Advanced Pressurized Fluidized Bed Coal Combustion with Carbon Capture

Design Basis Report

Concept Area: With Carbon Capture/Carbon Capture Ready

Contract: 89243319CFE000020

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January 14, 2020

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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 level of performance from the Conceptual Design Report to round out this discussion.

1.1 Coal-Fired Power Plant Scope Description

The Advanced PFBC project team is currently considering an alternate configuration utilizing an amine-based CO_2 capture system instead of the UOP Benfield capture system utilized in the Phase 1 work. The plant description presented in this background section will remain based on the Benfield configuration. Changing the CO_2 capture system from the Benfield to an amine-based system will have a significant impact on the overall configuration. We will briefly discuss the alternate amine-based configuration in Section 2 and will continue to evaluate the pros and cons of these options during this Pre-FEED work. Subsequent reports will be based on either the amine-based or Benfield-based configurations, but not both.

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 systems while maintaining relatively high efficiency. Carbon capture may be added to a capture-ready plant configuration without major rework or compromise to plant operating characteristics 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 will be designed to fire waste coal (which can also accommodate coal with steam coal heating value and ash characteristics).

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. For the Illinois No. 6 coal case, the CO_2 is compressed to 2215 psig. For the Business Case, with CO_2 as a potentially saleable coproduct, the CO_2 may be compressed to a lower pressure to suit alternative disposition.

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 for firing in the PFBC power generating plant.

The power generating plant includes a heat sink (evaporative cooling tower), a water treatment facility to prepare several different levels of water quality for use in the entire 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.

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 386 MWe net without CO_2 capture (but in complete capture ready configuration) and 286 MWe net with CO_2 capture operational at a rate of 97% of all CO_2 produced based on the Benfield capture system. When operating at this fully rated capacity (286 MWe) the CO_2 available for delivery at the plant boundary is ~7750 tons/day of pure CO_2 mixed with small amounts of other gases.

The annual production of electricity for delivery to the grid is 2.13 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 plant production capacity for the amine-based CO_2 system will be presented in a later report, if that configuration is selected as the preferred design moving forward.

1.3 Plant Location Consistent with NETL QGESS

As discussed above, the Base Case PFBC plant is being designed to fire Illinois No. 6 coal at a Midwestern site. A Business Case alternative will be designed to fire waste fuel available to CONSOL Energy in southwestern Pennsylvania. As such, we are presenting separate design bases for the two cases being considered: (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. 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. 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 Section 1.4 are based on the work performed during the Conceptual Design Phase, which assumed that the Benfield Process was used for CO_2 capture. These items will be updated during the current pre-FEED study to reflect the best overall plant design, which may be based on either the Benfield Process or an amine-based CO_2 capture process. As such, the design, performance and economics presented here should be viewed as preliminary and are subject to change.

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 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, and (3) integrating carbon dioxide capture via the Benfield process, which affords lower cost and energy penalties relative to conventional CO_2 capture technologies.

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 enables use of the commercially-available Benfield CO_2 capture process, which has the same working pressure as the PFBC boiler and affords lower regeneration energy requirements than typical amine scrubbing processes. 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 the carbon capture-equipped configuration, either involve the use of commercial technology (e.g., the Benfield CO_2 capture process) or are considered to be well within the capability of OEMs using existing materials and technology platforms (in the case of the turbomachine and supercritical steam cycle). 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 and incorporating 90% CO_2 capture (increased to 97% for 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, advanced materials, and/or heat exchange fluids 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 Phase. 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 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." 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.

Exhibit 1-1. Cost of Electricity Projections for Advanced PFBC Plant Cases

	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

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 coal plant [7]. 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 ºF, and main steam pipe temperature above approximately 800 ºF) 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 offered 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 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 Phase 3.
- A self-cleaning condenser will be employed for the steam cycle. The attainment of consistent 1.5 in Hg backpressure is achievable on an annual average basis for the proposed 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 ºF. Using aggressive design parameters for the heat sink, including a 5 °F terminal temperature difference for the condenser, a 7 or 8 ºF cooling tower approach, and a 17 or 18 ºF range for the circulating water system results in a condensing temperature of at least 99 or 100 ºF at 70 ºF ambient wet bulb temperature, which corresponds to a backpressure of 2.0 in Hga. Therefore, any time ambient wet bulb temperatures exceed 70 ºF, 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 Benfield capture process. This additional polishing step reduces sulfur emissions to a level

characterized by greater than 99.75% removal. A similar polishing step is also anticipated ahead of the amine capture system.

- Other low-cost solutions will be identified as applicable during the Phase II pre-FEED study.

1.6 Proposed PFBC Target Level of Performance

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. 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 (Capture Ready – Benfield Configuration)

No. of P200 Modules	Total Unit Output, MWe, net	Efficiency, HHV	Steam Cycle Parameters
1	87	36.0	1600/1025/1025
2	181	37.6	2000/1050/1050
3	279	38.6	2400/1075/1075
4	386	>40.0%	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 number of P200 modules at the stated load.

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

Percent Load	No. Modules in Operation	MWe, net	Estimated Efficiency %, net, HHV
100	4	386	>40%
80	4	309	39.2
60	3	231	38.4
40	2	155	36.6
20	1	77	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 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 Benfield technology at a 97% capture rate to one, two, three, or all four P200 PFBC modules (the Conceptual Design Report used 90%). 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 Heat/Mass Balance diagrams in the Conceptual Design Report Appendix F. This configuration is based on currently available materials of construction, design experience, and heat transfer fluid availability. The data in this column are based on the use of a new turbomachine in lieu of the GT35P, which is not configured to be compatible with CO_2 capture as designed. In all other respects, the efficiency levels in this column reflect the use of current technology materials and practices. The second efficiency column ("Advanced State-of-the-Art") is based on resolution of Technology Gap #4 identified in the section "Technology Development Pathway Description" in the Conceptual Design 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. Resolving the "Other Gaps" identified in the "Technology Development Pathway Description" in the Conceptual Design Report can involve improvements and optimizations for the turbomachine and the regenerative heat transfer loop.

Exhibit 1-4. Efficiency with CO_2 Capture for 4 x P200 PFBC Plant (Benfield 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	>40	>44%
1	24.25	37.6	42
2	48.5	35.2	40
3	72.75	33.2	38
4	97.0	30.4	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. Predicted emissions values may vary slightly for the waste coal case, but will be within the stated DOE target values. 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 addition of the caustic scrubbing polishing step is driven by the limitation of sulfur in the gas feed to the CO_2 capture process. 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

Pollutant	DOE Target, lb/MWh	DOE Target, lb/MM Btu	PFBC, lb/MM Btu	Comments
SO_2	1.00	0.117	<0.0036	Based on 90% capture in-bed, with added polishing step (required by CO_2 capture process)
NOx	0.70	0.082	0.05	Catalyst not required
PM (filterable)	0.09	0.0105	0.001 with metal filter (per Mott Inc. quote 2015)	Based on metallic filter
Hg	3×10^{-6}	0.35×10^{-6}	$<0.35 \times 10^{-6}$	Activated carbon bed in gas path (if significant Hg is elemental).
HCl	0.010	0.0012	<0.0003	Cl capture of 99.5% plus is required based on the high Ill. 6 Cl content. Achieved by high level of PM capture and two stages of gas scrubbing.

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).

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 reacted with CO_2 capture solvent and to be expanded in conventional gas expanders. The use of special expander materials and airfoil profiles is not required.

The fate of Hg and Cl requires detailed evaluation in Phase III. However, at this time, the following rationale is offered in support of our belief that these elements will be controlled to within regulatory limits. 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 metal 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 deep bed of activated carbon for capture of elemental Hg
3. The CO_2 capture absorber vessel

It is believed that the two stages of scrubbing and the activated carbon bed, in series, will capture a very high percentage of the Hg and Cl that remained in the gas after the cyclone/filter stages. The Hg concentration in the flue gas after the carbon bed is estimated at <0.001 ppb by volume. The HCl concentration in the flue gas after the sodium hydroxide SO_2 scrubber and CO_2 capture process is estimated to be in a range representing 99.5%+ removal, or <0.0003 lb/MM Btu. For both Hg and HCl, therefore, it is expected that emissions will be below the DOE specified values of 3×10^{-6} lb/MWh and 0.010 lb/MWh, respectively.

1.6.3 CO_2 Control Strategy

The CO_2 capture strategy employed for the proposed advanced PFBC plant is 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 is utilized to recover most of the thermal energy in the gas to maximize energy recovery and improve thermal efficiency. 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 herein 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 UOP Benfield process train. Each Benfield process train is provided with its own solvent regeneration equipment to release CO_2 for compression and ultimate geologic storage or beneficial use. Future applications may utilize some sharing of the regeneration components to reduce capital costs and space required.

As mentioned above, the project team is currently evaluating PFBC configurations based on both the Benfield and amine processes. Future documents will reflect the chosen process.

2 Brief Description of the PFBC Process

The project team is currently considering an alternate configuration utilizing an amine-based CO_2 capture system instead of the UOP Benfield Capture system utilized in the Conceptual Design Phase work. The PFBC process description is presented based on the Benfield configuration. However, we briefly discuss the alternate amine based configuration and provide a high-level comparison. The PFBC project team will continue to evaluate the pros and cons of these options during this Pre-FEED work. Ultimately, the project team will make a decision to pursue one of the configurations.

2.1 Preliminary Benfield and Amine Comparison

Exhibit 2-1 presents the pros and cons of PFBC configurations based on either the Benfield capture or the amine 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. • 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 with capture 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 [13], along with commercial availability of a high-temperature metallic filter, which appear to offer significant thermal performance benefits. Work is ongoing as part of the Phase 2 pre-FEED study to more thoroughly evaluate 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 presents the Benfield-based configuration and briefly discusses the amine-based configuration.

2.2.1 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 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, Benfield)

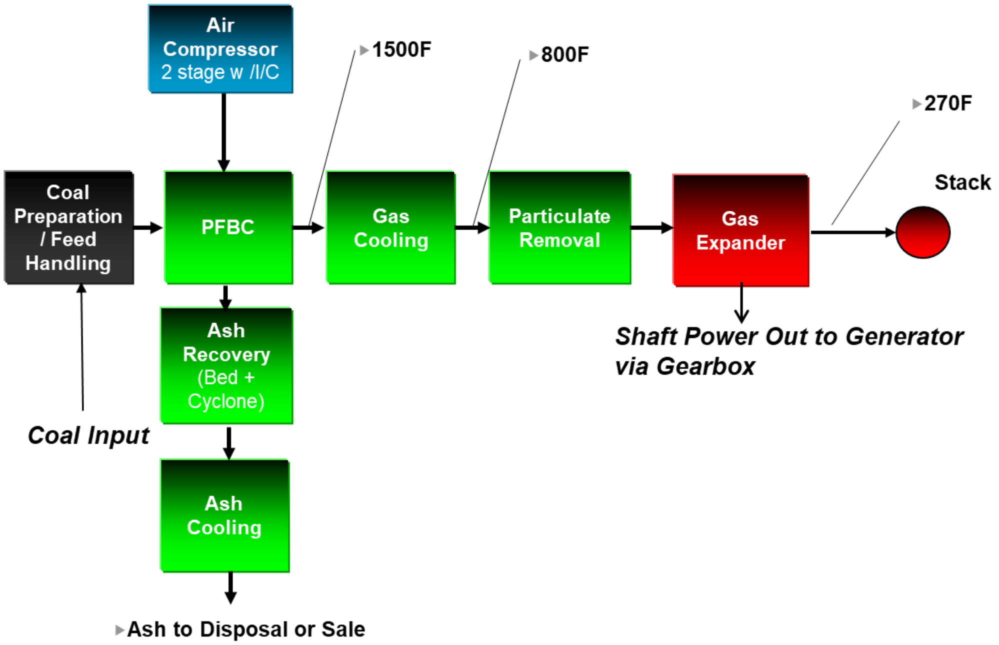


Exhibit 2-3. PFBC with CO_2 Capture (Benfield)

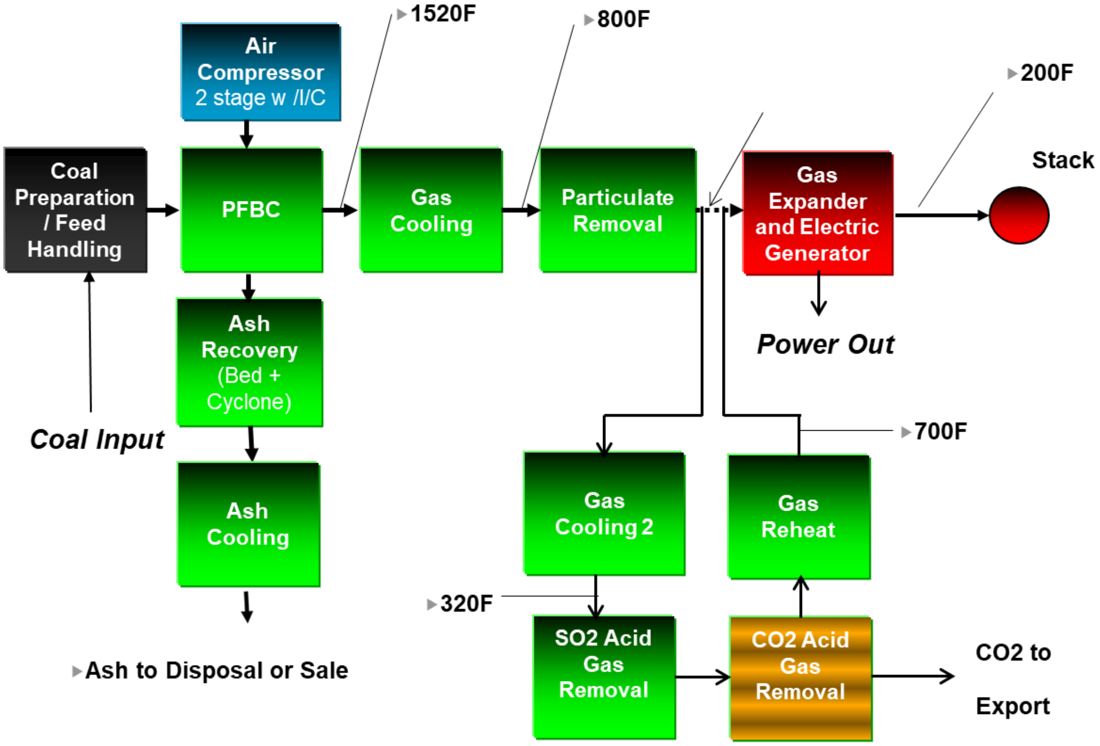
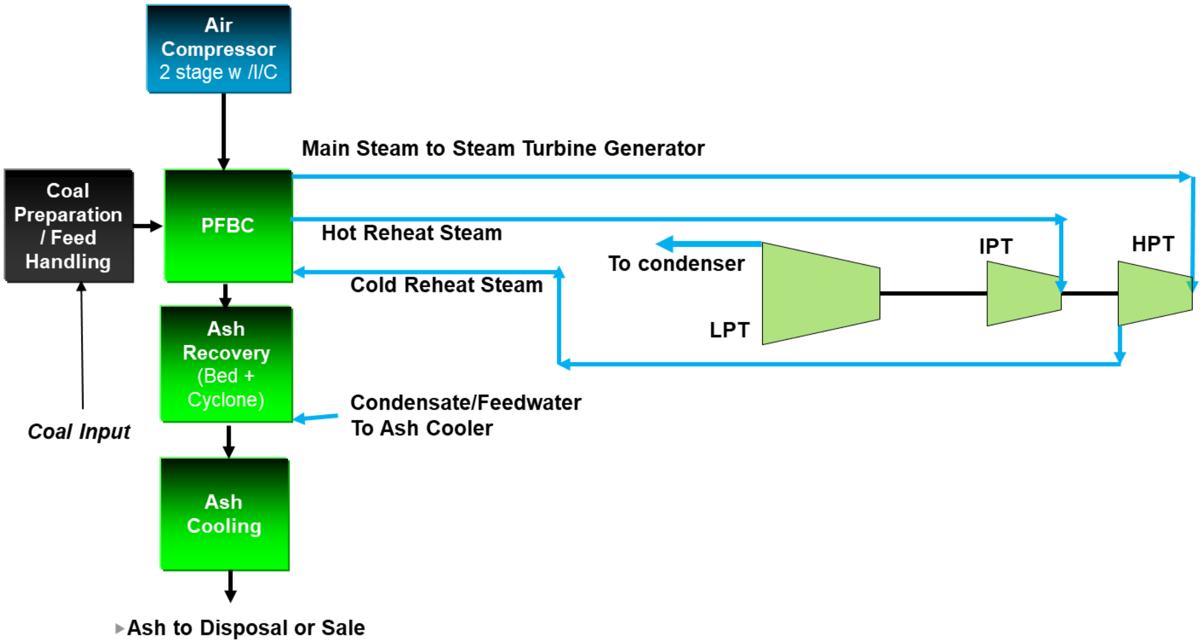


Exhibit 2-4. Steam Cycle Block Diagram Related to PFBC (simplified)



2.2.2 Amine-Based Configuration

An alternative configuration 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 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 2-5. 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 Benfield case.

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

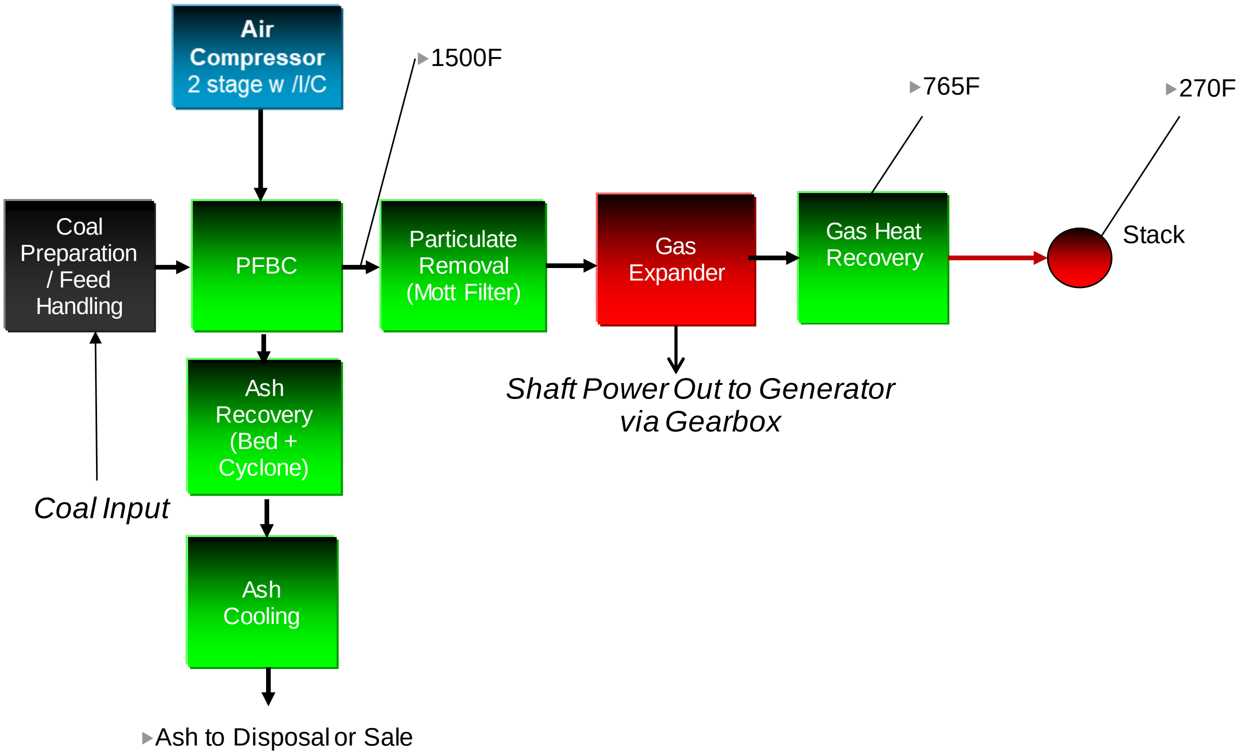
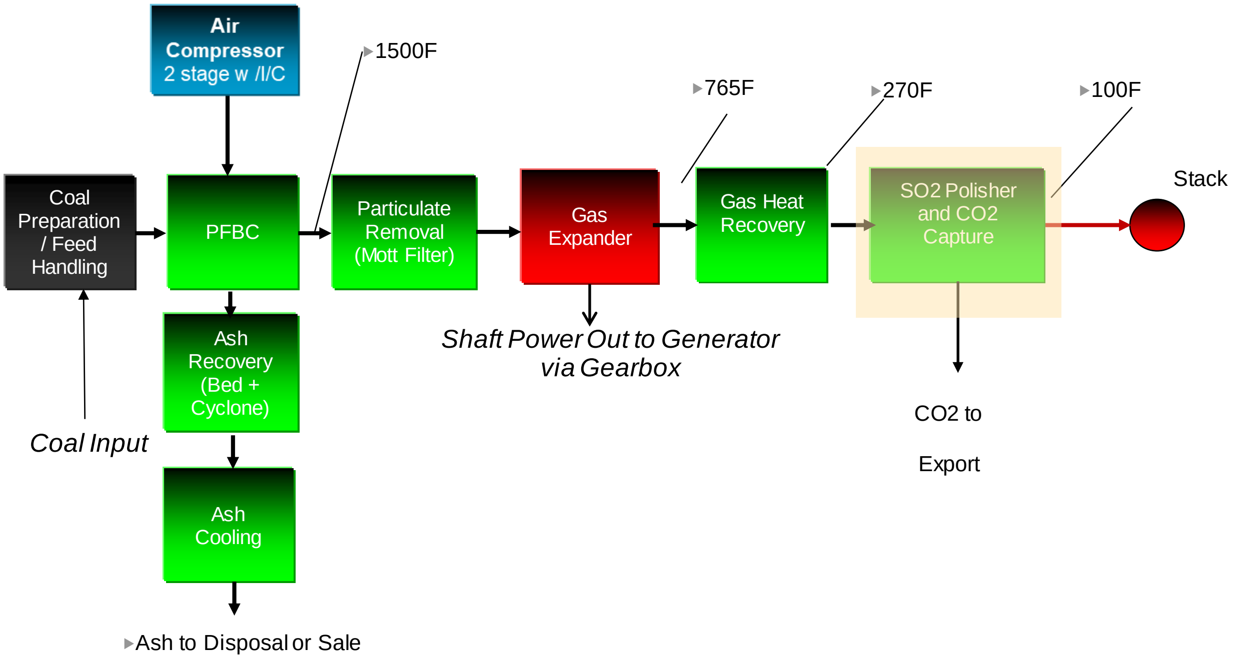


Exhibit 2-6. PFBC with CO_2 Capture (Amine-Based)



2.3 Description of Process Blocks – Benfield-Based Configuration

This section presents descriptions of each process block in the CO_2 capture 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 feed to the PFBC fluidized bed. 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 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.

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 calcium and sulfur reactions take place 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 and SO_2 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), the gas is cooled from 1500 °F to 800 °F in a heat recovery unit to generate additional steam and/or provide some of the superheat and reheat duty of the complete 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 is part of a pair of regenerative units. The gas is cooled to approximately 300 °F and then passes through a caustic scrubber (NaOH) 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.

2.3.4 CO_2 Removal, Expander 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 720 °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 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.

The steam cycle coupled to the PFBC boiler is shown in Exhibit 2-4. This steam cycle is conventional in most respects, except that some heat recovery is available from the gas path and ash flows to aid in feedwater and condensate heating for the steam cycle.

2.3.5 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 1115 °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.

2.4 Description of Process Blocks – Amine-Based Configuration

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

2.4.1 Coal Preparation and Handling

The coal preparation and handling system will be unchanged by the amine-based configuration.

2.4.2 PFBC Vessel and Boiler

The PFBC vessel and boiler are expected to be unchanged by the amine-based configuration.

2.4.3 Particulate Removal

The 1500°F gas passes through the 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 then passes to the gas expander.

2.4.4 Gas Expander and Gas Heat Recovery

The filtered gas enters the expander portion of the turbomachine to expand to approximately 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 300 °F prior to being conveyed to the SO_2 polisher.

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. 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 SO_2 polishing step and 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 and CO_2 removal steps.

2.4.6 Steam Cycle

The steam cycle is expected to be relatively unaffected by the utilization of the amine-based configuration. There will be minor changes in condensate and feedwater heating, steam extractions, and power generation levels.

2.5 Size of the Commercial Offering - Benfield-Based Configuration

The base case advanced PFBC plant includes 4 x P200 modules with a net output of ~286 MWe with 97% CO_2 capture (or ~386 MWe net without carbon capture or 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. 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 unit size increases to take advantage of different steam cycle parameters.)

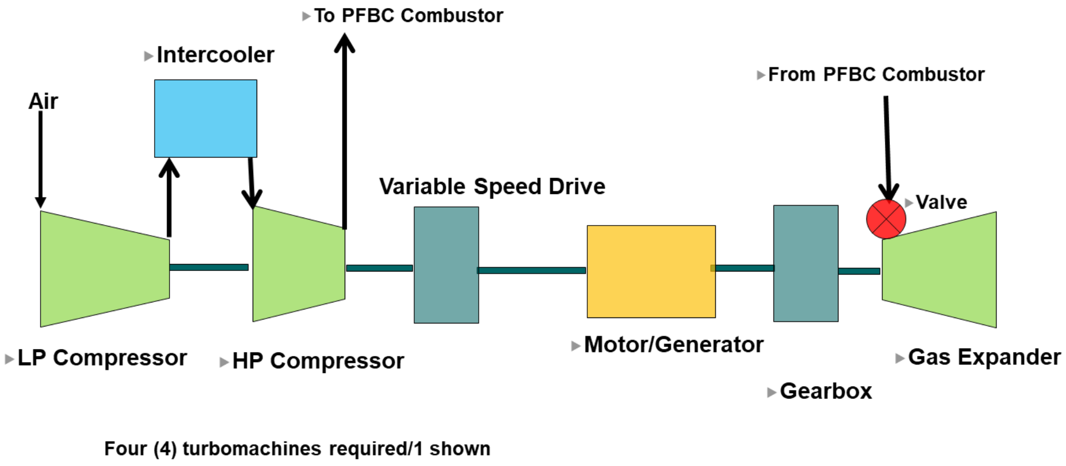
Should the amine-based carbon capture system be chosen for incorporation into the Phase II configuration, performance numbers will be developed as appropriate.

2.6 Advanced Technology Aspects – Benfield-Based Configuration

The advanced technology aspects of this offering 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 the sketch below. Discussions are in progress with General Electric 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) (note 286 MWe for 97% CO_2 Capture)



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 Advanced Technology Aspects – Amine-Based Configuration

The advanced technology aspects of this offering 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 shown schematically in the sketch above is not expected to change for the amine-based configuration. Discussions are in progress with General Electric Baker Hughes and Siemens to obtain performance and estimated costs for this new machine.

2.8 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 General Electric Baker Hughes for this gas turbomachine design.

2.9 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 the heating value for gas and steam heating to drive the interconnected cycles. Past experience and testing with the PFBC has 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.

2.10 Thermal Storage

The PFBC system contains thermal (and some chemical) 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 take up 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).

2.11 Techniques to Reduce Design, Construction, and Commissioning Schedules

2.11.1 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.

2.12 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 as a saleable byproduct, 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 Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water
Waste water	Zero Liquid Discharge (or utilization in coal preparation plant)
Coal Delivery	Rail Delivery of Typical Washed Coal Product

Ref. [**8**], Appendix B

The site for the Business Case will be taken as a generic site in the vicinity of CONSOL's operations in southwestern Pennsylvania and northern West Virginia. The site characteristics will be better defined and refined as the project progresses.

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

Parameter	Value
Location	Generic Greenfield, Southwest Pennsylvania U.S.
Topography	Level
Size, acres	300
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	Ohio River Water
Waste water	Zero Liquid Discharge (or utilization in coal preparation plant)
Coal Delivery	Pipeline Delivery of Waste Coal Slurry

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

Exhibit 3-3. 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. [**8**], Appendix B 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 3-4. Site Ambient Conditions – Business Case (Southwest Pennsylvania) (Washington County Airport, PA)

Parameter	SW PA Value	Note
Elevation, (ft)	1185	[**9**]
Barometric Pressure, MPa (psia)	0.097 (14.078)	
Average Ambient Dry Bulb Temperature, °C (°F)	10.1 (50.2)	[9]
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 [**9**] for Pennsylvania site elevation taken as Washington County Airport, PA.

[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 will not be quantified for this pre-FEED study. Allowances for normal conditions and construction will be 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), as well as the natural gas analysis for both cases.

3.2.1 Coal – Illinois #6

This section presents the coal analysis in Exhibit 3-5, ash analysis in Exhibit 3-6, and coal trace element analysis in Exhibit 3-7 for the Illinois No. 6 coal for the Base Case (Midwest Site).

Exhibit 3-5. 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, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	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: [**8**], [**10**] for sulfur.

Exhibit 3-6. 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 [**11**], pp. 36 & 37

Exhibit 3-7. 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: [**11**], 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.*

Fuel costs are specified according to the 2019 QGESS document "Fuel Prices for Selected Feedstocks in NETL Studies." [**12**] The current levelized coal price is \$2.11/GJ (\$2.23/MMBtu) on a higher heating value (HHV) basis for Illinois No. 6 bituminous coal delivered to the Midwest and reported in 2018 dollars. Fuel costs are levelized over an assumed 30-year plant operational period with an assumed on-line year of 2023.

3.2.2 Coal – Waste Coal

This section presents the coal analysis in Exhibit 3-8 and ash analysis in Exhibit 3-9 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.

Exhibit 3-8. Design Coal – Waste Coal Slurry (Bituminous)

Rank	**Bituminous**	
Seam	**Pittsburgh No. 8**	
Source	**Fine Waste Coal Slurry**	
Proximate Analysis (weight %)		
	As Received	**Dry**
Moisture		0.00
Ash		44.45
Volatile Matter		23.70
Fixed Carbon		31.86
Total		100.00
Sulfur		1.58
HHV, Btu/lb		7803
LHV, Btu/lb		
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture		0.00
Carbon		44.71
Hydrogen		2.97
Nitrogen		0.88
Chlorine		0.10
Sulfur		1.58
Ash		44.45
Oxygen[B]		5.31
Total		100.00
	As Received	**Dry**
Sulfur Analysis (weight %)		
Pyritic		0.97
Sulfate		0.03
Organic		0.58

Exhibit 3-9. 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

3.2.3 Natural Gas Characteristics

Natural gas characteristics are given in Exhibit 3-10.

Exhibit 3-10. 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. [8], Appendix B

The levelized price for natural gas delivered to the Midwest is assumed to be $4.19/GJ ($4.42/MMBtu), on an HHV basis and in 2018 U.S. dollars. [**13**]

3.3 Limestone Characteristics

The limestone analysis for the Base Case (Midwest site) and Business Case (Southwest Pennsylvania site) is presented in Exhibit 3-11.

Greer limestone is sourced near Morgantown, WV, and utilized by power plants along the Ohio River. This is a reasonable limestone source for the Pennsylvania plant using waste coal and anticipated to be located near the Ohio River.

Exhibit 3-11. 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 [**10**]

Limestone is assumed to be priced at $22/ton. [**13**, pp. 414/598]

We have determined that the Greer limestone can be received at 2 mm top size, so there is no need for a sorbent sizing building.

3.4 Environmental Targets

Exhibit 3-12 provides the air emission limits assumed for both cases and a brief description of the control technology utilized to satisfy the limits.

Exhibit 3-12. 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, metal filter
Hg	$3x10^{-6}$	Co-beneficial capture with ash
HCl	0.010	Polishing FGD

Ref. [**8**], Appendix B

Exhibit 3-13 provides the water discharge limits assumed for both cases.

Exhibit 3-13. 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. [**13**,**14]**

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 will be based on four (4) P200 modules consistent with the Cottbus P200 design. Thus, for the Phase II performance analysis, the PFBC bed velocities will be consistent with those of the Cottbus P200 design. The fuel heat input in all the cases will be similar but will reflect differences in the fuel composition (particularly ash). The PFBC coal-based power plant net capacity target will depend on the ultimate plant configuration (e.g., Benfield CO_2 capture system vs. amine-based CO_2 capture system). The net capacity for the Illinois No. 6 fueled PFBC plant equipped with the Benfield CO_2 capture system will be approximately 286 MW net with 97% CO_2 capture based on 4 x P200 PFBC modules (386 MW net in capture-ready mode). 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 Illinois No. 6 coal will be based on a capacity factor of 85%. This value is assumed to support the carbon capture investment and proposed revenue generated from CO_2 sales and/or tax credits.

The PFBC Power plant analysis for the waste coal will also be based on a capacity factor of 85%, as the plant is likely to be base loaded when fired on the very inexpensive waste coal and capturing carbon dioxide for storage or utilization with a corresponding tax credit/revenue stream.

3.7 Raw Water

The makeup water composition reported in Exhibit 3-14 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 3-15 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 3-14. 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 3-15. 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 motor)

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% 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 3-16.

Exhibit 3-16. Rankine Cycle Steam Conditions

Steam Parameter	Supercritical
Main Pressure, MPa (psig)	24.1 (3,500)
Main Temperature, °C (°F)	593 (1,100)
Reheat Temperature, °C (°F)	601 (1,115)

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 in the capture case.

For the capture case, the overall plant process will also utilize a caustic scrubber in a packed tower to polish the SO_2 prior to the flue gas entering the acid gas removal system for carbon capture. The scrubber will remove 98% of the incoming SO_2. Total sulfur removal is estimated at 99.8%.

For the non-capture case, we have assumed a Ca/S ratio of 3.8 as the configuration will not have a polishing scrubber required by the capture system. The total sulfur removal will be in excess of 97%.

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 3-17.

Exhibit 3-17. 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: [**15**]

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.

3.13 Sparing Philosophy

The sparing philosophy of the major process components are presented in Exhibit 3-18.

Exhibit 3-18. PFBC Process Configuration and Design Redundancy

System	Description	Quantity/Capacity
Fuel Feed (per PFBC)	Putzmeister pump	16x6.25% [4 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]
Gas Cooler/ Gas Reheater System	Heat Exchangers & Thermal fluid	4 x 25% [1/PFBC]
Particulate Filter	Metal filter bank (1 per PFBC)	4 x 25% [1/PFBC] Note 1
Polishing Scrubber	Flue Gas Desulfurization	4 x 25% [1/PFBC]
Acid Gas Removal	Benfield Potassium Carbonate system or amine-based system	4 x 25% [1/PFBC]
Stack	Flue Gas Stack	4 x 25% [1/PFBC]

Note 1. Spare capacity can be or is provided at the component level. 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.

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 Purity Requirements

Exhibit 3-19 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 [**16**]. The exhibit also presents the preliminary requirements specific to the PFBC project.

Additional information on specific contaminants is provided below. Much of this input is taken from reference [**16**].

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 3-19. CO_2 Stream Compositions Recommended Limits

Component	Unit (Max unless noted)	Carbon Steel Pipeline		Enhanced Oil Recovery		Saline Reservoir Sequestration		PFBC Project	Venting Concerns
		Conceptual Design	Range in Literature	Conceptual Design	Range in Literature	Conceptual Design	Range in Literature	Pre-FEED Design	
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**	
N2	vol%	4	- 7	1	0.01 - 2	4	- 7	**1**	
O2	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**	
CH4	vol%	4	0.01–4	1	0.01–2	4	0.01–4	**1**	Yes- Asphyxiate, Explosive
H2	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
H2S	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
SO2	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
NH3	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)
C2H6	vol%	1	0–1	1	0–1	1	0–1	**1**	Yes- Asphyxiant, Explosive
C3+	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 Post-combustion capture process for the PFBC plant are shaded above.

Ref: **[16]**

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 SO2 levels. Additional background, largely from the QGESS document [**16**] 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.

3.15 Balance of Plant Inputs

The balance of plant assumptions are presented in Exhibit 3-20.

Exhibit 3-20. Balance of Plant Assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Coal (Waste coal)	>30 days (via existing slurry impoundments at the prep
Coal (Illinois No 6)	>30
Coal - Day Bin (Waste coal or Ill No 6)	1 day
Limestone	30
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
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.
Process Wastewater	Zero liquid discharge (ZLD) or integration with fuel preparation facility to minimize the capacity of any
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

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16 National Energy Technology Laboratory, Quality Guidelines for Energy System Studies – CO_2 Impurity Design Parameters, U.S. Department of Energy, Pittsburgh, PA, January 2019, NETL-PUB-22529.