FINAL REPORT

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PROJECT TITLE

Modular Pressurized Coal Combustion for Flexible Generation

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Business Case for the Proposed Technology

The proposed coal power technology for this project is a staged pressurized oxy-combustion (SPOC) system for a supercritical steam-Rankine cycle at a nominal 300 MWe size.[1] This document describes the current U.S. domestic and international coal power market and how the proposed technology is ideally suited to ensure that coal power is available to address the existing and future challenges of ensuring that the U.S. grid can supply reliable, low cost, low-emissions power.

The current market for coal power varies widely on a regional basis, but in all cases, one or more of the following drivers impact its future viability:

- ***Competition against other power sources*** – In some regions, coal remains a low-cost generator, while in others, NG-based power is more economical due to the availability of low-cost NG.
- ***Drive towards low carbon*** – 179 countries have signed the 2015 COP 21 Paris Agreement (Accord de Paris), with the goal of reducing greenhouse gas (GHG) emissions. While the U.S. is not a party to this agreement, many states have enacted low-carbon initiatives, including several that have committed to 80% reductions by 2040. Coal plants produce twice as much CO_2 per MWh as NGCC plants, and are being targeted for closure at an alarming rate.
- ***Energy security*** – Coal is an abundant natural resource, representing energy security and reducing the need for reliance on fuels or energy from foreign countries. This is true in the U.S. as well as abroad, and identifying ways to use it more effectively can be critical for geopolitical security.
- ***Environmental regulations*** **–** Coal emission regulations – CO, NO_X, hazardous air pollutants, mercury, particulate matter, and SO_X – vary globally, but coal universally remains a tougher permitting challenge than NG.
- ***Financing*** **–** Financing is becoming more challenging for larger plants, as the future power market has significant uncertainties, especially around carbon emissions. Coal power plants are a particular challenge (30 banks have stopped financing coal). Smaller, modular plants are thought to be lower risk since these require less capital and a faster rate of return, and hence afford a better opportunity for financing.
- ***Meeting a changing market*** **–** The energy market is changing, largely due to the growth of intermittent renewable energy (IRE). Intermittency requires grid protection provided by dispatchable sources, which largely comes from fossil-based units. In the U.S., coal power plants are needed to provide such grid support, but this requires that they operate flexibly, which can be deleterious to plant performance and integrity, potentially compromising plant life. Such operating behavior will likely occur worldwide, as renewables grow, reducing the demand for base-load fossil power, while putting extra importance on their ability to provide grid resilience.

United States

New coal power has stagnated in the U.S., where coal is often not competitive with NG, or presents significant future environmental risks. There are few known coal power projects advancing in the U.S. and some utilities have pledged to eliminate coal from their supply mix. For a significant resurgence in new coal, several changes are needed, in addition to what has been discussed above. These include:

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[1] All powers, energies and efficiencies reported are net, unless explicitely stated otherwise.

- ***Increase in the relative price of NG compared to coal*** **–** While this has not been forecasted, it remains a possibility, especially as the demand for NG grows internationally and the push for renewables reduces the ability to increase the number of NG pipelines.
- ***Larger value for CO_2 either by regulation or for utilization*** **–** If a significant market for CO_2 develops, this could help drive new coal power with carbon capture and storage (CCS). Enhanced oil recovery (EOR) remains the primary form of utilization and tapping into this market will likely be a necessity for any new coal plants with CCS in the short term. US Governmental programs such as 45Q [2] provide a value for captured CO_2 as well, which aids in the overall project economics. In general, the worth of capturing CO_2 must be greater than the cost, which is not presently the case in most circumstances. Hence, the value must increase (perhaps by regulation) but, more importantly, the cost of capture must decrease significantly.
- ***Regulatory certainty*** – Uncertainty in future regulations increases risk, which makes coal power projects difficult to finance, and generators more reticent to invest in such projects.

Outside the U.S.

The demand for coal outside of the U.S. differs by region and country, as summarized below.

- ***China*** **–** China is the largest coal producer and consumer in the world and coal accounts for 70% of its total energy consumption. Although China anticipates coal capacity growth of about 19% over the next five years, this comes at a time of a slowdown in electricity demand. As a result, many coal plants have been operating at reduced capacity factors. However, there is still a need for new power, especially in the west, and a large supply of coal exists in China. Coal plants that are efficient and smaller will likely be of appeal. There is also a growing interest in CO_2 utilization for EOR and enhanced gas recovery.
- ***Europe*** **–** In Western Europe, several countries have announced plans to end coal-fired generation within their borders or set in place emissions targets that would effectively require an end to coal without CCS: France by 2023, the United Kingdom and Austria by 2025, the Netherlands by 2030, and Germany by 2050. This makes new coal power difficult if not accompanied by CCS. In Eastern Europe, there is greater potential for new coal plants as brown coal is abundant and cheap. CCS may be a challenge in Europe, as underground storage is not popular, although Norway is developing a potential sink for CO_2 in the North Sea.
- ***India*** **–** India has large domestic coal reserves and recently had the largest growth in coal use of any country. India's draft National Electricity Plan indicates that the 50 GWe of coal capacity under construction is sufficient to meet the country's needs for the next decade, but new coal remains a possibility. Most new coal plants proposed are state-of-the-art pulverized coal (PC) or circulating fluidized-bed (CFB) supercritical units, as India has imposed a carbon tax on coal, approximately \$6.25/tonne-CO_2, making efficiency important. Work has been undertaken to locate CO_2 storage reservoirs, but CCS is not yet a major initiative.
- ***Japan*** **–** As of 2018, Japan had over 44 GWe of coal plants in operation, with over 6 GWe permitted or in construction. Japan's climate pledge is to reduce GHG emissions by 26% from 2013 levels by 2030, so improving efficiency and potentially performing CCS are important factors in Japan. Smaller-scale plants are also likely, in part because availability of required

[2] 26 USC 45Q: Credit for carbon oxide sequestration. From Title 26-Internal Revenue Code, Subtitle A-Income Taxes, Normal Taxes and Sub-taxes, Subchapter A-Determination of Tax Liability, Part iv- Credits Against Taxes, Subpart D-Business Related Credits

space/footprint is an issue. Japan is very interested in novel coal power cycles, including oxy-combustion.

- ***South Korea –*** Coal produces roughly 40% of South Korea's power and the country plans for additional coal power,[3] despite having a climate pledge for a 30% reduction in GHG emissions by 2030. South Korea's 8th Basic Plan for Electricity Supply and Demand (8th BPE) has a target of 35% of coal in the generation mix before 2030. Nonetheless, the country is set to add a net five gigawatts of new coal capacity by 2022. There is also strong interest in oxy-combustion, and the country is investing in several technologies, including pressurized oxy-combustion.[3]
- ***Others –*** Coal is growing in some regions of Africa (e.g., Kenya and Zimbabwe) and Southeast Asia (e.g., Indonesia and Vietnam), which presents opportunities for new coal plants. Low-cost coal power and smaller-scale plants will be critical in these regions.

Advantages of the Proposed Technology

- The SPOC technology is ideally suited for net electrical output capacities of 300 MWe or less. The modular construction ensures that a high efficiency is maintained, even at this small plant size, while maximizing flexibility. The smaller units also minimize the financing hurdle needed for investment.
- Pressurized oxy-combustion is one of the highest-efficiency and least-cost technologies for CO_2 capture. The net efficiency for the proposed technology, using Illinois #6 coal and Powder River Basin (PRB) coal at 300 MWe, is 35.64 % and 34.5% HHV basis, respectively. Typical improvements in efficiency, compared to atmospheric oxy-combustion or post-combustion capture (PCC), are 3.5–7.5 percentage points. Furthermore, on a total plant cost (TPC) basis, the proposed technology will be more economic than these options even at smaller scale.
- The SPOC technology is well suited for energy storage, as storage of liquid oxygen allows the energy used to generate oxygen to be scheduled to meet local energy market demands. Energy storage is growing in importance as the penetration of IRE increases. Liquid oxygen storage (LOS) would allow the coal unit to operate with less cycling, delivering power to the grid when needed and storing energy when not. This allows the unit to operate more often under optimum design conditions while reducing power export when IRE is at maximum production and prices are low. Moreover, if this unit captures CO_2 for utilization (e.g., EOR), it may be required to operate near continuously, either to deliver an agreed-to amount of CO_2 or to improve the overall economics. With energy storage, the SPOC plant can provide CO_2 continuously while allowing power to be provided to the grid when needed. In short, energy storage can have a significant impact on the competitiveness of SPOC.
- In addition to the potential for integrated energy storage, the proposed system has substantial flexibility. This is due to the ability of the individual fuel stages to be shutdown, allowing steam generation to be matched with demand requirements and very low turndown. The flexibility provided by the technology could be key to the demands of future markets, particularly when energy storage is incorporated into the design.
- The opportunity exists to construct the system as a pressurized-air technology (i.e. as Modular Pressurized Air-fired Combustion, MPAC), to deliver high efficiency power before converting the unit to SPOC, if desired. This ensures cost competitiveness in many regions in the short term, where there is no market mechanism to cover capture costs, e.g., Africa. Also, a greater market for the modular boilers will reduce the cost of the modules even in the U.S.

[3] KEPCO Annual Report, 2017, page 62

Factors That Must Be Addressed with the Proposed SPOC Technology

- Advancement of the components that are at lower technology readiness levels must be achieved, and the proposed technology must be demonstrated at significant scale.
- Assessment of the most beneficial duration for, and size of liquid oxygen storage for the overall system in target market scenarios.
- Evaluation of how the air separation unit, which provides the O_2 for oxy-combustion (SPOC), can operate flexibly with and without liquid oxygen storage.

What Is Needed for the Technology to be Competitive

The U.S. Department of Energy (DOE) performed a techno-economic analysis for coal power plants using PRB with and without CCS (i.e., Post Combustion Capture (PCC)), as shown in Table 1, with TPC, levelized cost of electricity (LCOE), and CO_2 captured cost adjusted to 2019 dollars by EPRI.

Table 1: Techno-Economic Performance Summary

Technology	Case	Size, MWe	Efficiency, % HHV	TPC, $/kW	LCOE, $/MWh	CO_2 Captured Cost, $/tonne
Oxy-combustion (atmospheric, supercritical)	S12F	650	31.0	4084	169.0	51
PC without CCS (supercritical)	S12A	650	38.8	2406	94.2	N/A
PC with PCC CCS (supercritical)	S12B	650	27.0	4243	181.4	52

The DOE calculated that a 727-MWe NG power plant without CCS had a TPC of $780/kWe and an LCOE of $59.3/MWh. With CCS the TPC was $1984/kWe and LCOE was $110.4/MWh, with a CO_2 captured cost of $103/tonne-$CO_2$. Based on these data, EPRI has determined that:

- For the LCOE of NG with CCS to equal the LCOE of coal (at $2.2/MMBtu) with PCC the NG price must increase from $4.4/MMBtu to $11.6/MMBtu (2 ½ times increase).
- The TPC needed for the SPOC technology to equal that of coal with PCC is $3914/kW.
- The TPC needed for SPOC to result in a cost of CO_2 captured of $40/tonne is $2926/kW.

Note that these numbers are all for larger-scale power plants and hence do not account for any economies associated with scale. One project that provides some insights is Petra Nova's WA Parish 650-MWe Unit 8. The project installed PCC to capture a 240-MWe equivalency slipstream of CO_2 for EOR in 2017, which is comparable in size to the proposed technology. The CCS retrofit cost of $635M includes the cogeneration facility that is used to provide power and heat to the CCS island. Add to this the projected cost of the original 650-MWe supercritical unit, and the estimated TPC for the full plant with partial capture was $5052/kWe – substantially higher than the TPC value given in Table 1. This project acts as a cautionary tale, illustrating the higher cost of CCS at smaller scales for more conventional technology.

Another example is the most recent coal power plant built in the U.S.: a small 84-MWth combined-heat-and-power plant at the University of Alaska Fairbanks built for $248M, which equates to a TPC of around $8000/kWe. Annual fuel costs for the plant were about $5M for coal and $20M for NG. In such areas where NG supply is not available or is inconsistent, if coal can be delivered cheaply, smaller-scale coal plants have an opportunity. For the proposed technology, to account for the risk associated with less mature technology, a TPC of ~$6000/kWe would be appealing. EOR opportunities will also be important in such cases.

Based on this high-level review, Table 2 provides cost targets for the technology in various regions and scenarios.

Table 2: Technology Cost Targets for Various Regions and Scenarios

Case	Region	Scenario	Competition	Cost Targets
1	U.S.	NG not available, coal and potentially EOR / 45Q available	Smaller-scale coal	TPC < $6000/kWe
2	U.S.	NG < $4.4/MMBtu (coal $2.2/MMBtu) and no CO_2 value	NG without CCS	LCOE < $59/MWh
3	U.S.	NG < $4.4/MMBtu (coal $2.2/MMBtu) and EOR / 45Q available	Coal or NG with CCS	TPC < $3000/kWe; CO_2 cost < $40/tonne
4	Africa, Asia, Eastern Europe	NG > $11.6/MMBtu (coal $2.2/MMBtu)	Coal with CCS	LCOE < $160/MWh; TPC < $3900/kWe
5	Anywhere	CO_2 value of $50/tonne	Any CCS	CO_2 cost < $50/tonne
6	Anywhere	Non-baseload operation with CCS	Coal FIRST technologies	TPC < $3900/kWe; CO_2 cost < $50/tonne; value for energy storage

Cases 1 to 5 in Table 2 assume a base-load unit with 85% capacity factor and ~3M tonnes of CO_2 captured annually. The CO_2 cost value of $40/tonne is approximately a summation of EOR value with 45Q credits (or 45Q credits for storage only). Case 2, with low NG price and no value for CO_2, is not a competitive option for this technology. Case 3 is a stretch goal and possibly attainable in the future. Hence, the cost targets for the technology are: TPC = $3900/kWe, LCOE = $160/MWh net, and CO_2 cost = $50/tonne. Based on preliminary calculations, the costs for the proposed technology should be able to achieve these targets.

EPRI did a detailed AACE Class V cost estimate for coal-fired, 550-MWe net SPOC system for the recently completed DOE-funded project DE-FE0029087 “Enabling Staged Pressurized Oxy-Combustion: Improving Flexibility and Performance at Reduced Cost.” This cost estimate used standard DOE-NETL costing assumptions and methodologies consistent with several coal-based cost studies that have been published by NETL (e.g., “Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3,” DOE/NETL-2015/1723). Based on this, the TPC for the SPOC system at 550 MWe was estimated to be $3475/kW and the LCOE was $145/MWh (using PRB).

Using these numbers as a starting point and applying estimated DOE QGESS scaling factors, a rough estimate of the costs for a 300-MWe SPOC system are a TPC of $4150/kW and an LCOE of $169/MWh (note: both of these values are lower than NETL Case S12B), which are incrementally higher (~6%) than the business case targets specified for this proposed technology of $3900/kW and $160/MWh. However, these estimates do not account for any cost reductions associated with modularization or improved integration and engineering, and use a conservative overall scaling exponent of 0.71. The team is confident that the more detailed design and costing work to be done in the pre-FEED will result in a SPOC system at 300 MWe that bests the targets in terms of both LCOE and TPC.

Plant Concept Description

Introduction

The rapid addition of intermittent renewable energy sources into the electricity grid has led to uncertainties in the reliability and stability of the grid. Additionally, significant use of natural gas for power generation is reducing grid diversity, which could lead to price volatility, and risks to grid reliability during times of peak demand for heating and electricity. In this environment, there is a need for a coal-based process that has high efficiency and is low cost, while being intrinsically modular in its design, flexible in its operations, and is either inherently carbon-capture or is carbon-capture ready. Furthermore, it should be economical and quick to build and easier to finance at smaller scales in the range of 50–350 MWe, and have low water use.

The staged, pressurized oxy-combustion (SPOC) process is ideally and naturally suited for these requirements. The SPOC process, which was conceived at Washington University in St. Louis (WUSTL), and is being developed with U.S. Department of Energy (DOE) support **in collaboration with the Electric Power Research Institute, Inc. (EPRI), Doosan Babcock Ltd (DBL), and Air Liquide (AL),** has shown promise as a near-zero emissions (including CO_2) source of coal-fired power with high efficiency and good flexibility. The efficiency of the SPOC process is almost 3.5–7.5% points higher than first-generation, 550 MWe atmospheric-pressure carbon capture processes. The SPOC process has a small modular design which provides high flexibility and low capital cost. This system also allows for additional load-following capability through energy storage, in which pressurized, liquid oxygen can be stored in times of low demand and utilized in times of peak demand. This mode of operation, with LOS, ensures that the system can operate closer to design capacity by minimizing the ramping of the power plant. This also improves the overall economics of the plant because the sale of electricity can be maximized during times of high prices, as the air separation unit (ASU) will not need to be operated at full capacity. Storage also significantly reduces parasitic load and, since there is less cycling, yields less wear and tear on the plant.

The process flow diagram for the SPOC process is shown in Figure 1. There are two innovative ideas incorporated in this design which will be described below: 1) pressurizing the oxy-combustion process, and 2) staging the fuel delivery. This approach to oxy-combustion significantly improves the efficiency of this system over others, allows for a modular design, and improves the flexibility of operation, which are all critical criteria for future coal technologies.

1. Benefits of Pressurizing the Oxy-combustion Process

Since carbon capture and storage (CCS) requires pressurized CO_2, and compressing CO_2 downstream takes a similar amount of energy compared with compressing oxygen upstream, there is no additional energy required to pressurize the combustion process.

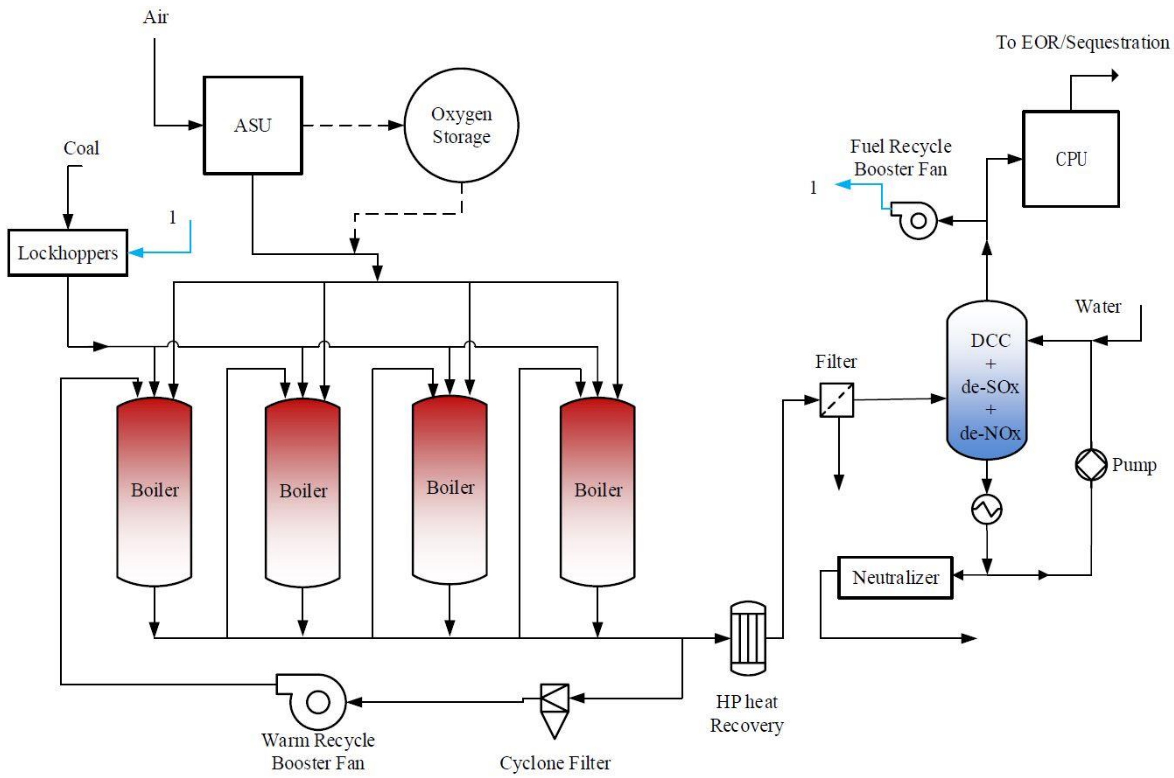

Figure 1: Process Flow Diagram of the SPOC Process

The are many benefits of pressurizing the oxy-combustion process, including:

1. Capturing the latent heat of condensation and utilizing this heat to increase cycle efficiency. Capturing the latent heat also reduces the efficiency penalty associated with using high-moisture fuels, since the latent heat is recovered, thereby making low-rank coal more valuable.
2. Simplifying the capture of SOx and NOx because pressure allows for co-capture of these pollutants in a simple water-wash column.
3. Greatly reducing gas volume, thereby reducing the size and cost of key components, which facilitates modular construction.
4. Avoiding air ingress, thereby reducing the cost of purification in the CO_2 compression and purification unit (CPU).
5. Improving burnout, thereby reducing the O_2 requirement for complete combustion and thus reducing purification costs as well.

The first two of the benefits listed above are explained in more detail below.

- ***High Efficiency Through Latent Heat Recovery From Flue Gas*** – By pressurizing the oxy-combustion process, rather than running at atmospheric pressure, the latent heat of the moisture in the flue gas can be recovered, which partially compensates for the parasitic energy consumption of carbon capture. The temperature at which the phase change occurs is strongly dependent on operating pressure. For example, at atmospheric pressure, the flue gas moisture condenses at 50–55°C. At a pressure of 16 bara, condensation occurs at 167°C. The significant increase in condensation temperature makes it feasible to utilize the latent heat in the steam cycle through heating the boiler feed water. At 16 bara, this approach leads to the elimination of the steam extraction from the low-pressure turbines and a portion of the extraction from the higher-pressure turbines. Less extraction allows more steam flow through the turbines and, thus, an increase in gross power and plant efficiency.

- ***Integrated Emissions Removal –*** Higher pressure enables integrated emissions control, which can replace traditional and expensive environmental control equipment such as selective catalytic reduction (SCR) for NOx and flue gas desulfurization (FGD) for SOx. This integrated environmental control scheme also reduces the capital cost of the process and allows for modular construction since the major equipment involved is a single direct contact column, and since the system is pressurized, the column is small enough to be manufactured in a factory.

  Studies have demonstrated that at elevated pressures of 15 bara or greater, gaseous pollutants in the flue gases are captured and converted to weak sulfuric and nitric acids when in the presence of water, due to an enhanced chemical interaction between S- and N-containing species.[4] The chemistry that drives these reactions only occurs at elevated pressure and test results have shown that almost all the SOx and about 80% of NO is removed at 16 bara.[5] The key requirements for this mechanism are that the NOx/SO_2 molar ratio is greater than about 0.5, the pressure is greater than 15 bara, and the process occurs in the presence of liquid water.

  In the SPOC process, the capture of emissions is combined with the process of flue gas moisture condensation and latent heat recovery in a single, counter-flowing, water-wash column. Wet flue gas at a temperature greater than the acid-gas dew point (≥ 200°C) flows into the gas-liquid reactor column against a downward flowing stream of cooling water, thereby reducing the flue gas temperature. Condensation of the flue gas moisture releases the latent heat into the circulating cooling water, and since moisture dew point temperature increases with pressure, the temperature of the exiting cooling water is sufficiently high to allow the heat to be used for low-pressure boiler feed water heating. The acidic water outlet from DCC is treated in a neutralization tank using a alkaline solution or equivalent. A part of the purified water is recycled to the DCC inlet, the rest is used as the cooling water makeup.

When applied in a SPOC system, this approach provides the following benefits:

1. Unlike atmospheric-pressure oxy-combustion, the flue gas need not be compressed because it is already at elevated pressure; thus, the challenge of avoiding corrosion when compressing a sour gas is eliminated.
2. The capture of flue gas latent heat occurs along with SOx and NOx removal, which is more economical as compared to separate capture systems.
3. Acid gas condensation occurs in a single device, reducing the chance of corrosion in other parts of the system.
4. Because no cooling is necessary before the flue gas enters the DCC, the overall efficiency of the process is maximized.

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[4] S. Ajdari, F. Normann, K. Andersson, F. Johnsson, Modeling the nitrogen and sulfur chemistry in pressurized flue gas systems, Ind. Eng. Chem. Res. 54 (2015) 1216–1227

[5] T. Zelalem Tumsa, S. Hoon Lee, F. Normann, K. Andersson, S. Ajdari, W. Yang, In Press, Concomitant removal of NOx and SOx from a pressurized oxy-fuel combustion process using a direct contact column, Chem. Eng. Res. Des. (2017)

2. Benefits of Staging Fuel Delivery

The second important innovation of the SPOC process is staging. Staging fulfills three important requirements for the technology: 1) increasing the efficiency of the process; 2) making the process intrinsically modular; and 3) enhancing flexibility for variable-load operation.

First-generation atmospheric-pressure oxy-combustion typically consists of burning coal with a combination of oxygen and a large amount of flue gas recycle (FGR) (60–70%) to obtain a similar heat flux profile to that of air-fired systems. The costs of first-generation oxy-combustion are high, partly because of this large amount of recycle . There is a strongly non-linear relationship between net plant efficiency and the amount of FGR, with a nearly linear impact of FGR on efficiency at low recycle, and an almost exponential impact at high FGR. Fan power requirements also scale non-linearly with recycle ratio, resulting in significant FGR fan power requirements for high FGR as well. Results suggest that FGR should be kept below 30% to miximize plant efficiency. [6]

The wall heat flux, which in first-generation oxy-combustion processes is controlled through high FGR, is managed through the staging of the boilers in the SPOC process (Figure 1) and FGR is maintained less than 30%. Furthermore, by having multiple boiler stages, as opposed to a single boiler, the system is intrinsically modular, and this modular design allows for the complete bypassing of one or more boiler stages during low demand, thus adding a significant level of control during load following.

Addressing the RFP requirements

The specific requirements as outlined in the RFP are addressed below. The requirements are shown in bold and an explanation of how SPOC meets those requirements follows.

1) High overall plant efficiency (with minimal reductions in efficiency over the required generation range) – The net efficiency of the proposed 300 MWe proposed power plant (inherently including carbon capture) can reach 35.6% HHV when a supercritical (SC) steam cycle and Illinois #6 coal are used, which is about 4-6%-points higher than first-generation atmospheric-pressure oxy-combustion power plants with the same SC steam cycle. Furthermore, the SPOC process lends itself to more advanced cycles, such as ultra-supercritical (USC), advanced ultra-supercritical (AUSC) or supercritical CO_2 (sCO_2) power cycles, where even higher efficiencies can be realized. These cycles have not been considered in this work, not because they are not relevant to the SPOC process, but rather to reduce risk during the early stages of the SPOC development. These cycles can be incorporated into the SPOC process as the technology matures. Efficiency improvements with these advanced cycles would be in the neighborhood of 4%-points or more.

In addition to having a high efficiency at full load, the SPOC process can maintain high efficiency during turn down by shutting down one or more of the boiler stages, while maintaining the rest of the boiler stages at full-load conditions. Thus the efficiency penalty due to part-load operation is minimized.

The target output for the SPOC process is 300 MWe (approx. 400 MWe gross). For plants less than 300 MWe, consideration must be given to the appropriate sizing of steam turbine and generator, taking into account the corresponding steam cycle efficiency. Very approximately, it is estimated that the steam turbine cycle efficiency will reduce from about 51.5 % for a nominal 350-

[6] A. Gopan, P. Verma, Z. Wang, R. Axelbaum, Quantitative analysis of the impact of flue gas recirculation on the efficiency of oxy-coal power plants, Int. J. Greenh. Gas Control. (2019) *(Submitted)*

400 MWe gross steam turbine down to about 46.5% for a nominal 100 MWe gross steam turbine. Table 3 provides a summary of steam turbine cycle efficiencies, together with estimated overall power plant efficiencies for both SPOC and MPAC for a range of steam turbine generators (STG).

Table 3 : Summary of Small Supercritical STG Sizes and Approx. Plant Efficiencies

Supercritical STG	**MWe gross**	**100**	**200**	**350 - 400**
Steam Turbine Efficiency	%	~ 46.5%	~ 49.0%	~ 51.5%
Overall Plant Net Efficiency : MPAC	% HHV basis	~ 37.5	~ 40.0	~ 41.5
Overall Plant Net Efficiency : SPOC	% HHV basis	~ 31.0	~ 33.8	~ 35.6

2) Modular (unit sizes of approximately 50–350 MW net), maximizing the benefits of high-quality, low-cost shop fabrication to minimize field construction costs and project cycle time – The SPOC system is inherently smaller because of the reduction in the total volume of the gas at pressure. The staged boiler configuration and modular design further reduces the size and cost of each boiler. Because of the long, thin nature of the pressure vessels, the design allows them to be factory built using skilled labor and high-quality control procedures, and then shipped to the power plant location. The size of each boiler is small enough to allow them to be shipped by rail. The use of modular construction facilitates: 1) significantly lower construction costs; 2) on-time and in-budget plant construction; and 3) excellent quality control.

3) Near-zero emissions, with options to consider plant designs that inherently emit lower amounts of carbon dioxide (amounts that are approaching those of comparable natural gas technologies) or could be retrofitted with carbon capture without significant plant modifications – The proposed conceptual plant has 90% or better carbon capture. In addition, as discussed above, SOx and NOx are removed from the flue gas in the DCC.

4) Capable of high ramp rates and minimum loads – The proposed plant will have comparable ramp rates (envisaged at this stage to be in excess of that achieved by commercial IGCC plant of 4%/min) and lower minimum loads than a conventional PC plant due to the parallel, modular boiler configuration and smaller boiler size. The plant is expected to be able to operate at a load as low as 25% of turbine maximum continuous rating (TMCR) with a modest reduction in efficiency.

5) Integration with thermal or other energy storage (e.g., chemical production) to ease intermittency inefficiencies and equipment damage – Integrating liquid oxygen storage into the system improves the process in several ways, including:

- The flexibility of power production is improved because the load of the combustion system can be held constant or only varied modestly as plant power output is varied. This is accomplished because the ASU compression work can be increased at times of low demand to allow oxygen to be stored, and reduced at times of peak demand by using the stored liquid oxygen so that less oxygen needs to be produced (less parasitic load).
- The overall economics of the system will be better because more electricity can be supplied during times of peak demand (high electricity prices), while avoiding selling electricity at times of low demand (low electricity prices).

6) Minimized water consumption – An important feature of the proposed plant is its small or negative water demands:

- The moisture in the flue gas is recovered, which reduces overall water consumption as the condensed water is actually supplied to the system.
- If dry cooling is used, the plant would be a net producer of water, which would be especially important in arid regions. Alternatively, a combination of wet-dry cooling (Heller coolers) can be used to ensure that plant performance is not compromised and water consumption is low.
- The plant efficiency is higher than other carbon capture plants, and thus less steam flow is needed in the steam cycle. Since cooling rate is proportional to the steam flow rate, the high plant efficiency reduces water consumption.

7) Reduced design, construction, and commissioning schedules from conventional norms by leveraging techniques including but not limited to advanced process engineering and parametric design methods for modular design – A significant reduction in the overall schedule comprising detailed engineering, construction and commissioning is envisaged for the modular SPOC boiler plant compared to that of a corresponding size of conventional pulverized coal-fired supercritical boiler plant. The utility boiler plant construction inherently requires more of a stick-built approach, whereas the SPOC boiler stages allow for the opportunity to maximize a more modular build. Both the Combustor pressure vessels (PVs) and Convective PVs can be fabricated off-site and delivered in sub-modular assemblies. This approach will maximize off-site fabrication, assembly and inspection in order to minimize the extent of on-site construction.

The overall construction plan will be optimized to ensure successful implementation of the modular approach utilizing 4D-Planning, linking timely design and procurement activities with constructability reviews, manufacturing, quality, transportation, erection logistics and commissioning scheduling. Furthermore, the degree to which design schedules are able to be reduced depends upon the level of standardization of size and configuration of the SPOC boiler modules. A detailed parametric design methodology, underpinned by a knowledge-based engineering process, will allow greater design adaptation in delivering a SPOC modular boiler plant to meet client specific needs.

Virtual reality (VR) modelling can be combined with more conventional 2D and 3D plant modelling to enhance the design. The VR model will also provide a basis for future plant assessment through ready reference to a digital twin, allowing future modifications, upgrades and outages to be considered in a comprehensive manner, integrating with the benefits of utilizing 4D planning for optimum scheduling and risk mitigation.

8) Enhanced maintenance features including technology advances with monitoring and diagnostics to reduce maintenance and minimize forced outages – To ensure planned and unplanned outages are minimized, the full life cycle of SPOC from conceptual design through end-of-plant-life must be considered. Factors that will be considered include: reliability engineering and asset management solutions comprising reliability, availability and maintainability (RAM) assessments, risk based inspection (RBI) together with reliability centered maintenance (RCM). These combined approaches, enhanced with big data management and digitalization, will allow the EAF of 85% to be achieved and improved upon. Where possible, advanced technologies will also be used for monitoring and diagnostics. For example, in-situ monitoring of corrosion will be employed to enable active process control and maximize tube life.

9) Integration with coal upgrading, or other plant value streams (e.g., co-production) – The proposed plant, being a pressurized combustion process, has better combustion performance than atmospheric-pressure oxy-combustion processes. The coal combustion rate is significantly enhanced by faster reaction rates, gasification, and longer residence times. Therefore, complete combustion can be achieved for a wider range of coals. Also, the plant has excellent performance for low-rank coals since much of the latent heat in the flue gas can be captured in pressurized combustion, which results in the effective heating value of “low-Btu” fuels being significantly increased. Also, since oxygen is available, the combustion performance of low-rank coal can be enhanced by increasing the oxygen concentration.

The SPOC process is, in essence, a poly-generation plant in that, in addition to power, it produces CO_2, N_2, Ar, ash and water, all of which can generate a value stream.

10) Capable of natural gas co-firing – A unique feature of the pressurized boiler design in the SPOC process is that it utilizes a broad, tailored particle size distribution (PSD) for the coal (i.e., a small and large size range) to adjust heat flux profiles along the height of the boiler. This feature makes the boiler inherently capable of co-firing with natural gas, as the heat flux profile in the boiler can be adjusted to approach the designed profile by varying the coal PSD (through control of the mills). Co-firing natural gas has been demonstrated from 0% to 100% in small-scale (100 kWth) pilot testing at WUSTL. In addition, the SPOC process can be co-fired with biomass to produce carbon-negative power.

Detailed Description of the SPOC Process

In the SPOC process, oxygen is produced via a cryogenic ASU (Figure 1). The heat generated from the compression of air is integrated into the steam cycle and utilized for boiler feed water regeneration. The boilers are arranged in a series-parallel configuration to allow for minimal FGR but also modular design. Coal is fed with a pneumatic dry feeder using a small amount of FGR as motive gas and the amount of coal fed to each of the nominally four boiler stages is nearly the same. A small amount of FGR (< 30%) is recycled back to the first boiler stage from the combined flue gas flow emanating from all SPOC stages. A portion of the flue gas from the first boiler is fed into the next one and acts as the diluent to control heat flux. The rest is sent downstream. Note that the amount of flue gas sent to the second stage is nearly the same as that sent to the first stage, so the operations of both boilers are similar, but the total amount of FGR has not changed, since the flue gas entering the second stage was not recycled. The process is repeated for the last two boilers. The exit temperature of the flue gas from each combustion stage and economizer is 340°C.

Downstream of the pressurized boilers, the flue gas stream is fed into a high-pressure heat recovery unit. In this unit, heat is extracted and integrated into the power cycle and the flue gas is cooled to slightly above the acid dew point temperature. After the pressurized heat recovery unit, fly ash particles in the flue gas are removed by a particulate filter.

After particulate removal, the flue gas is further cooled in the DCC column, in which the flue gas flows against a stream of cooler water, thereby reducing the flue gas temperature and resulting in condensation of the flue gas moisture. The water leaving the bottom of the column is at sufficiently high temperature that it can use for boiler feed water heating, improving plant thermal efficiency. Due to the high-pressure operation, sulfur- and nitrogen-containing species are dissolved in the cooling water and removed. This process of emission removal, which is effective only under pressure, combined with latent heat recovery, is a key benefit of the SPOC process.

The CO_2 from the DCC goes to the CPU where it is further purified to meet specifications for utilization (e.g., enhanced oil recovery [EOR]) or sequestration.

The process modeling approach used is similar to that used for National Energy Technology Laboratory (NETL) studies. Aspen Plus™ (v10) software is used for the process modeling and NETL guidelines for CO_2 purity are used.[7] Bituminous coal is assumed, and the proximate and ultimate analyses of the coal are presented in Table 4. The modeled SPOC power plant has an output of 300 MWe with a supercritical Rankine cycle, and is located at a generic Midwest location. The process is designed for 90% carbon capture but is capable of higher than 95% carbon capture, with EOR-grade purity. The design, operation, and performance characteristics of the key components of the SPOC models are shown in Appendix A.

Table 4: Design Coal Characteristics: Illinois #6

Proximate Analysis	**Wet Basis, %**
Moisture	11.12
Ash	9.70
Volatile Matter	34.99
Fixed Carbon	44.19
Total	*100.00*
Heating Value	**Wet Basis**
HHV, kJ/kg	27,113
Ultimate Analysis	**Wet Basis, %**
Carbon	63.75
Hydrogen	4.50
Nitrogen	1.25
Sulfur	2.51
Chlorine	0.29
Ash	9.70
Moisture	11.12
Oxygen (By Difference)	6.88
Total	*100.00*

The steam conditions and key assumptions and approaches follow NETL's guidelines baseline cases.[8] The steam cycle considered is a single-reheat supercritical Rankine cycle, with the main steam at 241 bar and 593℃, and the reheat steam at 49 bar and 593℃. The steam cycle parameters are presented in Appendix A (Table A2) and the steam cycle is shown in Figure 2. Seven indirect feedwater heaters and one direct feedwater heater for deaeration were used in the steam cycle.

For the gas-side modeling, the Peng–Robinson equation of state was used. For SOx and NOx removal, the ENRTL-RK method (ENRTL activity coefficient method with RK equation of state) was used so as to model the stream of dilute acid formed and the electrolytes present in the unit. For the steam side (Rankine cycle), STEAM-TA (steam table) was used.

Detailed Results from Process Modelling during Flexible Operation

As noted above, the boilers are connected in a series-parallel configuration, unique to the SPOC process. This mode of operation minimizes FGR and maximizes efficiency. By adjusting the flow rates of the flue gas entering each stage, all stages can have similar operating conditions. Also, the plant achieves a very high level of flexibility, since low load can be achieved by shutting down one or more boiler stages, while operating the remaining boiler stages at optimum efficiency.

[7] M. Matuszewski, Detailed Coal Specifications, Off. Progr. Perform. Benefits. NETL (2012) 55

[8] NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3, Natl. Energy Technol. Lab. 1a (2015) 240

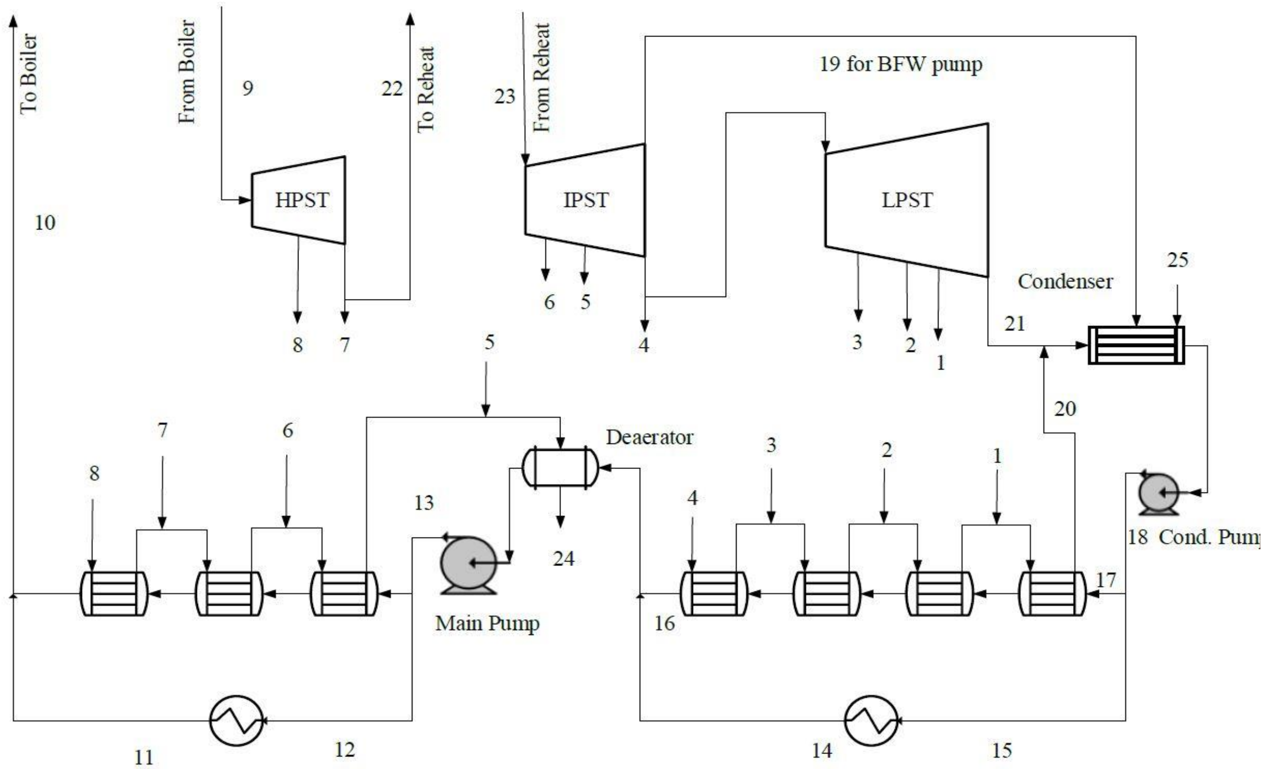

Figure 2: Process Flow Diagram of SPOC's Steam Cycle

This unique flexibility of the SPOC system, driven by the ability to bypass individual combustion/boiler stages, enables the ability to maintain stable combustion and heat transfer in the remaining stages. This mode of operation, where one or more boiler stages are taken out of service, can be employed, for example, where there are seasonal variations in demand, i.e., where it is expected that demand will be low for a considerable amount of time. For daily or weekly changes in demand, the system will be cycled down in a more traditional manner. The main constraint to flexibility is in the ASU and CPU, as both units contain compressors that have tight operating windows.

The SPOC process has been evaluated from full to part-load down to 12% net load. These cases are summarized in Table 5. The steam turbine is configured to operate in sliding-pressure (SP) mode from full load down to the boiler-design Benson load (assuming all stages are in operation), the Benson load being the lowest load at which the boiler is designed to maintain once through operation. For each SPOC boiler stage, at loads below the Benson load, constant pressure

Table 5: SPOC Turndown Case Performance Summary (Illinois #6 Coal)

Parameter Load	**100%**	**75%**	**50%**	**25%**	**12%**
Steam Turbine Operation Mode	SP	SP	SP	CP	CP
SPOC Boiler Modules in Service	4	4	4	2	1
Module Firing Load, %	100	76.5	51.9	64.0	89.0
Overall Plant Efficiency, % HHV	35.64	34.85	34.24	27.99	19.63

operation will need to be maintained with the boilers operating in forced circulation mode. The design Benson load has been proposed as 40% BMCR (nominally 40% TMCR). Below this overall plant load, main steam is throttled at the turbine stop valve to ensure the boiler circuits do not operate at too low a pressure to maintain stable furnace thermo-hydraulic performance; the Steam turbine being operated in constant pressure (CP) mode.

Table 5 shows the number of SPOC boiler stages in operation for the given %TMCR plant loads along with the steam turbine operating mode. For low load operation and to achieve significant plant turndown, the SPOC system can vary the number of boiler stages, e.g. 4-off for 50%TMCR down to 2-off for 25%TMCR, by maintaining the combustor stage firing load in the remaining stages.

If the system permitted full sliding-pressure operation, the prospect of operating at a high individual-stage firing rate with ultra-low back pressure and with the steam turbine operating at very low load would be introduced. Very low pressure yields much larger density differences between water and steam at the point of boiling, normally requiring larger bore tubes to accommodate this flow without incurring excessive internal steam velocities. Throttling the steam turbine at reduced load also helps to maintain the system in a better state of readiness for rapid load ramping, as the throttle valve can be opened immediately, while bringing "hot standby" stages back into service.

The minimum individual-stage firing rate is just over 50% of full firing rate with all 4 stages in service at 50% net output. WUSTL has demonstrated stable combustion down to as low as 8% fuel heat input in the 100-kWth pilot facility, suggesting boiler loads would only be limited by the steam turbine system ability to maintain synchronization on the grid. The main overall loss in efficiency at reduced-load operation centers around the ASU and CPU equipment. These compressor-based units can only turndown to 85% load before requiring recycle flow (thereby consuming more specific power). The ASU for this design consists of 2 individual trains (due to the oxygen generation duty needed), such that a turndown to 50% does not represent a significant efficiency loss since one of the ASU trains can be placed in "cold standby." However, as the CPU is a single-train arrangement, this will consume significantly more specific power at all loads below 85%. The extreme case here is 12% net load, which consumes 22% of the fuel input to maintain auxiliary power requirements.

Regarding cold start-up (CSU), warm start-up (WSU) and hot start-up (HSU), based on current state-of-the-art ultra-supercritical coal fired power plants, typical start up times to full load are on the order of 6 hours for CSU, 3 hours for WSU and < 2 hours for HSU. Similar start up times should be achieveable for SPOC based on utilization of a suitable sized LOx store. During the Pre-FEED study, further analysis of start-up times will be undertaking to attempt to reduce these to the 2 hour requirement of the Coal FIRST Initiative.

Emissions control summary

Particulate emissions are controlled by a high pressure particulate filter. As mentioned in detail above, a key feature of the SPOC process is that the removal of SOx and NOx from the flue gas will be accomplished in the DCC, with higher than 99% removal of SOx and over 75% removal of NOx, which is already low in oxy-combustion systems since the N_2 is removed from the air. Over 90% of the CO_2 is removed from the flue gas of the SPOC plant.

CO_2 control strategy (Inherently Capture with an option for Carbon-Capture ready)

The SPOC process has inherent carbon capture. The CO_2 coming out of the CPU at a pressure of 150 bar can be used for EOR or sequestration.

One important consideration for the Coal FIRST initiative is ensuring that the modular construction affords sufficient cost savings to ensure the viability of the technology for the U.S. market. One method of ensuring this is to have a system that has broad international appeal. Much of the international markets, particularly in developing countries, are not able to make the investment in carbon capture up front. For this market, the SPOC can be modified as a carbon capture ready process. The new process, shown in Figure 3, is called the Modular, Pressurized Air-fired Combustion (MPAC) and incorporates air-fired, pressurized-coal combustion to obtain a higher efficiency than present air-fired plants, while being adaptable to carbon capture at modest cost. The main components of the MPAC system are like the SPOC system. Thus, the economies of mass production can be realized since the market for the main novel components are similar. The MPAC is like the SPOC system except there is an air compressor, instead of an ASU, and instead of a CPU, an expander is added downstream of the DCC to recover much of the compression work of the compressor.

The MPAC plant can be upgraded to a SPOC plant by adding the ASU components (note the ASU air compressor is already available) and adding a CPU (compare Figures 1 and 3). The only component that is lost during the upgrade is the expander. The MPAC system has been modeled with Aspen Plus™ software for similar process conditions and load. Importantly, since the MPAC cycle captures the energy in the latent heat of the flue gas moisture, the process has a net efficiency that is more than 1 %-point greater than a conventional air-fired PC plant with the same steam

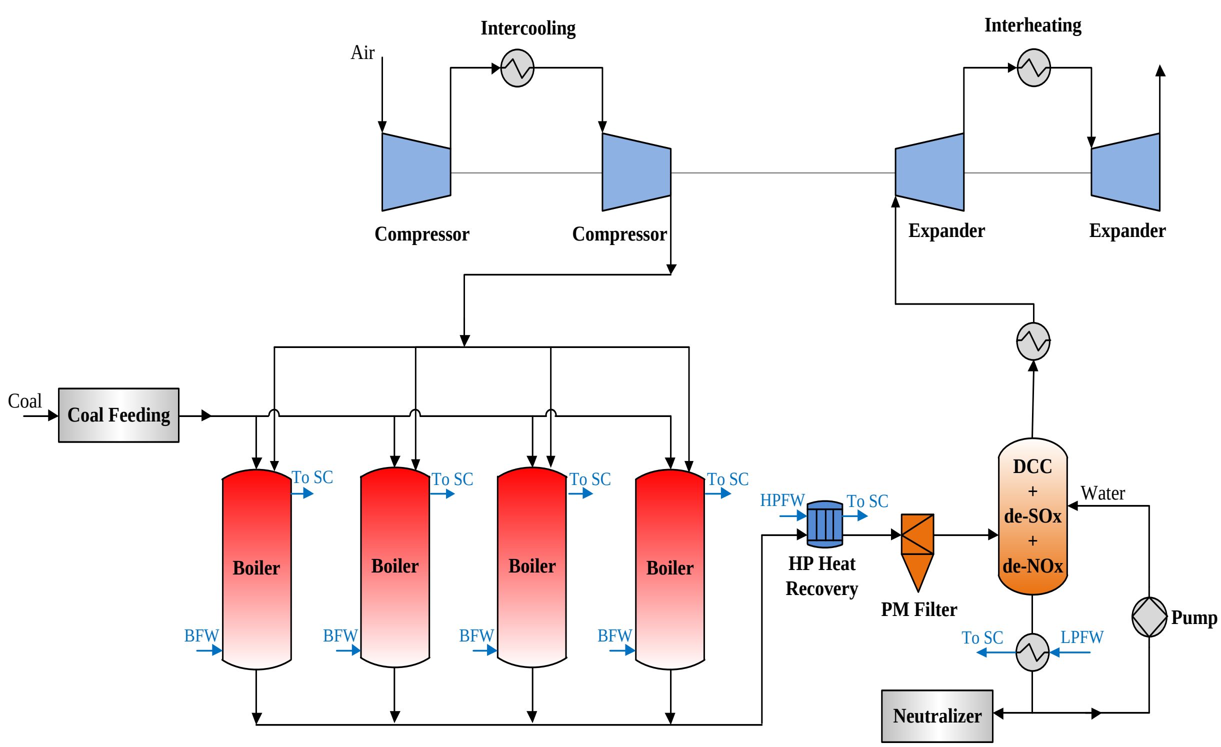

Figure 3: Process Flow Diagram of the MPAC Process (Carbon capture ready)

cycle configuration. The cost of a MPAC is expected to be equivalent or lower than a conventional air-fired PC plant, although more work must be done to evaluate actual costs. Thus, MPAC should be attractive to an international market where high-efficiency, 300–350 MWe systems are desirable. The assumptions and detailed results from the modeling of MPAC and design considerations are provided in Appendix B.

Description of each process block

1) ASU and Liquid Oxygen Storage – Since adsorption and polymeric membrane processes for air separation are economical only when the oxygen requirement is less than 200 tonnes/day and 20 tonnes/day respectively[9], a cryogenic ASU was chosen for the SPOC system. Air separation is performed at low pressure (1–5 bar) in a 3-column cryogenic unit, producing oxygen of 99.0 vol% purity. This oxygen stream is then compressed in multiple stages with intercooling to reach the desired combustor operating pressure (16 bara). The intercoolers for both the air and oxygen compressors use boiler feed water as coolant.

As noted above, WUSTL has demonstrated stable combustion down to as low as 8% fuel heat input in the 100-kWth pilot facility, suggesting boiler loads would only be limited by the steam-turbine system's ability to maintain synchronization on the grid. Thus, the main overall loss in

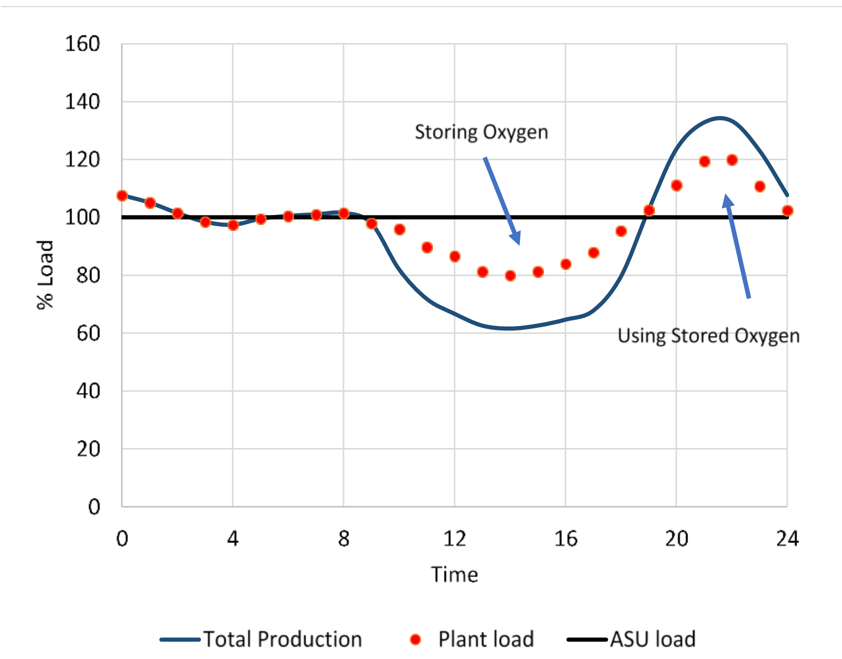

Figure 4: Oxygen Storage Methodology

[9] NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3, Natl. Energy Technol. Lab. 1a (2015) 240

efficiency at reduced-load operation centers around the ASU equipment. To address this problem during load following, oxygen storage can be used to maintain the ASU load close to 100% as well as enhance the overall efficiency of the SPOC power plant over a given period.

In Figure 4, the methodology to minimize the cycling of the ASU and power plant is presented. The minimization of cycling can be achieved by integrating the oxygen storage with the ASU. During the hours of low load, the ASU operates close to the rated capacity, while the power plant can be turned down to follow the required load. The extra oxygen produced during the period can then be stored. Since the ASU load will remain constant even during the turndown period, the overall electricity production can be further minimized, providing the capacity for the SPOC power plant to follow steeper load changes. During the period of high demand for electricity, the power plant can be operated at a higher capacity, while keeping the ASU load constant. The excess oxygen required to turn up the output can be provided by the stored oxygen. Since the ASU load will remain constant during high-load periods, the maximum electricity production will be higher than the high-load power plant capacity, again providing higher load coverage. The integration will use a low temperature thermal energy storage module (to recover cryogenic cold from LOx when being regenerated) which can be used for incoming air liquefaction during LOx storage. Final LOx/GOx heating will be steam driven using LP steam (like a steam air heater), this will ensure combustion equipment isn't over chilled and additional firing isn't necessary

Calculations based on load following suggest that an oxygen storage capacity of 0.5–2 hours of full load can follow a typical day of load change without changing the ASU load. Since, a typical start-up of an oxy-combustion power plant requires oxygen storage of at least 8 hours of full-load operation, there is sufficient storage built into the standard ASU to address diurnal load variations, but greater storage can be considered to address daily or weekly demand variations. The liquid oxygen coming out of the low-pressure column of the ASU is typically at 1.2–1.6 bar and less than -180°C. This oxygen then goes to the heat exchanger to cool the incoming air. A part of this oxygen can then be stored. This storage, however, increases the energy requirement of the ASU because there is less oxygen to cool the incoming air. Depending on the optimization technique, efficiency of storage, and type of ASU used, storing a total of 30 minutes' worth of full-load oxygen, can increase the ASU electricity consumption between 0.8–1.5% per hour. This should still be economical considering the variation of electricity prices at high- and low-load hours. Additionally, the reduction in the cycling of both the ASU and the SPOC power plant is beneficial to plant efficiency, maintanence and life.

2) Combustor/Boiler – As noted, the boilers are arranged in a series and parallel combination. This arrangement makes the boiler design and operation nearly identical, hence reducing the capital and operational cost of the system. The temperature of the flue gas exiting the boiler stages is 340°C to prevent acid condensation in the heat exchanger. The combined flue gas is then sent to an HP Heat Recovery (Flue Gas Cooler).

In a first-generation oxy-combustion power plant operated at atmospheric pressure, the oxygen concentration in the flue gas is normally kept above a minimum value, typically 3 vol % to ensure complete coal combustion. However, experimental studies have confirmed that coal conversion rates under pressurized conditions are higher because char gasification rates increase significantly with pressure. Also, the gas volume in a boiler decreases proportionally with pressure, reducing velocity and increasing residence time. This further increases the coal conversion at the exit of the boiler. Accordingly, the oxygen concentration in the flue gas can be smaller in a pressurized oxy-combustion boiler. This reduces the amount of oxygen required from the ASU, and on the back end, less oxygen must be removed from the flue gas in the CPU, leading to increased plant efficiency and reduced cost of electricity. Experiments at WUSTL have shown that an excess oxygen concentration as low as 1% is adequate for complete burnout of coal.

3) Particulate filter – The SPOC system concept proposes the use of candle filters for particulate removal. Both metal and ceramic candle filter elements have been utilized in industry. However, ceramic filters are susceptibility to breakage, which can have a negative impact on performance and availability. The application of candle filters to the SPOC system concept is analogous to integrated gasification combined cycle experience. A pressurized electrostatic precipitator can also be considered, the development of which is in works at WUSTL.

4) Ash Removal & Disposal **–** Regarding ash removal, dry bottom ash and flyash removal is proposed. No technology gap is envisaged for ash removal equipment. Subsequent utilization and/or disposal of bottom ash and flyash to be fully considered with respect to best practice.

5) DCC – Further cooling and moisture condensation occur in a DCC, with cooling water flowing from the top, and flue gas from the bottom. This column has a dual role. The first is to cool and condense the moisture from the flue gas, which occurs in the bottom stages. The DCC heat recovery is a two-stage system with direct flue gas cooling using the circulating fluid (exposed to the flue gas and thus containing dissolved acid gases and trace solids) and then a DCC cooler heat exchanger that transfers heat from the circulating water to the clean low-pressure feedwater stream. The cooling water used in the DCC for cooling and condensation exits the bottom of the column at relatively high temperature (< 165°C), with an acid concentration of about 730–4000 ppmv, depending upon the sulfur content of the coal. After neutralization of these dilute acids, the water is passed through an indirect heat exchanger for the regeneration of low-temperature boiler feedwater. This heat, in conjunction with the low-grade heat that is available from the ASU, eliminates or nearly eliminates (depending on the fuel) the need for steam extraction from the low-pressure turbine, allowing for higher gross power generation.

The second role of the DCC is to remove SOx and NOx, via conversion to dilute sulfuric and nitric acid. Because of the high pressure, the reaction between NO and O_2 in the flue gas is significant compared to that at atmospheric pressure. This enables the formation of NO_2 in the flue gas, which is soluble in water and enhances the removal of NOx and SOx. WUSTL has studied integrated SOx and NOx removal from gases at elevated pressure for oxy-combustion applications, in which removal of sulfur and nitrogen-containing species in the flue gas is enhanced due to their mutual interaction during the flue gas compression process. The integrated SOx and NOx removal is associated with a complex set of reactions, and a reduced mechanism of this interaction has been developed but WUSTL for modeling the process.

The process modeling results indicate nearly complete removal of the pollutants, while experimental tests conducted at WUSTL for SPOC have shown that almost all the SOx and about 80% of the NOx is removed at the 16-bara stage. If further polishing of NOx is found necessary for the SPOC process, an additional efficiency penalty of no more than 0.05% points will be added, since the clean flue gas inherently requires further compression to 35 bar in the CPU for auto-refrigeration requirements.

6) CPU– After removal of particulates, SOx, and NOx, the flue gas is compressed to a pressure of 35 bar. A small fraction (3–5%) of this compressed, dry, and clean flue gas is recycled back for carrying the coal in a dense phase, while the majority (>90 vol%) is sent to the CPU after passing through molecular sieves for further moisture removal, and a bed of an activated carbon for removal of any mercury remaining in the gas. The CPU uses cryogenic distillation to purify the CO_2 to the desired EOR specification. Two designs were initially analyzed – an ammonia-chilled CPU, and an auto-refrigeration CPU. The auto-refrigeration CPU was found to be significantly more efficient, so the other option was dropped at an early stage in the model optimization.

List of components that are not commercially available

From the Technology OEM Review described below, two equipment items have been identified to require further R&D, these being the SPOC Burner/Combustor and SPOC Convective PV.

SPOC Burner/Combustor – this item has significant thermal input, and performance at scale is unknown. CFD modelling has been performed and validated against 100kWth rig data for anticipated SPOC stage combustion conditions, however practical demonstration of a complete SPOC boiler system at significant pilot plant scale is required.

SPOC Boiler – Combustor PV & Convective PV: the boiler concept has undergone an OEM review by DBL with provisional sizing carried out through application of OEM knowledge, experience and design tools to predict plant performance based on WUSTL testing and modeling. However, boiler performance predictions remain to be validated for SPOC applications. Detailed engineering design and practical demonstration of a complete SPOC boiler system at significant pilot plant scale is required.

In addition, while the DCC is commercially available, the integration of latent heat recovery with SOx and NOx removal in a single DCC unit has not been demonstrated at commercial scale. While SOx and NOx removal has been demonstrated in the 100 kW facility at WUSTL and scale up is deemed low risk, demonstration of the process at large scale would be advisable.

Proposed Technology Development Pathway

Overview of Current Systems

The proposed coal power technology is a nominal 300-MWe staged pressurized oxy-combustion (SPOC) system coupled to a supercritical steam-Rankine cycle, with energy storage via liquid oxygen storage to accelerate start-up and ramp rates. This section provides a summary of state-of-the-art coal-based systems with CCS and discusses their key challenges, and concludes with a comparison with the SPOC technology. The candidate technologies, which are at different technology readiness levels (TRLs) — as assessed by EPRI — are:

- Integrated gasification combined cycle (IGCC) with pre-combustion capture
- Oxy-combustion: sCO_2, Allam cycle
- Oxy-combustion: atmospheric, supercritical Rankine Cycle
- Pulverized coal (PC) with post-combustion capture (PCC)

A high-level summary of relevant characteristics of each system is given in the table below.

Table 6: Candidate Technologies – Key Characteristics

Type	TRL	Size, MWe net	Efficiency, % HHV	TPC, $/kWe
IGCC with Pre-Combustion Capture (B1B, B5B)	8	300–550	31.0–32.0[10]	5350–6500[9]
Oxy-Combustion (Allam cycle)	5	300–562	36.7[11]	3850[10]
Oxy-Combustion (atm., SC S12F)	7	30–550	31.0[9]	4084[9]
PC with PCC (SC, S12B)	8	300–650	27.0[9]	4243[9]

IGCC with Pre-Combustion Capture

In IGCC, coal is gasified to produce a synthetic gas (syngas) primarily consisting of CO and hydrogen, which is then used as a fuel in a combustion gas turbine tied to a steam-Rankine bottoming cycle. When pre-combustion capture is added, a water-gas-shift conversion process is included to convert steam and CO to hydrogen and CO_2. The CO_2 is subsequently removed at pressure in a physical or chemical-based solvent system, yielding a syngas with a high concentration of hydrogen as the fuel. The flexibility of IGCC plants is limited, partially due to the air separation and gas purification systems, but adding pre-combustion capture should not adversely impact this.

IGCCs have been successfully installed in multiple locations and over a dozen are still operating. IGCC with pre-combustion capture has been tested at up to 582-MWe scale at Southern Company's Kemper plant. Nonetheless, recent IGCC experience in the U.S. has not been positive, as several high-profile projects had significant cost overruns. New-build IGCCs are still being contemplated elsewhere, especially in Asia. An example of an IGCC plant with comparable size to the proposed technology is Korea Western Power Company's 305-MWe IGCC in Taean County, which began commercial operation in August 2016. The project cost has been reported at

[10] Based on recent U.S. Department of Energy (DOE) studies with cases noted in parentheses. IGCC (over a range of gasifiers) data use Powder River Basin (PRB) at 550 MWe. PC data use PRB at 650 MWe. Oxy-combustion data also use PRB at 550 MWe. Cost numbers have been adjusted by EPRI to 2019 $.

[11] "Performance and Cost Assessment of a Coal Gasification Power Plant Integrated with a Direct-Fired sCO_2 Brayton Cycle," NETL-PUB-21435, 2017. While Illinois #6 was used on a 562-MWe unit in the report, EPRI adjusted these values to PRB. Note that 8 Rivers, LLC, who is developing a coal-based Allam cycle, has published higher efficiencies and lower cost numbers

$1.4B without CCS, which equates to $4590/kWe in 2016, which would be a significantly higher Total Plant Cost (TPC) with CCS compared to the values given in Table 6.

Challenges for IGCC plants with pre-combustion capture lie mainly with their complexity and high capital costs. A more efficient way to produce oxygen and reducing the size and height of the gasifiers would reduce cost. Reliable hydrogen-based turbines also require development and testing.

Oxy-Combustion

In Oxy-combustion, coal is combusted with oxygen, which has be cryogenically separated from air and mixed with recirculated flue gas, to produce a product stream of principally CO_2 and water, thereby greatly simplifying CO_2 capture. The largest operational (atmospheric) oxy-combustion plant was CS Energy's 30-MWe gross Callide Unit 4, which operated for over 15,000 hours. The demonstration project was a retrofit to an existing unit, and costed about $130M (this equates to a TPC of $4333/kWe, without including the cost of the original equipment that was reused). The estimated net efficiency for this subcritical unit with oxy-combustion was ~22% HHV. Under the FutureGen 2.0 program, a design for retrofitting atmospheric oxy-combustion to an existing subcritical unit was developed, producing a 100-MWe unit with a net efficiency of 21.5–22.5% HHV, compared to 31.5% HHV net when air firing. The overall projected cost of the FutureGen 2.0 project was $1.65B, but these are first of a kind units and as such costs are high, this included operations and a significant pipeline for storage. These two examples show the large cost increases at smaller scales compared to the costs shown in the table for oxy-combustion.

The Allam cycle is a type of pressurized oxy-combustion, which utilizes a direct-fired supercritical CO_2 power cycle, which improves power cycle efficiency, but requires front-end gasification of the coal. Allam cycles are purported to have low minimum operating loads and high ramp rates, limited by air separation technology. Allam cycles are still relatively immature. NET Power has built a 50-MWth Allam cycle pilot plant, which is operational, but uses natural gas. Developing a syngas version will require considerable effort and funding. 8 Rivers, LLC, the developer of the syngas-based Allam cycle, is driving towards constructing a DOE-funded 10-MWe pilot within the next five years. The commercial system, planned for 300 MWe in size, is unlikely to be ready until 2030 at the earliest. Consequently, more accurate estimates on cost will not be available until this technology gets closer to the TRL finish line.

Challenges for atmospheric oxy-combustion include the high cost of air separation, back-end CO_2 compression and purification systems that have had limited operating experience, issues with air in-leakage and corrosion, and relatively low efficiencies compared to more novel oxy-combustion technologies. Challenges for the Allam cycle include combustion at ultra-high-pressure (c.a. 300 bar), high-temperature heat exchanger durability, sCO_2 turbine performance, control system effectiveness, potential corrosion and materials issues, overall system complexity, and lack of testing at scale.

PC with PCC

In PCC, CO_2 is captured from the PC flue gas after removal of NO_X, SO_X, and particulate matter. Typically, an amine-based solvent is used that chemically captures the CO_2, then releases it under temperature, where this heat is generally supplied by steam from the cycle (or from a standalone island). Membranes that are selective to CO_2 can also be used for PCC, but are less mature. One advantage of PCC is that it can be retrofitted to existing PC units.

Two commercial PCC systems have been retrofitted to PC units: SaskPower's Boundary Dam Unit 3 and Petra Nova's WA Parish Unit 8. Petra Nova's project installed PCC on a 650-MWe unit to capture a 240-MWe equivalency slipstream of CO_2, which is comparable in size to the proposed technology. The CCS retrofit cost of $635M included the cogeneration facility that is used to provide power and heat to the CCS island. Add to this to the projected cost of the original 650-MWe supercritical unit, and the estimated TPC for the full plant with partial capture is $5052/kWe net—substantially higher than the value given in the table, potentially showing the impacts of economies of scale.

Challenges for PC with PCC include solvent degradation, potential amine and amine byproduct emissions, potential corrosion, increased water use, and a large footprint, along with its inherent cost and energy penalty. Adding PCC also impacts the overall flexibility of the unit, adding to the startup time and likely limiting ramp rates and turndown. However, techniques have been proposes to mitigate these effects and bring plant capabilities to nearly those without capture.

Comparison with proposed SPOC technology

Based on this summary of state-of-the-art coal-based CCS systems, the proposed technology has several potential advantages:

- ***Higher Efficiency at 300 MWe net*** – As shown in the various examples in Table 6, none of the other technologies, save potentially the Allam cycle, will be able to compete with the projected 34.5% HHV efficiency (when using PRB coal) of the proposed technology.
- ***Better Flexibility*** **–** With integrated energy storage via stored liquid oxygen, and the ability to take one or more boiler stages off line, the proposed technology will be better able to meet flexible market demands than other technologies.
- ***Lower Costs*** **–** The estimated TPC for the proposed technology is lower than all the other technologies shown in Table 6, save potentially the Allam cycle (which is a high risk technology). The costs per kWe shown in Table 6 for the other technologies are for full scale units; smaller sized units will likely have even higher costs.

Proposed Technology Development Pathway

The proposed technology is a variant of the staged pressurized oxy-combustion (SPOC) technology that Washington University in St. Louis (WUSTL) has been developing since 2012. Based on EPRI's assessment, the SPOC concept has achieved a TRL of 5. A review of work done is given here to support this assessment, along with a projected development pathway for the proposed technology.

With support from the DOE's Advanced Combustion Systems Program, WUSTL has built and operated a SPOC prototype oxy-combustor at approximately 100-kWth scale operating at a pressure up to 15 bara (Figure 5). Pressurized oxy-combustors of this type had not been operated at any significant scale, making the 100-kWth scale essential for developing data to refine and scale up the process. Lab-scale tests with the pressurized combustor began in 2016. Experiments to date have demonstrated that stable combustion can be achieved, that the flow field is comparable to that anticipated by computational fluid dynamic (CFD) modeling and that, with appropriate scaling, atmospheric combustion testing can be used to characterize combustion at elevated gas-side pressure. Full-load testing at 100 kWth and 15 bara has demonstrated excellent flame stability on 100% coal feed, without CO or soot emissions, and complete char combustion for an exit O_2

concentration as low as 1% v/v.[12] Significant CFD combustion modeling has also been undertaken to develop a conceptual pressurized boiler design.[13] In addition, the radiation heat transfer characteristics under the unique conditions of elevated gas-side pressure and high flame temperature have been thoroughly studied.[14]

(a) (b)

Figure 5: 100 kW SPOC research facility a) Combustor and b) DCC (water wash column)

WUSTL and EPRI were also funded by DOE to collaborate with leading industrial OEM partners —DBL for oxy-combustion boiler technology and AL for air separation technology— to review the SPOC concept, which led to the current conceptual designs and configurations. The integration between the flue gas and water/steam sides of SPOC was also optimized to improve its performance at both full- and part-load operation. Testing using the existing 100-kWth pressurized oxy-combustor has been ongoing throughout 2018 to validate combustion characteristics and heat release rates (using heat flux measurements) for multiple load cases to provide validation data for updated CFD modeling and economic assessments.

Although significant progress has been made and no significant barriers have been identified, a substantial amount of development must be undertaken to advance this technology from TRL 5 to its first commercial deployment. The 100-kWth pressurized oxy-combustor will continue to be employed for lab-scale operations to investigate potential technology gaps/concerns including ash deposition, combustion/heat transfer effectiveness, and the water-wash column (DCC) design. WUSTL's experimental and computational studies have focused on gas-side technologies to ensure that wall heat fluxes are appropriate for safe and efficient heat transfer to water/steam. WUSTL's current collaboration with Doosan Babcock Limited has allowed for Boiler OEM consideration of steam integration and plant operations. Although no significant challenges have been identified, the water/steam-side circuit design is more challenging than that for air-fired boilers in that there are separate combustors that require parallel water/steam paths with potential

[12] "Staged, Pressurized Oxy-Combustion - Update," R. Axelbaum, U.S.-China Clean Energy Research Center – Advanced Coal Technology Consortium Webinar, October 2018.

[13] "Pressurized Oxy-Combustion with Low Flue Gas Recycle: Computational Fluid Dynamic Simulations of Radiant Boilers," F. Xia, Z. Yang, A. Adeosun, A. Gopan, B. Kumfer, and R. Axelbaum, Fuel 181, 2016.

[14] "Control of Radiative Heat Transfer in High-Temperature Environments via Radiative Trapping—Part I: Theoretical Analysis Applied to Pressurized Oxy-Combustion. F. Xia," Z. Yang, A. Adeosun, B. Kumfer, and R. Axelbaum, Fuel 172, 2016.

for uneven heating rates. Conversely, the multiple boiler arrangement has been shown to provide opportunities for process optimization, plant flexibility, and turndown.

The overall commercial timeline for the proposed technology is shown in Figure 6. For each stage, several blocks of work must be performed to vet the technology and produce sufficient data and information to advance and scale up the design to the next level. These stages are:

- **Preliminary Planning –** Project objectives are clearly stated and the preliminary designs for the project are prepared with a AACE Class 5 cost estimate. This phase culminates in the decision to commit the capital funds necessary to build the proposed plant.
- **FEED –** Quality of the cost estimate is improved preparatory to the decision to proceed with construction. Once commitment to FEED has been made, minimum time to complete is unlikely to be less than 12 months and in later TRLs can be longer.
- **Detailed Engineering, Construction, and Commissioning –** Once the decision is made to proceed with a project, detailed engineering is completed (permitting, which would start during FEED, would also be completed in this time frame) and the plant is built and commissioned. Construction periods will depend on the overall project size and scope. As with construction, the length of the commissioning period will generally depend on project scope. As SPOC is first-of-a-kind (FOAK), a longer commissioning period is expected.
- **Plant Operations –** Normal operations commence at the close of commissioning. Projects are designed with operations for a fixed period required to achieve project objectives. Process Development Unit operations are typically a minimum of 3 months and Pilot Plant operations are a minimum of 12 months. A Commercial Pilot Plant can achieve the development goals for the project once a single maintenance cycle has been completed (18 months).

The stages required to advance SPOC to commercial readiness are given below and the timeline is shown in Figure 6. Each stage is staggered such that design and engineering begins while the previous stage is in operation.

- **Small Scale Pilot Plant testing –** Work will continue on the existing 100-kWth pressurized oxy-combustor to further refine the design and improve the modeling.
- **Process Development Unit –** The next step would be to design, build, and test a process development unit of 10-20 MWth size to achieve a TRL of 6. This stage would have most of the components such that it would operate like a complete SPOC system. Funding needed would come from private or public funding (or both) and would be on the order of $50M.
- **Commercial Pilot Plant –** A semi-commercial deployment of 100-MWth scale plant, wherein some value can be realized for the power and CO_2 produced, will advance the technology to TRL 7. The cost of such a plant would be on the order of hundreds of millions; public and private funding will again be required to offset any remaining costs not provided by commercial revenue streams.
- **Commercial Plant –** It is envisioned that a full-scale, 300-MWe SPOC unit can be in operation by 2032, achieving TRL 8. It is expected for such a project, that while FOAK, significant commercial return will occur, reducing the need for public funding. Subsequent units can use this as a reference and be sold as commercial plants with standard financing.

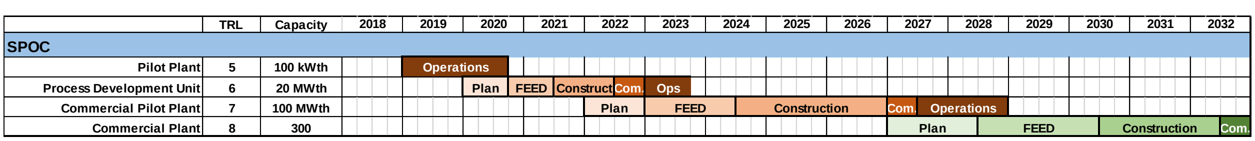

Figure 6 – Commercial Timeline for the Proposed SPOC Technology

Technology OEM Review

The objective of this review of Technology Original Equipment Manufacturers (OEMs) is to identify and succinctly describe the proposed technology OEMs, which includes a listing of commercial equipment and equipment requiring R&D. Acting as Architect Engineer, Doosan Babcock (DBL) has undertaken a review of the key equipment required, covering both the Staged Pressurized Oxy-Combustion (SPOC) for carbon capture and the Modular Pressurized Coal Combustion (MCPP) air-fired capture-ready process. Outline PFDs for both SPOC and MCPP are given in the section on "Plant Concept Description".

For the Technology OEM Review three equipment categories have been defined as follows:

Table 7: Equipment categories and definitions

CAP	**Commercially Available/Proven**	1	Equipment is already fully commercially available and has been offered and/or proven in practice at required scale and/or operating conditions.
DCR	**Design Customization Required**	2	Equipment type is commercially available but requires design customization for required scale and/or operating conditions for SPOC/MPAC.
R&D	**R&D Required as Novel/FOAK**	3	Equipment is deemed to be novel, i.e. first of a kind (FOAK); and therefore, requires R&D to verify technical feasibility for commercial demonstration.

Table 8 below provides a summary of the preliminary review of Technology Equipment Items against the equipment categories given in Table 7. For example, the Air Separation Unit (ASU) is deemed to be commercially available (Y = Yes); does not require equipment customization (N = No); and does not require any research & development (N = No). Potential Technology OEMs are indicated for the ASU along with a brief description of DBL's previous working with the potential OEM indicated.

Table 8: Technology OEMs Review Summary

Technology Equipment Item	**1** CAP	**2** DCR	**3** R&D	**Potential Technology OEM**	**AE Previous Working/Reference**
Air Separation Unit (ASU)	**Y**	**N**	**N**	Air Liquide	Doosan: DBL: Collaborating on SPOC and development projects for Atmospheric Oxy-fuel Carbon Capture for PC Utility Power Plant.
				Air Products	Doosan: DHI (Doosan Heavy Industries & Construction): ASU EPC for 300MWe IGCC: ASU from Air Products.
				Linde/Praxair	BOC (Linde Group) part of White Rose proposal.
Liquid Oxygen Storage (LOS)	**Y**	**N**	**N**	Air Liquide	Doosan: DBL: Collaborating on SPOC and development projects for Atmospheric Oxy-fuel Carbon Capture for PC Utility Power Plant.
				Air Products	Doosan: DBL: Air Products supplied LOS for DBL's atmospheric oxyfuel combustion test facilities. Also development of oxyfuel CCS.
Pulverized Fuel (PF) Mills	**Y**	**N**	**N**	Doosan: DBL B&W	Doosan has OEM capability for E-Mills with option for manufacturing. Similar to B&W Mills.
				LOESCHE	Doosan: DBL: LOESCHE - Mills for Solid Fuels engaged on projects for coal and biomass.
				Gebr. PFEIFFER	OEM for the versatile MPS vertical mill.

Lock Hoppers: Coal Handling & Feeding System	Y	Y	N	Clyde Bergemann Materials Handling Ltd	Doosan: DBL: Collaborated on UK DTI development projects for Air Blown Gasification Combustion (ABGC) Power Plant. Also supply biomass feeding systems.
SPOC: Combustor Pressure Vessel (Combustor PV) • SPOC: Combustor PV: Burner/Combustion	N	Y	Y	WUSTL R&D Design/DBL OEM Support	Doosan: DBL collaboration with WUSTL on US DOE NETL development projects for WUSTL's SPOC Technology.
• SPOC: Combustor PV: PV & Boiler Radiant Heating Surface Arrgt.				Doosan: DBL Boiler OEM	DBL in-house experience: Supercritical Boiler OEM, Air Blown Gasification Cycle (ABGC) and Pressurized Fluidized Bed Combustion (PFBC); PV design.
SPOC: Convective Pressure Vessel (Convective PV) • SPOC: Convective PV: PV & Boiler Convective Heating Surface Arrgt.	N	Y	Y	Doosan: DBL Boiler OEM	DBL in-house experience: Supercritical Boiler OEM, Air Blown Gasification Cycle (ABGC) and Pressurized Fluidized Bed Combustion (PFBC); pressure vessel design.
SPOC: Flue Gas Dampers	Y	Y	N	OEM tbc	OEM tbc for suitable flue gas side dampers for SPOC stages; tbc vs design development.
Cyclone Filter *Particulate matter removal from pressurized FGR.*	Y	Y	N	Doosan / Other OEM tbc	OEM tbc. Related Doosan/DBL in-house experience: ABGC, PFBC, Circulating Fluidized Bed Combustion (CFBC); PV design.
Flue Gas Recycle Booster Fan (FGR Booster Fan) *FGR for SPOC Stages.*	Y	Y	N	Howden	Doosan: DBL: Long standing relationship with Howden for supply of industrial and utility-scale air and flue gas fans for EPC Boiler projects. Also for Gas-Air Heaters/Gas-Gas Heaters.
Flue Gas Cooler (FGC) *Heat recovery from pressurized 'dirty' flue gas (~15 bar).*	Y	Y	N	AMEC-FW	AMEC-FW reference relates to Petrochemical, FCC applications.
				GREEN's (tbc)	DBL: experience with GREEN's Economizers/Flue Gas Cleaners; but for nominal atmospheric pressure operation. Pressurized FGC tbc.
Particulate Filter *SPOC: High Pressure Particulate Matter Filter req'd; note not High Temp.*	Y	Y	N	Howden (tbc)	Doosan: DBL: Howdens Bag house and Fabric Filter Plant typically for nominally atmospheric applications; customizing for gas side ~15bar tbc.
				Carbis Filtration (tbc)	None. Carbis Filtration: incl. Candle Filter type (ceramic/sintered) OEM design/supply; tbc SPOC
				Rath Group (tbc)	None. Rath Group Flue Gas Filtering; incl. Candle Filter type (ceramic/sintered); tbc for SPOC req'ts.
Ash Handling System	Y	Y	N	Clyde Bergemann Materials Handling Ltd	Doosan: DBL: Collaborated on UK DTI development projects for Air Blown Gasification Combustion (ABGC) Power Plant. Also supply biomass feeding systems.
Direct Contact Cooler (DCC)	Y	Y	N	ERG Air Pollution Control	Doosan: DBL: ERG APC supply for UK Ferrybridge Carbon Capture Project (AQCS) and UK Ratcliffe SCR (NH_3 Scrubber) and also development for pressurized oxyfuel (gas fired only).
Flue Gas Recycle Fan (FGR Fan) *FGR Booster Fan for Transport Gas to Coal Handling System*	Y	Y	N	Howden	Doosan: DBL: Long standing relationship with Howden for supply of industrial and utility-scale air and flue gas fans for EPC Boiler projects. Also for Gas-Air Heaters/Gas-Gas Heaters.

Compression & Purification Unit (CPU) *CPU system package comprising: CO_2 Compressor Stages, CO_2 Dryer/Purification, Interstage Coolers, etc.*	Y	Y	N	Air Liquide	Doosan: DBL: Collaborating on SPOC development project and previously on Atmospheric Oxy-fuel Carbon Capture for PC Utility Power Plant.
				Air Products	Doosan: DBL: Collaborated on development projects for Atmospheric Oxy-fuel Carbon Capture for PC Utility Power Plant and Post-combustion capture.
				Siemens & MAN Energy Solutions - Turbomachinery	OEMs for CO_2 Compressors. Doosan: DBL has worked with both Siemens and MAN Turbo on developing CO_2 compressor designs for a number of large scale CCS FEED studies.
Supercritical Steam Turbine & Generator: *Targeting approx. 400MWe gross/approx. 300MWe output with steam conditions at a nominal 245 bar/593°C/593°C (Single Reheat)*	Y	Y	N	Doosan: Doosan Heavy Industries & Construction (DHI)/Doosan Skoda	Doosan is OEM of Steam Turbines covering the range from Industrial Scale Subcritical up to state-of-the-art Ultra-Supercritical (USC) Steam Turbines. Examples covering both Thermal and Nuclear sectors include: - 2 STG units of 260 bar/600°C/610°C 1000MW class STG are in Service and 7 units in construction. - 1 STG unit of 250 bar/600°C/605°C for 660MWe. - More than 10 STG units of 242 bar/566°C/593°C 500MW STG 2Unit in Service; 7 units in construction. - 2 STG units of 120 bar/565°C/565°C of 200MW class STG are in Service.
				GE (Alstom)	Doosan: DBL: Boiler Island for Jänschwalde 250 MWe (gross) Supercritical Oxyfuel Combustion Power Plant; nominally 286 bar/600°C/610°C (Single Reheat); Alstom ST. Commercial project but did not proceed due to CO_2 storage issues.
				Siemens	Doosan: DBL as Boiler OEM, has worked with Siemens on both commercial and development projects. DBL has Siemens license for Benson Once Through boilers covering subcritical through to ultra-supercritical (USC) boilers and Advanced USC.
Condenser *Steam Turbine Island*	Y	Y	N	Doosan: DHI/Doosan Skoda	As OEM Doosan (DHI & Doosan Skoda) has several surface condenser types dependent upon condenser shape covering the full range of capacity from small industrial up to large utility scale corresponding to condenser capacities in the range of approx. 5 MW to 1100 MW.
Condensate/Boiler Feed Water Pumps *Steam Turbine Island*	Y	Y	N	Doosan EPC: Specific OEM(s) tba	Doosan: EPC Supply: Specific OEM(s) tbc vs the cycle configuration/requirements.
Feed Water Heaters (FWHs) *Steam Turbine Island*	Y	Y	N	Doosan: DHI/Doosan Skoda	Doosan: As OEM, Doosan Skoda provide both HP Heaters and LP Heaters. DHI OEM capability with option for outsourcing manufacture.
Deaerator *Steam Turbine Island*	Y	Y	N	Doosan: DHI/Doosan Skoda	As OEM, Doosan Skoda and DHI provide Dearators to meet the particular steam cycle and steam turbine island requirements. DHI OEM capability with option for outsourcing manufacture.
Misc. Tanks & Vessels *Steam Turbine Island*	Y	Y	N	Doosan: DHI/Doosan Skoda	Doosan: OEM/EPC Supply: DHI OEM capability with option for outsourcing for manufacture tbc vs the cycle configuration/requirements.
Steam Cycle Valves & Fittings	Y	Y	N	Doosan EPC: Specific OEM(s) tba	Doosan: EPC Supply: Specific OEM(s) tbc vs the cycle configuration/requirements.

MPAC Concept: Flue Gas Expansion Turbine	Y	Y	N	PBS ENERGO	PBS ENERGO OEM Expansion Turbines: NG/COG/etc.
				Siemens	Doosan: DBL has worked with both Siemens and MAN Turbo on developing CO_2 compressor designs for a number of large scale CCS FEED studies.
				MAN Energy Solutions – Turbo.	

Summary Overview

1) Commercially Available (CAP) – As can be seen from Table 8 above, a number of the equipment items identified are deemed to be either fully commercially available, or are known to have been offered commercially.; i.e. the ASU, LOS and PF Mills.

2) Design Customization (DCR) – As indicated all equipment items apart from the ASU, LOS and PF Mills are deemed to require at least some degree of customization based current state-of-the-art technologies. For example, FGR fans/FGR Booster fans are known to be proven in pressurized applications; but still do need due consideration to be given to the specific design and operating requirements for SPOC.

3) R&D Required (R&D) – Only two equipment items have been identified to require further R&D, these being the SPOC Combustor and SPOC Convective PV.

- ***SPOC Burner/Combustor*** – as proposed has significant thermal input and performance at scale is unknown. CFD modelling has been performed and validated against 100kWth rig data for anticipated SPOC stage combustion conditions, however practical demonstration of a complete SPOC boiler system at significant pilot plant scale is required.
- ***SPOC Boiler: Combustor PV & Convective PV*** – the boiler concept has undergone an OEM review by DBL with provisional sizing carried out through application of OEM knowledge, experience and design tools to predict plant performance based on WUSTL testing and modelling. However, boiler performance predictions remain to be validated for novel SPOC application. Detailed engineering design and practical demonstration of a complete SPOC boiler system at significant pilot plant scale is required.

4) Other Considerations – While DCC's are commercially available, integration of latent heat recovery with SOx and NOx removal in a single DCC has not been demonstrated at commercial scale. SOx and NOx removal has been demonstrated in the 100 kW facility at WUSTL, and scale up is deemed low risk, however, demonstration of the process at large scale would be advisable.

NFPA Codes: Existing NFPA standards (e.g. NFPA-85 Edition 2019) are considered fit for purpose for the proposed SPOC process based on the existing guidance for both gasification and conventional coal plant. Design Safety requirements will be fully considered for SPOC.

Access to Information

DBL has been heavily involved in the development of the boiler concept for the SPOC process and has had access to relevant information required to make the necessary engineering judgements to complete this preliminary review. DBL has also drawn on Doosan in-house OEM and EPC experience through support from both Doosan Heavy Industries & Construction (DHI) and Doosan Skoda. It is recognized that the Technology OEM Review undertaken has not been exhaustive, and will require further thorough review commensurate with technology roadmap for commercialization of the SPOC process.

Appendix A: Supplemental information – SPOC Process design parameters and Aspen Results

Table A1: SPOC Gas Side Parameters

Parameter		Unit	Value
Coal Input	Feed rate	kg/s (klb/hr)	30.90 (245.24)
	Temperature	°C (°F)	15 (59)
	Pressure	barg (psia)	16 (232)
Oxygen Input	Feed Rate	kg/s (klb/hr)	65.67 (521.24)
	Temperature	°C (°F)	15 (302)
	Pressure	barg (psia)	16 (247)
Thermal Input		MW	837.79
Evaporator + Super heater heat duty		MW	700.24
Re-heater heat duty		MW	67.10
HP Heat recovery heat duty		MW	16.10
DCC heat duty		MW	54.11
Heat from ASU		MW	24.12
Condenser duty		MW	464.34

Table A2: Key steam cycle process parameters

Parameter	Value
High-Pressure Efficiency	91.5%
Intermediate-Pressure Efficiency	94%
Low-Pressure Efficiency	89.2%
Generator Efficiency	98.8%
Motor Efficiency	97%
Condenser Pressure	0.048 bar
Terminal Temperature Difference	11.7°C

Table A3: Aspen Plus™ Model Results

Parameter		Units	Aspen™ Results	Notes
Main Steam	Pressure	barg (psia)	242.2 (3514)	Defined
	Temperature	°C (°F)	593.3 (1100)	Defined
	Mass Flowrate	kg/s (klb/hr)	282.1 (2239)	Calculated
Feedwater	Pressure	barg (psia)	288.7 (4186)	High-pressure heater pressure drop
	Temperature	°C (°F)	290.1 (553)	Calculated
	Mass Flowrate	kg/s (klb/hr)	282.1 (2239)	Calculated
Hot Reheat Steam	Pressure	barg (psia)	45.2 (655.8)	Defined
	Temperature	°C (°F)	593.3 (1100)	Defined
	Mass Flowrate	kg/s (klb/hr)	241.3 (1915)	No sprays
Cold Reheat Steam	Pressure	barg (psia)	49.2 (710.8)	Defined
	Temperature	°C (°F)	339.4 (711)	Calculated
	Mass Flowrate	kg/s (klb/hr)	241.3 (1915)	Calculated
Boiler Feed Pump Turbine Steam Flow		kg/s (klb/hr)	14.65 (116.3)	Power match
Main Steam Duty		MWth	700	Calculated
Reheat Steam Duty		MWth	67	Calculated
Gross Power Output		MWe	388.57	Defined
Net Power Output		MWe	298.61	Defined
Net Plant Efficiency		%	35.64	Calculated

Table A4: Auxiliary Loads

Auxiliary load	kWe
Coal Handling	286
Coal Pulverizer	1670
Lime Handling	528
Ash Handling	385
Fuel Delivery (primary fans)	826
Baghouse	56
FGD/CPU	1000
Steam Turbine Auxiliaries	274
Condensate Pumps	549
Circulating Water Pumps	3406
Group Water Pumps	347
Cooling Tower Fans	1763
Air-Cooled Condenser Fans	3615
Balance of Plant	1372
Transformer Losses	1248
ASU	62,591
SCR/CPU	10,051
Total	**89,960**

Table A5: SPOC Product Specification

Parameter	Limit	Requirement
Temperature	<35°C (95°F)	Transportation pipeline specification
Pressure	152 barg (2200 psig)	Transportation pipeline specification
CO_2	>95% vol	Minimum miscible pressure for enhanced oil recovery (EOR)
N_2	<4% vol	Minimum miscible pressure for EOR
H_2O	dew point <-40°C (-40°F)	Transportation pipeline corrosion / hydrate formation
O_2	<40 ppmv	Transportation pipeline corrosion
CO	<0.1% vol	Safety and corrosion

Appendix B: Supplemental information – MPAC Process design parameters and Aspen Results

Table B1: MPAC Gas Side Parameters

Parameter		**Unit**	**Value**
Coal Input	Feed rate	kg/s (klb/hr)	30.90 (245.24)
	Temperature	°C (°F)	15 (59)
	Pressure	barg (psia)	16 (232)
Air Input	Feed Rate	kg/s (klb/hr)	65.67 (2231)
	Temperature	°C (°F)	15 (59)
	Pressure	barg (psia)	1(15)
Thermal Input		MW	837.79
Evaporator + Super heater heat duty		MW	569
Re-heater heat duty		MW	141
HP Heat recovery heat duty		MW	51
DCC heat duty		MW	57
Heat from ASU		MW	0
Condenser duty		MW	435

Table B2: MPAC Aspen Plus™ Model Results

Parameter		Units	Aspen™ Results	Notes
Main Steam	Pressure	barg (psia)	242.2 (3514)	Defined
	Temperature	°C (°F)	593.3 (1100)	Defined
	Mass Flowrate	kg/s (klb/hr)	258.19(2049)	Calculated
Feedwater	Pressure	barg (psia)	288.7 (4186)	High-pressure heater pressure drop
	Temperature	°C (°F)	290.1 (553)	Calculated
	Mass Flowrate	kg/s (klb/hr)	258.19 (2049)	Calculated
Hot Reheat Steam	Pressure	barg (psia)	45.2 (655.8)	Defined
	Temperature	°C (°F)	593.3 (1100)	Defined
	Mass Flowrate	kg/s (klb/hr)	232.0 (1841)	No sprays
Cold Reheat Steam	Pressure	barg (psia)	49.2 (710.8)	Defined
	Temperature	°C (°F)	339.4 (711)	Calculated
	Mass Flowrate	kg/s (klb/hr)	232 (1841)	Calculated
Boiler Feed Pump Turbine Steam Flow		kg/s (klb/hr)	14.29 (113.4)	Power match
Main Steam Duty		MWth	700	Calculated
Reheat Steam Duty		MWth	67	Calculated
Gross Power Output		MWe	376.27	Defined
Net Power Output		MWe	346.92	Defined
Net Plant Efficiency		%	41.41	Calculated

Table B3: MPAC Auxiliary Loads

Auxiliary load	kWe
Coal Handling	286
Coal Pulverizer	1670
Lime Handling	528
Ash Handling	385
Fuel Delivery (primary fans)	826
Baghouse	56
Steam Turbine Auxiliaries	259
Condensate Pumps	519
Group Water Pumps	460
Cooling Tower Fans	1663
Air-Cooled Condenser Fans	3615
Balance of Plant	1298
Transformer Losses	1248
ASU	0
Air compressor/decompression	17000
Total	29350