity

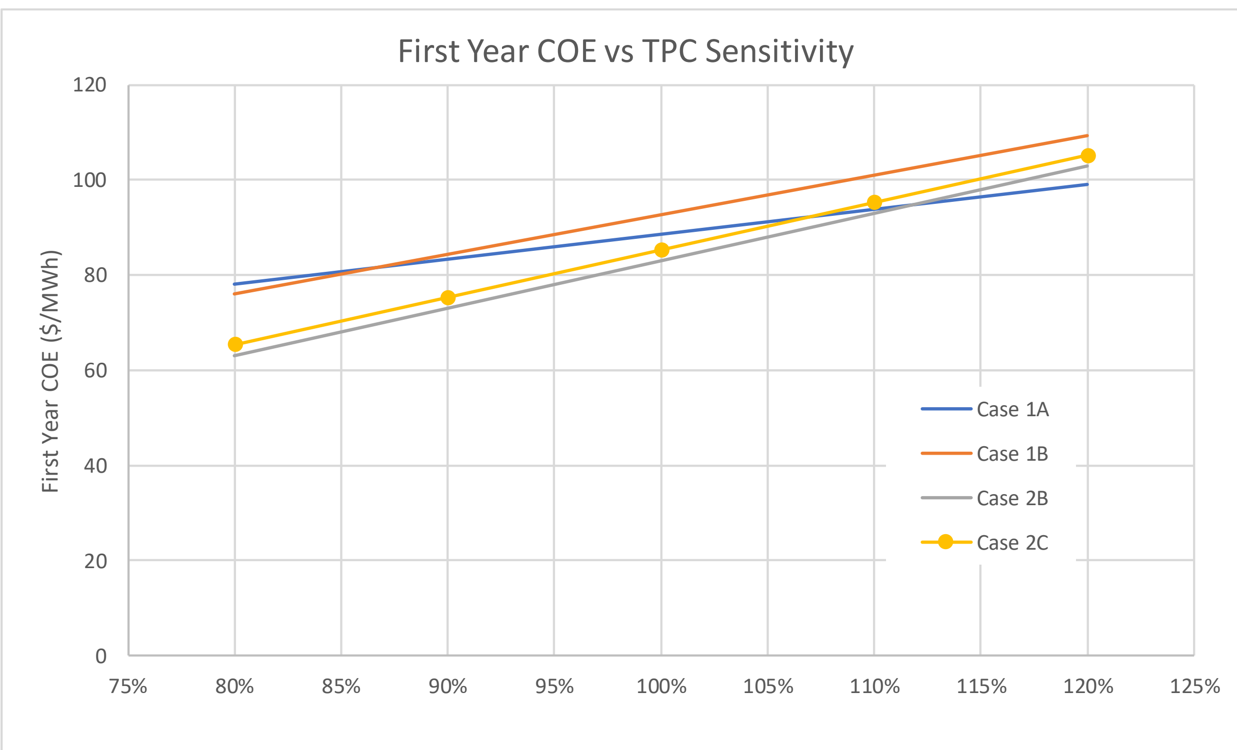


Exhibit 5-21. First Year COE vs Capacity Factor Sensitivity

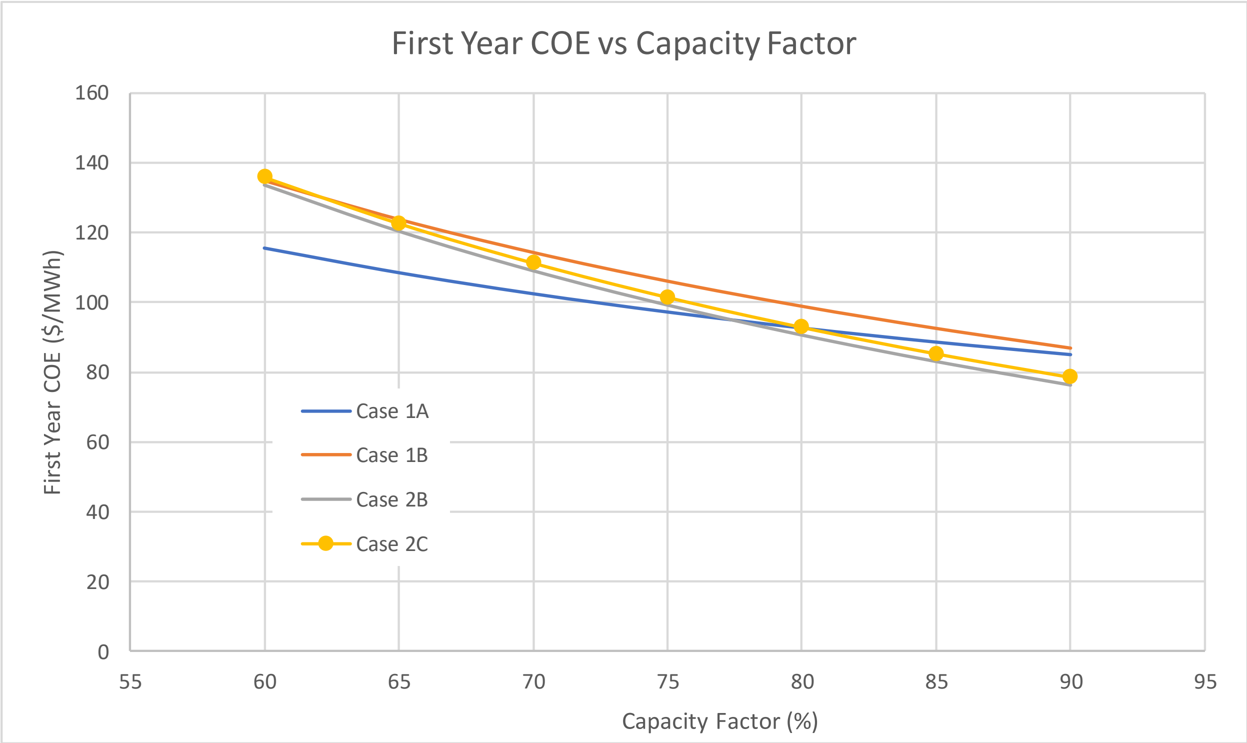
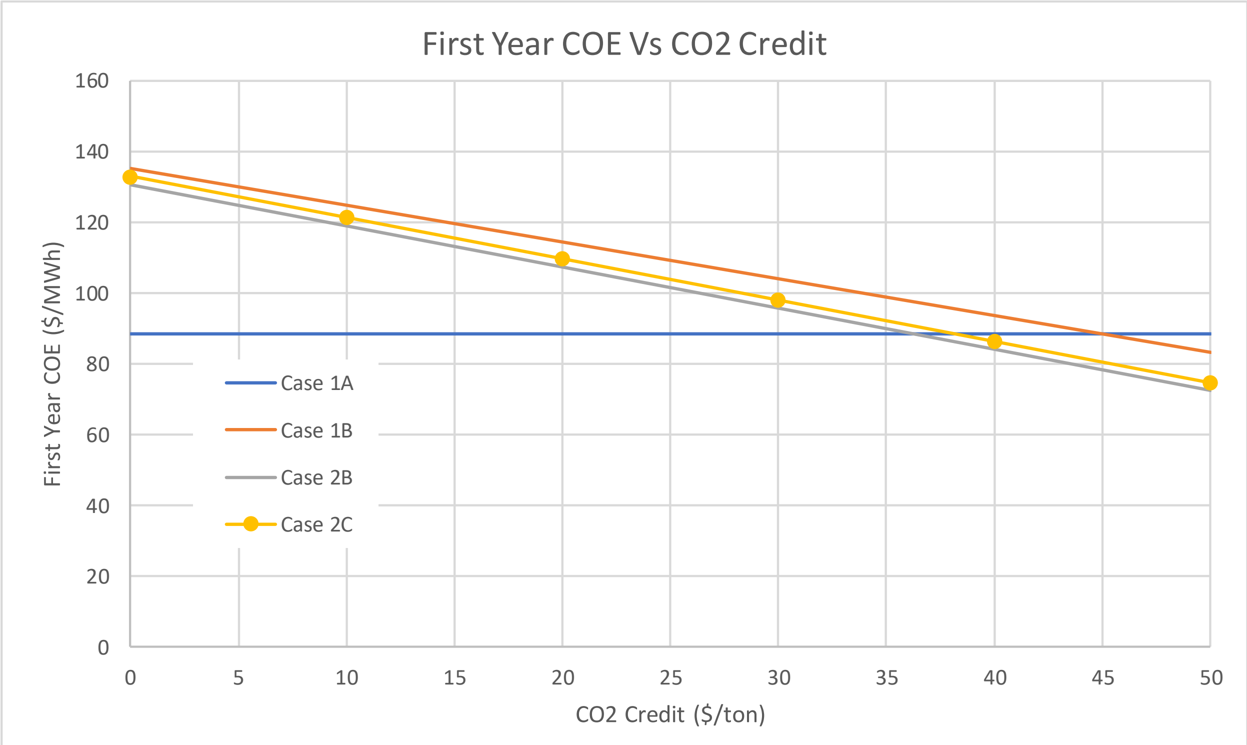


Exhibit 5-22. First Year COE vs CO_2 Credit Sensitivity



6 Technology Gap Analysis and Commercial Pathway

This report evaluates potential technology gaps and the most likely commercial pathway to designing and constructing a PFBC power plant with carbon dioxide capture as required by the solicitation funding this effort. This report is organized into the following topical areas:

- History of the PFBC relevant technologies and current state-of-the-art
- Shortcomings, limitations, and challenges for this application
- Key technical risks/issues associated with the proposed plant concept
- Perceived technology gaps and R&D needed for commercialization by 2030
- Development pathway description to overcome key technical risks/issues
- Key technology/equipment OEM's

6.1 History of the PFBC Relevant Technologies and Current State-of-the-Art

This section provides some historical perspective relating to the following:

- History of the Pressurized Fluidized Bed Combustion (PFBC) technology
- History of integration of carbon capture into the gas path
- First commercial 4 x P200 supercritical PFBC plant with carbon capture
- Current state-of-the-art of the PFBC

6.1.1 History of the PFBC Technology

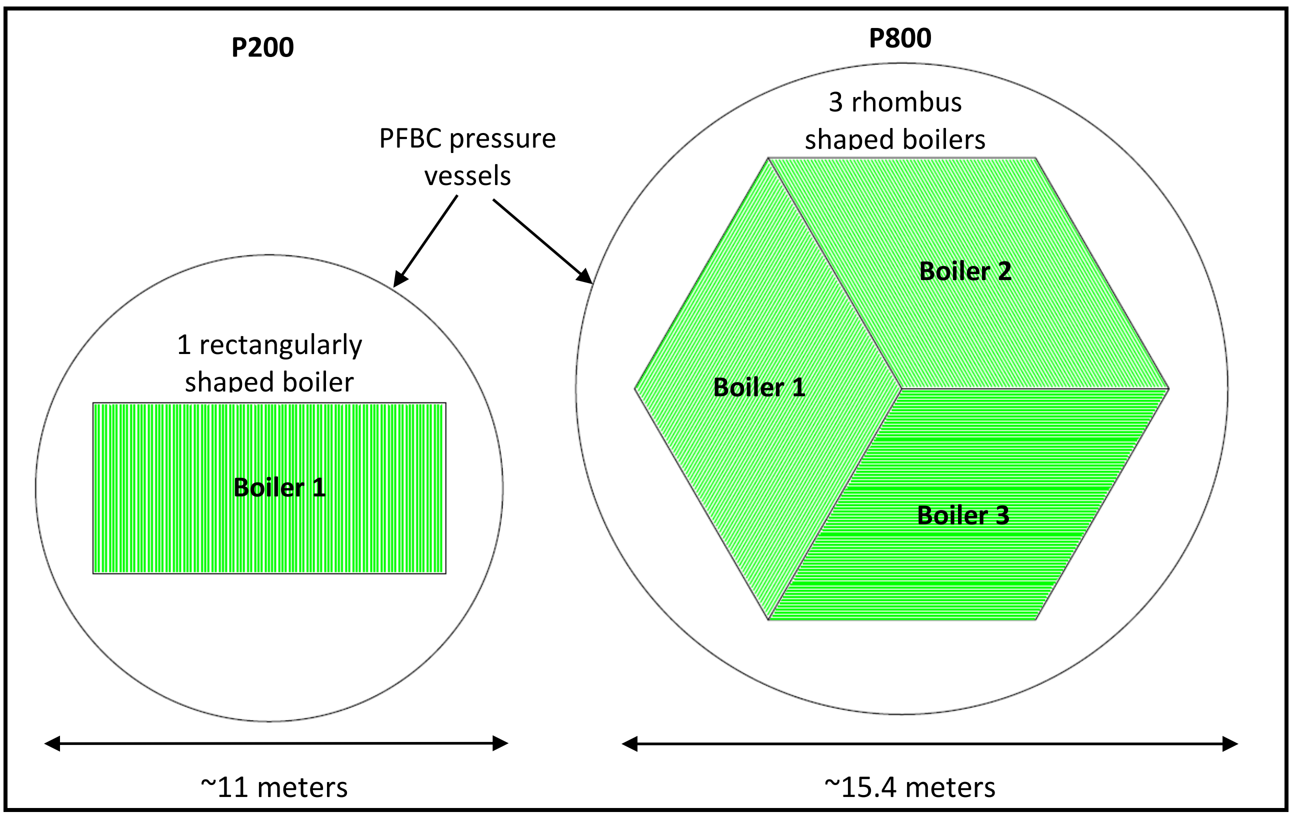
The PFBC technology was originally developed in Sweden by the former Asea Brown Boveri (ABB) in the late 1980s timeframe. The first two P200 modules were installed at the Vartan plant in Stockholm, Sweden, becoming operational in 1991 with an extraction steam turbine. This plant continues to supply electric power and district heating steam to metropolitan Stockholm today (January 2020). Subsequently, four (4) more P200 modules were constructed and were operational for varying periods of time. The plants include:

1. **Endesa Station**, owned by Escatron in Spain, entered service in 1991 and operated for about seven (7) years after which it was shut down due to fuel supply issues. The unit fired Spanish lignite.
2. **Tidd Station** was comprised of one new P200 module coupled to an existing older non-reheat steam turbine. This unit began operation in 1991 and operated successfully for several years. The original 3-year demonstration period was extended by a 4th year with DOE funding for testing with a ceramic hot gas filter, and exhaustive testing of different coal and sorbent qualities. After the completion of the program, the Tidd plant was closed in 1995.
3. **Wakamatsu** was a single P200 module plant owned by the Japanese Electric Power Development Corporation (EPDC) going on-line in 1994. Wakamatsu was a demonstration plant that repowered an existing 50 MW steam turbine and planned for operation only for a limited number of years. In November 1995 the "Wakamatsu PFBC team" was presented with the Engineering Innovation Award from the Japanese Society for the Advancement of Engineering. The Wakamatsu plant has since shut down.

4. **Cottbus Station** in Cottbus, Germany is the last of the P200 plants to be constructed. Still in regular service, this plant incorporates lessons learned from previous P200 modules, which are being carried over to the P200 design for the first 4 x P200 plant with carbon capture that is being developed under the Coal FIRST program.

The Karita Station, owned by Kyushu Electric Power Company in the town of Karita-Chou in northern Kyushu Island, Japan, is the first and only P800 PFBC configuration constructed and is still in operation. The P800 relies heavily on the P200 design by incorporating three essentially complete "P200" pressurized boilers (parts internal to the pressure vessel) that operate at an elevated pressure inside a single pressure vessel, resulting in a thermal capacity rating that is four times that of a single P200 boiler. The added capacity is achieved by operating the P800 at a nominal 16 bar pressure, in contrast to the P200, which operates at nominal 12 bar pressure. This four-thirds (4/3) pressure ratio allows each of the three "P200" boilers within the P800 to have a capacity of 133% of the true P200 boiler. The geometry of each "P200" boiler is adjusted into a rhombus so that three (3) such boilers can be nested into a single cylindrical pressure vessel of reasonable diameter. Exhibit 6-1 provides a plan view illustration of how this is accomplished with minimal increase in the diameter of the P800 PFBC pressure vessel relative to the P200 vessel. The circles represent the inside diameter of each of the respective PFBC pressure vessels. The green shaded figures represent the plan view of the "P200" boilers inside the pressure vessels. By changing the plan of the single P200 boiler into a rhombus, three of these can be fit into a hexagonal-shaped plan that fits inside a larger diameter vessel,

Exhibit 6-1. Increased Capacity of P800 vs P200 - Plan View



The P200 PFBC plants noted above all relied on a unique gas turbine design, the ABB GT35P machine. This machine is a derivative of the GT35, an industrial gas turbine with a long pedigree in various types of service. This machine is unique in that the gas expander is specifically designed to accept inlet gas at the appropriate temperature (~1525 °F) with significant particulate loading. In the P200 (and P800) designs, the hot combustion product gases pass through two stages of cyclones for particulate removal and then are routed to the gas turbine inlet. The unique aspects of the GT35P machine include provision for exporting air from the compressor discharge at elevated pressure (nominally 12 bar) for use as the combustion and fluidizing air in the PFBC fluidized bed boiler, and then accepting the resulting hot flue gas (downstream of the cyclones at nominally 12 bar pressure) for expansion in the turbine section. The P800 design relies on a single gas turbomachine, the GT140P. Only a single machine of this type was constructed and is now in operation at the Karita plant. This machine provides for the required flow (about three times the volumetric flow of a single P200) and pressure for the P800 PFBC.

Another unique feature of both the GT35P and GT140P machines is the design of the turbine blades, which are uncooled (that is, they do not utilize turbine cooling air which relies on very small flow passages) to eliminate the potential for blockage of these cooling air passages. These airfoils have a specific velocity triangle design to extract work from the expanding hot gas with relatively low incident velocity to minimize abrasive wear.

The GT35P gas turbine was an important part of the complete PFBC package design but is no longer in production due to corporate realignments. ABB was purchased by Alstom, which then separated the ABB turbomachine lines of equipment from the thermal equipment (boilers and heat exchangers, etc.) and retained the latter while trading the former to a new owner, Siemens. Due to lack of demand for this machine in the gas turbine market, Siemens has ceased production of the GT35P, and it is no longer available (except in very large quantities, for which Siemens might consider reopening a production line).

In order to move forward with marketing and delivering a PFBC in the near term without the GT35P, the current project team has incorporated a hot gas filter into the gas path upstream of the gas turbine. The resulting large reduction in particulate matter entering the expander section of the turbomachine now opens the opportunity to source a purpose-designed machine from any competent supplier. For the purposes of this pre-FEED evaluation, both Baker Hughes and Siemens have been engaged to provide assistance and have stated their willingness to design and deliver a suitable machine upon receipt of a commercial order.

A tabular history of the PFBC projects is presented in Exhibit 6-2.

Exhibit 6-2. PFBC Project Data / History

Plant Name		Vartan	Escatron	Tidd	Wakamatsu	Cottbus	Karita
Owner		**Stockholm Energy**	**ENDESA**	**AEP**	**EPDC**	**Municipality of Cottbus**	**KyEPCO**
Location		**Sweden**	**Spain**	**Ohio**	**Japan**	**Germany**	**Japan**
Plant Type		CHP	Condensing	Demonstration	Demonstration	CHP	Condensing
Plant Type		New	Repowered STG	Repowered STG	Repowered STG	New	New
Capacity	MWe/MWt	135/224	79.5/0	70	71/0	71/40	360/0
Efficiency, Net	HHV	85%	36.4%	35.0%	37.5%	NA	42.0%
PFBC Type		**2xP200**	**1xP200**	**1xP200**	**1xP200**	**1xP200**	**1xP800**
Gas Turbine		2xGT35P	1xGT35P	1xGT35P	1xGT35P	1xGT35P	1xGT140P
PFBC Nominal P	bar (a)	12	12	12	12	12	16
PFBC Bed T	F	1580	1580	1580	1580	1544	1598
First Coal Fire	year	1990	1990	1990	1993	1998	NA
Year Online	year	1991	1992	1992	1994	1999	1999
Steam Turbine		New	Existing unit 4	Existing unit	Existing unit	New ABB	New
ST type		subcritical	subcritical	subcritical	subcritical	subcritical	Supercritcal
MS Pressure	psia	1987	1363	1305	1494	2060	3495
MS T/ RH T	F	986 / NA	955 / NA	925 / NA	1099 / 1099	999 / 999	1051 / 1099
Coal							
Coal Type		Bituminous	Black Lignite	Bituminous	Bituminous	Brown	Lignite to Anthracite
HHV	Btu/lb	9,600-12,500	3,650-8,170	10,000-12,250	10,400-12,500	~8,700	~11,200
Sulfur	%	0.1 - 0.5%	2.9-9.0%	3.4 - 4.0%	0.3 - 1.2%	<0.8%	<1.0%
Ash	%	8 - 21%	23-47%	12 - 20%	2 - 18%	5.50%	<20%
Moisture	%	6 - 15%	14-20%	5 - 15%	8 - 26%	18.50%	<7%
Coal Feed		Paste	Dry pneumatic	Paste	Paste	Dry Feed	Paste
Sorbent		Dolomite	Limestone	Dolomite	Limestone	Limestone	Limestone
Sorbent feed		with fuel	with fuel	dry feed	separate	Dry Feed	with fuel
NOx Control		NH_3 & minicat	Inherent	Inherent	SCR	Not Avail	Not Avail

Notes: CHP – Combined Heat and Power, STG – Steam Turbine Generator, SCR -Selective Catalytic Reduction

6.1.2 History of Integration of Carbon Capture into the PFBC Gas Path

One of the major features of the proposed PFBC coal-fueled power plant of the future is the ability to capture 97% of the CO_2 in the combustion product gases for geologic storage or beneficial use. Prior studies (Phase 1 of this U.S. DOE initiative) and several earlier efforts had focused on the use of the UOP Benfield process employing hot potassium carbonate solvent at elevated pressure to achieve the desired capture of CO_2 from the gas path.

An early attempt at using a hot potassium carbonate-based process for CO_2 capture was described by a Norwegian firm, Sargas, in the early 2000s. Based on this concept, in early 2008 a pilot scale system was installed at Vartan in Stockholm, Sweden. A slip stream of combustion product gas was taken from one of the two PFBC units at Vartan, cooled, and then introduced into a pilot-scale train of process vessels to capture CO_2. The CO_2 was then stripped from the solvent and exhausted to the atmosphere. This demonstrated that the basic concept was workable.

The pilot scale apparatus was purchased by PFBC-EET and brought to the U.S. where it was coupled to the 1 MWt PFBC pilot combustor previously installed at the CONSOL Energy Research & Development Center in South Park, PA, in 2009-2010.

In 2015, a study was conducted by Worley Group, Inc. (then WorleyParsons) for a proposed offering to a US-based utility to repower two (2) of three (3) older steam turbines at a 1960s vintage pulverized coal plant in West Virginia. The CO_2 capture configuration selected was similar to that portrayed in the Conceptual Design Report produced earlier in this program. The overall project was to repower each of the two (2) steam turbines with 3 x P200 PFBC modules, with a Benfield CO_2 capture loop installed on one (1) of the three (3) PFBC modules for a nominal 30% level of CO_2 capture. At the time, the utility declined to proceed with the concept, and no further study or development efforts were undertaken.

6.1.3 First Commercial 4xP200 Supercritical PFBC Plant with Carbon Capture

In the Conceptual Design phase of this effort, a design was presented for a PFBC power plant utilizing a supercritical steam cycle integrated with a gas turbine Brayton cycle, integrating the Benfield process into the gas path to capture CO_2. This configuration was based on one of two fundamental ways to couple the Benfield process with the PFBC.

This approach employed a Heat Recovery Steam Generator (HRSG) to reduce the temperature of the combustion gases leaving the PFBC vessel to approximately 800 °F. The gases then were further cooled in a regenerative heat exchanger consisting of two shell-and-tube units using a high temperature heat transfer fluid on the tube side. The high temperature fluid was a synthetic high molecular weight liquid manufactured by Dow Chemical Company; this fluid is used in solar thermal applications. Extensive performance analysis of this system configuration indicated that the various losses (temperature, pressure, and CO_2 expansion power) significantly impacted performance. The resulting thermal performance was considered to be suboptimal, and the project team decided to evaluate other configurations that would be more consistent with the overall goals of the Coal Based Power Plants of the Future program.

A second approach was evaluated utilizing a gas-to-gas regenerative heat exchanger to reduce the temperature of the CO_2-laden combustion product gas at elevated pressure to a value compatible with the Benfield process (~235 °F). The scrubbed product gas exiting the Benfield process is then reheated on the return pass of the heat exchanger to a value that is consistent with reasonable heat exchanger approach temperatures for a gas/gas unit. This approach is more closely aligned with the concept originally proposed by Sargas.

Based on current input from heat exchanger vendors, the hot side approach temperature would be at least 100 °F, with a total pressure drop of 20 psi (1.5 bar). During the course of this pre-FEED evaluation to date, it was tentatively determined that performance deficits were caused by the irreversible temperature drop across the entire heat exchanger (hot and cold sides), the added pressure drop, and the loss of expansion power from the CO_2 gas that is captured at pressure. These contribute to a large part of the losses in output and efficiency attributable to carbon capture. Note that while the CO_2 capture occurs at elevated pressure, the stripping or liberation of the CO_2 from the solvent occurs at low pressure (between 1 and 2 bar absolute pressure). Preliminary thermal analysis of this configuration still indicates shortcomings in overall thermal performance relative to expectations.

After extensive evaluation of the two methods for integrating the Benfield process with the PFBC, the use of an amine process at the terminal end of the gas path was evaluated. For the purposes of this pre-FEED study, the amine process approach used in the September 2019 NETL Cost and Performance Baseline for Fossil Energy Plants report was employed [**16**]. This approach used the CANSOLV process offered by Shell. This overall system configuration yielded superior thermal performance, with an increase of several percentage points in thermal efficiency in both the capture-ready and capture-equipped (at 97% capture rate) PFBC plant configurations.

Given the substantial improvement in thermal performance relative to either of the Benfield approaches, a capital cost and O&M cost review of the amine configuration vs. the Benfield configuration was also conducted. The difference in capital costs between the two CO_2 capture approaches was determined to be small, i.e., within the accuracy of the total estimates. The O&M cost review indicated a small increase in operating expense for the amine system, but this increase was not enough to override the benefits of the increased electric power generation and efficiency resulting from the amine-based approach. Therefore, the plant design based on the amine CO_2 capture system has been adopted by the project team as the working design for the balance of the work to be performed under the pre-FEED study. It is recommended that a comprehensive screening evaluation be performed on contemporary commercial amine CO_2 capture systems at the beginning of the full FEED study phase of the project, so that the optimum commercial amine system for integration with the PFBC power plant can be selected.

The plant proposed for advancement in this solicitation for the Coal Based Power Plant of the Future is comprised of four (4) current state-of-the-art P200 modules providing steam at supercritical conditions (3500 psig/1100 °F/1100 °F) to a single steam turbine. The gas cleanup includes a hot gas filter, an SO_2 polisher to remove sulfur not captured in the bed, and a mercury capture system, followed by CO_2 capture at 1 atm using an amine-based system and a CO_2 compression and drying system. The turbomachine will provide the compressed air for the PFBC and will expand the slightly cooled and particulate matter-free flue gas.

6.1.4 Current State-of-the-Art of the PFBC

The current state-of-the-art for the P200 PFBC module is embodied in the Cottbus PFBC pressure vessel and boiler, which was designed for subcritical steam conditions. To move forward with the proposed concept, a supercritical boiler must be designed. The P800 PFBC installed at Karita in Japan utilizes a supercritical boiler. The gas path for the Cottbus plant, with the boiler design for the Karita plant (on the P200 scale) must be integrated into a complete P200 module. The new P200 boiler design will then resemble one of the three (3) boiler modules used in the Karita P800 PFBC design, with minor adjustments to the geometry to return to the P200 plan arrangement.

It should also be noted that the fuel induction to the fluidized bed at Cottbus utilizes dry injection via a lock hopper system, whereas the proposed 4 x P200 design for this project will utilize a paste feed system similar to that used at Vartan in Stockholm, Sweden. The following elements must be integrated into the new design:

1) The hot gas filter is required to enable the use of state-of-the-art gas turbomachine design experience. This hot gas filter can be provided by Mott Corporation or Pall, a unit of Danaher Corporation. Both companies have extensive experience in designing hot gas filters for industrial applications.
2) The new gas turbomachine requires a custom design specific to the PFBC operating conditions. Baker Hughes and Siemens have committed to providing budgetary proposals for this machine.
3) The boiler surfaces must be designed for supercritical steam conditions. The subcritical P200 boiler design, as used in the six (6) P200 modules actually built, is a Benson once-through design. Therefore, the changes to adapt to supercritical steam conditions are limited to modifying tubing and header wall thicknesses and limited changes in materials for parts of the boiler surface area.
4) The addition of the amine CO_2 capture process is relatively straightforward, as it does not require “cutting into” the PFBC gas path as would be required for integration of the Benfield process for either of the variations discussed above (gas-to-gas or gas-to-liquid heat transfer). However, this is still a new overall configuration, and remains to be fully demonstrated. The amine regeneration steam will need to be integrated into the supercritical steam cycle in a

way that minimizes the performance impact and yet allows for operation at low loads while retaining sufficient steam pressure for the regeneration steam.

The design integration noted above represents a custom, purposeful design challenge but not a fundamental R&D challenge. The relevant technical knowledge is available, and the task is to execute the design using the aforementioned knowledge and good engineering practice.

An area of design that will require significant effort is controls. The 4 x P200 PFBC power plant with CO_2 capture will have to integrate the individual "island" control systems from the following:

1) Steam Turbine Generator – these machines typically are equipped with their own control system, using contemporary industry hardware and software.
2) Gas Turbomachine – these new machines will be equipped with individual control systems similar to that employed for the steam turbine generator.
3) PFBC Boiler – each boiler will be provided with a semi-autonomous controls package that will be subordinate to and integrated with the plant control system using a central computer of appropriate design and with the necessary software.
4) The suite of AQC systems that polish and scrub SO_2 and CO_2 from the flue gas will most likely be provided with an island control system to regulate the various gas and liquid flows, etc.

6.2 Shortcomings, Limitations, and Challenges for this Application

At this time there are no significant perceived shortcomings or limitations to designing and constructing the proposed 4 x P200 PFBC plant with CO_2 capture, apart from the design and integration challenges noted above. Detailed design and engineering with consideration of lessons learned at Cottbus and Karita should be able to inform the preparation of the design for construction of this plant. A potential shortcoming may be perceived in the operation of this plant relating to the CO_2 capture system. Recent experience at a coal-fired power station in Saskatchewan with a CANSOLV carbon capture system indicates higher-than-expected rates of deterioration for the amine solvent material, with subsequent accelerated replacement rates. This does not impair the operation of the plant but can impact annualized O&M costs and plant economics. (It is not known what the potential impacts of long-duration CO_2 capture operation are on the solvent used in the Benfield process when applied to coal-derived flue gas). As such, a generous allowance has been made for makeup of fresh amine solvent on an annual basis.

Given that progress is continuing to be made in the area of post-combustion CO_2 capture technology performance, largely as a result of substantial funding and effort contributed by the U.S. DOE and commercial technology developers, the review of carbon capture technologies and solvents that is recommended to be undertaken at the beginning of the FEED study should seek to identify more robust and/or cost-effective commercially-available solvents that might be able to improve upon the performance of the CANSOLV system as presented in this pre-FEED study.

6.3 Key Technical Risks/Issues Associated with the Proposed Plant Concept

The technical risks and issues associated with the proposed plant concept are related to process integration, procurement of new purpose-designed equipment, and project execution. The new purpose-designed components must be brought together and integrated into a reliable power plant that is functionally capable of flexible, commercial operation. The CONSOL project team believes that the 4 x P200 PFBC with supercritical steam cycle and amine-based CO_2 capture meets the objectives of the DOE Coal Based Power Plants of the Future program and also meets the objectives required for operation as a fully dispatchable producer of electric power for sale to the local grid and CO_2 for geologic storage or sale to an offtake customer with commercial interests.

The well-qualified group of technology providers assembled by the CONSOL project team affords confidence that the project objectives can be met. The principal equipment and service providers comprising this group include:

1. **PFBC Boiler and Pressure Vessel** (4 required) will be provided by PFBC-EET and Nooter/Eriksen. This team will rely on the Cottbus design in most respects with an important exception in that the Cottbus plant relies on a dry fuel feed system to the PFBC, whereas the present CONSOL offering will use a paste feed system. This latter system will rely on the design at the Vartan plant in Sweden, which has been in regular commercial service for almost 30 years. The PFBC closely resembles the previous six modules that have been built and operated. The reliance on the Cottbus design, the newest of the six modules, takes advantage of the historical chain of lessons learned from application of the PFBC technology. The P800 PFBC experience at Karita is also relevant for informing this effort, as it features a supercritical boiler.

2. **Fuel/Sorbent Paste Feed System** is being designed by Farnham & Pfile Engineering (F&P) of Monessen, PA, which has extensive experience in designing coal and material handling systems and designed the feed system for the 1 MWt PFBC Process Test Facility (PTF) formerly located at CONSOL Energy's R&D Center. F&P is working with industry-recognized vendors for the fuel and sorbent handling and storage systems, including Dome Technology and VibraFloor (to ensure movement of the paste from the storage facility). Putzmeister, who participated in the 1 MWt PFBC demonstration at CONSOL Energy's R&D Center, is working closely with F&P on design of the fuel and sorbent mixers, pumps, and feed lances for the PFBC boiler. F&P has worked with Greer Limestone (Riverton, WV) to determine that limestone sand will be supplied; commercial limestone crushing/sizing equipment will be specified.

   With the potential for biomass to be utilized in the PFBC, a biomass feed system is also being evaluated, and the design will be optimized based on the type of biomass being supplied. The project team is collaborating with Fred Circle Enterprises on biomass production and handling logistics.

   For the business case with waste coal, a waste coal dewatering system will be utilized. This will consist of filter presses for which there are many reliable vendors. The project team has experience with this step as a result of the work done at the 1 MWt PTF at CONSOL R&D. Waste fuel was prepared for testing in the PTF by using filter presses to dewater thickener underflow from CONSOL Energy's Bailey Central Preparation Plant to 25% moisture.

   All of the technologies being utilized in the fuel/sorbent paste feed system are commercially available. As such, the risks associated with this area are minor and relate to providing the appropriate design and equipment specifications for the facility and providing the appropriate control system to integrate with the balance of plant.

3. **Gas Turbomachine** (4 required) will be provided by either Baker Hughes or Siemens. Both firms have the capability to design and manufacture machines to meet specific technical requirements. Earlier in the Conceptual Design phase of the project, finding a suitable replacement for the ABB GT35P machine had been identified as a key technology gap, as the GT35P is not currently in commercial production and was unique in its ability to match the P200 operating conditions and ingest combustion product gases containing significant

quantities of particulate matter. The identification of a suitable hot gas filter in the pre-FEED phase has opened the door to more conventional design approaches for the turbomachine and will allow this machine to be competitively procured.

4. **Hot Gas Filter** will be provided by either Mott Corporation or Pall Corporation, a unit of Danaher Corporation. The hot gas filter will remove virtually all of the particulate matter in the gas path at elevated temperature, allowing the gas turbomachine procurement to become a much lower-risk endeavor.
5. **Supercritical Steam Turbine Generator** will be provided by either General Electric or Siemens.
6. **The flue gas polishing and CO_2 capture system** risks and issues will be treated within subsection 6.3.1.

6.3.1 Key Technical Risks/Issues/Opportunities Associated with CO_2 Capture System

A flue gas polishing and CO_2 capture system can be provided by any of several vendors now offering such systems. A general overview of amine-based systems is provided below along with characterization of select commercial amine-based systems.

All amine-based processes for CO_2 removal have similar process flow diagrams as presented in Exhibit 6-3, in which the amine solvent circulates between an absorber, where CO_2 is removed from the flue gas stream to produce a rich-loading stream, and a stripper/reboiler, where steam is introduced to strip the CO_2 from the rich-loading stream and produce a lean stream that is returned to the absorber for removing CO_2. [**20**,**21**]

Exhibit 6-3. Basic Chemical Absorption Process for CO_2 Capture

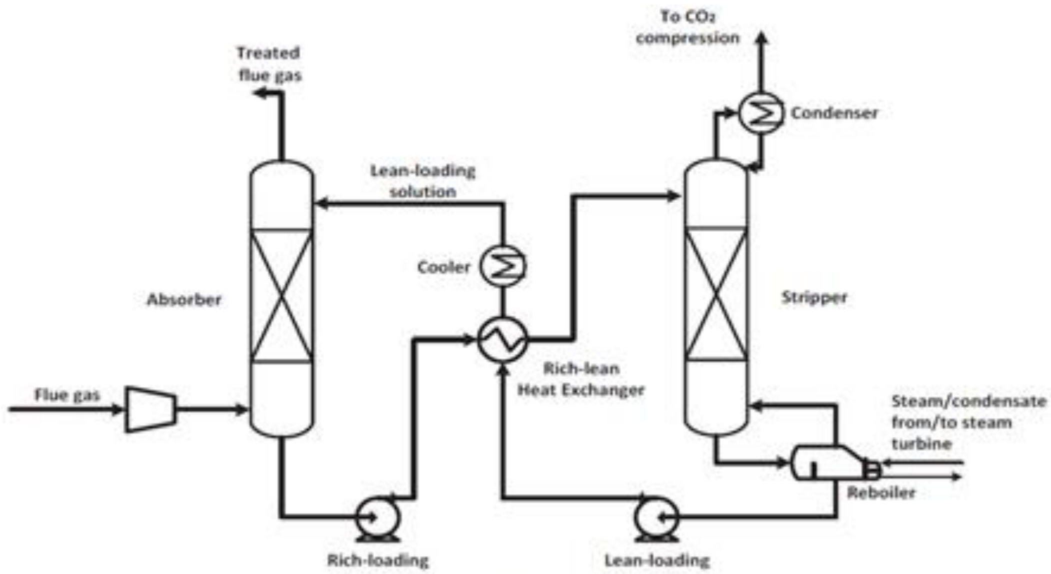
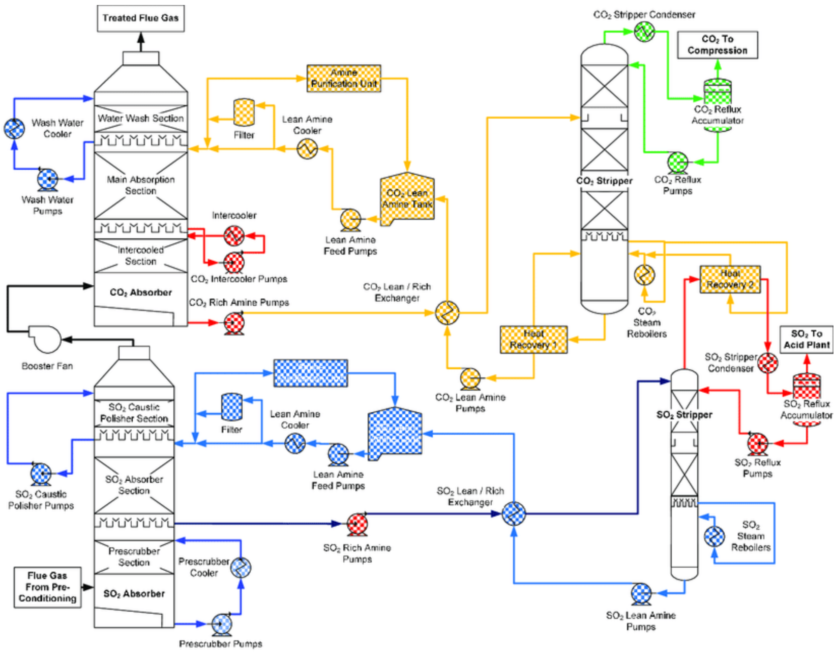


Fig. 2. Schematic of a basic chemical absorption process for CO_2 capture

The following current commercial amine-based capture systems have been identified by name:

- **Shell Cansolv** is an amine-based process following the industry standard design approach with solvents formulated to achieve relatively fast kinetics, low degradation, low thermal regeneration energy (~2.1 to 2.6 GJ/tonne CO_2 removed), and low solvent recirculation rates. The sorbents used are monoethanolamine (MEA) or tertiary amines with additives for activators (reaction rate enhancers) and free radical scavengers [**22**, **23**].

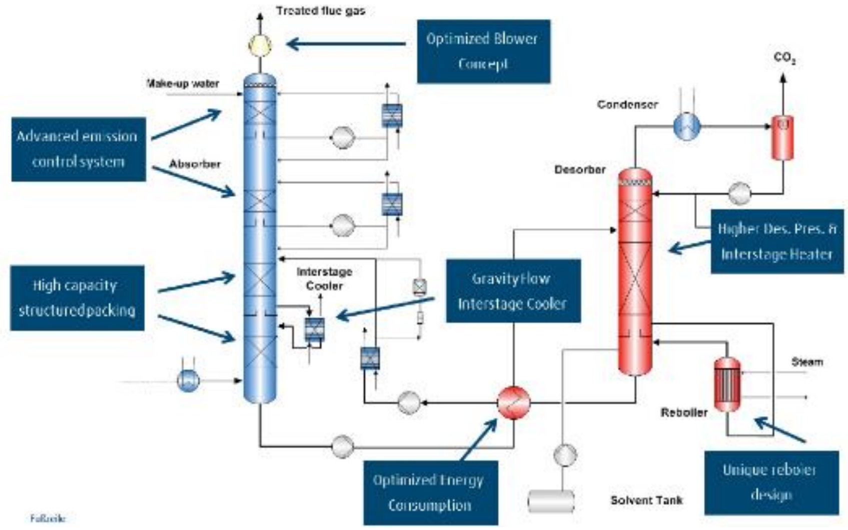
Exhibit 6-4. Shell CANSOLV Absorption Process for CO_2 Capture



Status: Shell has declined to support the current pre-FEED study phase but will support in a future actionable job.

- **BASF/Linde OASE Process** is an amine-based process following the industry standard design approach targeting energy demand, cyclic capacity, solvent stability, reactivity, volatility, and availability. The reboiler energy requirements are as low as 2.7 GJ/tonne CO_2 removed, with a target as low as 2.3 GJ/tonne CO_2 removed via other process improvements. BASF/Linde is developing the design to incorporate a higher-pressure stripper (3.4 bar(a)) to improve the energy consumption for CO_2 compression [**24**].

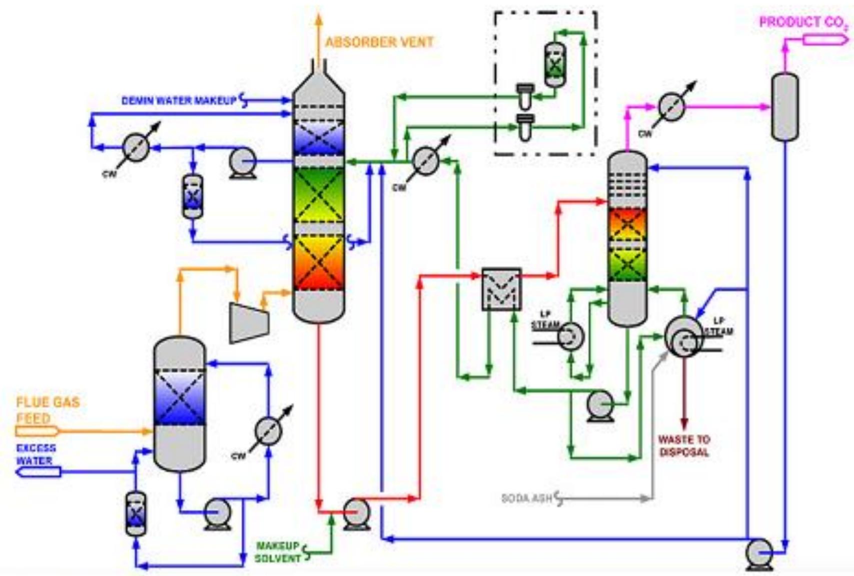
Exhibit 6-5. BASF/Linde OASE Absorption Process for CO_2 Capture



Status: Linde has responded to the project teams request for a quote for the OASE system.

- **Fluor Econamine FG Process** is an amine-based process following the industry standard design approach that uses MEA as the basic solvent ingredient and targets CO_2 recovery from low-pressure, oxygen-containing flue gas streams. Process improvements are related to solvent formulation, absorber intercooling, a large-diameter absorber, and a lean vapor compressor [**25**].

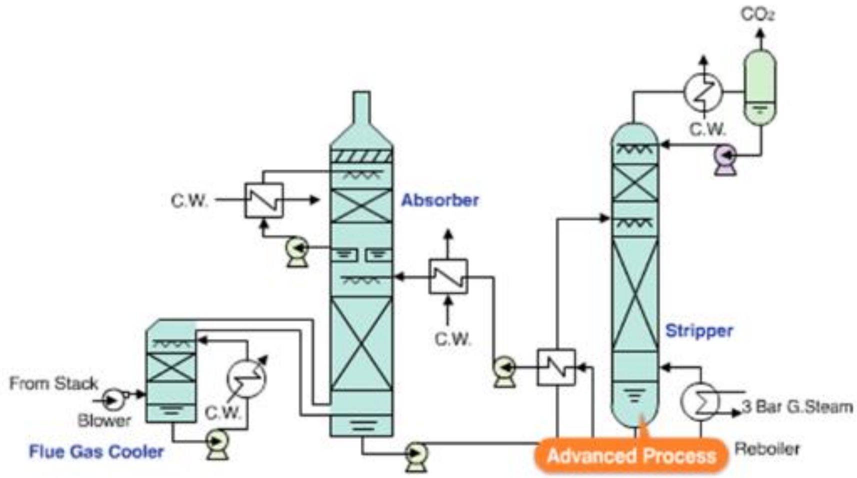
Exhibit 6-6. Fluor Econamine Absorption Process for CO_2 Capture



Status: Fluor has not provided a response on the project RFQ request.

- **MHI KM CDR Process** is an amine-based process following the industry standard design approach using KS-1 solvent, an advanced activated hindered amine, targeting low energy consumption (2.9 GJ/tonne CO_2 removed) and low solvent degradation [**26**].

Exhibit 6-7. MHI KM CDR Absorption Process for CO_2 Capture



Status: MHI was unable to provide quote at this time.

The risks and gaps associated with integrating a CO_2 capture system with PFBC include the following:

- Integrating amine-based technology for CO_2 capture on a PFBC is similar to integrating amine-based technology on a pulverized coal (PC) plant application. Flue gas constituents are similar in both scenarios with complete combustion and similar residual oxygen content. In reality, the PFBC has fewer flue gas contaminants than the PC due to the limestone additive in the combustion process that reduces the SO_2 and SO_3 levels. There is substantial NOx control with the lower-temperature combustion zone in the PFBC. To reach these levels, an SCR with ammonia injection would be required on PC plants. In both cases, effective heat integration and process control system integration are critical to maximize overall net plant efficiency, flexibility, and performance across a range of operating conditions.
- As stated earlier, the amine-based systems are the most mature technologies and have been demonstrated in both pilot and larger-scale installations. Consideration of alternative technologies would depend on their application timeline to commercial operation. If the project commercialization timeline is greater than 10 years, other technologies might be considered and could include the following:
    - Membrane-based CO_2 capture technologies using transfer rates permeating through membrane materials selectively removing CO_2 from the flue gas stream.
    - Sorbent-based CO_2 capture technologies using solid adsorbent material to either physically or chemically remove CO_2 from the flue gas stream.
    - Hybrid technologies using a combination of optimized amine-based and membrane-based CO_2 capture technologies to remove CO_2 from the flue gas stream.

6.4 Perceived Technology Gaps and R&D Needed for Commercialization by 2030

At this time, there are no perceived technology gaps that require R&D or new technology development in order to achieve commercialization by year 2030. There is a “design” gap that must be filled: the design and manufacture of a new custom gas turbomachine to replace the GT35P machine. Using state-of-the-art engineering information and design techniques, the informed opinion of Baker Hughes and Siemens is that a machine matching the required design specification can be designed, built, and offered on a commercial basis by year 2025.

The supercritical steam turbine generator is specified based on current state-of-the-art steam conditions. This type of machine has been constructed for application in several European and Asian (Chinese and Japanese) steam electric power plants over the last few decades. Large global organizations such as General Electric and Siemens have the capability of transferring their expertise internationally, and either company can provide a machine to match the specification requirements for this technology. No additional R&D is required to produce a machine that can meet the specification requirements of the proposed 4 x P200 PFBC power plant.

The project team believes that commercialization can be achieved in advance of 2030 if commercial risks can be covered. It is believed that some form of financial backing from DOE would be meaningful in helping to mitigate perceived financial and commercial risk by potential project sponsors. Construction of a pilot plant is not considered essential to advance the PFBC to commercial operation. Laboratory testing is sufficient for determining the handling properties of the paste for the fuel handling system, as was done for the 1 MWt pilot scale unit at CONSOL Energy’s R&D Center. A picture of such a “slump” test is given in Exhibit 6-8. The addition and integration of a CO_2 capture system operating at 97% capture rate also represents a new design challenge. The perceived issue is one of control systems integration and process performance, not design and physical construction. Operation on a continuous basis at high capacity factor in regular commercial use needs to be demonstrated.

Exhibit 6-8. Coal Water Paste 6” Slump Test

6.5 Development Pathway Description to Overcome Key Technical Risks/ Issues

The following outlines a development pathway for the advanced PFBC with carbon capture technology, including both near-term (i.e., required for the first plant) and longer-term priorities.

6.5.1 Development Items for the Next Commercial Plant (4 X P200 with Supercritical Steam Cycle)

The following items represent areas that require study, testing, or other efforts to mitigate risk in proceeding with the proposed 4 x P200 PFBC plant.

As a first step, the project team intends to undertake a screening study of candidate post-combustion CO_2 capture technologies, including the amine-based technologies identified in Section 2.3.1, to identify the technology that best integrates with the PFBC process to optimize overall plant efficiency and cost and minimize its commercial risk profile. The team also intends to perform a value engineering exercise, which is a structured process whereby alternative features of design and/or construction are identified and reviewed to determine applicability. Value engineering seeks to reduce total cost while preserving functional capability and assuring the adequacy of fit and finish and other aspects of a completed design. Examples of candidate subjects for Value Engineering include: (1) extent of design redundancy (e.g., 3x 50%, 2x100%), (2) specifications compared to performance requirements (3) materials of construction including linings, coatings, etc. (i.e., good enough vs gold plating), and (4) reuse of acid mine drainage (AMD) process water vs use of Ohio River water (weighing additional pipeline and pumps, smaller ZLD and elimination of AMD discharge against the alternative). These steps are considered to be important for ensuring that the detailed design is based on the best overall plant configuration and system specifications.

The next development item involves the design and manufacture of the new turbomachine specified to replace the GT35P machine. The design team of PFBC-EET, CONSOL, Worley, and Nooter/Eriksen will remain in close contact with the turbomachine provider (Baker Hughes or Siemens) to coordinate and participate in decisions affecting the design.

Another development item involves the preparation of a complete master control system for the integrated PFBC/Gas Turbomachine/Steam Turbine Generator/AQC Systems (including the CO_2 capture) and the paste fuel preparation. The operation of the plant must be studied and thoroughly understood in order to prepare the hierarchy of control algorithms, controller set points, alarms, interlocks, permissives, etc. that are necessary to operate the plant in a safe and efficient manner. Work on this item must be started early in the design process, and the architecture of this system and its subordinate programs and subprograms must evolve and be checked so that it is operationally ready when the physical construction is complete.

Waste fuel quality will also be addressed. The waste fuel quality parameters provided in the Design Basis for the pre-FEED study were obtained through sampling of CONSOL Energy's Bailey Central Preparation Plant thickener underflow stream. This represents the fine waste that is discarded currently into slurry impoundments. The ash content reported on a dry basis is 44.5%, and the heating value, also on a dry basis, is 7,803 Btu/lb. Sampling and analysis of this stream is ongoing. However, the quality of the fuel fed to the PFBC affects performance, and lower ash/higher heating value feedstocks improve the performance. During fuel preparation for the PFBC Process Test Facility at CONSOL Energy's former R&D facility, additional potential waste streams were collected and analyzed at the preparation plant. These included the spiral middlings (intermediate density particles) that had a lower ash content (18.48%, dry) and higher heating value (12,095 Btu/lb, dry) and ultrafines (~ -325 mesh) from the thickener underflow stream that had a higher ash (62.73%, dry) and lower heating value (4758 Btu/lb, dry). Additional sampling of individual fine and ultrafine waste streams within the preparation plant will determine if these streams represent opportunities for preparing waste fuel with lower ash/higher heating value. In addition, the project team will evaluate technologies that reject ash-forming minerals and recover these minerals for beneficial use, with the goal of eliminating all waste streams. Testing of one such process is being conducted at the preparation plant at this time. Ultimately, paste testing will be performed to determine the material characteristics (e.g., particle size distribution, solids density, etc.) of the fuels and sorbent materials selected as feedstocks for the plant, and to determine the rheology of the prepared fuel, and results will be used to inform the paste plant design and engineering effort.

Finally, technical risks and considerations associated with CO_2 transport, storage, and/or utilization (i.e., providing one or more certain offtake options for the CO_2 that is captured from the advanced PFBC plant) are critical to the development and success of the project, but are beyond the scope of this report. Nevertheless, the project team has been proactive in this area and has initiated conversations with the Pennsylvania Geologic Survey, Battelle, Oxy Low Carbon Ventures, and others to begin the evaluation and explore a range of alternatives including geologic storage and EOR. This development item will be a key piece of our project execution plan (See Appendix A).

6.5.2 Longer-Term Development Items

Longer term development items have been identified that are not required for commercial deployment of the first advanced PFBC plant with carbon capture but may be considered for the first plant (during the FEED study) or in follow-on plants to improve performance. These include consideration of the following, which are aimed at improving plant economic performance by reducing capital costs and/or by reducing operating and maintenance (O&M) costs. A significant contribution can be made towards reducing these costs by improving steam cycle efficiency, which reduces the amount of fuel fired to make a specified amount of electricity. It may also increase plant output at a given fuel firing rate and overall capital cost.

The development pathway will focus on improvements in several key areas:

- 16 bar P200 PFBC design concept
- Improved steam cycle conditions
- Improved gas turbomachine cycle performance
- Improved CO_2 capture performance
- Improved thermal performance of the PFBC boiler

6.5.2.1 16 Bar P200 PFBC Design Concept

One specific low-risk development path has been recognized, which is being evaluated for potential incorporation into the Coal FIRST plant design and will be considered during the full FEED study, depending on the outcome of this evaluation. This path increases the operating pressure of the PFBC P200 boiler by increasing the compression ratio of the gas turbomachine. The proposed increase will be from 12 bar nominal pressure to 16 bar in the PFBC P200 fluidized bed boiler. A similar boiler has already been operated at 16 bar and with supercritical steam conditions in the P800 configuration (as described in the discussion on the Karita plant above). The essential new components in this higher-pressure configuration are a revised gas turbomachine operating at around 17 bar pressure at the compressor discharge (16 bar at the fluidized bed) and a revised P200 vessel designed for the higher pressure. This is likely to require some redesign of the new gas turbomachine sought for the present effort; it can likely be accomplished without major new design, but with addition of some additional compressor stages. The expander stages may also require some modification, along with pressure retaining parts (casings, etc.).

The operation of the P200 at a nominal 16 bar in lieu of 12 bar could enable three (3) P200 combustors and turbomachines to deliver the thermal performance of four (4) systems operating at 12 bar. The entire steam cycle, including the steam turbine generator, heat sink, etc., is not impacted by this change. In terms of overall plant costs, it is estimated that this will result in a nominal 10% decrease in total plant cost, with no change in plant output and efficiency. Therefore, the plant economic performance is enhanced with minimal risk and redesign.

6.5.2.2 Improved Steam Cycle Conditions

The focus on the development of improved steam cycle design parameters involves higher steam throttle pressures and temperatures. While the proposed plant is based on nominal steam conditions of 3500 psig/1100 °F/1100 °F, European and global interests have been targeting higher, more challenging conditions. These higher pressures and temperatures can provide higher electric generating efficiencies. Implementation of these more aggressive conditions relies on the availability of materials with improved creep strength at elevated temperatures.

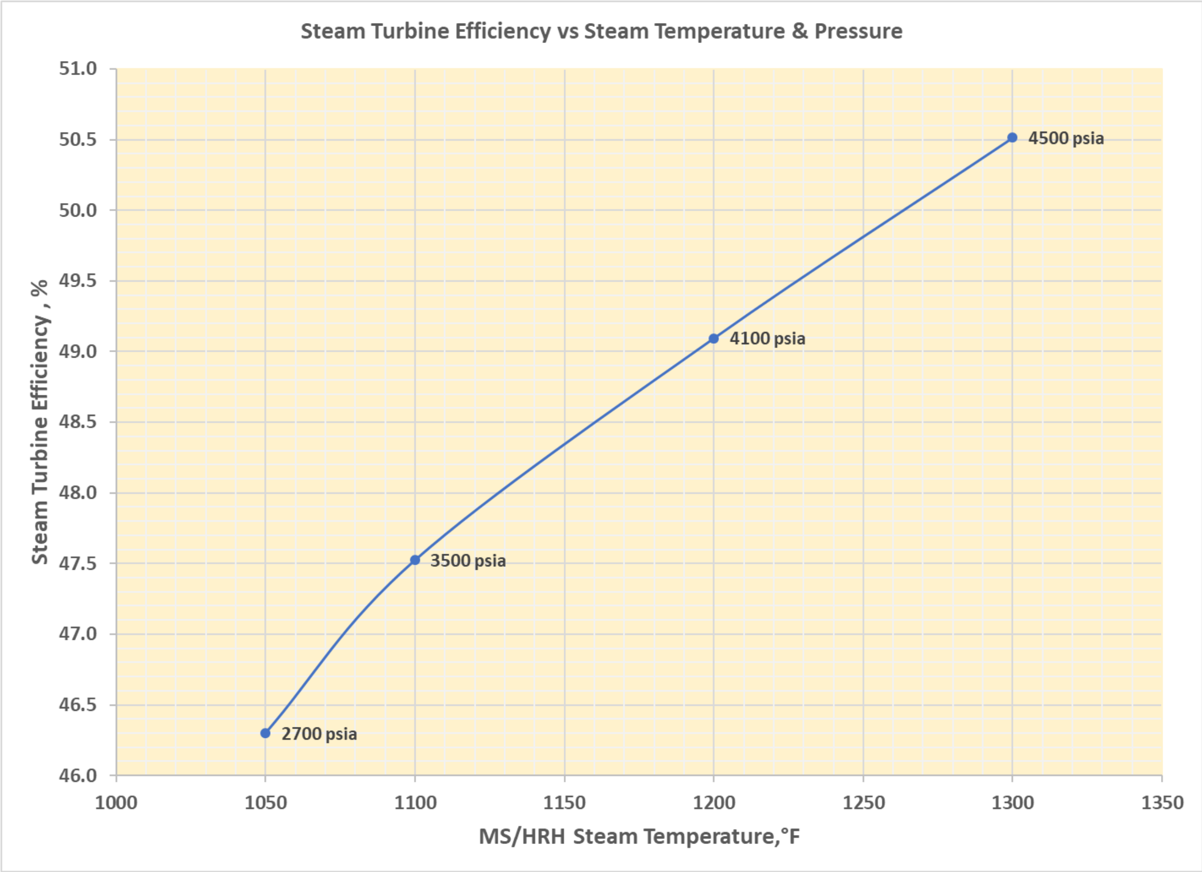
A number of materials are available now that offer meaningful improvements in high-temperature creep and yield strength but at a cost that precludes commercial use. Some of these materials also require official sanction and inclusion in the ASME Boiler and Pressure Vessel Code and related ancillary piping codes (e.g., B31.1 Power Piping, etc.). Examples of these materials include Inconel Alloy 740, an alloy of Nickel, Chromium, and Cobalt that is precipitation hardened, and Nimonic Alloy 263, an alloy of Nickel, Chromium, and Molybdenum that is also precipitation hardened.

Both alloys are capable of service at temperatures up to about 1650 °F with reasonable creep strength. These alloys may also be used to fabricate the heat exchanger required to enable the implementation of the Benfield CO_2 capture scheme described above. These alloys are extremely expensive and have no or limited affirmation for use in the principal boiler and pressure vessel codes to date.

Besides thermal efficiency, capital cost and operating cost are principal drivers of power plant economics. The upper limits of thermal efficiency, particularly with high levels of carbon capture, often do not make economic or business sense. The economic optimum condition must be evaluated for each project to determine how far to go with high temperatures and pressures.

Exhibit 6-9 presents comparative steam cycle efficiencies based on different values of throttle pressure and temperature (with corresponding hot reheat temperature) pairs. The impact on PFBC plant efficiency has not been calculated, but as the steam cycle produces about 80% of the total electric power for the 4 x P200 power plant, the lapse rate shown below is indicative of potential performance improvements that are possible with advanced steam conditions.

Exhibit 6-9. Steam Turbine Cycle Efficiency as Function of Steam Conditions

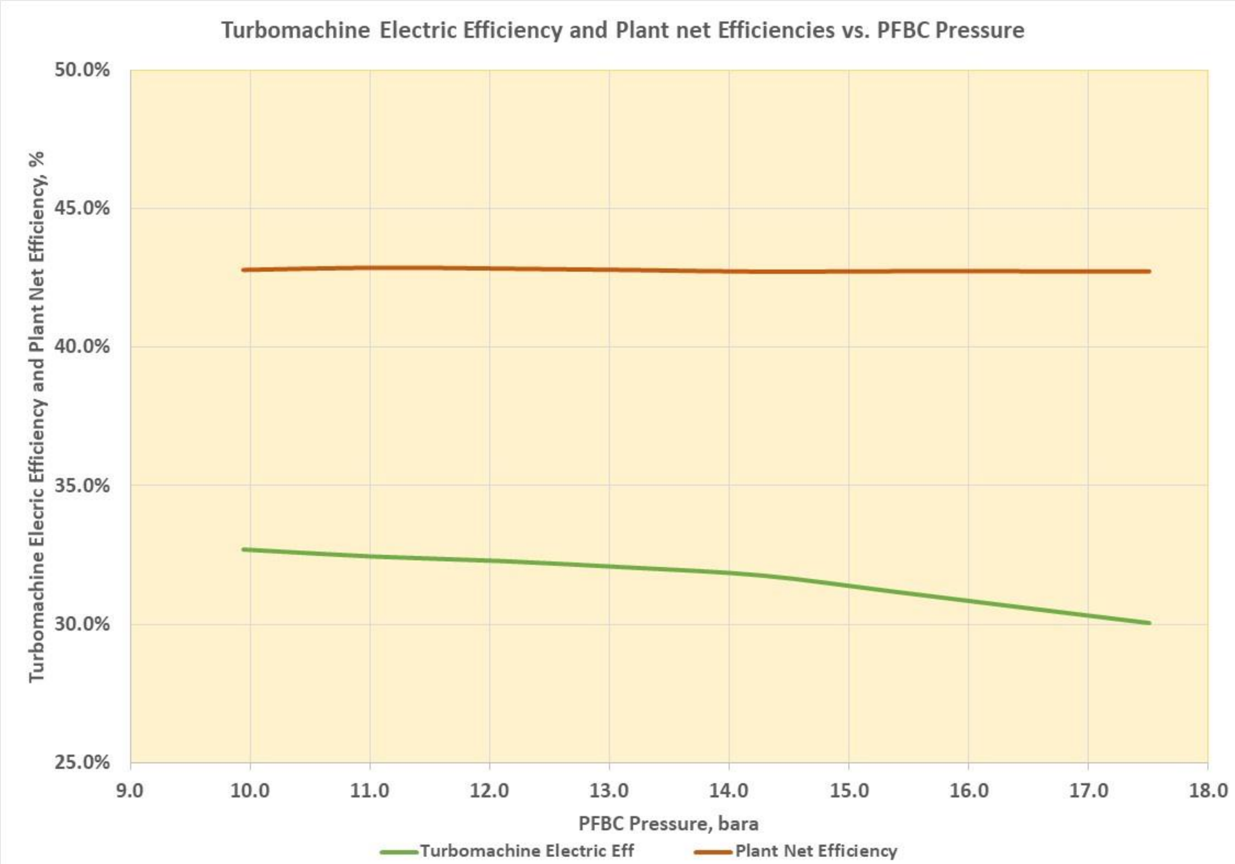


6.5.2.3 Improved Gas Turbomachine Cycle Performance

As noted above, the introduction of higher boiler pressure has significant benefits in plant capital costs. A brief evaluation was performed to ascertain the impacts on gas turbine cycle efficiency of changing the compressor pressure ratio. This is reflected in Exhibit 6-10 and Exhibit 6-11. Exhibit 6-10 shows that although increasing the PFBC nominal pressure from 12 to 16 bar is not optimal for the turbomachinery itself, the pressure change does not negatively impact the overall plant efficiency. The impetus of the increased PFBC pressure is that of capital cost reduction resulting from the elimination of one (1) of the four (4) PFBC trains while maintaining the capacity and performance.

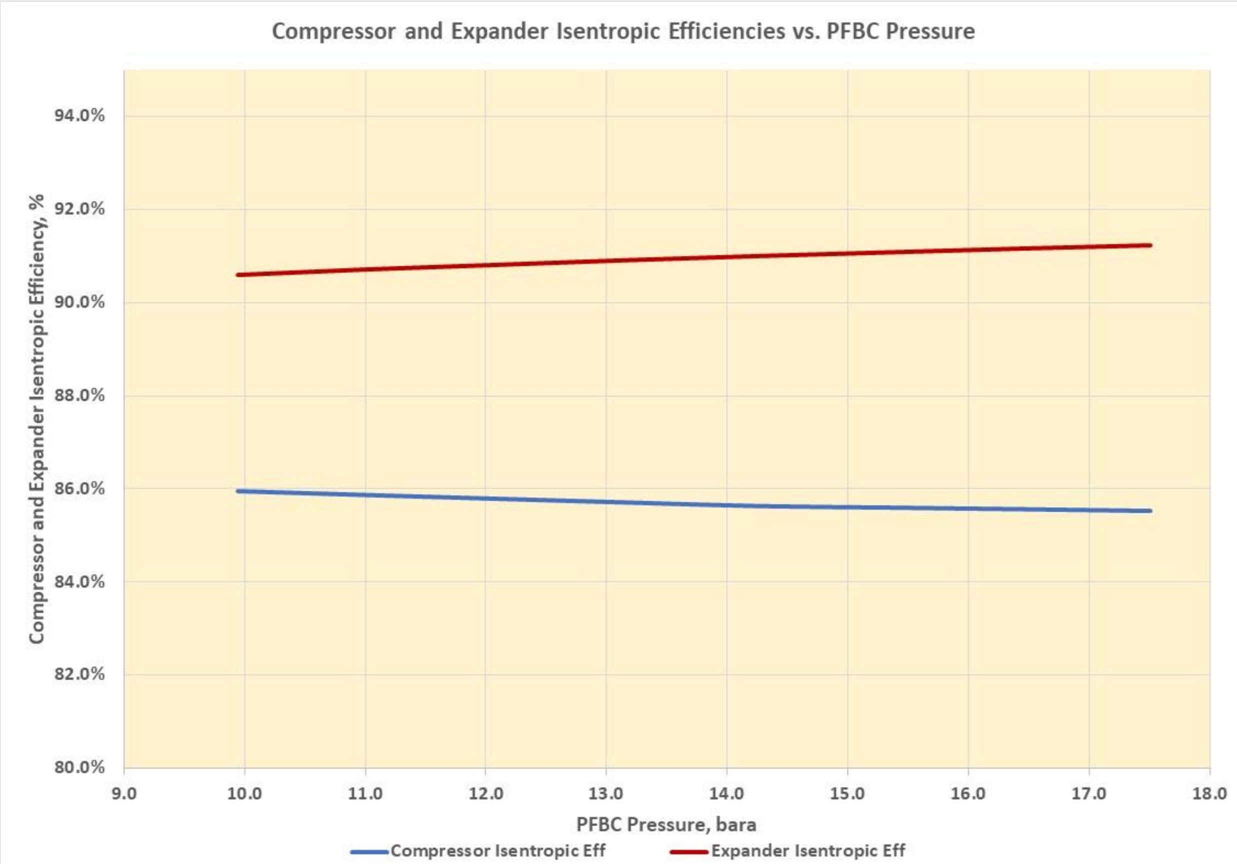
Exhibit 6-11 helps the reader understand that the drop in the turbomachinery performance with increasing pressure is a result of the decreasing compressor adiabatic efficiency with increasing pressure levels. This is a consequence of the behavior of turbomachines assuming constant polytropic (small stage) efficiency. The intercooled cycle used in the P200 PFBC actually reaches peak efficiency at a relatively low pressure ratio. This is a consequence of the low turbine inlet temperature of 1450 °F. More typical gas turbines that fire oil or gas with significantly higher compressor pressure ratios (ranging up to over 40:1 for some aeroderivative models) do not have intercooling and they also have turbine inlet temperatures ranging up to values in excess of 2600 °F. The low temperature intercooled machine occupies a place in the performance spectrum not often encountered in the world of gas turbines in the current era.

Exhibit 6-10. Gas Turbine and Plant Net Efficiencies as Function of PFBC Pressure



Note: Efficiencies are based on constant 1448°F gas temperature at Expander inlet.

Exhibit 6-11. Compressor and Expander Efficiencies as Function of PFBC Pressure



Note: Efficiencies are based on constant 1448°F gas temperature at Expander inlet.

6.5.2.4 Improved CO_2 Capture Performance

Amine-based CO_2 capture systems have seen significant development over the last decade or two. The PFBC plant concept can take advantage of improvements in amine-based performance as these become available without significant redesign or added construction. New solvents can be substituted in the amine system as they become available. Improvements that are of the most interest include the reduction of energy required to strip CO_2 from the solvent in the regeneration unit and more robust amine performance in terms of resistance to degradation during service.

Energy improvements have been pursued in multiple areas including solvent development and operational and process modifications. These areas are discussed below.

- Solvent development has led to an ~8% reduction in reboiler energy consumption.
- Operational improvements have led to ~20% improvement in energy consumption.
- A baseline reference for reboiler duty using MEA solvent as of 2007 was 3.29 GJ/tonne CO_2 removed [**27**]; however, improvements have resulted in current estimated reboiler heat duty levels of 2.3 to 2.6 GJ/tonne CO_2 removed.
- Drivers of these improvements include the following:
  - Optimization of the CO_2 rich and lean loadings, the feed stream temperature, and the amount of stripping steam used

  - Using higher solvent concentrations and increasing the reboiler operating pressure
  - Operating at higher solvent temperatures
  - Increasing the height of the transfer area in the absorber and stripper
- Process improvements have included or can include the following:
  - Absorption enhancements – increasing the CO_2 loading and CO_2 capacity of the solvent, thereby reducing the solvent flow and reboiler heat duty
  - Heat integration – optimizing waste heat recovery within the process to reduce reboiler heat duty
  - Absorber intercooler – allows higher CO_2-rich loading from the absorber, resulting in reduced solvent recirculation rates and reboiler energy requirements
  - Lean vapor compressor – has shown the ability to reduce reboiler energy on the order of 2-8%
  - Stripper inter-stage heater – introduces low-quality steam in the stripper to reduce the energy load that needs to be supplied by higher-quality steam (via steam turbine generator extraction) in the reboiler, resulting in higher coal plant efficiencies
  - Increasing the regenerator operating pressure (e.g., up to 3 bar) to reduce CO_2 compression power consumption

As discussed in Section 6.3.1, the longer-term technology development pathway for PFBC may also take advantage of advances in emerging CO_2 capture technologies, such as membranes, solid sorbents, and membrane/solvent hybrid systems, which have longer timelines to commercialization but have shown potential to improve on the performance of amine-based systems.

6.5.2.5 Improved Thermal Performance of the PFBC Boiler

The PFBC boiler performance could be improved upon by increasing the combustion air temperature prior to induction into the bed. This can be achieved in several ways. The PFBC does not employ an air preheater as seen on atmospheric boilers. However, a possible performance improvement that was investigated involved deleting the intercooling function from the gas turbine air compression process. While this decreases the net power produced by the turbomachine, it increases the air temperature to the PFBC bed and reduces the fuel heat input required. An evaluation of this concept has been completed with the finding that there is no gain in net efficiency. Therefore, the concept of removing compressor intercooling to increase the combustion air temperature will not be evaluated further nor incorporated into the design.

6.6 Key Technology/Equipment OEM's

This section provides information on the following areas:

- List of Equipment – Commercial and that Requiring R&D
- The A&E Firm Experience with Equipment OEMs
- The A&E Firm Access to Equipment Information

6.6.1 List of Equipment – Commercial and that Requiring R&D

Major equipment and systems for the supercritical PFBC plant are shown in the following tables. A single list is used for both the capture-ready (Case 1A) and capture-equipped (Cases 1B, 2B, 2C) configurations. Items that relate to the capture-equipped configuration only are highlighted in light green in Account 5 (Flue Gas Cleanup). The accounts used in the equipment list correspond to the account numbers used in the cost estimates. The commercial status for the major equipment/systems has been identified with one of following three designations.

4. Commercial
5. Custom design
6. R&D needed

It should be emphasized that there are no technologies that require R&D. Although the unique configuration will need to be carefully designed, optimized, and demonstrated as an integrated system that combines many sub-systems for the first time, none of the components require R&D.

Following the convention from the Performance Results Report, the capture-ready and capture-equipped configurations are designated per Case number matrix in Exhibit 6-12.

Exhibit 6-12. PFBC Case Matrix

Case Definition	Capture-Ready (Subcase A)	Capture-Equipped (Subcase B)	Capture-Equipped & Biomass (Subcase C)
Illinois No. 6 (Case 1)	Case 1A	Case 1B	Case 1C (Not developed)
Waste Coal (Case 2)	Case 2A (Not developed)	Case 2B	Case 2C

Exhibit 6-13. Case 1A & 1B – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Commercial Status
	DRY FUEL HANDLING/SIZING		
1	Rail Car/Bottom Dump/Hopper Unloader	Field Erect	Commercial
2	Hopper Unloading Feeders	Vibrating	Commercial
3	Rail Unloading Conveyor to Stacking Tube	Belt	Commercial
4	Cross Belt Sampler	Swing Hammer	Commercial
5	Stacker Transfer Conveyor #1	Belt	Commercial
6	Stacking Tubes (2) Reclaim Tunnel with Escape	Open	Commercial
7	Reclaim Feeders (4)	Vibratory	Commercial
8	Reclaim Conveyor with Scale Magnet	Belt	Commercial
9	Reclaim Transfer Conveyor	Belt	Commercial
10	Sizing Station Feed Conveyor	Belt	Commercial
11	Sizing Building	Enclosed	Commercial
12	Sizing Screens	8x16 DD Incline	Commercial
13	Reversible Hammermill Crusher		Commercial
14	Oversize Protection Screens	8x16 DD inclined	Commercial
15	Sizing Station Discharge Conveyor/Scale	Belt	Commercial
16	Fuel Prep Feed Conveyor	Belt	Commercial
	SORBENT HANDLING		
1	Truck Scale	72' x 11' Sorbent	Commercial
2	Sorbent Truck Dump/Hopper	Field Erect	Commercial
3	Truck Dump Feeders	Vibrating	Commercial
4	Truck Dump Collecting Conveyor		Commercial
5	Conveyor to Sorbent Storage Stacker	Belt	Commercial
6	Sorbent Storage Reclaim Hoppers/Feeders	Augers	Commercial
7	Sorbent Reclaim Conveyor to Sizing Bldg with Scale	Belt	Commercial
8	Sorbent Sizing Bldg	Enclosed	Commercial
9	Bulk Material Bin with Gates (2)	Enclosed	Commercial
10	Bin Rotary Airlock/Feeders		Commercial
11	Sizing Screens		Commercial
12	Crusher Hammermill		Commercial
13	Oversize Protection Screen		Commercial
14	Fuel Prep Feed Conveyor/Scale		Commercial
15	Process Bag Filter	Dust Collecting	Commercial
16	Process Bag Filter	At Fuel Prep Bldg	Commercial
17	Trough Conveyors	At Fuel Prep Bldg	Commercial

Exhibit 6-14. Case 1A, 1B & 2B/C – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Commercial Status
	FUEL PREPARATION & DELIVERY SYSTEM (Equipment Per Pumpaction Quote PRJ20-0023		
1	Fuel Prep Building	Enclosed	Commercial
2	Floor Sump Pump	Vertical	Commercial
3	Fuel Receiving Bins	Field Erect	Commercial
4	Sliding Frames	Hydraulic Power Pack	Commercial
5	Auger Feeders	Auger	Commercial
6	Fuel Weigh Feeders	Belt	Commercial
7	Sorbent Receiving Bins	Field Erect	Commercial
8	Inlet Rotary Airlocks/Feeders		Commercial
9	Outlet Rotary Airlocks/Feeders		Commercial
10	Sorbent Weigh Feeders	Belt	Commercial
11	Paste Sumps/ Mixers/Moisture Control	Mixers	Commercial
12	Prepared Fuel Sumps/ Agitators		Commercial
13	Prepared Fuel Transfer Pumps	Hydraulic Power Pack	Commercial
	FUEL PREP LOCATION AT POWER PLANT BOILER		Commercial
14	Buffer Silos/Level Detectors	Platework	Commercial
15	Buffer Silo Agitators	Mixer	Commercial
16	Fuel Injection Pumps	Hydraulic	Commercial

Exhibit 6-15. Case 1A, 1B, 2B, 2C – Account 3: Feed Water and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Commercial Status
1	Condensate Pumps	Vertical canned	Commercial
2	Deaerator and Storage Tank	Horizontal spray type	Commercial
3	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	Commercial
4	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	Commercial
5	Emergency Diesel driven backup FWP	Barrel type, multi-stage, centrifugal	Commercial
6	LP Feedwater Heater 1	Horizontal U-tube	Commercial
7	LP Feedwater Heater 2	Horizontal U-tube	Commercial
8	LP Feedwater Heater 3	Horizontal U-tube	Commercial
9	LP Feedwater Heater 4	Horizontal U-tube	Commercial
10	LP Feedwater Heater 5	Horizontal U-tube	Commercial
11	HP Feedwater Heater 7	Horizontal U-tube	Commercial
12	HP Feedwater Heater 8	Horizontal U-tube	Commercial
13	HP Feedwater Heater 9	Horizontal U-tube	Commercial
14	Topping Feedwater Feeder	Horizontal U-tube	Commercial
15	Auxiliary Boiler	Shop fabricated, water tube	Commercial
16	Closed Cycle Cooling System	Shell and tube HX & Horizontal centrifugal Pumps	Commercial
17	Condensate Polisher System	Deep Bed Condensate Polisher System with three service vessels, cation separation/regeneration vessel, anion regeneration vessel, resin refill hopper, resin storage vessel, acid and caustic storage tanks, acid and caustic regeneration skids, mixing skids, design of neutralization tank, neutralization tank internals, PLC Controls	Commercial
18	Neutralization Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
19	Sluice/Regen Water Pumps	All 316 stainless steel construction, horizontal centrifugal	Commercial
20	Condensate Polisher Booster Pumps	316 Stainless Steel construction, horizontal centrifugal	Commercial
21	Raw Water Pretreatment Clarifier System	Two train clarifier system: Including clarifiers, sludge handling equipment, filter presses, sludge storage and forwarding tanks, sludge feed pumps, chemical feed systems and PLC Controls	Commercial
22	Raw Water System Pumps with VFD	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
23	Raw Water/ Fire water Storage Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
24	Clarified Water Storage Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
25	Clarified Water Pumps with VFD	Cast Iron construction, 316 stainless steel shaft & Impeller, vertical centrifugal	Commercial
26	Cooling Tower Makeup Water Pumps with VFD	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
27	Service Water Transfer Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, vertical centrifugal	Commercial
28	Service Water Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial

Equipment No.	Description	Type	Commercial Status
29	Service Water Storage Tank	Vertical, cylindrical, outdoor, carbon Steel, internal epoxy lining	Commercial
30	Sodium Hypochlorite Storage Tank	Vertical, cylindrical, outdoor, FRP construction, external UV protection	Commercial
31	SO2 Polishing Makeup Water Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
32	Liquid Waste Treatment System	ZLDS two train Evaporator & Cyrstallizer System	Commercial
33	ZLD Primary Feed Tank	Vertical, cylindrical, indoors, AL6XN	Commercial
34	ZLD Distillate Tank	Vertical, cylindrical, indoors, 304L stainless steel	Commercial
35	ZLD Brine Holding Tank	Vertical, cylindrical, indoors, FRP	Commercial
36	ZLD WW Feed Pumps	316 Stainless Steel construction	Commercial
37	ZLD Fuel Prep Feedwater Transfer Pumps	316 Stainless Steel construction	Commercial
38	LP Economizer- Water Side	Horizontal Field Erected Waste Heat Recovery	Commercial
39	HP Economizer 1 - Water Side	Horizontal Field Erected Waste Heat Recovery	Commercial
40	HP Economizer 2 - Water Side	Horizontal Field Erected Waste Heat Recovery	Commercial
41	BFP Condenser	Single pass including vacuum pumps	Commercial
42	SO2 Polishing Makeup Water Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
43	Motor Driven Fire Pump	Horizontal Centrifugal	Commercial
44	Diesel driven fire pump	Vertical Turbine	Commercial
45	Jockey fire pump	Horizontal Centrifugal	Commercial
46	Emergency Instrument Air Compressor	Oil Free Screw	Commercial
47	Instrument Air dryer	Duplex, regenerative	Commercial
48	Instrument Air Accumulator	Carbon Steel, Vertical	Commercial
49	Service Air Compressor	Flood Screw	Commercial
50	Service Air dryer	Heatless	Commercial
51	Service Air Accumulator	Carbon Steel, Vertical	Commercial
52	Raw Water Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
53	Clarifier Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
54	Demineralized Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
55	RO Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
56	Condensate Polisher Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
57	Transformer Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
58	Cooling Tower Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
59	Chemical Area Sump Pumps	Submersible Duplex, 316 Stainless Steel Wetted Components	Commercial
60	Evaporator Area Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
61	Cyrstallizer Area Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
62	ZLD Area Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
63	ZLD Waste Sump Pumps	Vertical Centrifugal Rubber Lined Sump Pumps	Commercial
64	Oil Water Separator	Horizontal Cylindrical tank with pump out chamber and effluent pumps	Commercial

Exhibit 6-16. Case 1A, 1B, 2B, 2C – Account 3.1: Demineralized Water Systems

Equipment No.	Description	Type	Commercial Status
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor, 304L	Commercial
2	Demineralized Water Ultrafiltration (UF) System	Two train UF System with feed tank and pumps, CIP System, UF backwash System, PLC Controls	Commercial
3	UF Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
4	Demineralized Water Reverse Osmosis (RO) System	Two train, two stage RO System with feed tank and pumps, CIP system, RO feed pumps, chemical Feed Skids, PLC Controls	Commercial
5	First Pass RO Supply Pumps	Ductile Iron, 316 stainless steel shaft & Impeller, horizontal centrifugal	Commercial
6	First Pass RO Permeate Tank	Vertical, cylindrical, outdoor, 304L	Commercial
7	RO Product Tank	Vertical, cylindrical, outdoor, 304L	Commercial
8	Demineralized Water Mixed Bed (MB) System	Two train, MB System with feed tank and pumps, recirculation pumps, acid and caustic regeneration system, acid and caustic storage tanks, design of neutralization tank, neutralization tank internals, PLC Controls	Commercial
9	Mixed Bed Feed Pumps	All 316 stainless steel construction, horizontal centrifugal	Commercial
10	Neutralization Tank	Vertical, cylindrical, outdoors, carbon Steel, internal epoxy lining	Commercial
11	Demineralized Water Feed Pumps	All 316 stainless steel construction, horizontal centrifugal	Commercial

Exhibit 6-17. Case 1A, 1B, 2B, 2C – Account 4: PFBC Coal Boiler and Accessories

Equipment No.	Description	Type	Commercial Status
1	PFBC	P200, supercritical, SNCR	Custom Design (supercritical)
2	SNCR Ammonia Storage & Feed System	Horizontal tank, centrifugal pump, injection grid	Commercial
3	External Reheater	Shell & Tube Heat exchanger	Commercial
4	Process Air Compressors	Screw Type	Commercial
5	Process Air Receiver	Vertical	Commercial
6	Process Air Moisture Separator	Duplex	Commercial
7	Process Air Membrane Drier		Commercial
8	Nitrogen Storage Tank	Horizontal	Commercial
9	Nitrogen Vaporizer	Electrical Heating	Commercial
10	Nitrogen Buffer Tank	Horizontal	Commercial

Exhibit 6-18. Case 1A, 1B, 2B, 2C – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Commercial Status
1	Hot Gas Metallic Filter	Pressure vessel with replaceable filter elements, back-pulse cleaning	Custom Design
2	Mercury Control system	GORE® Sorbent Polymer Catalyst (SPC) composite material	Commercial
3	SO_2 Polisher Absorber Module	Counter-current pack column Absorber, caustic solvent	Custom Design
4 Capture only	Gas Pre-cooler	Direct Contact	Custom Design
5 Capture only	CO_2 Absorber System	Amine-based CO_2 capture (e.g., CANSOLV capture technology)	Custom Design
6 Capture only	CO_2 Dryer	Triethylene glycol (TEG)	Custom Design
7 Capture only	CO_2 Compression system	Integrally geared, multi-stage centrifugal compressor	Custom Design
8 Capture only	CO_2 Intercooler	Shell and tube heat exchanger (Included w/MAN CO2 Compressor Quote)	Custom Design
9 Capture only	CO_2 Aftercooler	Shell and tube heat exchanger	Custom Design
10	CEMS	Standalone building	Commercial

Exhibit 6-19. Case 1A, 1B, 2B, 2C – Account 6: Turbo-Machines

Equipment No.	Description	Type	Commercial Status
1	Intake Air Filter/Silencer	Dry	Custom Design
2	Gas turbo machine	Integrated compressor, expander, and motor/generator	Custom Design
3	Gas turbo Intercooler	Shell Tube	Custom Design
4	Heat Recovery	Fin-Tube Heat Exchange, See water side economizers in account 3	Custom Design

Exhibit 6-20. Case 1A, 1B, 2B, 2C – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Commercial Status
1	Stack	Reinforced concrete with FRP liner	Custom Design

Exhibit 6-21. Case 1A, 1B, 2B, 2C – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Commercial Status
1	Steam Turbine	Commercially available advanced steam turbine	Custom Design
2	Steam Turbine Generator	Hydrogen cooled, static excitation	Custom Design
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	Custom Design
4 Cases 2 Only	Air Cooled Condenser	"A" Frame Type	Custom Design

Exhibit 6-22. Case 1A, 1B, 2B, 2C – Account 9: Cooling Water System

Equipment No.	Description	Type	Commercial Status
1	Circulating Water Pumps	Vertical, wet pit	Commercial
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	Commercial

Exhibit 6-23. Case 1A, 1B, 2B, 2C – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Commercial Status
	Bed Ash Handling System	-	
1	L-Valve	non-mechanical	Commercial
2	Lock Hopper		Commercial
3	Atmospheric Bin		Commercial
4	Atmospheric Bin Filter	Pulse Jet	Commercial
5	Conveyor	Screw	Commercial
6	Conveyor	Belt	Commercial
7	Bucket Elevator		Commercial
8	Conveyor	Belt	Commercial
9	Bed Ash Storage Silo	Reinforced concrete, Vertical cylinder,	Commercial
	Cyclone & Filter Ash Handling System		
1	Pressure Reducer		Commercial
2	Storage Hopper	Reinforced concrete, Vertical cylinder,	Commercial
3	External Ash Cooler	Shell Tube	Commercial
4	External Cyclone	Cyclone with air ejector	Commercial
5	Wet Unloader		Commercial
6	telescoping unloading chute		Commercial
7	Fly Ash Silo	Reinforced concrete, Vertical cylinder,	Commercial

Exhibit 6-24. Case 1A, 1B, 2B, 2C – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Commercial Status
1	STG Transformer	Oil-filled	Commercial
2	Turbo-machine Transformer	Oil-filled	Commercial
3	High Voltage Transformer	Oil-filled	Commercial
4	Medium Voltage Transformer	Oil-filled	Commercial
5	Low Voltage Transformer	Dry ventilated	Commercial
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	Commercial
7	Turbo-machine Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	Commercial
8	Medium Voltage Switchgear	Metal clad	Commercial
9	Low Voltage Switchgear	Metal enclosed	Commercial
10	Emergency Diesel Generator	Sized for emergency shutdown	Commercial
11	Station Battery and DC Bus		Commercial
12	120 AC Uninterruptible Power Support		Commercial

Exhibit 6-25. Case 1A, 1B, 2B, 2C – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Commercial Status
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Custom Design
2	DCS -Processor	Microprocessor with redundant input/output	Custom Design
3	DCS - Data Highway	Fiber optic	Custom Design

Below are fuel and sorbent handling equipment account areas that are unique to the business case.

Exhibit 6-26. Case 2B – Account 1: Waste Coal and Sorbent Handling

Equipment No.	Description	Type	Commercial Status
	WASTE FUEL STORAGE EQUIPMENT		
1	Thickeners	Static	Commercial
2	Thickener Rakes Rotation	Structural	Commercial
3	Thickener Rakes Lift	Vibrating	Commercial
4	Thickener Underflow Pumps	Centrifugal	Commercial
5	Clarified Water Pumps	Centrifugal	Commercial
	WASTE FUEL DRYING SYSTEM		
6	Waste Fuel Drying Building	Structural	Commercial
7	Plate Press Feed Sumps/ Mixers		Commercial
8	Plate Press Feed Pumps Stage 1		Commercial
9	Plate Press Feed Pumps Stage 2		Commercial
10	Plate Press Hydraulic Pumps		Commercial
11	Plate Press Plate Shifter		Commercial
12	Plate Press Plate Shaker		Commercial
13	Plate Press Hydraulic Drip Trays		Commercial
14	Plate Press Washdown Pumps		Commercial
15	Plate Press Air Compressors		Commercial
16	Gland Water Pumps		Commercial
17	Plate Press Effluent/ Sumps/Pumps		Commercial
18	Plate Press Hoist/Tram		Commercial
19	Floor Sump Pumps		Commercial
20	Waste Fuel Conveyor	Belt	Commercial
21	Waste Fuel Collecting Conveyor with Belt Scale		Commercial
22	Waste Fuel Transfer Conveyor with Scale	Belt	Commercial
23	Waste Fuel Storage Conveyor	Belt	Commercial
24	Cross Belt Sampler	Swing Hammer	Commercial
25	Waste Fuel Storage Dome		Commercial
26	Dome Vibrafloor Reclaim System		Commercial
27	Waste Fuel Reclaim Conveyors	Belt	Commercial
28	Waste Fuel Transfer Conveyor with Scale	Belt	Commercial
29	Waste Fuel Fuel Prep Bldg Feed Conveyor	Belt; Enclosed	Commercial
	SORBENT SIZING / HANDLING		
1	Truck Scale	Field Erect	Commercial
2	Sorbent Truck Dump/Hopper	Field Erect	Commercial
3	Truck Dump Feeders	Vibrating	Commercial
4	Truck Dump Conveyor to Sorbent Storage Stacker	Belt	Commercial
5	Sorbent Storage Reclaim Hoppers/Feeders	Augers	Commercial
6	Sorbent Reclaim Conveyor to Sizing Bldg with Scale	Belt	Commercial
7	Sorbent Sizing Bldg	Enclosed	Commercial
8	Bulk Material Bin with Gates (2)	Enclosed	Commercial
9	Bin Rotary Airlock/Feeders		Commercial
10	Sizing Screens		Commercial
11	Crusher Hammermill		Commercial
12	Oversize Protection Screens		Commercial
13	Fuel Prep Feed Conveyor/Scale		Commercial
14	Process Bag Filter	Dust Collecting	Commercial

Equipment No.	Description	Type	Commercial Status
15	Process Bag Filter	At Fuel Prep Bldg	Commercial
16	Trough Conveyors	At Fuel Prep Bldg	Commercial

Exhibit 6-27. Case 2C – Account 1: Biomass Handling & Sizing

Equipment No.	Description	Type	Commercial Status
	WASTE FUEL BIOMASS EQUIPMENT		
1	Covered Storage	500 Ton Each	Commercial
2	Reclaim Feeder Apron		Commercial
3	Biomass Sizing Plant Feed Conveyor	Belt / Scale / Magnet	Commercial
4	Biomass Sizing Building	Structural; Insulated	Commercial
5	Biomass Sizing Screen	Incline 8 x 16	Commercial
6	Biomass Crusher	Reversible Hammermill	Commercial
7	Biomass Sized Collection Bin / Feeder	20 Ton Bin; Vibratory Feeder	Commercial
8	Biomass Sizing Plant Discharge Conveyor with Scale	Belt	Commercial

6.6.2 The A&E Firm Experience with Equipment OEM's

The A&E firm (Worley Group, Inc.) has worked with the OEMs of the proposed equipment over a wide range of past projects. These include the following:

PFBC-EET: Worley has performed numerous studies and conceptual designs for the U.S. Department of Energy and for PFBC-EET and its predecessor organization (Asea Brown Boveri, or ABB). These studies began with a Gilbert/Commonwealth Reference Plant design in September 1998 (Ref DE-AM21-94MC31166, Task 6) for a P800 subcritical 350 MWe power plant. This design study was part of a series of Reference design reports.

Worley's predecessor, Parsons Power, worked with ABB to offer a 3 x P200 design for repowering an existing 235 MWe coal-fired power station for Lakeland Electric in 1998.

In 2005, PFBC-EET acquired the license to market the P200 technology in North America. From this date on, Parsons Energy & Chemicals (successor to Parsons Power) assisted PFBC-EET in several evaluations of different multi-module P200 configurations. The last such endeavor was a proposed repowering of an eastern U.S. utility power station. This last evaluation incorporated 30% carbon capture by integrating the Benfield process with one of the three (3) P200 PFBC modules in each group of two (2) such groups (2 x 3 x P200 modules repowering two existing steam turbine generators).

Finally, Worley is assisting CONSOL and PFBC-EET in the present DOE-sponsored Coal Based Power Plants of the Future effort.

General Electric: Worley has been working with GE for over 75 years in the design of fossil and gas turbine power plants. Worley has performed engineering services for GE directly and has also specified GE equipment on a large number of power plants over this timespan.

Baker Hughes: Worley has worked with Baker Hughes (still associated with General Electric) as Baker Hughes is the successor organization to GE Oil & Gas. This latter entity is the home of the smaller lines of GE steam and gas turbine equipment. The relationship is similar to that prevailing with the GE unit above, which deals with utility-scale machines.

Siemens: In a manner similar to GE as noted above, Worley has worked with Siemens and one of its constituent parts, the former Westinghouse Electric Corporation, on a long time series of electric generating plants involving fossil and gas turbine-related technologies.

Mott Corporation: Worley's relationship with Mott has been one of specifying filters for various client applications. Previous experience with Mott has indicated a readiness to supply a complete system.

Pall: Worley's relationship with Pall has been one of specifying filters for various client applications. Previous experience with Pall has indicated that they are willing to supply essential filter elements but do not seem interested in supplying a complete filter system.

Amine-Based CO_2 Capture System Vendors: Worley's relationship with the amine system vendors is more pronounced in the hydrocarbon and chemical industries. Worley has worked with the various vendors (Shell Oil (CANSOLV), Fluor Corp, and others) by specifying CO_2 capture systems and other work in the petrochemical industry. Worley worked with a major vendor for a large utility on a project that was ultimately cancelled. The project was active in the 2010-2011 timeframe.

Farnham and Pfile: Worley has worked with Farnham & Pfile in previous PFBC studies.

Nooter/Eriksen: Worley has worked with Nooter/Eriksen in previous PFBC studies, as well as other power projects involving HRSGs and pressure vessels.

Dürr MEGTEC: Worley has worked with the predecessor of Dürr Megtec, Babcock & Wilcox MEGTEC, on previous projects for air quality control systems, such as caustic scrubbers as needed in the current PFBC project.

6.6.3 The A&E Firm Access to Equipment Information

The A&E firm (Worley Group, Inc.) has adequate access to information on the equipment included in the proposed concept. Worley and Nooter/Eriksen are working closely with PFBC-EET and have complete access to their store of data, drawings, etc., for the P200 commercial module. Information from other suppliers (including those listed in Section 6.6.2) has been requested in key equipment specifications that have been released to solicit conceptual design drawings, budgetary quotes, and other technical information for this stage of evaluation (pre-FEED).

7 Business Case

This business case presents the following:

- Market scenario
- Domestic and/or international market applicability
- Market advantage of the concept
- Estimated cost of electricity establishing the competitiveness of the concept

7.1 Market Scenario

The overall objective of this project is to design an advanced coal-fueled power plant that can be commercially viable in the U.S. power generation market of the future and has the potential to be demonstrated in the next 5-10 years and begin achieving market penetration by 2030. Unlike the current U.S. coal fleet, which was largely installed to provide baseload generation at a time when coal enjoyed a wide cost advantage over competing fuels and when advances in natural gas combined cycle, wind, and solar technologies had not yet materialized, the future U.S. coal fleet must be designed to operate in a much more competitive and dynamic power generation landscape. For example, during 2005-2008, the years leading up to the last wave of new coal-fired capacity additions in the U.S., the average cost of coal delivered to U.S. power plants ($1.77/MMBtu) was $6.05/MMBtu lower than the average cost of natural gas delivered to U.S. power plants ($7.82/MMBtu), and wind and solar accounted for less than 1% of total U.S. power generation. By 2019, the spread between delivered coal and natural gas prices ($2.02 and $2.88/MMBtu, respectively) had narrowed to just $0.86/MMBtu, and renewables penetration had increased to 9% [**2**].

The advanced PFBC power plant proposed in this study is anticipated to begin commercial operations circa 2027, as described in the Project Execution Plan presentation, and to operate for 30+ years. In its 2020 Annual Energy Outlook (AEO) [**31**], the U.S. Energy Information Administration (EIA) provided projections for the U.S. energy and electric power markets through 2050. These projections, while subject to substantial uncertainty due to unknown future changes in regulatory, economic, technology, and other key drivers, nevertheless provide an unbiased, illustrative market scenario for purposes of considering our proposed Coal FIRST project during the initial 20+ years of its operating life (i.e., 2027-2050).

Exhibit 7-1 summarizes the AEO Reference Case projections for average delivered power plant fuel prices (both coal and natural gas), average annual electric power sector generation, and the average makeup of the electric power sector generation mix, for the total U.S. in 2027-2050. Data are also presented for the 2005-2008 and 2019 periods referenced above for comparison. As shown, EIA projects that during 2027-2050, the spread between delivered coal and natural gas prices to U.S. power plants ($1.95/MMBtu and $3.79/MMBtu, respectively, in 2019 dollars) will average $1.84/MMBtu, which is marginally wider than the fuel price spread observed recently in 2019 but still far less than the fuel price spread in 2005-2008 that compelled decision-making for the last wave of coal-fired power plant buildouts in the U.S.

In this future market scenario, the AEO Reference Case forecasts zero new coal-fired power plant capacity additions in the U.S. through 2050. The reasons are primarily economic. Even in the absence of a price on CO_2 emissions, at the U.S. average delivered coal and natural gas prices predicted in the AEO Reference Case, a typical new advanced natural gas combined cycle (NGCC) power plant without carbon dioxide capture would be expected to dispatch with a delivered fuel + variable operating and maintenance (O&M) cost of $25.84/MWh (assuming a 6,363 Btu/kWh HHV heat rate and $1.71/MWh variable O&M cost [**16**]) and could be built for a total overnight cost of <$1,000/kWe (2018$) [**4, 16**]. By comparison, a new advanced supercritical pulverized coal-fired (PC) power plant would be expected to dispatch at a slightly lower delivered fuel + variable O&M cost of ~$24.28/MWh (assuming an 8,473 Btu/kWh HHV heat rate and $7.72/MWh variable cost [**16**]), but with a capital cost that is about 2.5 to 4 times greater than that of the NGCC plant [**4, 16**]. The modest advantage in O&M costs for the coal plant is insufficient to outweigh the large disparity in capital costs vs. the NGCC plant, posing a barrier to market entry for the coal plant. By contrast, if the same comparison is run using the coal and natural gas prices from the 2005-2008 market scenario, the dispatch costs (fuel + variable O&M) for the PC plant are about 56% ($28.77/MWh) lower than those for the NGCC plant (Exhibit 7-1), making the difference in capital cost much easier to bear. This highlights the need for advanced coal-fueled power generation technologies that can overcome this barrier – via reduced capital cost, reduced O&M cost, or both – and enable continued utilization of the nation's valuable coal reserve base to produce affordable, reliable, resilient electricity.

Exhibit 7-1. Market Scenario Data

	2005-2008 US Average (Actual)[1]	**2019 US Average (Actual)[1]**	**2027-2050 US Average (Projection)[2]**	**2027-2050 PJM West Average (Projection)[2]**
Delivered Coal Price ($/mmBtu)[4]	1.77	2.02	1.95[3]	2.17[3]
Delivered Natural Gas Price ($/mmBtu)[4]	7.82	2.88	3.79[3]	3.35[3]
Total Annual Generation (billion kWh/y)[4]	3947	3956	4491	382
% Coal	50%	24%	16%	26%
% Gas	19%	37%	36%	57%
% Nuclear	20%	20%	15%	5%
% Wind + Solar	1%	9%	25%	10%
% Other	10%	10%	8%	2%
New PC Fuel+Variable O&M ($/MWh)[5]	22.70	24.84	24.28	26.08
New NGCC Fuel+Variable O&M ($/MWh)[6]	51.47	20.04	25.84	23.03

1. Source: [**2**]
2. Source: [**31**]
3. In 2019 US dollars
4. For the electric power sector
5. Assuming an 8,473 Btu/kWh HHV heat rate and $7.72/MWh variable cost [**16**]
6. Assuming a 6,363 Btu/kWh HHV heat rate and $1.71/MWh variable O&M cost [**16**]

Exhibit 7-1 also presents the AEO Reference Case projections for the PJM West region, in which our proposed Business Case PFBC power plant in southwestern Pennsylvania (or northern West Virginia) would be located. This region is in the heart of the Marcellus Shale play, one of the most prolific natural gas producing regions in the United States, and as such the spread between coal and natural gas prices in this region is expected to be somewhat narrower than the U.S. average during the 2027-2050 market scenario period, giving conventional NGCC plants a continued dispatch cost advantage over conventional PC plants (similar to what we have observed recently on a nationwide basis in 2019). (It should also be noted that the difference in projected delivered coal prices between the U.S. and PJM West regions relates to differences in assumed coal types and associated mining and transportation costs, with the PJM West expected to be predominantly served by Northern Appalachian coals produced from deep mines, and the U.S. average reflecting a blend of coal types and mining and transportation methods from all major thermal coal producing regions of the country). However, another key distinction between the PJM West region and the broader U.S. is the significantly lower projected renewables penetration in PJM West during the 2027-2050 period. For the U.S. as a whole, solar and wind energy are forecasted to account for roughly 25% of annual electric power sector generation on average during 2027-2050, or 1,104 billion kWh/y - almost triple their 2019 generation of 371 billion kWh. In contrast, because of more limited renewable resource availability, wind and solar are projected to account for just 10% of annual generation on average in PJM West during the 2027-2050 period, which is roughly on par with the amount of total wind and solar penetration in the U.S. today. As such, while operating flexibility will be important in both regions to accommodate intermittent generation from renewables, we expect that there will be substantially more opportunity in PJM West for a coal- or natural gas-fueled power plant with attractive dispatch economics to operate as a baseloaded unit with a high capacity factor.

Finally, it remains uncertain what constraints and/or prices on CO_2 emissions will be in effect throughout the entire duration of the operating life of our proposed coal-fueled power plant of the future. However, as described in the Project Execution Plan (Appendix A), the plant will have an opportunity to qualify for tax credits available under Section 45Q of the U.S. tax code for the first 12 years of its service life, provided that it begins construction prior to January 1, 2024, and we believe it is likely that similar credits or other mechanisms will remain available after that period to continue to incentivize deployment of low-carbon energy sources by placing a value on CO_2 emissions reductions to help offset the costs of carbon dioxide capture, utilization, and storage (CCUS). Under Section 45Q, all CO_2 that is verified as sequestered in geologic formations qualifies for \$50/ton of CO_2 in tax credits, and all CO_2 that is verified as used and sequestered for enhanced oil recovery (EOR) or otherwise beneficially used qualifies for \$35/ton of CO_2 in tax credits. As such, and in the absence of more definitive information beyond the 12-year period covered by 45Q, we have assumed that these same values will apply throughout the operating life of our Coal FIRST plant. Additionally, given the location of our Business Case plant in southwestern Pennsylvania (or northern West Virginia), and the relative uncertainty associated with offtake for EOR (which is market dependent) vs. geologic storage (which is much more controllable once the necessary permits have been obtained), we have assumed that all CO_2 captured by the plant is injected for storage in a deep geologic formation in the vicinity of the plant. DOE-NETL has estimated the costs for CO_2 transport and storage to be approximately \$10/tonne (\$9/ton) of CO_2 in the midwestern U.S. [**16**]. As such, all of the costs presented in this report assume that any captured CO_2 is credited at a value of \$41/ton (\$50/ton value of 45Q credit less \$9/ton for transport and storage) at the power plant gate.

Against this market backdrop, we believe that the commercial viability of any new coal-fueled power generation technology depends strongly upon the following attributes: (1) excellent environmental performance, including very low air, water, and waste emissions (to promote public acceptance and alleviate permitting concerns), (2) lower capital cost relative to other coal technologies (to help narrow the gap between coal and natural gas capex), (3) significantly lower O&M cost relative to natural gas (to help offset the remaining capital cost gap vs. natural gas and ensure that the coal plant is favorably positioned on the dispatch curve across a broad range of natural gas price scenarios), (4) operating flexibility to cycle in a power grid that includes a meaningful share of intermittent renewables (to maximize profitability), and (5) ability to incorporate carbon capture with moderate cost and energy penalties relative to other coal and gas generation technologies (to keep coal as a competitive dispatchable generating resource in a carbon-constrained scenario). These are generally consistent with or enabled by the traits targeted under DOE's Coal-Based Power Plants of the Future program (e.g., high efficiency, modular construction, near-zero emissions, CO_2 capture capability, high ramp rates and turndown capability, minimized water consumption, integration with energy storage and plant value streams), although our view is that the overall cost competitiveness of the plant (capital and O&M, including the ability of the plant to dispatch at a high capacity factor to offset the inevitably larger capital costs associated with coal vs. other candidate electric power generation technologies) is more important than any single technical performance target. In addition, the technology must have a relatively fast timeline to commercialization, so that new plants can be brought online in time to enable a smooth transition from the existing coal fleet without compromising the sustainability of the coal supply chain.

7.2 Domestic and/or International Market Applicability

Pressurized fluidized bed combustion (PFBC) provides a technology platform that is well-suited to meet this combination of attributes. A base version of this technology has already been commercialized, with units currently operated at three locations worldwide: (1) Stockholm, Sweden (135 MWe, 2 x P200, subcritical, 1991 start-up), (2) Cottbus, Germany (80 MWe, 1 x P200, subcritical, 1999 start-up), and (3) Karita, Japan (360 MWe, 1 x P800, supercritical, 2001 start-up). These installations provide proof of certain key features of the technology, including high efficiency (the Karita plant achieved 42.3% net HHV efficiency using a supercritical steam cycle), low emissions (the Vartan plant in Stockholm achieved 98% sulfur capture without a scrubber and 0.05 lb/MMBtu NOx emissions using only SNCR), byproduct reuse (ash from the Karita PFBC is used as aggregate for concrete manufacture), and modular construction. Several of these installations are combined heat and power plants, and as shown in Exhibit 6-2, the existing plants have demonstrated excellent fuel flexibility by firing a wide variety of coal types ranging from lignite to bituminous and anthracite as well as opportunity fuels.

The concept proposed here builds upon the base PFBC platform to create an advanced, state-of-the-art coal-fueled power generation system. Novel aspects of this advanced PFBC technology include: (1) integration of the smaller P200 modules with a supercritical steam cycle to maximize modular construction while maintaining high efficiency, (2) optimizing the steam cycle, turbomachine, and heat integration, and taking advantage of advances in materials and digital control technologies to realize improvements in operating flexibility and efficiency, (3) integrating carbon dioxide capture, and (4) incorporating a new purpose-designed gas turbomachine to replace the earlier ABB (Alstom, Siemens) GT35P machine.

In addition, the Business Case being pursued to introduce a new advanced supercritical PFBC power plant with CO_2 capture into the U.S. domestic power generation market arises from taking advantage of its tremendous fuel flexibility to use fine, wet waste coal and wet biomass as fuel sources. The waste coal, which is a byproduct of the coal preparation process, can be obtained either by reclaiming tailings from existing slurry impoundments or by diverting the thickener underflow stream (before it is sent for disposal) from actively operating coal preparation plants. It can be transported via pipeline and requires only simple mechanical dewatering to form a paste that can be pumped into the PFBC combustor. There is broad availability of this material, with an estimated 33+ million tons produced each year by currently operating prep plants located in 13 coal-producing states, and hundreds of millions of tons housed in existing slurry impoundments, as illustrated in Exhibit 7-2. CONSOL's

Bailey Central Preparation Plant in Greene County, PA, alone produces close to 3 million tons/year of fine coal refuse with a higher heating value of ~7,000-8,000 Btu/lb (dry basis), which is

Exhibit 7-2. Current US Fine Coal Waste Production Estimate*

State	Raw Feed Capacity (tph)	tph @ 7.5% - 100 M	tph @ 50% Yield	tpy @ 6000 operating hours
Alabama	7,470	560	280	1,680,750
Colorado	3,500	263	131	787,500
Illinois	12,400	930	465	2,790,000
Indiana	9,925	744	372	2,233,125
Kentucky	30,125	2,259	1,130	6,778,125
Maryland	1,350	101	51	303,750
Montana	2,000	150	75	450,000
Ohio	7,960	597	299	1,791,000
Pennsylvania	16,850	1,264	632	3,791,250
Tennessee	450	34	17	101,250
Utah	1,100	83	41	247,500
Virginia	10,400	780	390	2,340,000
West Virginia	46,375	3,478	1,739	10,434,375
Total	149,905	11,243	5,621	33,728,625
		Could range from 5-10%	Could range from 0-100%**	24 h/d x 5 d/wk x 50 wk/y
* Based on US Prep Plant Census 2018 (Coal Age, October 2018)				
** Note that many plant dewater fines and combine with coarse refuse				

more than sufficient to fuel a 300 MW net advanced PFBC power plant with CO_2 capture. This slurry is currently disposed of at a cost. As a result, it has the potential to provide a low- or zero-cost fuel source if it is instead used to fuel an advanced PFBC power plant located in close proximity to the coal preparation plant. Doing so also eliminates an environmental liability (slurry impoundments) associated with the upstream coal production process, improving the sustainability of the overall coal supply chain. The biomass, when co-fed with the waste fuel at a modest rate (5-10% of the total fuel input) and coupled with reasonably deep CO_2 capture (~97%), provides an opportunity for the overall power plant to achieve CO_2-negative operation through BECCS ("Bioenergy with Carbon Capture and Storage"), as the biomass provides a means for CO_2 to be removed from the atmosphere for permanent geologic storage. The PFBC provides an advantage in enabling the biomass to be fired without pre-drying, resulting in a streamlined supply chain and lower cost. As described in the Project Execution Plan (Appendix A), the use of waste coal and biomass are also expected to enable the power plant to qualify for various economic incentives at the state and federal levels. In light of these opportunities, the relative abundance of potential waste coal sources in the United States, and the probable need for low-carbon dispatchable sources of electricity generation, it is anticipated that a successful demonstration of the advanced supercritical PFBC technology with CO_2 capture at the Bailey Central Preparation Plant could lead to additional market opportunities for the technology in the U.S.

Moreover, given the existing international operating experience with the base PFBC technology platform, as described above and more fully covered in Section 6.1.1 and Exhibit 6-2, the project team believes that a successful demonstration in the U.S. as part of the Coal FIRST project would likely trigger global interest in similar applications of the technology as well. Coal remains the second-largest source of primary energy in the world, behind only oil, accounting for ~27% of the world's primary energy consumption in 2018, and for a much greater share (55-60%) in highly-populated, developing countries such as China and India where coal use continues to grow [**32**]. Going forward, these developing countries are expected to have a need for low-emission, high-efficiency, readily constructible, flexible coal-fueled power plants, as they place a higher priority on environmental goals, incorporate more intermittent renewables in their generation mix, and continue to rely on coal as the lowest-cost, most readily accessible dispatchable fuel to support their growing electricity needs. China is the largest producer of coal in the world, and India is among the top five largest producers [**32**], so we expect ample international opportunities for PFBC to take advantage of waste coal as an opportunity fuel as well.

7.3 Market Advantage of the Concept

The market advantage of advanced PFBC relative to other coal-fueled generating technologies, then, stems from its unique ability to respond to all five key attributes of new coal-fueled power plants identified in Section 7.1 above, while providing a rapid path forward for commercialization. Specifically:

1. Excellent Environmental Performance – The advanced PFBC is able to achieve very low NOx (<0.05 lb/MMBtu) and SO_2 (≥90% removal) emission rates by simply incorporating selective non-catalytic reduction and limestone injection at pressure within the PFBC vessel itself. After incorporation of an SO_2 polishing step before the CO_2 capture process, the SO_2 emissions will be <0.009 lb/MMBtu or ≤0.08 lb/MWh (gross), even for the relatively high-sulfur fuels under consideration (up to ~4.3 lb SO_2/mmBtu fuel sulfur content). As mentioned above, the PFBC can also significantly improve the environmental footprint of the upstream coal mining process if it uses fine, wet waste coal as a fuel source, and it produces a dry solid byproduct (ash) having potential commercial applications.

2. Low Capital Cost – The advanced PFBC in carbon capture-ready configuration can achieve >42% net HHV efficiency at normal supercritical steam cycle conditions, avoiding the capital expense associated with the exotic materials and thicker walls needed for higher steam temperatures and pressures. This fundamental efficiency advantage also translates to higher net efficiency vs. conventional coal plant designs when CO_2 capture is installed. In addition, significant capital savings are realized because NOx and SO_2 emission targets can be achieved without the need for an SCR or full-size FGD. Finally, the P200 is designed for modular construction and replication based on a single, standardized design, enabling further capital cost savings.
3. Low O&M Cost – By fully or partially firing fine, wet waste coal at low-to-zero fuel cost, the advanced PFBC can achieve dramatically lower fuel costs than competing coal and natural gas plants. This is especially meaningful for the commercial competitiveness of the technology, as fuel cost (mine + transportation) often accounts for the majority (~2/3) of a typical pulverized coal plant's total O&M cost, and for an even greater amount (>80%) of its variable (dispatch) cost [**6**]. The low O&M cost achieved by an advanced PFBC plant firing waste coal is expected to result in very high capacity factors and minimal need for cycling, improving its overall economic performance.
4. Operating Flexibility – The advanced PFBC plant includes four separate P200 modules that can be run in various combinations to cover a wide range of loads. Each P200 module includes a bed reinjection vessel to provide further load-following capability, enabling an operating range from <20% to 100%. A 4%/minute ramp rate can be achieved using a combination of coal-based energy and natural gas co-firing, and hot start-ups can be achieved in less than 2 hours when firing coal (or even shorter periods when co-firing natural gas).
5. Ability to Cost-Effectively Incorporate Carbon Capture – The PFBC plant is well-suited for integration with state-of-the-art post-combustion (e.g., amine-based) CO_2 capture systems, and the greater inherent efficiency of the supercritical PFBC plant vs. a supercritical PC plant results in a higher net plant efficiency once CO_2 capture is installed. In addition, the fuel flexibility afforded by the advanced PFBC boiler provides an opportunity to easily co-fire biomass with coal to achieve carbon-neutral or negative operation. Finally, although CO_2 capture is carried out at atmospheric pressure (downstream of the gas turbomachine) in the designs presented here, as this configuration yields the best overall cost and efficiency performance for current commercially-available CO_2 capture technologies, future advances may allow for reconsideration of carrying out CO_2 capture at elevated pressure (~11 bar) ahead of the turbomachine, where the higher CO_2 partial pressure and smaller gas volume could provide performance and cost benefits for certain emerging CO_2 capture technologies.

The timeline to commercialization for advanced PFBC is expected to be an advantage relative to other advanced coal technologies because (1) the core P200 module has already been designed and commercially proven and (2) the main technology gaps associated with the advanced PFBC plant, including integration of multiple P200 modules with a supercritical steam cycle, development of a suitable turbomachine for integration with the PFBC gas path, and integration of carbon capture, are considered to be well within the capability of OEMs using existing materials and technology platforms. The concept of firing a PFBC with fine, wet waste coal (thickener underflow) was demonstrated in a 1 MWt pilot unit at CONSOL's former Research & Development facility in South Park, PA, both without CO_2 capture (in 2006-2007) and with potassium carbonate-based CO_2 capture (in 2009-2010), providing evidence of its feasibility. We believe that the first-generation advanced PFBC plant would be technically ready for commercial-scale (nominally 300 MWnet) demonstration in the mid-2020s, with construction targeted to begin in 2023 and commissioning by the end of 2027. This plant would be equipped with a supercritical steam cycle that enables it to achieve >42%

efficiency in CO_2 capture-ready configuration, with an amine-based CO_2 capture system that enables it to achieve 97% CO_2 removal for geologic storage or beneficial use, and with the capability to fire wet fine waste coal and co-fire biomass to achieve attractive dispatch economics and carbon-neutral or negative operation. We are evaluating CONSOL's Bailey Central Preparation Plant as the source of fuel (fine, wet waste coal) and potential location for this demonstration plant. We also have identified a number of potential design initiatives, including operation at 16 bar (enabling a reduction in the number of separate PFBC modules and certain ancillary equipment required for the plant), delivery of pre-fabricated PFBC modules (enabling a reduction in capital costs), alternative fuel processing options (enabling a reduction in fuel ash content and corresponding improvement in net plant efficiency), and various other trade-off, optimization, and value engineering studies, that have the potential to significantly improve the economics and performance of the first-generation advanced PFBC plant beyond the results developed in this pre-FEED phase of the project. Estimates of the potential impacts of these initiatives, which will be pursued during the first seven months of the FEED study, are quantified below.

7.4 Estimated Cost of Electricity Establishing the Competitiveness of the Concept

A summary of the estimated COE for the advanced PFBC power plant is presented in Exhibit 7-3, based on work performed during the pre-FEED study. Estimates are presented for the Base Case plant firing Illinois No. 6 coal in carbon capture-ready configuration (Case 1A), the Base Case plant firing Illinois No. 6 coal with 97% CO_2 capture via an amine-based system (Case 1B), the Business Case plant in southwestern Pennsylvania firing wet, fine waste coal with 97% CO_2 capture via an amine-based system (Case 2B), and this same Business Case plant firing 95% waste coal and co-firing 5% biomass (Case 2C). As discussed earlier in this report, the design basis for the Base Case plant (Cases 1A and 1B) was largely developed to mirror that set forth in DOE's "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity" [**16**], as stipulated in the Performance Work Statement for our Coal FIRST project, and represents a generic greenfield project located in the Midwestern U.S. The design basis for the Business Case plant (Cases 2B and 2C) represents the commercial project actually envisioned to be pursued under the Coal FIRST program, and it features a first-generation advanced PFBC plant constructed on a brownfield site within the footprint of CONSOL's Bailey Central Preparation Plant that fires fine waste coal slurry (thickener underflow) delivered by pipeline from the preparation plant, captures 97% of its CO_2 emissions for geologic storage, and is equipped to co-fire locally sourced biomass to achieve carbon-neutral or negative operation. This plant is particularly advantaged because it has access to and is capable of firing zero-cost fuel; the waste coal that would be supplied to the power plant is currently disposed in slurry impoundments located in close proximity to the proposed power plant site, so the costs to pump the waste coal to the power plant would be offset by the savings associated with not pumping it for disposal. There are additional benefits associated with the avoided costs of slurry impoundment development, monitoring, and reclamation, and the related environmental liabilities, which have not been explicitly captured in the economics presented below.

Capital cost estimates for all cases are in late-2019 or early-2020 dollars and were developed by Worley Group, Inc. using project-specific vendor quotations as well as Worley's database of quotations for similar equipment and systems from other recent or ongoing projects. Costs for labor, Illinois No. 6 coal, and other consumables were adopted from the DOE Baseline Report [**16**] and/or based on approximate current market prices for the plant's location. The cost of biomass delivered to the Business Case plant was assumed to be $50/ton; this relatively low cost is enabled by local sourcing (from land owned by CONSOL as well as a network of local landowners) and by the

PFBC's ability to accept wet (as opposed to dried) biomass. For purposes of this estimate, and based on the success achieved with beneficially utilizing PFBC ash produced at the Karita plant, it was assumed that PFBC bed and fly ash are provided for beneficial reuse at zero net cost/benefit. Also, as discussed in Section 7.1, we have assumed that any captured CO_2 (in both the Base and Business Cases) is sent for geologic storage and credited at a value of $41/ton at the power plant gate. Otherwise, the cost estimating methodology used here is largely consistent with that used in the DOE Baseline Report [**16**] and Quality Guidelines for Energy System Studies (QGESS) [**1**]. The cost of electricity (COE) values presented in Exhibit 7-3 are based on an 85% capacity factor (see discussion below), 1.154 TASC multiplier, and 0.0707 fixed charge rate (FCR), consistent with the DOE QGESS.

Exhibit 7-3. Cost of Electricity Projections for Advanced PFBC Plant Cases from Pre-FEED Study

	Case 1A: IL No. 6 coal capture-ready	Case 1B: IL No. 6 coal 97% capture	Case 2B: waste coal 97% capture	Case 2C: 95% waste coal / 5% biomass 97% capture
Net Plant Capacity (MW)	404	308	280	279
Net HHV efficiency	42.5%	32.4%	30.3%	30.2%
CO_2 Emissions (lb/MWh)[1]	1,542	54	60	(47)
Total Overnight Cost ($/kW)	$4,084	$6,424	$7,610	$7,621
COE Breakdown				
Capital ($/MWh)	$44.75	$70.39	$83.39	$83.50
Fixed O&M ($/MWh)	$15.44	$24.14	$29.22	$29.24
Coal ($/MWh)	$17.88	$23.48	--	--
Biomass ($/MWh)	--	--	--	$2.19
CO_2 Credit ($/MWh)	--	($42.72)	($47.77)	($47.81)
Other Variable O&M ($/MWh)	$10.48	$17.30	$18.15	$18.16
TOTAL COE ($/MWh)	$88.55	$92.59	$82.99	$85.29

1. Based on gross power; Case 2C includes biomass credit

As shown in Exhibit 7-3, the fuel flexibility of the PFBC plant provides an opportunity to use fine, wet waste coal to achieve dispatch costs that are expected to be substantially lower than those of competing coal and natural gas-based plants. As illustrated by Cases 2B and 2C, a near-zero emissions PFBC plant firing waste coal is expected to achieve total fuel plus variable O&M costs of ~$18-21/MWh, substantially better than the $23-26/MWh range for new supercritical coal and natural gas combined cycle plants without CO_2 capture cited in the 2027-2030 market scenario above. After applying the $41/ton credit associated with CO_2 capture, the effective fuel plus variable O&M cost for the Business Case PFBC plant is actually less than zero, which should allow it to dispatch as a baseload unit at a very high capacity factor, improving its economic viability. In addition, with this CO_2 credit applied, the COE for the advanced PFBC plant with 97% CO_2 capture is actually expected to be slightly lower than the COE for a capture-ready plant. Adding biomass co-firing to the Business Case PFBC has a very minor impact (<$2.50/MWh) on its COE, while allowing it to achieve carbon-negative operation.

As with essentially all coal-based technologies, capital costs are expected to present the greatest commercial hurdle for the advanced PFBC technology. The capital cost estimates developed during the pre-FEED study increased meaningfully compared to those developed in the conceptual design study, owing to several factors, including: (1) increases resulting from more detailed estimates developed for several key plant components, such as the PFBC vessel itself and the coal and sorbent prep and feed system; (2) increases resulting from more detailed definition of certain balance of plant areas, such as water treatment and electrical systems; and (3) increases resulting from use of labor rates specific to the planned Business Case site (i.e., Pittsburgh, PA, region). It is also important to recognize that in keeping with the objectives of the Coal FIRST program, the use of multiple smaller, modular plant components as opposed to a single, larger component reduces the ability to take advantage of economies of scale and naturally increases capital cost (in exchange for improved flexibility and reliability). The project team recognizes the importance of capital costs for the overall viability of the project and will focus on capital cost reductions for the Business Case plant as a key element of the Phase 3 FEED study.

As described above, while concluding the current Phase 2 pre-FEED study, the project team identified several high-potential opportunities that show promise for significantly improving the capital cost of the Business Case plant, as well as its overall technical and cost performance. These opportunities, which were described more fully in Section 5.2, are summarized in Exhibit 7-4 below. All of these opportunities will be fully vetted during the first seven months of the FEED study (as part of the initial design studies task) and incorporated into the plans for the Business Case plant where possible. (For purposes of this initial scoping estimate, no specific opportunities were quantified for the blank cells in the table below. However, it is possible that modest additional opportunities could exist in some of these areas. For example, CO_2 capture system optimization, reduction in the size of the ZLD, value engineering, and/or redesign of the PFBC vessel could potentially lead to efficiency improvements and corresponding increases in net capacity, in addition to the indicated capital cost reductions).

Exhibit 7-4. Cost and Performance Improvement Initiatives for Phase 3 FEED Study

Initiative	Estimated Capital Cost Reduction ($MM)	Potential Efficiency Improvement (Percentage Points)	Potential Net Capacity Increase (MW)
Redesign PFBC for 16 bar (rather than 12 bar) operation	$100		
Direct delivery of pre-fabricated PFBC vessels	$30-50		
Pre-process waste coal to reduce ash content		≥ 2	≥ 28
Value engineering process	$45-90		
Reduce ZLD size	$5-10		
CO_2 capture system optimization, competitive bid	$10-20		
TOTAL	**$190-270**	**≥ 2**	**≥ 28**

Exhibit 7-5 illustrates how the Business Case economics change if the improvements highlighted in Exhibit 7-4 are realized. (For purposes of this illustration, data are only presented for Case 2B; however, results for Case 2C are expected to be very similar). As shown in the exhibit, if the targeted improvements can be accomplished, the waste coal-fueled plant will be able to achieve the same higher net output and efficiency that are characteristic of a plant firing higher-quality commercial coal product (as illustrated by Case 1B firing Illinois No. 6 coal), but with the benefits of substantially reduced capital cost, low-to-zero fuel cost, and the opportunity to achieve net negative CO_2 emissions (when biomass co-firing is employed). The net result, after accounting for the value of the assumed CO_2 capture credit, is a COE on the order of $56-62/MWh, which, though considerably higher than current electricity prices, must be viewed in the context of a future market scenario in which low/zero carbon emission, dispatchable, fossil fuel-derived electricity is likely to carry a substantial premium.

Exhibit 7-5. Cost of Electricity Targets After FEED Study Improvement Initiatives

	Case 2B: waste coal 97% capture LOW CAPITAL REDUCTION	Case 2B: waste coal 97% capture HIGH CAPITAL REDUCTION
Net Plant Capacity (MW)	308	308
Net HHV efficiency	32.4%	32.4%
Total Overnight Cost ($/kW)	$5,989	$5,602
Capital ($/MWh)	$65.62	$61.38
Fixed O&M ($/MWh)	$23.61	$22.38
Coal ($/MWh)	--	--
Biomass ($/MWh)	--	--
CO_2 Credit ($/MWh)	($42.68)	($42.68)
Other Variable O&M ($/MWh)	$15.43	$14.99
TOTAL COE ($/MWh)	$61.99	$56.08

At the outset of the Phase 3 FEED study, the project team plans to place top priority on achieving the improvements set forth in Exhibit 7-4 and Exhibit 7-5. A parallel effort will focus on pursuing the portfolio of economic enhancements identified in the Project Execution Plan (Appendix A), many of which are tied to unique aspects of the PFBC technology and project concept (e.g., federal and/or state incentives associated with the use of waste fuel and use of biomass; potential opportunity for behind-the-meter power sales and other integration with CONSOL's Pennsylvania Mining Complex, etc.). These hold potential to further improve the competitiveness of the project beyond what is reflected in the COE numbers presented above.

8 Project Execution Plan

The project execution plan (PEP) has been developed as a presentation, consistent with the performance work statement. The PEP is included herein as Appendix A.

The PEP describes a project timeline (schedule) that culminates in a detailed design for the project concept and includes the following topics:

- **Non-commercial component development**
- **Project financing**
- **Site selection**
- **Partnering with technology providers**
- **Permitting**
- **Detailed design**

A corresponding project schedule is presented in Appendix B.

9 Project Engineering Support Documents

In addition to the documentation required by the performance work statement, numerous engineering documents have been developed to support the project development and cost estimating efforts. The most important of these supplemental documents are included in the following appendices.

- **Appendix C: General Arrangement**
- **Appendix D: PFD**
- **Appendix E: Water Balance Diagram**
- **Appendix F: Major Process and Mechanical Equipment List**
- **Appendix G: Equipment and Motor List**
- **Appendix H: Single Line Diagram**

Appendices C, D and E have multiple engineering documents within them. A listing of these documents is included herein to aid the reader.

9.1 Content List of Appendix C: General Arrangement (GA)

The general arrangements included in Appendix C are listed below in Exhibit 9-1.

Exhibit 9-1. Content List of Appendix C: General Arrangement

Item	Drawing Number	Rev	Document Title
1	PFBC-0-DW-111-002-660	A	Conceptual Site Plan Case 1A -Illinois Coal, Midwest Site, CO_2 Capture Ready (Not Installed)
2	PFBC-0-DW-111-002-661	A	Conceptual Site Plan Case 1B -Illinois Coal, Midwest Site, CO_2 Capture Installed
3	PFBC-0-DW-111-002-662	A	Conceptual Site Plan Case 2B/2C -Waste Coal, PA Site, CO_2 Capture Installed
4	PFBC-0-DW-111-002-670	A	Conceptual Power Block Plan Case 1A -Illinois Coal, Midwest Site, CO_2 Capture Ready (Not Installed)
5	PFBC-0-DW-111-002-671	A	Conceptual Power Block Plan Case 1B -Illinois Coal, Midwest Site, CO_2 Capture Installed
6	PFBC-0-DW-111-002-672	A	Conceptual Power Block Plan Case 2B/2C -Waste Coal, PA Site, CO_2 Capture Installed

9.2 Content List of Appendix D: Process Flow Diagrams (PFD)

The PFDs for the fuel and sorbent preparation systems included in Appendix D are listed in Exhibit 9-2. These fuel and sorbent preparation flow sheets are presented in pairs: the first is for the base case (Illinois no 6), while the second is for the business case (waste fuel/biomass).

Exhibit 9-2. Content List of Appendix D: PFDs – Fuel & Sorbent Preparation

Item	Drawing Number	Rev	Document Title
1	PFBC-EET-576-FS-001	B	Fuel Preparation -Illinois No 6 (Base Case)
2	PFBC-EET-576-FS-001	B	Fuel Preparation -Waste Fuel/Biomass (Business Case)
3	PFBC-EET-576-FS-002	B	Fuel Sizing / Handling -Illinois No 6 (Base Case)
4	PFBC-EET-576-FS-002	B	Fuel Sizing / Handling -Waste Fuel/Biomass (Business Case)
5	PFBC-EET-576-FS-003	B	Sorbent Sizing Building -Illinois No 6 (Base Case)
6	PFBC-EET-576-FS-003	B	Sorbent Sizing Building-Waste Fuel/Biomass (Business Case)

The PFDs for the power plant systems included in Appendix D are listed in Exhibit 9-3. These plant PFDs are applicable to the Base and Business cases, exception where the cooling tower and condenser are not applicable to the business case as drawn..

Exhibit 9-3. Content List of Appendix D: PFDs – Plant

Item	Drawing Number	Rev	Document Title
1	PFBC-0-DW-234-305-001	A	Combustion Air System Flow Diagram
2	PFBC-0-DW-239-305-001	A	Flue Gas Path Flow Diagram
3	PFBC-0-DW-262-305-001	A	Bed Ash System Flow Diagram
4	PFBC-0-DW-441-305-011	A	Turbine Steam System: MS, HRH, CRH
5	PFBC-0-DW-445-305-001	A	Extraction Steam [HP, IP] Flow Diagram
6	PFBC-0-DW-445-305-002	A	Extraction Steam [LP] Flow Diagram
7	PFBC-0-DW-449-305-001	A	Auxiliary Boiler System Flow Diagram
8	PFBC-0-DW-461-305-001	A	Circulating Water [CT Basin] Flow Diagram
9	PFBC-0-DW-461-305-002	A	Circulating Water [Condenser Water Box] Flow Diagram
10	PFBC-0-DW-461-305-003	A	Circulating Water [Cooling Tower] Flow Diagram
11	PFBC-0-DW-464-305-001	A	Closed Cooling Water System Flow Diagram
12	PFBC-0-DW-471-305-001	A	Condensate [Condenser to DEA] Flow Diagram
13	PFBC-0-DW-471-305-002	A	Condensate [Condensate Storage Tank] Flow Diagram
14	PFBC-0-DW-479-305-001	A	Heater Drain System Flow Diagram
15	PFBC-0-DW-481-305-002	A	Backup Feedwater System Flow Diagram
16	PFBC-0-DW-481-305-013	A	Feedwater Flow Diagram
17	PFBC-0-DW-481-305-017	A	Intercooler Loop Flow Diagram
18	PFBC-0-DW-533-305-001	A	Fly Ash Removal System Flow Diagram
19	PFBC-0-DW-541-305-001	A	Ammonia Storage & Delivery Flow Diagram
20	PFBC-0-DW-543-305-001	A	Compressed Air System Flow Diagram
21	PFBC-0-DW-543-305-007	A	Combustor Depressurization System Flow Diagram
22	PFBC-0-DW-543-305-008	A	Combustor Ventilation Air System Flow Diagram
23	PFBC-0-DW-543-305-009	A	Process Air System Flow Diagram
24	PFBC-0-DW-548-305-001	A	Nitrogen Storage and Distribution System Flow Diagram
25	PFBC-0-DW-561-305-001	A	Natural Gas System Flow Diagram

The water treatment and waste water treatment PFDs included in Appendix D are listed below in Exhibit 9-4.

Exhibit 9-4. Content List of Appendix D: PFDs – Water & Waste Water Treatment

Item	Drawing Number	Rev	Document Title
1	PFBC-0-DW-511-305-020	A	Raw Water Flow Diagram
2	PFBC-0-DW-512-305-021	A	Clarifier Water Flow Diagram
3	PFBC-0-DW-512-305-022	A	Ultrafiltration System Flow Diagram
4	PFBC-0-DW-513-305-023	A	Reverse Osmosis System Flow Diagram - First Pass
5	PFBC-0-DW-513-305-024	A	Reverse Osmosis System Flow Diagram - Second Pass
6	PFBC-0-DW-513-305-025	A	Mixed Bed System Flow Diagram
7	PFBC-0-DW-513-305-026	A	Demineralized Water System Flow Diagram
8	PFBC-0-DW-511-305-027	A	Raw Water Chemical Feed Equipment Flow Diagram
9	PFBC-0-DW-512-305-028	A	Clarifier Chemical Feed Equipment Flow Diagram
10	PFBC-0-DW-513-305-029	A	RO Chemical Feed Equipment Flow Diagram
11	PFBC-0-DW-512-305-030	A	UF Accessories Flow Diagram
12	PFBC-0-DW-513-305-031	A	CIP Equipment Flow Diagram
13	PFBC-0-DW-512-305-032	A	Clarifier Sludge Equipment Flow Diagram
14	PFBC-0-DW-525-305-033	A	Service Water System Flow Diagram
15	PFBC-0-DW-515-305-034	A	Condensate Polisher Mixed Bed Vessels Flow Diagram
16	PFBC-0-DW-515-305-035	A	Condensate Polisher Regeneration Vessels Flow Diagram
17	PFBC-0-DW-515-305-036	A	Condensate Polisher Acid Regeneration Flow Diagram
18	PFBC-0-DW-515-305-037	A	Condensate Polisher Caustic Regeneration Flow Diagram
19	PFBC-0-DW-526-305-038	A	Wastewater System Flow Diagram
20	PFBC-0-DW-529-305-039	A	Zero Liquid Discharge System Flow Diagram - Sumps
21	PFBC-0-DW-529-305-040	A	Zero Liquid Discharge System Flow Diagram - Evaporator and Crystallizer Train A
22	PFBC-0-DW-529-305-041	A	Brine Crystallizer (BC) Feed Equipment Flow Diagram
23	PFBC-0-DW-529-305-042	A	Zero Liquid Discharge System - BC and FC Train B
24	PFBC-0-DW-529-305-043	A	FC and Common Chemical Feed Equipment Flow Diagram
25	PFBC-0-DW-529-305-044	A	Zero Liquid Discharge Distillate System Flow Diagram
26	PFBC-0-DW-529-305-045	A	Zero Liquid Discharge Brine System Flow Diagram
27	PFBC-0-DW-021-305-046	A	Flow Diagram - Flow Rate Sheet - All Cases

9.3 Content List of Appendix E: Water Balance Diagram

The water balances included in Appendix E are listed below in Exhibit 9-5.

Exhibit 9-5. Content List of Appendix E: Water Balances

Item	Drawing Number	Rev	Document Title
1	PFBC-0-DW-043-305-001	A	Preliminary Plant Water Balance – Case 1A Capture Ready
2	PFBC-0-DW-043-305-002	A	Preliminary Plant Water Balance – Case 1B Capture Equipped
3	PFBC-0-DW-043-305-003	A	Preliminary Plant Water Balance – Case 2B Capture Equipped

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