Advanced Pressurized Fluidized Bed Coal Combustion with Carbon Capture

Technology Gap Analysis and Commercial Pathway Report

Concept Area: With Carbon Capture/Carbon Capture Ready

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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 levels of performance to round out this discussion.

1.1 Coal-Fired Power Plant Scope Description

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

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 and with little interruption to the operation of the capture-ready plant. The essential feature of the capture-ready plant is the provision of additional space for housing the additional components, along with space for supporting auxiliaries (electrical cabinets, piping, etc.) The Base Case plant will be designed to fire Illinois No. 6 coal, while the Business Case plant will be designed to fire waste coal while also being fully capable of accommodating typical thermal coal products.

The complete scope of the proposed power plant includes a fuel preparation plant co-located with the power generating plant. The power generation process 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 PFBC 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 various parts of the power generating process, a waste water treatment facility to treat waste water streams for beneficial reuse within the complete facility (power generating plant or fuel preparation plant), and necessary administrative and maintenance facilities.

1.2 Plant Production / Facility Capacity

The plant production capacity for the PFBC plant is set primarily by the number of PFBC modules as the PFBC design is essentially fixed. The overall plant production capacity with four (4) PFBC modules firing Illinois No. 6 coal is set at a nominal 404 MWe net without CO_2 capture (but in complete capture ready configuration) and 313 MWe net with CO_2 capture operational at a rate of 97% of all CO_2 produced based on the amine capture system. When operating at this fully rated capacity (313 MWe) the CO_2 available for delivery at the plant boundary is ~7700 tons/day of pure CO_2 mixed with small amounts of other gases.

The annual production of electricity for delivery to the grid is 2.33 million MWh at 85% capacity factor. The annual production of CO_2 for export at 85% capacity factor is 2.4 million tons/year.

1.3 Plant Location Consistent with NETL QGESS

As discussed above, the Base Case PFBC plant 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 developing separate designs 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 of the Design Basis Report. Wherever possible, we have utilized available site information in lieu of generic information.

1.4 Business Case from Conceptual Design

The business case and underlying performance estimates and economics presented in 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. The project team is updating this information during the current pre-FEED study to reflect the best overall plant design, which will be based on an amine-based CO_2 capture process.

This business case presents the following:

- Market Scenario
- Market Advantage of the Concept
- Estimated Cost of Electricity Establishing the Competitiveness of the Concept

1.4.1 Market Scenario

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

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

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

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

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

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

1.4.2 Market Advantage of the Concept

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

1. <u>Excellent Environmental Performance</u> – The advanced PFBC is able to achieve very low NOx (<0.05 lb/MMBtu) and SO_2 (<0.117 lb/MMBtu) emission rates by simply incorporating selective non-catalytic reduction and limestone injection at pressure within the PFBC vessel itself. After incorporation of an SO_2 polishing step before the CO_2 capture process, the SO_2 emissions will be

<0.03 lb/MMBtu or <0.256 lb/MWh. As mentioned above, the PFBC can also significantly improve the environmental footprint of the upstream coal mining process if it uses fine, wet waste coal as a fuel source, and it produces a dry solid byproduct (ash) having potential commercial applications.

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

The timeline to commercialization for advanced PFBC is expected to be an advantage relative to other advanced coal technologies because (1) the core P200 module has already been designed and commercially proven and (2) the main technology gaps associated with the advanced PFBC plant, including integration of carbon capture, integration of multiple P200 modules with a supercritical steam cycle, and development of a suitable turbomachine for integration with the PFBC gas path, are considered to be well within the capability of OEMs using existing materials and technology platforms. The concept of firing a PFBC with fine, wet waste coal (thickener underflow) was demonstrated in a 1 MWt pilot unit at CONSOL's former Research & Development facility in South Park, PA, both without CO_2 capture (in 2006-2007) and with potassium carbonate-based CO_2 capture (in 2009-2010), providing evidence of its feasibility. We believe that the first-generation advanced PFBC plant, capable of achieving ≥40% HHV efficiency in CO_2 capture-ready configuration or incorporating 90% CO_2 capture (increased to 97% in the pre-FEED study) and compression with ≤22% energy penalty, would be technically ready for commercial-scale demonstration in the early 2020s. We propose to evaluate CONSOL's Bailey Central Preparation Plant as a potential source of fuel (fine, wet waste coal) and potential location for this demonstration plant. Additional R&D in the areas of process optimization, turbomachine design, 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 enhanced oil recovery (EOR) or beneficially reused. Otherwise, the cost estimating methodology used here is largely consistent with that used in DOE's "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity." 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 - Benfield

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

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

Based on the initial projections from the Conceptual Design Phase in Exhibit 1-1, it is possible to highlight several competitive advantages of the advanced PFBC technology vs. other coal-fueled power generation technologies. First, although capital costs are expected to present a commercial hurdle for all coal-based technologies relative to natural gas-based technologies, the total overnight cost (TOC) range of $2,466/kW to $3,193/kW presented above for a capture-ready PFBC plant compares favorably with the expected TOC of ~$3,600/kW for a less-efficient new supercritical pulverized coal plant [**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 °F, and main steam pipe temperature above approximately 800 °F) requires less than 2 hours on coal; this time is reduced to approximately 1 to 2 hours with natural gas co-firing. It should be noted that very short startup times are not compatible with use of a supercritical steam cycle with high main and reheat steam design temperatures. There are two compelling factors that work against very fast starts for this type of steam cycle: first are the severe secondary stresses induced in heavy wall piping and valves necessary for supercritical steam conditions. Longer warmup times are necessary to avoid premature material failures and life-limiting changes in the pressure part materials for the piping, valves, and high-pressure turbine components. The second limiting factor on rapid startup times is the feed water chemistry limitation inherent in supercritical steam cycles. After a complete shutdown, condensate and feed water chemistry typically requires some length of time to be returned to specification levels. Assuring long material life and preventing various kinds of corrosion mechanisms from becoming an issue requires that water chemistry be brought to the proper levels prior to proceeding with a full startup from cold, no-flow conditions. Resolution of this entire bundle of issues could be viewed as a "Technology Gap" of sorts, requiring investigation to determine if realistic, cost-effective remedies can be developed.
- The PFBC can turn down to the required 20% load and below by reducing the number of modules in operation. A 20% power level can be achieved by operating one of four P200 modules at approximately 80% load or two modules at about 40% load each. Operation is expected at full environmental compliance based on known previous operational experience.
- The PFBC technology described employs 97% CO_2 capture, but it can also be offered as fully CO_2 capture-ready without the capture equipment installed. The addition (construction) of the CO_2 capture equipment may be performed while the plant is in operation without interference, and the switch-over to CO_2 capture, after construction is completed, can be made by opening/closing specific valves to make the transition while at power. This is accomplished one PFBC module at a time to minimize any impacts on system operation.
- The proposed PFBC plant will incorporate a Zero Liquid Discharge system. The power plant portion of the facility will be integrated with the fuel preparation portion of the facility to

incorporate internal water recycle and to reuse water to the maximum extent. This will minimize the capacity, and thereby the cost, of any required zero liquid discharge (ZLD) system.

- Solids disposal is characterized by two major streams of solids: bed ash and cyclone and filter ash. The ash material has mild pozzolanic properties, and it may be landfilled or used in a beneficial way to fabricate blocks or slabs for landscaping or light-duty architectural applications. The ash products are generally non-leachable as demonstrated by PFBC operations in Sweden and Japan.
- Dry bottom and fly ash discharge: PFBC ash (both bed and fly ash) is dry. Discharge is made through ash coolers that provide some heat recovery into the steam cycle condensate stream. The cooled ash is discharged into ash silos and then off-loaded into closed ash transport trucks for ultimate disposal or transport to a facility for use in manufacture of saleable end products, as noted above.
- Efficiency improvement technologies applicable to the PFBC will include neural network control features and learning models for plant controls balancing air supply against fuel firing rate (excess air), ammonia injection for SNCR, balancing bed performance against the performance of the caustic polishing scrubber for removing sulfur, and other opportunities to optimize overall performance.
- The limitation of air heater outlet temperatures is not applicable to PFBC technology.
- High-efficiency motors will be used for motor-driven equipment when and where applicable. Electric generators will be specified to be constructed to state-of-the-art efficiency standards.
- Excess air levels will be maintained at appropriate levels to optimize the operation of the overall PFBC Brayton and Rankine cycles, and the sulfur capture chemical reactions in the bubbling bed. A 12% excess air limit may or may not be applicable to this technology. Further evaluation is required. The excess air for the base design case is 16%. The PFBC technology does not include any component similar to a PC or CFB boiler air heater. However, attempts will be made to minimize leakage of hot gas that could result in loss of recoverable thermal energy.
- The consideration of sliding pressure vs. partial arc admission at constant throttle pressure will be made during 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 °F. Using aggressive design parameters for the heat sink, including a 5 °F terminal temperature difference for the condenser, a 7 or 8 °F cooling tower approach, and a 17 or 18 °F range for the circulating water system results in a condensing temperature of at least 99 or 100 °F at 70 °F ambient wet bulb temperature, which corresponds to a backpressure of 2.0 in Hga. Therefore, any time ambient wet bulb temperatures exceed 70 °F, the back pressure will exceed 2.0 in Hga. A back pressure of 1.5 in Hga (in the summer above 70 °F wet bulb temperature) might be maintained by use of a sub-dew point cooling tower technology. This is a relatively new innovation that promises to reduce the cooling water temperature produced by an evaporative cooling tower by adding the necessary components of the sub-dew point system to a relatively conventional evaporative cooling tower. Although the efficacy of the system to reduce cold water temperatures produced by an evaporative tower appears theoretically sound, the full economics of employing this type of system remain to be demonstrated in a commercial setting.

- When CO_2 capture is employed, additional sulfur capture is required ahead of the capture process. This additional polishing step reduces sulfur emissions to a level characterized by greater than 99.75% removal.
- Other low-cost solutions are being evaluated as applicable during this pre-FEED study.

1.6 Proposed PFBC Target Level of Performance

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

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

No. of P200 Modules	Total Unit Output, MWe, net	Efficiency, HHV	Steam Cycle Parameters
1	88	37.0	1600/1025/1025
2	185	39.0	2000/1050/1050
3	285	40.0	2400/1075/1075
4	404	>42.0%	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 – Amine Configuration)

Percent Load	No. Modules in Operation	MWe, net	Estimated Efficiency %, net, HHV
100	4	404	>42%
80	4	323	40.7
60	3	242	39.4
40	2	162	37.1
20	1	81	32.0

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

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

The first efficiency column ("Current State-of-the-Art") presents estimated efficiency values for the configuration described in the Block Flow Diagram (BFD) in Exhibit 2-4 of the Performance report. This configuration is based on currently available materials of construction, design experience, and practices. The second efficiency column ("Advanced State-of-the-Art") is based on resolution of 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.

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

No. of Modules with Capture	% Capture, Total Plant	Estimated Efficiency, %, HHV, Current State-of-the-Art	Estimated Efficiency, %, HHV, Advanced State-of-the-Art
0	0	>42%	>44%
1	24.25	40.1	42
2	48.5	37.7	40
3	72.75	35.3	38
4	97.0	32.9	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	Control Technology / Comments
SO_2	1.00	Target is achievable with ~97% capture in-bed for capture-ready case. Target is achievable with 90% capture in-bed and added polishing step (required by CO_2 capture process) for capture-equipped case.
NOx	0.70	Catalyst not required. Target is achievable with SNCR.
PM (filterable)	0.09	Cyclones and metallic filter will achieve target. Metallic filter is required to protect the turbomachine.
Hg	3 X 10-6	Particulate removal and GORE® mercury removal system will achieve target.
HCl	0.010	Cl capture of 99.5% plus is required based on the high Illinois No. 6 Cl content. Target is achieved by high level of PM capture.

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 the full FEED study. However, at this time, the following rationale is offered in support of our belief that these elements will be controlled to within regulatory limits particularly for the capture-equipped case. A significant portion of the Hg and Cl will be reacted to form a solid compound and will be captured by the two stages of cyclones inside the PFBC vessel and the 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 mercury removal system for removal of elemental Hg
3. The CO_2 capture absorber vessel

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

1.6.3 CO_2 Control Strategy

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

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

2 Technology Gap Analysis and Commercial Pathway

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

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

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

This section following provides some historical perspective relating to the following:

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

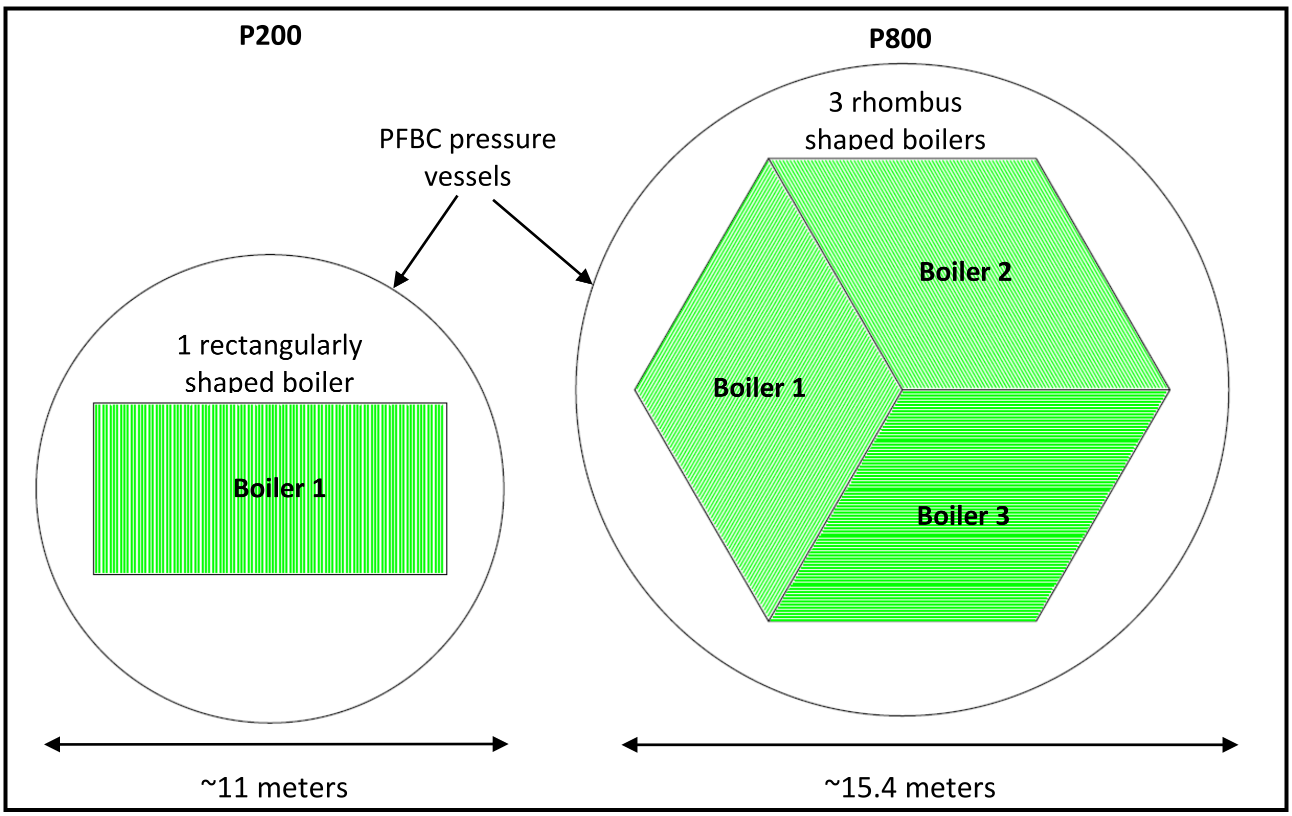
2.1.1 History of the PFBC Technology

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

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

4. **Cottbus Station** in Cottbus, Germany is the last of the P200 plants to be constructed. Still in regular service, this plant incorporates lessons learned from previous P200 modules, which are being carried over to the P200 design for the first 4 x P200 plant with carbon capture that is being developed under the Coal First program.
5. **Karita Station**, owned by Kyushu Electric Power Company in the town of Karita-Chou in northern Kyushu Island, Japan, is the first and only P800 PFBC configuration constructed and is still in operation. The P800 relies heavily on the P200 design by incorporating three essentially complete "P200" pressurized boilers (parts internal to the pressure vessel) that operate at an elevated pressure inside a single pressure vessel, resulting in a thermal capacity rating that is four times that of a single P200 boiler. The added capacity is achieved by operating the P800 at a nominal 16 bar pressure, in contrast to the P200, which operates at nominal 12 bar pressure. This four-thirds (4/3) pressure ratio allows each of the three "P200" boilers within the P800 to have a capacity of 133% of the true P200 boiler. The geometry of each "P200" boiler is adjusted into a rhombus so that three (3) such boilers can be nested into a single cylindrical pressure vessel of reasonable diameter. Exhibit 2-1 provides a plan view illustration of how this is accomplished with minimal increase in the diameter of the P800 PFBC pressure vessel relative to the P200 vessel. The circles represent the inside diameter of each of the respective PFBC pressure vessels. The green shaded figures represent the plan view of the "P200" boilers inside the pressure vessels. By changing the plan of the single P200 boiler into a rhombus, three of these can be fit into a hexagonal-shaped plan that fits inside a larger diameter vessel,

Exhibit 2-1. Increased Capacity of P800 vs P200



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

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

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

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

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

Exhibit 2-2. PFBC Project Data / History

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

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

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

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

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

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

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

2.1.3 First Commercial 4xP200 Supercritical PFBC Plant with Carbon Capture

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

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

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

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

After extensive evaluation of the two methods for integrating the Benfield process with the PFBC, the use of an amine process at the terminal end of the gas path was evaluated. For the purposes of this pre-FEED study, the amine process approach used in the September 2019 NETL Cost and Performance Baseline for Fossil Energy Plants report was employed [**8**]. This approach used the CANSOLV process offered by Shell. This overall system configuration yielded superior thermal performance, with an increase of several percentage points in thermal efficiency in both the capture-ready and capture-equipped (at 97% capture rate) PFBC plant configurations.

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

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

2.1.4 Current State-of-the-Art of the PFBC

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

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

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

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

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

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

2.2 Shortcomings, Limitations, and Challenges for this Application

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

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

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

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

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

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

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

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

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

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

3. **Gas Turbomachine** (4 required) will be provided by either Baker Hughes or Siemens. Both firms have the capability to design and manufacture machines to meet specific technical requirements. Earlier in the Conceptual Design phase of the project, finding a suitable replacement for the ABB GT35P machine had been identified as a key technology gap, as the GT35P is not currently in commercial production and was unique in its ability to match the P200 operating conditions and ingest combustion product gases containing significant quantities of particulate matter. The identification of a suitable hot gas filter in the pre-FEED phase has opened the door to more conventional design approaches for the turbomachine and will allow this machine to be competitively procured.

4. **Hot Gas Filter** will be provided by either Mott Corporation or Pall Corporation, a unit of Danaher Corporation. The hot gas filter will remove virtually all of the particulate matter in the gas path at elevated temperature, allowing the gas turbomachine procurement to become a much lower-risk endeavor.
5. **Supercritical Steam Turbine Generator** will be provided by either General Electric or Siemens.
6. **The flue gas polishing and CO_2 capture system** risks and issues will be treated within subsection 2.3.1.

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

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

All amine-based processes for CO_2 removal have similar process flow diagrams as presented in Exhibit 2-3, in which the amine solvent circulates between an absorber, where CO_2 is removed from the flue gas stream to produce a rich-loading stream, and a stripper/reboiler, where steam is introduced to strip the CO_2 from the rich-loading stream and produce a lean stream that is returned to the absorber for removing CO_2. [**9**,**10**]

Exhibit 2-3. Basic Chemical Absorption Process for CO_2 Capture

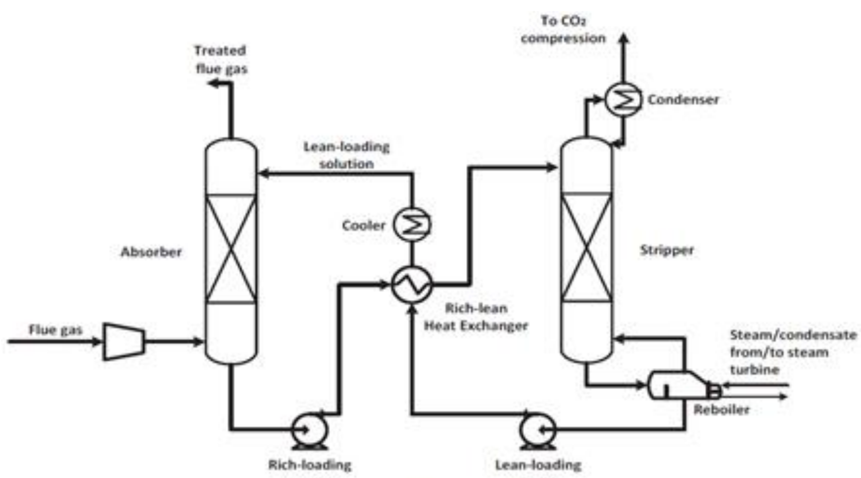
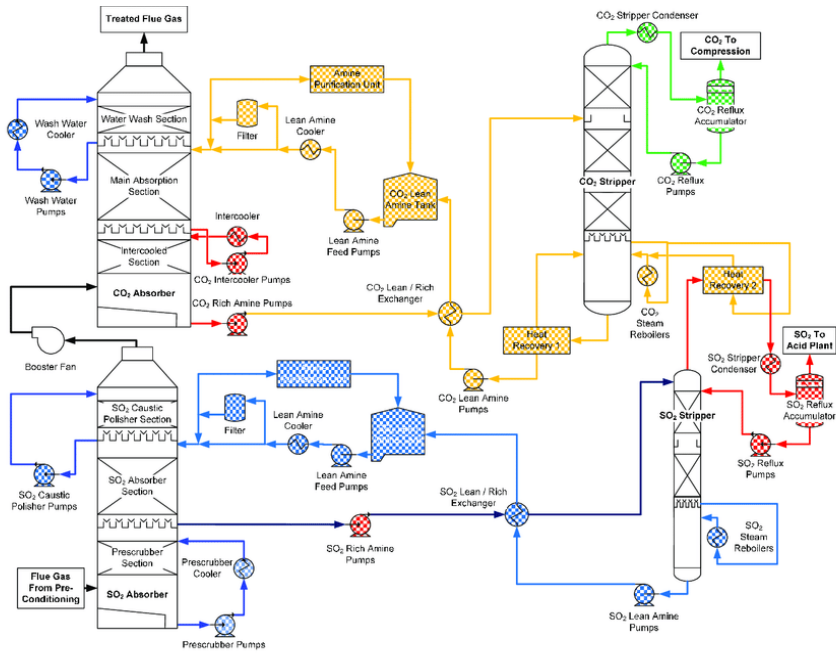


Fig. 2. Schematic of a basic chemical absorption process for CO_2 capture

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

- **Shell Cansolv** is an amine-based process following the industry standard design approach with solvents formulated to achieve relatively fast kinetics, low degradation, low thermal regeneration energy (~2.1 GJ/tonne CO_2 removed), and low solvent recirculation rates. The sorbents used are monoethanolamine (MEA) or tertiary amines with additives for activators (reaction rate enhancers) and free radical scavengers [**11**].

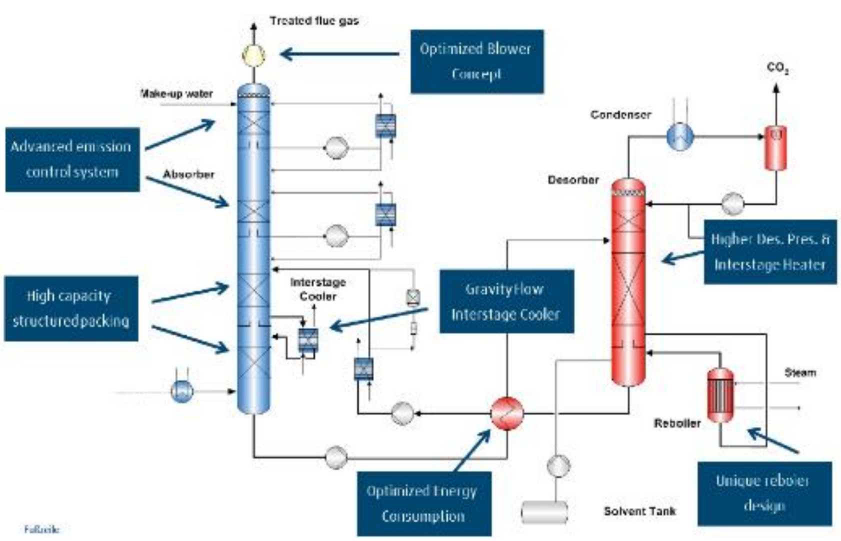
Exhibit 2-4. Shell CANSOLV Absorption Process for CO_2 Capture



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

- **BASF/Linde OASE Process** is an amine-based process following the industry standard design approach targeting energy demand, cyclic capacity, solvent stability, reactivity, volatility, and availability. The reboiler energy requirements are as low as 2.7 GJ/tonne CO_2 removed, with a target as low as 2.3 GJ/tonne CO_2 removed via other process improvements. BASF/Linde is developing the design to incorporate a higher-pressure stripper (3.4 bar(a)) to improve the energy consumption for CO_2 compression [**12**].

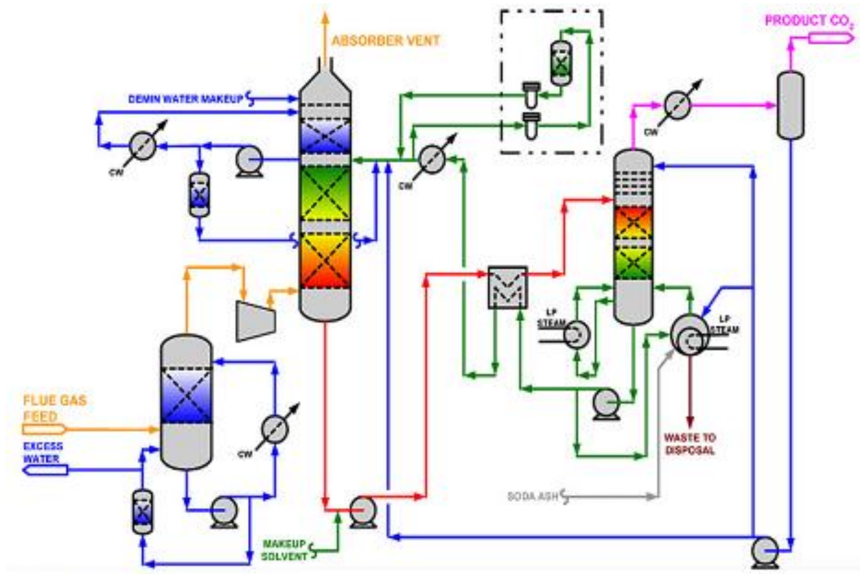
Exhibit 2-5. BASF/Linde OASE Absorption Process for CO_2 Capture



Status: Linde intends to respond to the project teams request for a quote for the OASE system.

- **Fluor Econamine FG Process** is an amine-based process following the industry standard design approach that uses MEA as the basic solvent ingredient and targets CO_2 recovery from low-pressure, oxygen-containing flue gas streams. Process improvements are related to solvent formulation, absorber intercooling, a large-diameter absorber, and a lean vapor compressor [**13**].

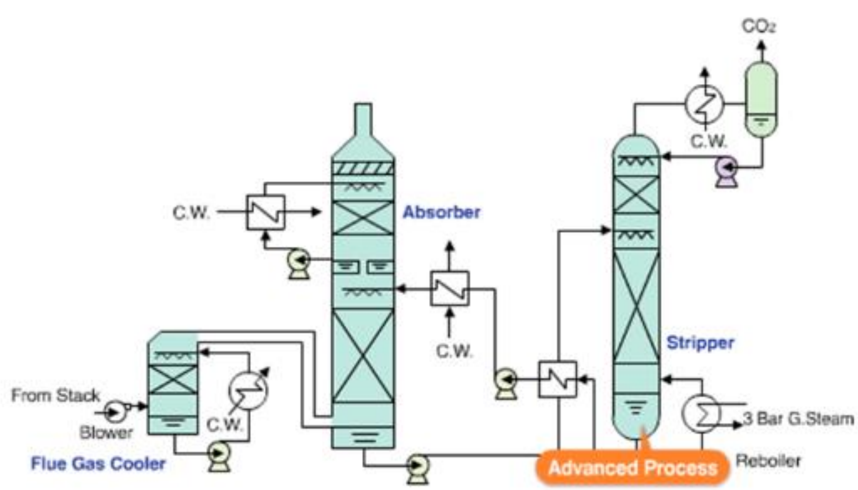
Exhibit 2-6. Fluor Econamine Absorption Process for CO_2 Capture



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

- **MHI KM CDR Process** is an amine-based process following the industry standard design approach using KS-1 solvent, an advanced activated hindered amine, targeting low energy consumption (2.9 GJ/tonne CO_2 removed) and low solvent degradation [**14**].

Exhibit 2-7. MHI KM CDR Absorption Process for CO_2 Capture



Status: The team has reached out to MHI, and we expect them to provide a quote.

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

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

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

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

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

The project team believes that commercialization can be achieved in advance of 2030 if commercial risks can be covered. It is believed that some form of financial backing from DOE would be meaningful in helping to mitigate perceived financial and commercial risk by potential project sponsors. Construction of a pilot plant is not considered essential to advance the PFBC to commercial operation. Laboratory testing is sufficient for determining the handling properties of the paste for the fuel handling system, as was done for the 1 MWt pilot scale unit at CONSOL Energy's R&D Center. A picture of such a "slump" test is given in Exhibit 2-9. The addition and integration of a CO_2 capture system operating at 97% capture rate also represents a new design challenge. The perceived issue is one of control systems integration and process performance, not design and physical construction. Operation on a continuous basis at high capacity factor in regular commercial use needs to be demonstrated.

Exhibit 2-8. Coal Water Paste Slump Test

2.5 Development Pathway Description to Overcome Key Technical Risks/ Issues

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

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

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

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

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

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

Waste fuel quality will also be addressed. The waste fuel quality parameters provided in the Design Basis Report were obtained through sampling of CONSOL Energy's Bailey Central Preparation Plant thickener underflow stream. This represents the fine waste that is discarded currently into slurry impoundments. The ash content reported on a dry basis is 44.5%, and the heating value, also on a dry basis, is 7803 Btu/lb. Sampling and analysis of this stream is ongoing. However, the quality of the fuel fed to the PFBC affects performance, and lower ash/higher heating value feedstocks improve the performance. During fuel preparation for the PFBC Process Test Facility at CONSOL Energy's former R&D facility, additional potential waste streams were collected and analyzed at the preparation plant. These included the spiral middlings (intermediate density particles) that had a lower ash content (18.48%, dry) and higher heating value (12,095 Btu/lb, dry) and ultrafines (~ -325 mesh) from the thickener underflow stream that had a higher ash (62.73%, dry) and lower heating value (4758 Btu/lb, dry). Additional sampling of individual fine and ultrafine waste streams within the preparation plant will determine if these streams represent opportunities for preparing waste fuel with lower ash/higher heating value. In addition, the project team will evaluate technologies that reject ash-forming minerals and recover these minerals for beneficial use, with the goal of eliminating all waste streams. Testing of one such process is being conducted at the preparation plant at this time. Ultimately, paste testing will be performed to determine the material characteristics (e.g., particle size distribution, solids density, etc.) of the fuels and sorbent materials selected as feedstocks for the plant, and to determine the rheology of the prepared fuel, and results will be used to inform the paste plant design and engineering effort.

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

2.5.2 Longer-Term Development Items

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

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

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

2.5.2.1 16 Bar P200 PFBC Design Concept

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

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

2.5.2.2 Improved Steam Cycle Conditions

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

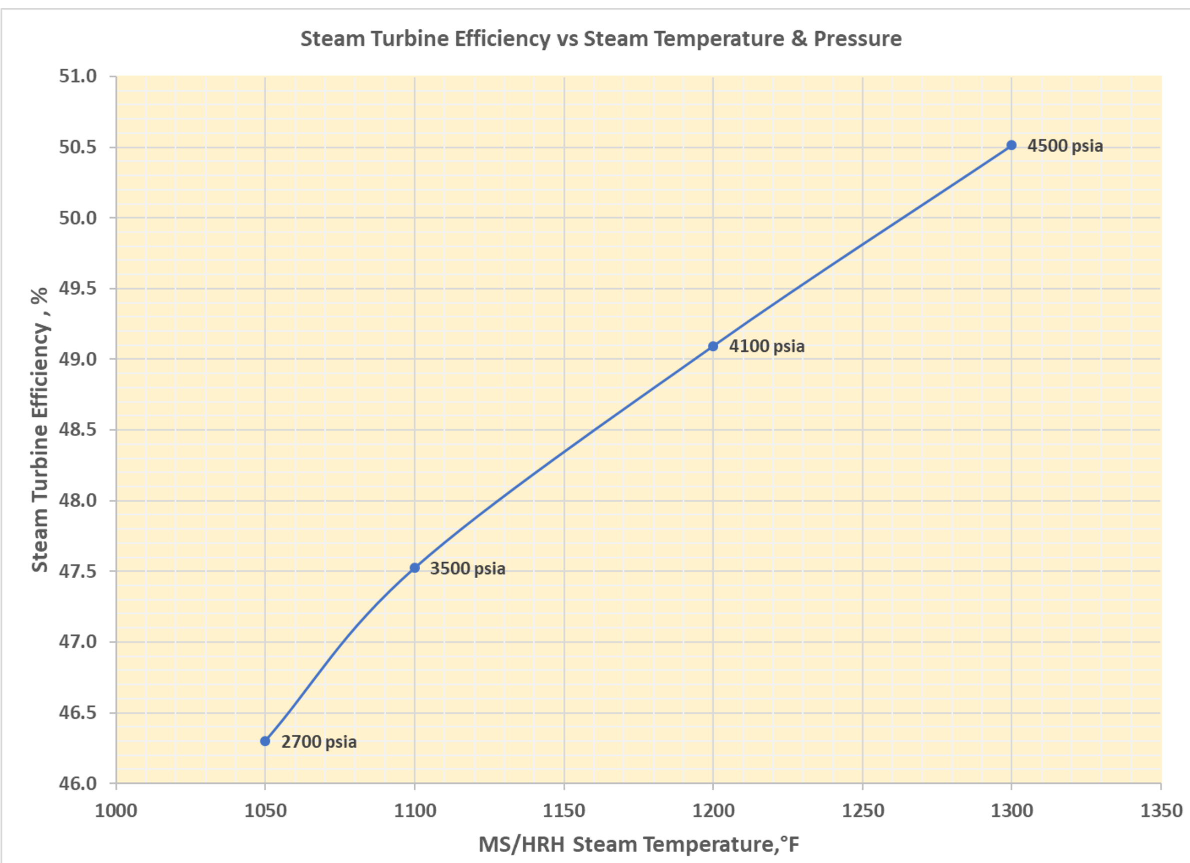
A number of materials are available now that offer meaningful improvements in high-temperature creep and yield strength but at a cost that precludes commercial use. Some of these materials also require official sanction and inclusion in the ASME Boiler and Pressure Vessel Code and related ancillary piping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

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

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

Exhibit 2-9 presents comparative steam cycle efficiencies based on different values of throttle pressure and temperature (with corresponding hot reheat temperature) pairs. The impact on PFBC plant efficiency has not been calculated, but as the steam cycle produces about 80% of the total electric power for the 4 x P200 power plant, the lapse rate shown below is indicative of potential performance improvements that are possible with advanced steam conditions.

Exhibit 2-9. Steam Turbine Cycle Efficiency as Function of Steam Conditions



2.5.2.3 Improved Gas Turbomachine Cycle Performance

As noted above, the introduction of higher boiler pressure has significant benefits in plant capital costs. A brief evaluation was performed to ascertain the impacts on gas turbine cycle efficiency of changing the compressor pressure ratio. This is reflected in Exhibit 2-10 and Exhibit 2-11. Exhibit 2-10 shows that although increasing the PFBC nominal pressure from 12 to 16 bar is not optimal for the turbomachinery itself, the pressure change does not negatively impact the overall plant efficiency. The impetus of the increased PFBC pressure is that of capital cost reduction resulting from the elimination of one (1) of the four (4) PFBC trains while maintaining the capacity and performance.

Exhibit 2-11 helps the reader understand that the drop in the turbomachinery performance with increasing pressure is a result of the decreasing compressor adiabatic efficiency with increasing pressure levels. This is a consequence of the behavior of turbomachines assuming constant polytropic (small stage) efficiency. The intercooled cycle used in the P200 PFBC actually reaches peak efficiency at a relatively low pressure ratio. This is a consequence of the low turbine inlet temperature of 1450 °F. More typical gas turbines that fire oil or gas with significantly higher compressor pressure ratios (ranging up to over 40:1 for some aeroderivative models) do not have intercooling and they also have turbine inlet temperatures ranging up to values in excess of 2600 °F. The low temperature intercooled machine occupies a place in the performance spectrum not often encountered in the world of gas turbines in the current era.

Exhibit 2-10. Gas Turbine and Plant Net Efficiencies as Function of PFBC Pressure

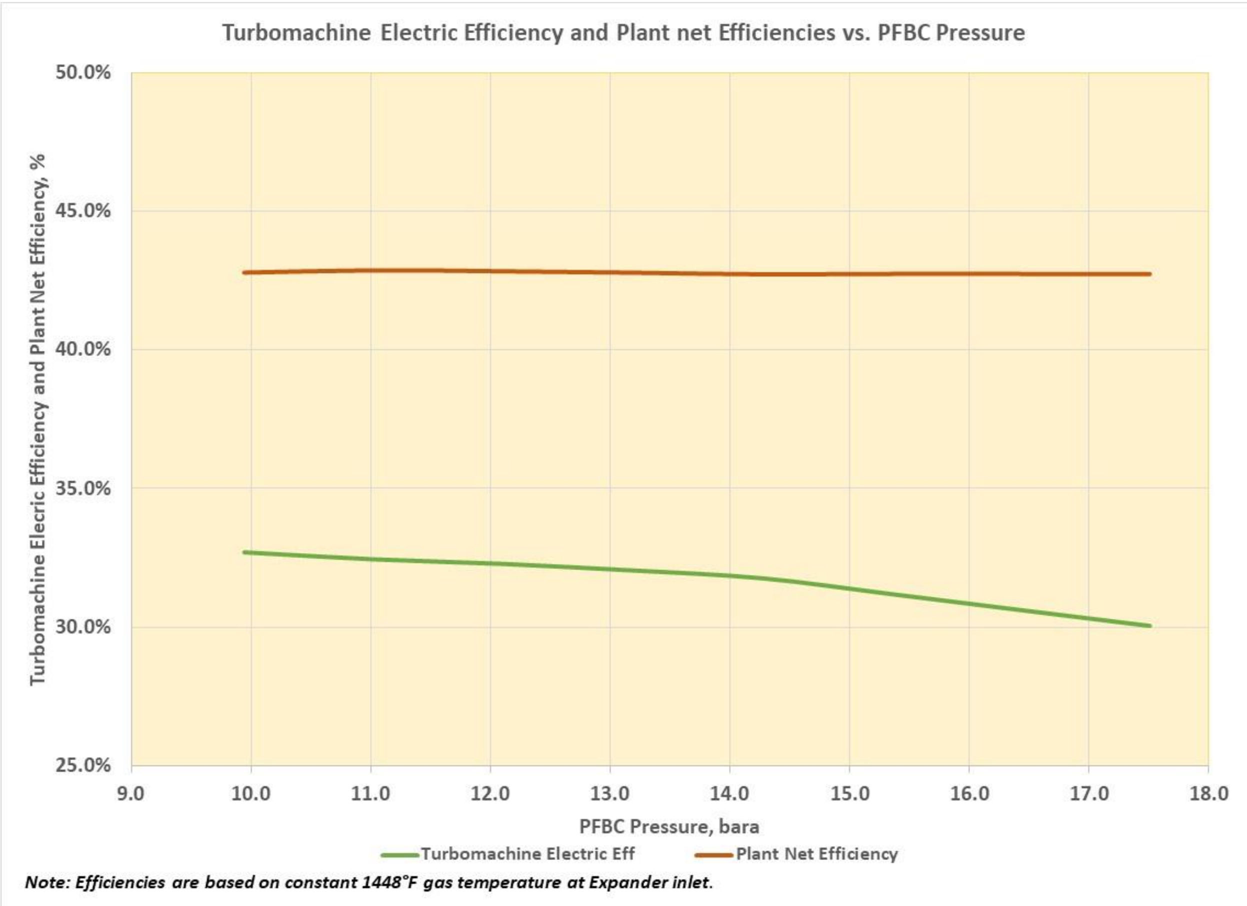
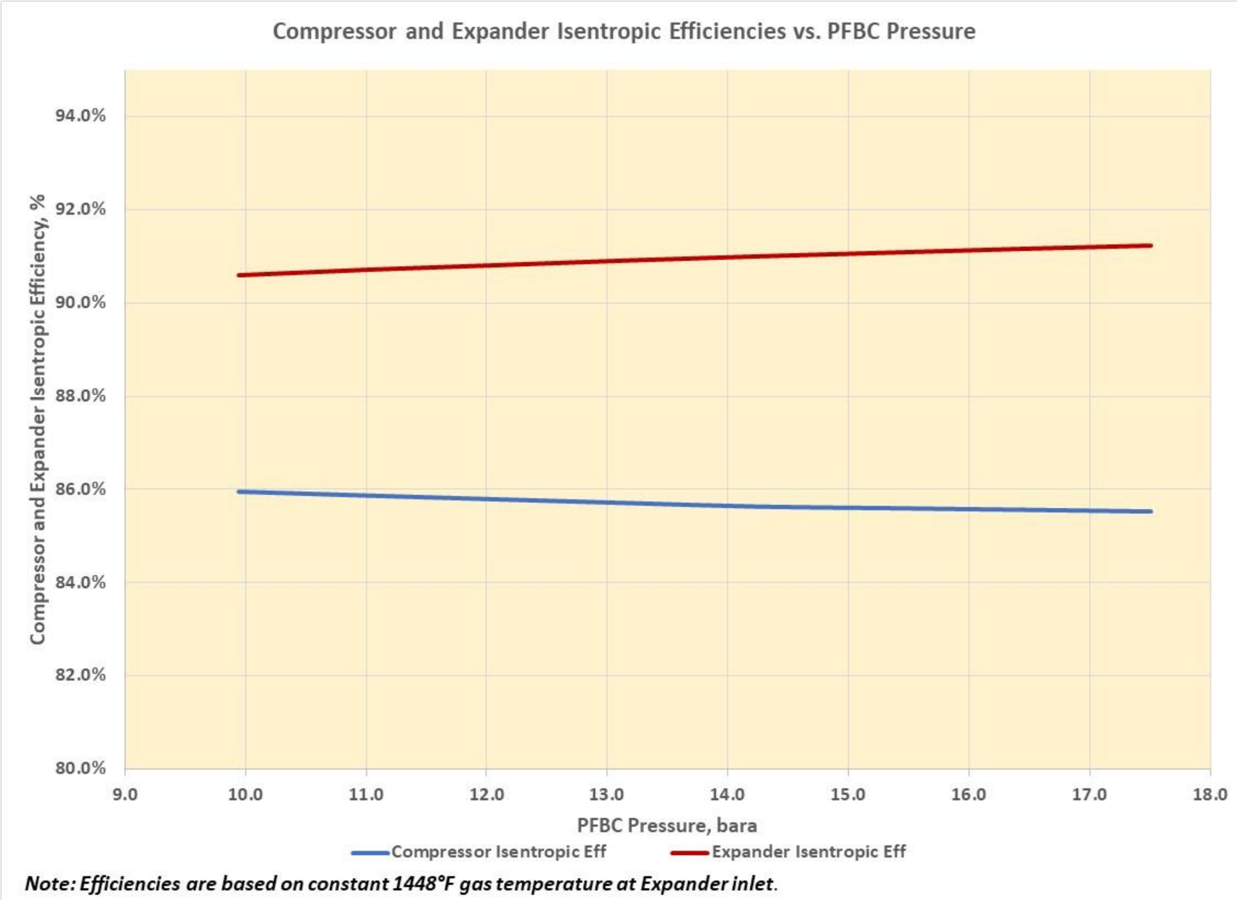


Exhibit 2-11. Compressor and Expander Efficiencies as Function of PFBC Pressure



2.5.2.4 Improved CO_2 Capture Performance

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

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

- Solvent development has led to an ~8% reduction in reboiler energy consumption.
- Operational improvements have led to ~20% improvement in energy consumption.
- A baseline reference for reboiler duty using MEA solvent as of 2007 was 3.29 GJ/tonne CO_2 removed [**15**]; however, improvements have resulted in current estimated reboiler heat duty levels of 2.3 to 2.6 GJ/tonne CO_2 removed.
- Drivers of these improvements include the following:
    - Optimization of the CO_2 rich and lean loadings, the feed stream temperature, and the amount of stripping steam used

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

As discussed in Section 2.3.1, the longer-term technology development pathway for PFBC may also take advantage of advances in emerging CO_2 capture technologies, such as membranes, solid sorbents, and membrane/solvent hybrid systems, which have longer timelines to commercialization but have shown potential to improve on the performance of amine-based systems.

2.5.2.5 Improved Thermal Performance of the PFBC Boiler

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

2.6 Key Technology/Equipment OEM's

This section provides information on the following areas:

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

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

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

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

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

Following the convention from the Performance Results Report, the capture-ready and capture-equipped configurations are designated per Case number matrix in Exhibit 2-12.

Exhibit 2-12. PFBC Case Matrix

Case Definition	Capture-Ready (Subcase A)	Capture-Equipped (Subcase B)
Illinois No. 6 (Case 1)	Case 1A	Case 1B

Exhibit 2-13. Case 1A & 1B – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Commercial Status
	DRY FUEL HANDLING		
1	Dry Fuel Dumper / Hopper	Field Erection	Commercial
2	Feeder System	Belt	Commercial
3	Conveyor #1 with Scale / Magnet	Belt	Commercial
4	Dry Fuel Sizing Building Screens / Crusher-Pulverizer	Enclosed	Commercial
5	Dry Fuel Sampling System	Two Stage	Commercial
6	Conveyor #2	Belt	Commercial
7	Conveyor #3 to Storage Dome	Belt	Commercial
8	Storage Dome	Enclosed	Commercial
9	Storage Dome Reclaim	Vibratory	Commercial
10	Reclaim Conveyor #4 with Scale	Belt	Commercial
11	Dry Fuel Sampler	Swing Hammer	Commercial
12	Conveyor #5 to PFBC Fuel Prep System	Belt	Commercial
	SORBENT HANDLING		
13	Sorbent Dumper / Hopper	Field Erection	Commercial
14	Feeder System	Vibratory	Commercial
15	Conveyor #1 to Sorbent Dome Storage with Scales	Belt	Commercial
16	Sorbent Sampling System	Two Stage	Commercial
17	Sorbent Storage Dome	Enclosed	Commercial
18	Storage Dome Reclaim	Auger	Commercial
19	Reclaim Conveyor #2 with Scale to Sorbent Sizing System	Belt	Commercial
20	Sorbent Sizing Building (Day Hopper Feeder/Screens/Pulverizer/Dust Control)	Enclosed	Commercial
21	Sorbent Sampler	Enclosed at Transfer	Commercial
22	Sorbent Handling System to PFBC Fuel Prep	Enclosed	Commercial

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

Equipment No.	Description	Type	Commercial Status
	FUEL PREP BUILDING	**ENCLOSED**	
1	Fuel Receiving Bin Sliding Frames	Shop Fab / Field Erected	Commercial
2	Fuel Weighfeeders (4) to Paste Mixers	Belt	Commercial
3	Sorbent Bin	Shop Fab / Field Erected	Commercial
4	Sorbent Bin Rotary Feeders (4)	Rotary	Commercial
5	Sorbent Weigh Belts (4)	Belt	Commercial
6	Paste Sumps / Mixers / Moisture Control	Mixers	Commercial
7	Prepared Fuel Sumps (4) with Agitators	Shop Fab	Commercial
8	Putzmeister Transfer Pumps (8) to PFBC Feed System	High Density Solids Pumps	Commercial
9	Buffer Silo Sumps with Agitators (8)	Shop Fab	Commercial
10	Putzmeister Feed Pumps (24) to PFBC Lances (48)	High Density Solids Pumps	Commercial

Exhibit 2-15. Case 1A & 1B – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Commercial Status
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	Commercial
2	Condensate Pumps	Vertical canned	Commercial
3	Deaerator and Storage Tank	Horizontal spray type	Commercial
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	Commercial
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	Commercial
6	LP Feedwater Heaters	Horizontal U-tube	Commercial
7	HP Feedwater Heaters	Horizontal U-tube	Commercial
8	Auxiliary Boiler	Shop fabricated, water tube	Commercial
9	Closed Cycle Cooling System	Shell and tube HX & Horizontal centrifugal Pumps	Commercial
10	Raw Water System	Stainless steel, single suction	Commercial
11	Service Water System	Stainless steel, single suction	Commercial
12	Demineralized Water System	Multi-media filter, cartridge filter, RO membrane assembly, electro-deionization unit	Commercial
13	Liquid Waste Treatment System	ZLD	Commercial

Exhibit 2-16. Case 1A & 1B – Account 4: PFBC Coal Boiler and Accessories

Equipment No.	Description	Type	Commercial Status
1	PFBC	P200, supercritical, SNCR	Custom Design (supercritical)
2	SNCR Ammonia Storage & Feed System	Horizontal tank, centrifugal pump, injection grid	Commercial

Exhibit 2-17. Case 1A & 1B – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Commercial Status
1	Hot Gas Metallic Filter	Pressure vessel with replaceable filter elements, back-pulse cleaning	Custom Design
2	Mercury Control system	GORE® Sorbent Polymer Catalyst (SPC) composite material	Commercial
3 Capture only	SO_2 Polisher Absorber Module	Counter-current pack column Absorber, caustic solvent	Custom Design
4 Capture only	CO_2 Absorber System	Amine-based CO_2 capture (e.g., CANSOLV capture technology)	Custom Design
5 Capture only	CO_2 Dryer	Triethylene glycol (TEG)	Custom Design
6 Capture only	CO_2 Compression system	Integrally geared, multi-stage centrifugal compressor	Custom Design

Exhibit 2-18. Case 1A & 1B – Account 6: Turbo-Machines

Equipment No.	Description	Type	Commercial Status
1	Gas turbo machine	Integrated compressor, expander, and motor/generator	Custom Design

Exhibit 2-19. Case 1A & 1B – Account 7: Ductwork and Stack

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

Exhibit 2-20. Case 1A & 1B – Account 8: Steam Turbine and Accessories

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

Exhibit 2-21. Case 1A & 1B – Account 9: Cooling Water System

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

Exhibit 2-22. Case 1A & 1B – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Commercial Status
1	Ash handling system	-	Custom Design
8	Bottom Ash Storage Silo	Reinforced concrete	Custom Design
12	Fly Ash Silo	Reinforced concrete	Custom Design

Exhibit 2-23. Case 1A & 1B – Account 11: Accessory Electric Plant

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

Exhibit 2-24. Case 1A & 1B – Account 12: Instrumentation and Control

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2.6.3 The A&E Firm Access to Equipment Information

The A&E firm (Worley Group, Inc.) has adequate access to information on the equipment included in the proposed concept. Worley and Nooter/Eriksen are working closely with PFBC-EET and have complete access to their store of data, drawings, etc., for the P200 commercial module. Information from other suppliers (including those listed in Section 2.6.2) has been requested in key equipment specifications that have been released to solicit conceptual design drawings, budgetary quotes, and other technical information for this stage of evaluation (pre-FEED).

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