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sCO_2 Primary Power Large-Scale Pilot Plant FEED Summary

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ABSTRACT

Echogen Power Systems and its project partners the Electric Power Research Institute, CDM Smith, Riley Power Inc. (a Babcock Power Inc. company), and the University of Missouri completed the Front-End Engineering Design (FEED) study of a nominal 10 MW_e supercritical carbon dioxide (sCO_2) large-scale pilot plant based on Recompression Brayton Cycle (RCBC) architecture. The FEED study was completed under Phase II of the U.S. Department of Energy Fossil Fuel Large-Scale Pilots program. The FEED study scope included the preliminary design of the combustion and environmental control systems, the primary heater, the sCO_2 power cycle and its associated turbomachinery, and the balance of plant equipment to determine accurate cost and schedule requirements for fabrication and installation of the system at the University of Missouri's Combined Cooling, Heat, and Power Plant, located in Columbia, Missouri. The RCBC sCO_2 cycle presents superior thermodynamic efficiency compared to steam-Rankine cycles and is adaptable to a broad range of heat sources. The risk aversion of the power generation industry requires a successful large-scale pilot plant demonstration to enable financing and deployment of commercial-scale plants. Therefore, successful construction and demonstration of a 10 MW_e RCBC sCO_2 power plant would empower a transformational step forward for the efficiency of the next generation of utility power plants. This paper provides details on the primary heater, environmental control systems, and sCO_2 power cycle design and performance.

INTRODUCTION

Innovative sCO_2 cycle designs that achieve high thermodynamic efficiency have been studied for a broad range of applications, including indirect-fired combustion heat sources [1,2]. Recent integration studies of sCO_2 with coal combustion power plants highlight the significant improvements in plant efficiency that sCO_2 can offer relative to even advanced steam Rankine cycles [3]. At commercial scales, sCO_2 plant net efficiency is predicted to be two to eight percentage points higher than conventional steam-Rankine systems. Further, the compact nature of sCO_2 turbomachinery offers capital cost and footprint advantages, and the low maintenance of water-free power cycles can significantly reduce operation and maintenance (O&M) costs over conventional steam-Rankine systems.

In 2017, the U.S. Department of Energy (DOE) announced a new funding opportunity for Fossil Fuel Large-Scale Pilots, a three-phase program created to encompass the feasibility assessment (Phase I, completed March 2019), design (Phase II, completed January 2021), and construction and operation (Phase III, a three- to five-year phase begun in 2021) of technologies that will enable “step-change improvements in coal powered system performance, efficiency, and cost of electricity” [4].

As part of this program, Echogen Power Systems (EPS) and its project partners completed the Front-End Engineering Design (FEED) study of a nominal 10 MW_e sCO_2 pilot power plant. The pilot plant was designed for installation in the Combined Cooling, Heat, and Power (CCHP) Plant at the University of Missouri (MU). Concurrent to the FEED study, MU coordinated the environmental permitting process with the Missouri Department of Natural Resources (MDNR). CDM Smith was the FEED contractor, responsible for developing the plant layout, defining interconnections with the existing CCHP systems, generating detailed bid packages for the construction phase, and developing installation cost estimates. EPS designed the sCO_2 power cycle and associated equipment. Riley Power Inc. (RPI), a Babcock Power Inc. company, designed the fired heater and environmental control systems. The Electric Power Research Institute (EPRI) developed the pilot’s performance test plan, completed a utility-scale techno-economic analysis (TEA), and acted as the industry voice for the program.

Any new technology introduces risk. An appropriately scaled and properly designed and operated pilot project advances the technology readiness level (TRL) of individual components and the integrated system. These advances are essential to overcome the risk aversion of the power generation industry and project financing community. The primary goal of the program was to demonstrate the technical and economic superiority of the sCO_2 power cycle over steam-Rankine cycles, retiring major risk elements through extended operation at high power and enabling the power generation industry to move forward with the first commercial deployment of this transformational system. Moreover, since the sCO_2 power cycle itself is not dependent on a specific heat source, advances in the technology benefit non-fossil primary power applications, including concentrating solar power (CSP), nuclear, and biomass.

In this paper, the host site is introduced by reviewing the site selection process, providing an overview of the existing MU CCHP plant, and surveying the opportunities and challenges associated with retrofitting an existing plant for a DOE demonstration project. Following the host site description, the FEED process is described, summarizing power plant optimization, power cycle equipment design, and fired heater and environmental control systems design. Finally, the potential for a successful pilot demonstration to advance sCO_2 technology for next-generation utility plants is established.

HOST SITE

Site Selection

The search for host sites began in 2017 and continued through October of 2018. An initial review of potential host sites for the 10 MW_e pilot plant yielded four primary sites or organizations for additional consideration: the National Carbon Capture Center (NCCC), the Painesville Municipal Electric Plant, Wellington Development, and the MU CCHP Plant. Summaries of the considered host sites are found in Table 1.

Table 1 – Potential host sites and summaries

Organization	Description
NCCC	The NCCC, located in Alabama, has hosted multiple CO_2 capture technologies through the DOE since its inception in 2009. The site is next to Southern Company's Gaston coal-fired power plant. The NCCC team has expertise and experience in working on research projects and expressed interest in housing the pilot.
Painesville Municipal Electric Plant	The Painesville Municipal Electric Plant, located in the city of Painesville, Ohio, is one of the oldest continuously operating public power plant facilities in Ohio and one of the few remaining coal-fired ones. The site has the requisite space and infrastructure to support pilot operations and expressed interest in continuing to fire coal.
Wellington Development	The Wellington Development site is located near Carmichaels, Pennsylvania. While there was no operating power plant on the site, the developers expressed intent to construct a horticultural project, which would be a large consumer of electricity that the proposed pilot might be able to supply.
MU CCHP Plant	The MU CCHP Plant is a cogeneration plant with a diverse set of existing power generators, supplying the needs of the University of Missouri in Columbia, Missouri. The university expressed interest in increasing electrical generating capacity and partaking in the research on the pilot plant's technology.

To determine the best host site possible for the project, the team developed a scoring matrix designed to capture key characteristics from each site in a quantifiable way so that comparisons could be made on a relative basis. The scoring matrix was divided into four major categories for which the team collected information from each site organization: business and financing, environmental and permitting, operations, and physical attributes.

A weighting system was developed for every item (42 in total) in the scoring matrix. Each host site was then evaluated and scored collectively by the team for each item based on questionnaires and site visits. Prior to site visits, the questionnaires were given to each site such that background information and specifics on items in the scoring matrix could be reviewed. If required, additional teleconferences were held. The project team then visited each of the potential sites for detailed meetings and first-hand site inspections. Finally, follow-up calls were held to verify information or to obtain any information not provided at the time of the site visits or from the initial questionnaires. Based on this process, the MU CCHP Plant was selected as the primary host site.

Existing Plant Overview

In 1883, MU became the first public institution in the United States to demonstrate electric light west of the Mississippi River, using a dynamo and lights donated by Thomas Edison. In the same spirit of innovation, MU agreed to partner with the project team to demonstrate sCO_2 power cycle technology. MU offered an ideal location to pilot and demonstrate this technology because of its well-established district-energy system and multi-fueled CCHP plant, centralized location, and access to university students and researchers. The CCHP plant's district energy operation is recognized for its high level of success, recently being selected by the International District Energy Association as its System of the Year in 2017. The comprehensive district energy operation serves over 15 million square feet of academic, research, and medical facilities on the campus in Columbia, Missouri.

MU's CCHP plant possesses the necessary facilities, infrastructure, and staffing talent to effectively demonstrate and showcase this emerging power generation technology. The CCHP plant provides up to 1.1 million pounds of steam per hour, 66 MW of electricity, 32,000 tons of district cooling, and an extensive distribution system with over 100 miles of underground infrastructure serving the campus. Figure 1 is a process flow diagram of MU's existing facility, including five solid fuel boilers, a package boiler, and two heat recovery steam generators (HRSGs) for steam generation; two combustion turbines and four steam turbines for power generation; electric and steam chillers for campus chilled water; and cooling towers.

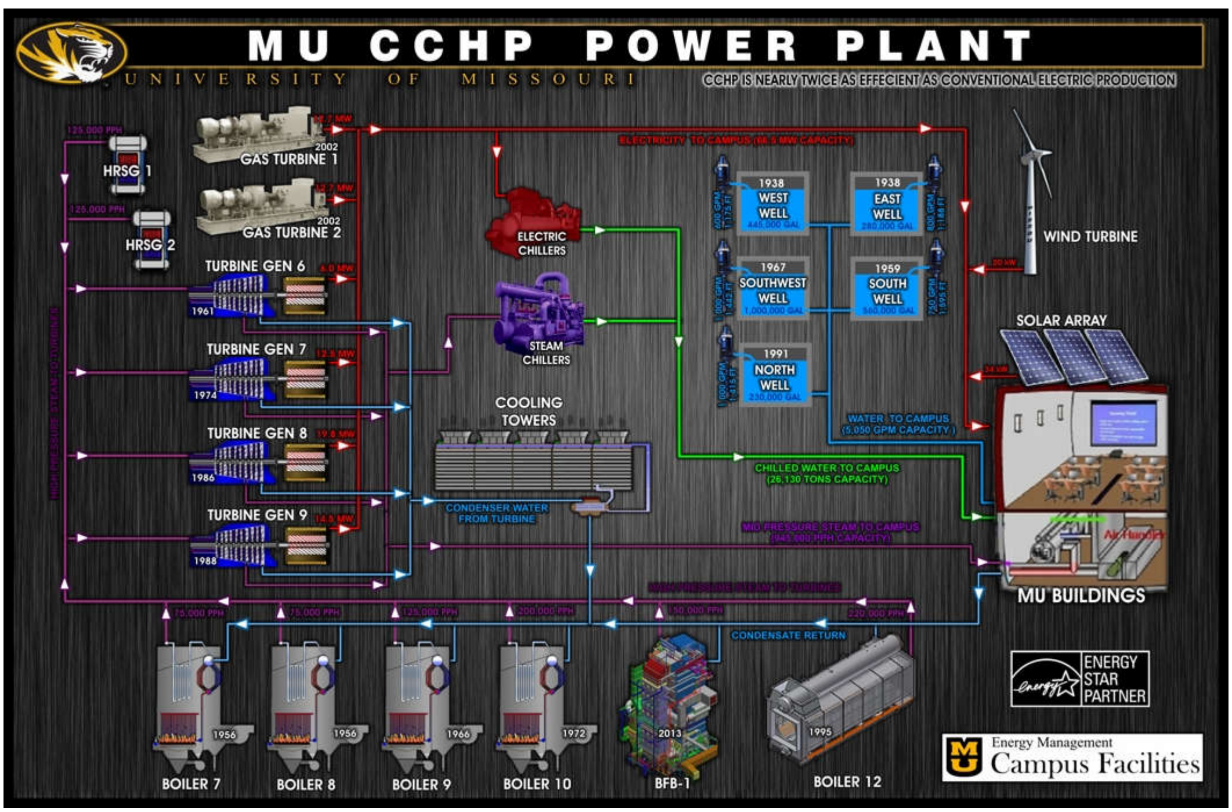

Figure 1 – MU CCHP plant process flow diagram

The generators are cost-effectively and reliably dispatched to serve MU's electricity demand. MU's unique micro-grid is electrically backed up with a 40 MW inter-tie where it purchases electricity, when advantageous, through the Midcontinent Independent System Operator

(MISO) grid. MU's CCHP plant is highly resilient with full generation capacity, black start capability, and fuel flexibility to optimize utility reliability, cost, and efficiency. It incorporates a diverse fuel portfolio consisting of biomass, natural gas, and coal, providing resiliency and price stability. The existing grid interconnection, stable campus electrical demands, and generation flexibility provide an excellent resource to demonstrate the 10 MW_e sCO_2 power cycle.

Retrofit Opportunities and Challenges

Figure 2 shows the layout of the existing MU CCHP Plant's boiler building. The plant's three oldest coal-fired boilers (7, 8, and 9) are rarely operated. While still possessing valid regulatory operating permits, these 1950s and 60s era units have been slated for removal or replacement in the long-term planning of the CCHP. Installation of the sCO_2 power cycle equipment and the fired heater required the removal of the three coal-fired boilers (highlighted in Figure 2) and their common fabric filter baghouse.

Figure 2 – MU CCHP existing boiler building layout, highlighting the units to be removed

The proposed equipment layout provided MU with the opportunity to remove its older equipment while supplementing the CCHP electric generation with an advanced non-traditional power cycle. The plant's existing infrastructure offered strong benefits to the project. The pilot project was designed to reuse a range of installed infrastructure including systems for coal and ash handling, lime and ammonia storage, steam, instrument air, and natural gas. The central and boiler control rooms with plant-wide DCS, medium and low voltage switch gear, utility metering and interconnect tie-point, and plant stack were also incorporated into the plant design. The facility operates continuously throughout the year, employing an experienced solid fuel firing and turbomachinery operations and maintenance staff.

Because this project planned to retrofit the existing plant, which is located on the MU campus in downtown Columbia, the main challenges were related to laying out the plant within existing spatial constraints. To reduce project costs, the design used the existing boiler building and baghouse structures to house the new equipment. Ducting, piping, and equipment layouts were carefully planned since the density of the surrounding infrastructure precluded expansion of the plant footprint.

Multiple CCHP plant modifications over the years have surrounded Boilers 7, 8, and 9 with additional equipment around and above them. These plant improvements remain in operation and include: the biomass boiler (BFB-1) to the west; the gas boiler (Boiler 12) to the south, along with its stack, the central control room, and electrical switchgear; the turbine building to the east; the combustion turbines, HRSG building, BFB-1 breeching, stack, cooling towers, pipe bridge, and an underground water storage well to the north; and a recently installed deaerator above Boilers 7 and 8. The only opportunity to facilitate the rigging and moving of large equipment into the space—both for demolition and installation—is the roof area above Boiler 9, requiring a 350-foot crane reaching from the street south of the plant. The final plan was the result of constructability reviews performed during the FEED study, with input from the FEED team, boilermakers, and rigging and lift plan professionals and including careful coordination with MU.

The age of the boiler building and the multiple upgrade projects that have occurred over the life of the plant posed unique retrofit challenges including relocation of existing power, control, and communication conduits and wiring; careful coordination with MU staff to ensure proper identification of all raceways and conduits throughout the multi-level, 8,000 square foot plant (to avoid costly reroutes and changes during the construction phase); and development of an outage schedule to coordinate these and other utility tie-ins to minimize interruptions to the CCHP plant.

PLANT DESIGN

Power Cycle Design and Optimization

The Recompression Brayton Cycle (RCBC) is advantageous for optimizing thermal efficiency in indirect-fired sCO_2 primary power applications [5]. Recuperative pre-heating creates a narrow temperature range for heat addition. A recompressor introduces a partial recuperator bypass, minimizing exergy destruction in the recuperators and optimizing internal heat recovery. The combination of high average hot side temperature and highly effective recuperation result in cycles with high thermodynamic efficiencies relative to steam.

Standard RCBC architecture (configured with turbine-driven compressors) is shown in Figure 3. The main compressor, or low-temperature compressor (LTC), compresses relatively dense fluid after the final heat rejection step in the cycle. The recompressor, or high-temperature compressor (HTC), compresses a lower-density fluid that bypasses heat rejection. Drive turbines (LTC DT and HTC DT) power the LTC and HTC, respectively. Net and auxiliary electrical power are supplied by a synchronous generator driven by the power turbine (PT). Heat addition from the thermal resource occurs in a single primary heat exchanger (PHX). Heat rejection to the cooling fluid occurs in the condensing heat exchanger (CHX). Ambient-range cooling fluid temperatures limit the pressure ratio of the working fluid, such that the CO_2 leaves the turbines at relatively high temperature. Two internal heat exchangers recuperate this energy to preheat the CO_2 entering the PHX. The high-temperature recuperator (HTR) preheats the full high-pressure flow. The low-temperature recuperator (LTR) preheats a portion of the high-pressure flow, minimizing the exergetic destruction associated with recuperation by closely matching the temperature glide between the hot and cold CO_2 streams.

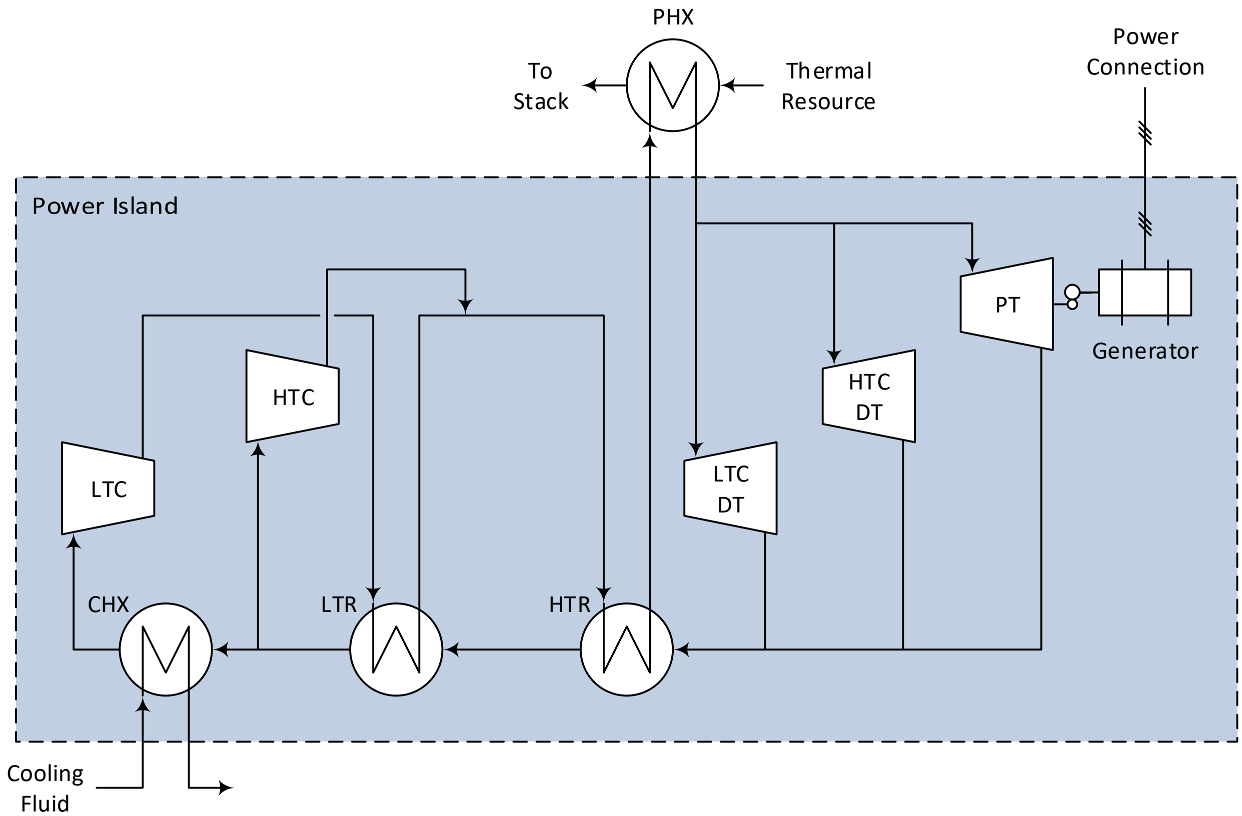

Figure 3 – RCBC configured with turbine-driven compressors

For the pilot project, the thermal resource was a combustion byproduct (flue gas) from a fired heater. While ideal for optimizing power cycle efficiency, standard RCBC architecture can restrict the efficiency of the fired heater and reduce the overall plant efficiency. Recuperative pre-heating of the CO_2 produces a high PHX inlet CO_2 temperature, limiting the enthalpy extraction from sensible thermal resources. Adding a combustion air preheater (not shown) has the potential to reduce the waste heat in the exhaust gas to the stack. For this project, the air preheater size was constrained by combustion air temperature limits, resulting in a preliminary fired heater efficiency percentage in the mid-70s.

To increase net plant efficiency, an economized RCBC architecture (RCBC-E, Figure 4) was considered. The RCBC-E uses an sCO_2 economizer to increase the fired heater efficiency. In the flue gas stream, the sCO_2 economizer (PHX-2) is in series with the main PHX (PHX-1), reducing the heat that is exhausted through the stack (Figure 5). In the CO_2 stream, PHX-2 is in parallel with the HTR, so that a portion of the total CO_2 flow bypasses high-temperature recuperation for low-temperature heat addition.

Depending on its duty, PHX-2 may penalize the power cycle efficiency. As the PHX-2 duty increases, the bypass flow requirement increases. The corresponding reduction of HTR high-pressure flow raises the HTR high-pressure outlet temperature. If the bypass flow is sufficiently high, the HTR duty is constrained by the heat capacity rate of the high-pressure CO_2, penalizing the power cycle efficiency. For low bypass flow, the HTR duty is unconstrained by the high-pressure CO_2, and the RCBC-E can achieve the same power cycle efficiency as the RCBC. (Note that a larger RCBC-E HTR is required to meet the same duty as the RCBC HTR.) For this project, the addition of PHX-2 created a potential increase of 10% points for the fired heater efficiency. Since the PHX-2 duty required low bypass flow (approximately 10% of the total flow), the RCBC-E architecture was used without penalizing the power cycle efficiency.

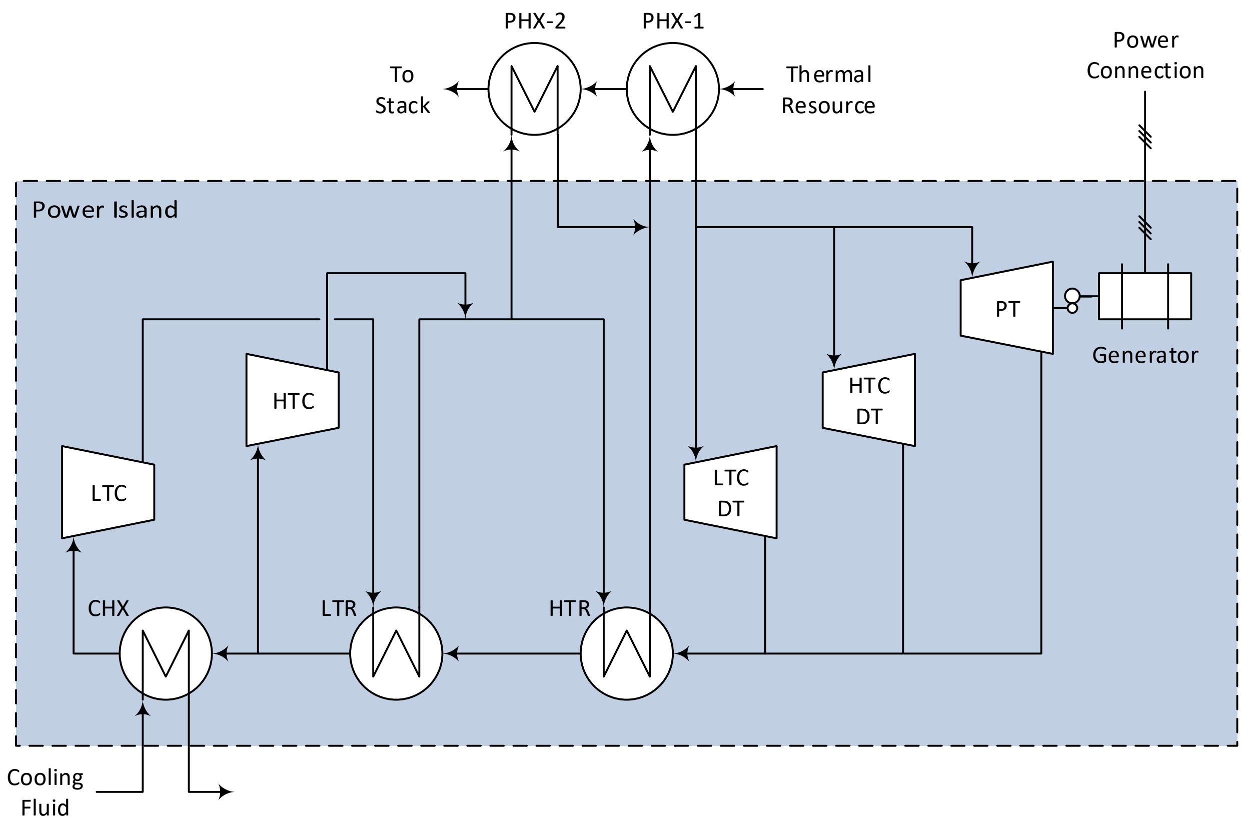

Figure 4 – RCBC-E with an sCO_2 economizer (PHX-2)

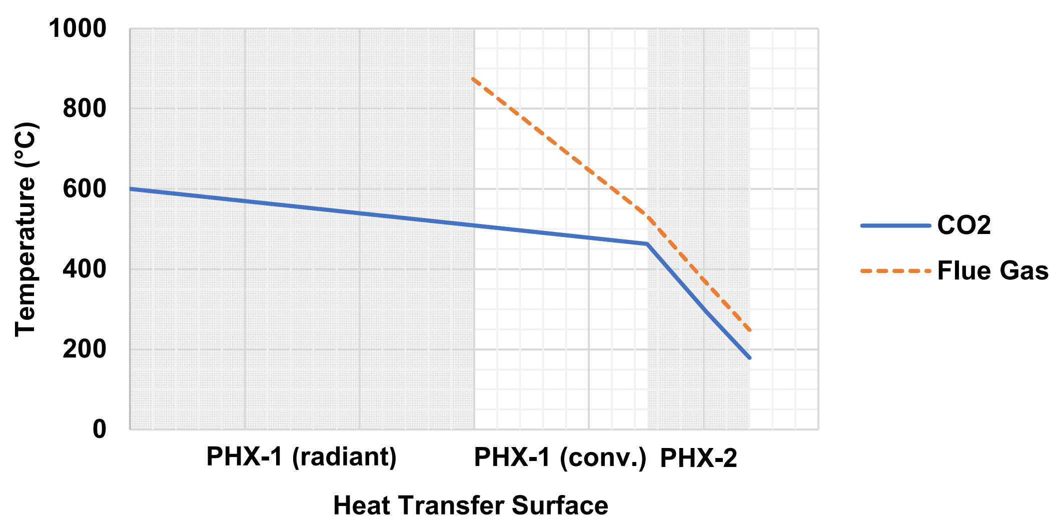

Figure 5 – Temperature profiles across the PHX sections

FEED Study Design Basis

Considering the overall plant efficiency benefit, the RCBC-E architecture was chosen for the pilot plant. The plant process flow diagram (PFD), shown in Figure 6, displays the proposed plant configuration. The power island matches the RCBC-E cycle described previously in Figure 4. For heat rejection, a clean-water cooling loop with an intermediate heat exchanger (IHX) is used to transfer heat to an existing plant water loop and cooling tower. Water in both the intermediate and plant loops is circulated by pumps (WP1 and WP2, respectively). The heat addition system includes coal combustion (with natural gas co-firing) in a stoker-fired heater. Combustion air is supplied from a forced draft (FD) fan through an air preheater (APH). Environmental control systems include selective catalytic reduction (SCR) for NO_x reduction, a circulating dry scrubber (CDS) for SO_2 reduction, and a baghouse (BH) for particulate management. The unit is balanced draft, with an induced draft (ID) fan discharging flue gas to an existing stack. The CO_2 economizer is split into sections downstream (PHX-2A) and upstream (PHX-2B) of the SCR to optimize the gas temperature for effective NO_x reduction.

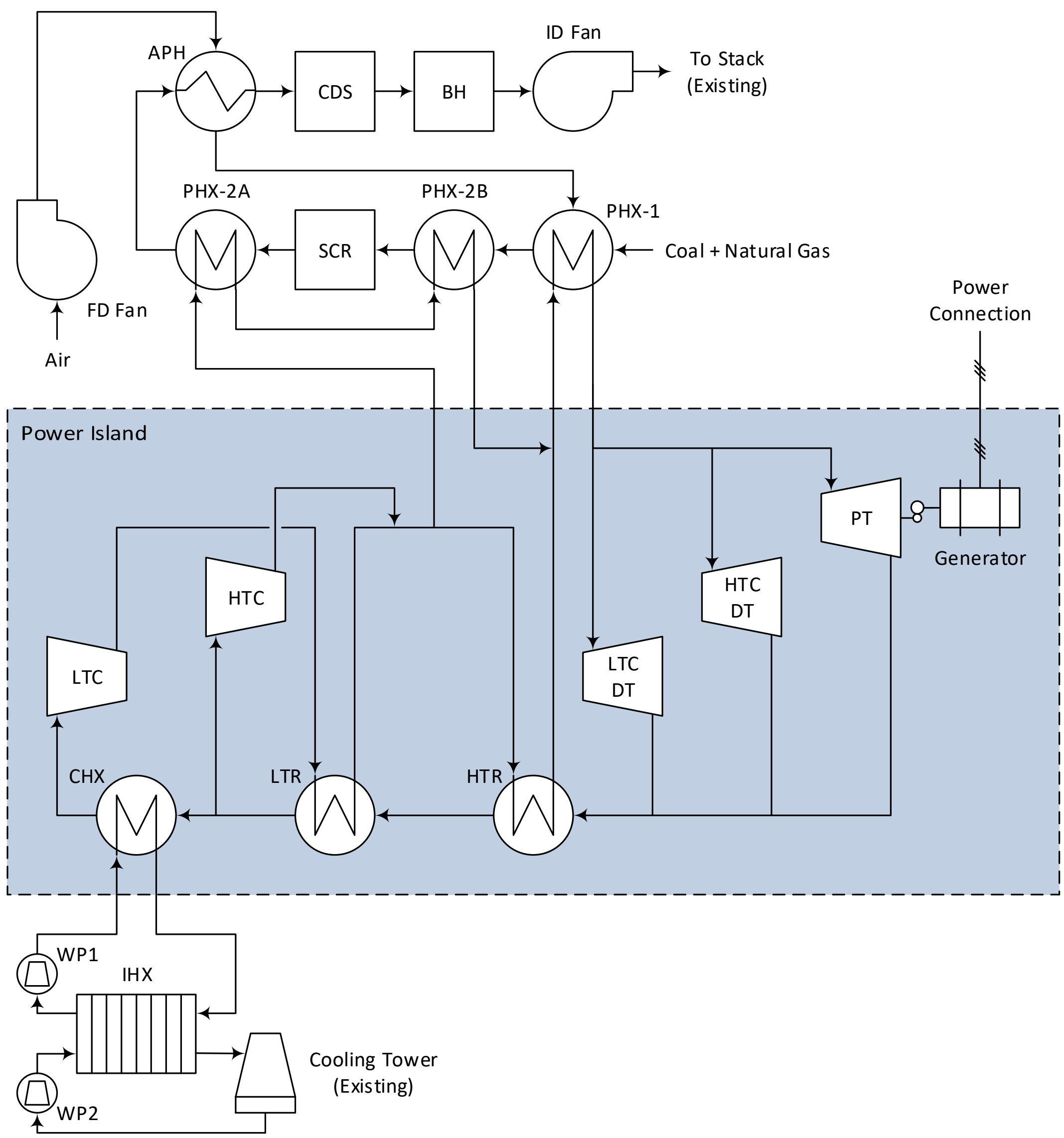

Figure 6 – FEED study process flow diagram

Table 2 summarizes key design parameters for the plant. The first column of values represents the basis for the FEED study. The second column of values represents the results of the FEED study. The net power (10 MW_e nominal) is suitable for demonstrating component and plant technologies that can be scaled up for future utility applications. The LTC discharge pressure (25 MPa) and the turbine inlet temperature (600°C) balance high-pressure and high-temperature efficiency gains with material costs. The gas temperatures are the results of a parametric study designed to maximize overall plant efficiency, with RPI providing guidance to set approach temperature difference limits. The PHX-1 pressure drop (1.00 MPa initial, 1.10 MPa final) and PHX-2 pressure drop (0.30 MPa initial, 0.16 MPa final) also represent a balance between efficiency and material cost. (Cycle efficiency and CO_2 flow imbalances are both inversely proportional to pressure drop.) Other heat exchanger pressure drop assumptions (0.1 MPa per CO_2 pass) are based on previous EPS experience. High-pressure and low-pressure piping pressure drops were initially estimated based on expected pipe lengths and diameters. The final numbers are based on a detailed plant layout, with values listed for piping losses only (piping) and overall losses after accounting for valves and other devices (total). The cooling tower water supply temperature is the average from historical plant data.

Table 2 – Design Parameters for Cycle Optimization

Description	Initial Value (FEED Basis)	Final Value (FEED Results)
Net power (MW_e)	10	10
LTC discharge pressure (MPa)	25	25
Turbine inlet temperature (°C)	600	600
PHX-1 exit / PHX-2 inlet gas temperature (°C)	525	533
PHX-1 inlet / PHX-2 exit CO_2 temperature (°C)	≤ 470	470
PHX-2 exit gas temperature (°C)	250	249
PHX-2 inlet CO_2 temperature (°C)	≤ 195	195
PHX-1 CO_2 pressure drop (MPa)	1.00	1.10
PHX-2 CO_2 pressure drop (MPa)	0.30	0.16
CHX / LTR / HTR CO_2 pressure drop (MPa)	0.10 (each pass)	0.10 (each pass)
High-pressure piping CO_2 pressure drop (MPa)	0.175 (piping)	0.289 (piping) 0.592 (total)
Low-pressure piping CO_2 pressure drop (MPa)	0.250 (piping)	0.266 (piping) 0.336 (total)
Cooling tower water supply temperature (°C)	26	26

Table 3 summarizes system efficiencies for the plant. The predicted thermal efficiency of the fired heater is based on a bituminous coal with a higher heating value (HHV) of 26,372 kJ/kg and 10% co-firing of natural gas. The power cycle efficiencies are based on the gross power (at the generator terminals) and the net power (after debiting parasitic loads). The overall plant efficiency is the produce of the fired heater efficiency and the net power cycle efficiency.

Table 3 – System Efficiencies

Description	Initial Value (FEED Basis)	Final Value (FEED Results)
Fired heater (%)	86.0	84.3
Power cycle, gross (%)	40.6	40.0
Power cycle, net (%)	37.0	35.8
Overall plant (%)	31.8	30.2

Power Cycle Equipment Design

Both compressors (LTC and HTC) are turbine driven. Turbine-driven compressors offer performance and footprint advantages compared with motor-driven compressors, which involve additional energy conversion losses as well as large motors and variable frequency drives (VFDs).

The LTC receives high-density (liquid-like) CO_2 from the CHX in either low-temperature supercritical or liquid state and compresses it to the high-side system pressure. The compressor is driven by the expansion turbine with a nominal shaft speed of 42 KRPM. A low-temperature compressor of similar scale and requirements was successfully designed and fabricated for a commercially-available EPS design, with the main difference being a higher turbine inlet temperature for the new LTC-DT. The compressor uses CO_2 hydrostatic bearings to support the rotor and is hermetically sealed, offering a leak-free solution.

The HTC takes low-pressure, gas-phase CO_2 and compresses it up to the high-side system pressure. An aerodynamic trade study was conducted to identify the most appropriate turbomachine topology. The resulting design concept consisted of a shrouded centrifugal compressor driven by a single-stage axial turbine with a nominal shaft speed of 43 KRPM. The HTC uses CO_2 hydrostatic bearings. There is no shaft seal present, and the compressor is hermetically sealed to atmosphere. The LTC and HTC bearing systems are interchangeable. Conceptual design results suggested that, with some minor design decisions, the central housing component could also be common between the two turbo compressors.

The PT is a multi-stage axial turbine. While a single-stage radial turbine would provide superior efficiency at this size, a multi-stage axial turbine will be required by commercial-scale systems. The multi-stage axial turbine also provides superior turndown efficiency, suiting the long-term operating profile of the MU CCHP plant. A parametric trade study (stage count, degree of reaction, and speed) guided downselection to a core aerodynamic configuration. The goal of the optimization was to trade complexity (stage count and airfoil design) with performance to arrive at a multi-stage axial design that could demonstrate reasonable pilot-plant efficiency at reasonable cost. The resulting selections for design aerodynamic geometry included three turbine stages, a pressure reaction of 10%, and a nominal design speed of 20 KRPM.

The 20,000 RPM shaft speed of the PT is reduced to 1800 RPM synchronous generator speed via a compound epicyclic gearbox. (Parallel shaft gearboxes were not an option for this application due to site spatial constraints.) The generator is a totally enclosed water-to-air cooled (TEWAC) unit designed to operate at 4-pole synchronous speed (1800 RPM). Electrical output is 13.8 kV at 60 Hz. The nameplate rating of 11,500 kW is at a power factor of 0.8 and reflects standard 25°C generator capability when limited to 80°C (class B) rise above 25°C ambient (cooling air) temperature.

Recuperators (HTR and LTR) recycle heat within the power cycle, transferring heat between CO_2 flows at various points in the process and greatly increasing cycle efficiency. The CO_2 cooler (CHX) rejects heat from the power cycle, transferring heat from CO_2 to cooling water. Printed Circuit Heat Exchanger (PCHE) designs are advantageous for achieving the required heat exchanger effectiveness (~98%). PCHEs take advantage of very small channels to create high heat transfer area in a relatively small volume.

Heater System Description

The CO_2 heating system was developed by RPI for the MU pilot plant host site. A stoker-fired combustor generates the hot flue gas, furnace and convective sections transfer heat to the CO_2 working fluid, and a tubular air heater transfers heat to undergrate air and overfire air. The design was developed for fuel flexibility, capable of firing coal during the demonstration project and allowing for future operation with biomass or natural gas. The environmental control systems include in-furnace combustion NO_x control using overfire air and an external SCR. SO_2 is controlled using a CDS that includes a fabric filter for particulate control. A schematic of the heater system and control equipment is shown in Figure 7. The heater system components, NO_x control, SO_2 scrubber, and particulate removal equipment are summarized in the following sections.

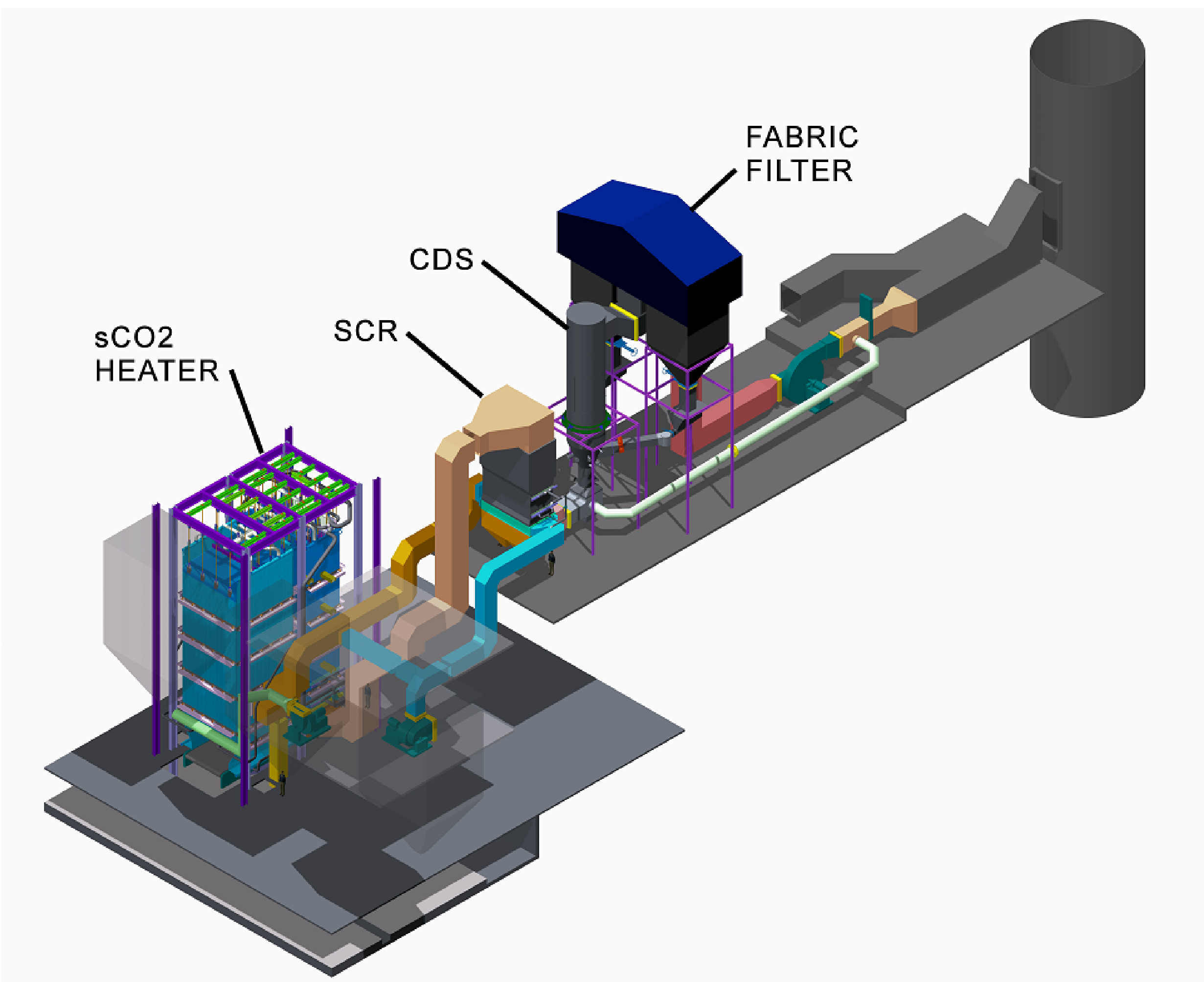

Figure 7 – Arrangement of RPI fired heater system with environmental control equipment

Fuel Systems

The demonstration plant design was developed using a stoker firing system. The stoker is a travelling grate design which is cooled by combustion air flow through the grate. The unit is equipped with an overfire air system to assist with complete burnout and CO reduction. This stoker system can burn both coal and biomass, providing fuel flexibility for long term operation of the unit. The stoker requires insulating materials when firing 100% natural gas due to the lack of cooling air flow through the grate in this mode.

Wall mounted natural gas burners are included as a secondary firing system. These burners are sized to allow for 100% natural gas operation and are used in co-firing applications, providing a rapid response heat input control and allowing the unit to maintain the target fluid outlet temperature.

Both firing systems share combustion air equipment, and the unit can co-fire any combination of fuels. Combustion air is provided by a single forced draft fan. Ambient air is taken through the air preheater, after which a set of dampers control the flow and pressure to the windbox for the natural gas burners, the grate for undergrate air, and the overfire air fan inlet. The overfire air fan takes the heated air, boosts the pressure, and provides this flow to the overfire air headers for injection into the furnace.

Heater Design

The CO_2 heater was designed to achieve the required system heat input while primarily firing coal on a stoker. This system considers overall efficiency, metal temperatures, existing space requirements for installation, mechanical interaction of equipment, and fabrication of the elements and tubing.

One of the driving factors of the CO_2 system is improving the overall efficiency of future plants. Efficiency of the CO_2 heater plays a large role in overall plant efficiency and is determined by several factors. The main goal of efficiency optimization is reducing heat losses, where the largest loss is the energy in the flue gas at the heater exit. Other losses include radiant heat loss to the environment, moisture loss from hydrogen combustion, and ash loss. Reducing the flue gas exit temperature is the most effective means of increasing unit efficiency.

Gas exit temperatures are primarily limited by the cold fluid temperatures available. The relationship between the fluid temperature and the gas temperature is called an approach temperature. Typical heat transfer surfaces have an approach temperature of approximately 55°C. For a counterflow element, this approach temperature is the difference between the coldest fluid at the fluid inlet and the coldest flue gas at the gas outlet. Attempting to reduce this further provides diminishing returns, as the amount of material required for additional heat transfer increases non-linearly with the heat recovered.

This 55°C approach temperature indicates that having the coldest fluid at the outlet of the heater’s flue gas path results in the highest overall heater efficiency. In a traditional steam system this is accomplished by adding an economizer element at the heater flue gas exit. The CO_2 system designed for this pilot has a similar economizer fluid flow. This flow is selected to achieve a flue gas outlet temperature comparable to a traditional steam unit and to achieve a similar efficiency in the heater. For this application, the flue gas temperature is reduced from 533°C at the primary circuit outlet down to 249°C at the economizer outlet. This economizer accounts for approximately 17% of the total duty added to the CO_2.

Additional efficiency can be gained by adding an air preheater to the unit. This system recovers waste heat into the combustion air, reducing fuel firing rate. For a coal-fired stoker system, this air preheat temperature is limited by the ash softening temperature of the fuel. For this unit, the maximum combustion air temperature is 120°C based on the provided design fuel analysis. With a combustion air mass flow based on 30% excess air, this system further reduces the flue gas temperature to approximately 175°C.

Considering the above constraints, the unit achieves a CO_2 heater efficiency of 84.3%, with a heat input of approximately 32 MW_{th}.

One of the goals of a pilot-scale plant design is to develop a configuration that may scale up to achieve greater duties in future applications. This unit was designed with a similar overall layout to a traditional utility scale steam boiler. A rectangular furnace composed of tube and membrane walls sits above the stoker, and a tube and membrane-walled convective pass provides space for serpentine tube elements in the convective zone. This design can scale to achieve a wide variety of fluid flows and overall heater duties, while keeping the general design principles intact.

To achieve maximum efficiency, the coldest fluids are used at the flue gas outlet. Fluid flows through the convective elements counter to the flue gas before being mixed through pipes and headers and sent to the furnace. The fluid flows up through the furnace walls and down the convective walls before achieving final temperature and leaving the system.

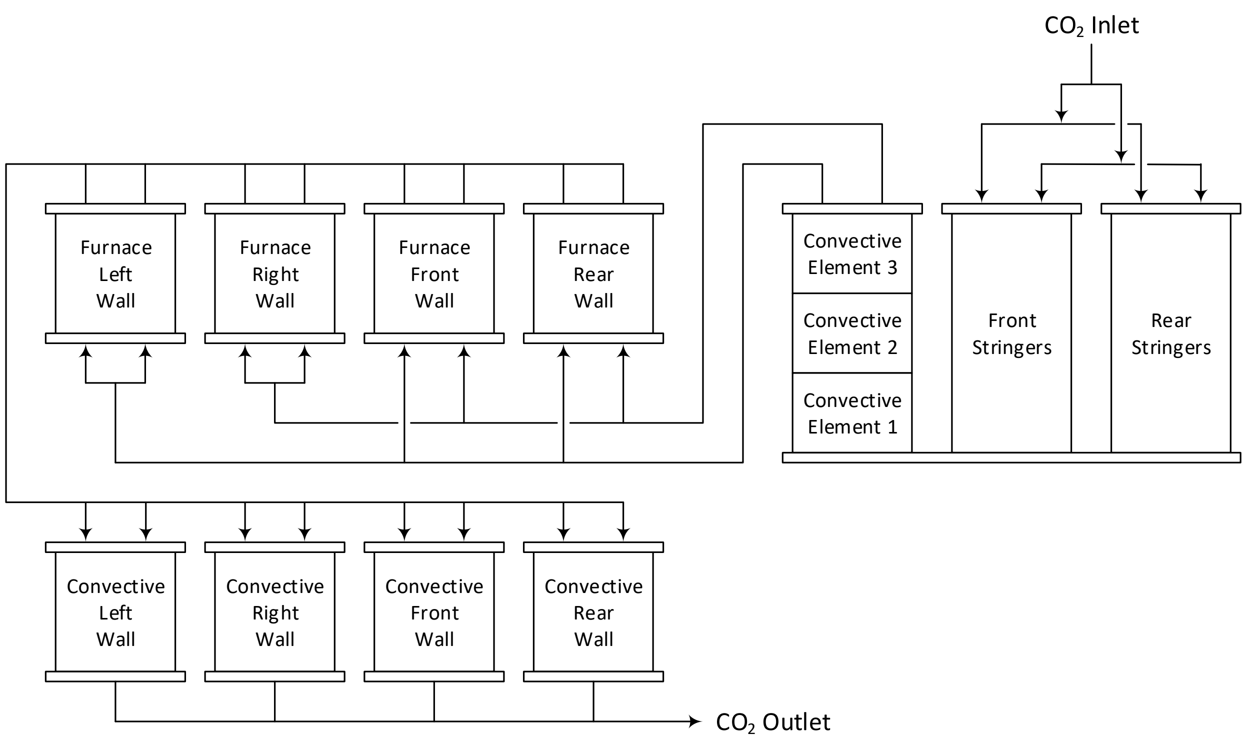

Figure 8 – CO_2 flow path through PHX-1

The economizer surface (PHX-2) is split, with a hot economizer inside the convective pass of the heater, and a cold economizer external to the main heater unit. This allows for flue gas temperature control entering the SCR, where the catalysts can be operated at ideal conditions.

Temperature control is achieved by individual fluid bypasses on each of the economizer modules. To minimize the amount of tubes required and the space consumed, both economizer elements are finned-tube surfaces.

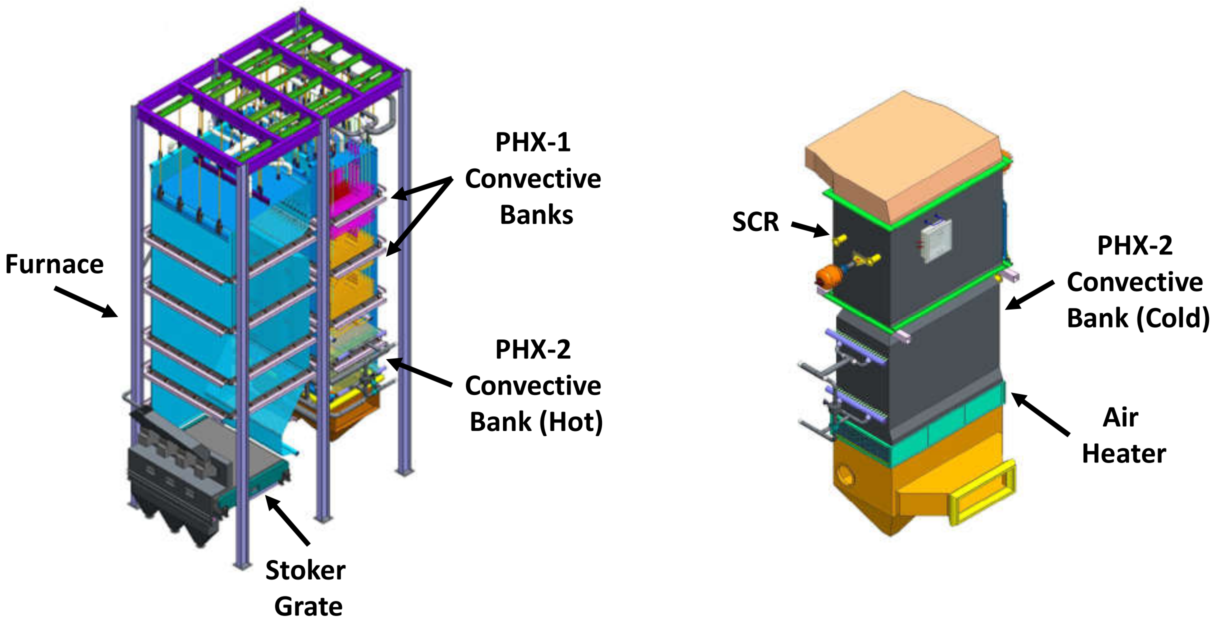

Figure 9 – CO_2 surface arrangement

Final CO_2 temperature control is achieved via heat input control similar to a process fired heater and atypical to a traditional fired steam generator. CO_2 attemperation is not effective since it lacks the latent heat available with water/steam attemperation. The volume of CO_2 required to provide a sufficient temperature control range means a substantial portion of the CO_2 flow would bypass the heater for attemperation. Firing 10% natural gas provides sufficient heat input control with reasonable response time to maintain CO_2 outlet temperatures within a reasonable range.

Fluid temperatures and furnace fluxes result in a peak mid-wall metal temperature of approximately 665°C. Considering the high design pressure of this unit, this requires advanced materials for the furnace tubing. The unit is designed with Super304 furnace tubes, providing adequate margin for fluid temperature and radiant flux variation within the walls.

The convective walls and coils are also designed with Super304 materials, allowing for minimal material changes and ensuring that mechanical properties such as thermal expansion are similar throughout the unit.

Due to the lower fluid temperatures, the economizer elements are composed of carbon steel at the cold economizer and SA213-T22 in the hot economizer.

The CO_2 heater is equipped with a tubular air preheater. This system is designed to achieve a maximum combustion air temperature of 120°C for 100% coal firing. For off-design loads, the air temperature can be controlled by an air bypass around the air preheater.

Environmental Control Systems Design

To manage NO_x emissions, a traditional SCR was incorporated into the flue gas path. This unit is located between the hot and cold economizers, maintaining an ideal flue gas and catalyst temperature near 370°C. Ammonia is injected in the upstream ductwork and is regulated by the Continuous Emission Monitoring System (CEMS) readings for NO_x at the stack. This is a proven technology and provides reliable emissions controls over the operating range for the coal fuel. In alternate fuel scenarios (such as 100% biomass), the SCR could be modified by changing out catalysts to prevent deleterious interactions between the trace elements in the biomass and the catalyst.

A CDS removes the acid gas constituents from the flue gas, primarily SO_2 but also SO_3, HCl, and HF by reacting the acid gases with hydrated lime, $Ca(OH)_2$. The system includes dedicated hydrated lime injection, water injection, byproduct ash recycle, and flue gas recirculation for operation at low loads. The CDS system also removes a high percentage of mercury in the flue gas.

As part of the CDS process, a baghouse fabric filter system removes the circulating byproduct from the flue gas. The particulate forms a layer on the outside of the filter bags that both aids in filtration and enhances SO_2 and Hg removal.

For turndown, a clean gas recirculation duct travels from the positive discharge of the induced draft fans to the negative pressure inlet of the CDS. When the flue gas flow is low, a damper in the duct opens to recirculate enough flue gas to maintain a minimum flue gas velocity for the fluidized bed in the CDS reactor.

COMMERCIAL POTENTIAL

As a project in the Fossil Fuel Large-Scale Pilots program, the primary heater was designed to primarily fire coal. The current marketplace for coal power varies widely on a regional basis. New coal power has stagnated in the U.S., where it is often not competitive with natural gas (NG) or presents future environmental risk. Outside the U.S., different regions have different appetites for coal. In Western Europe, most coal power plants have been decommissioned. In regions where new coal power plants are being built, efficiency and cleanliness will also be key. In all cases, one or more of the following drivers impact the future viability of coal power:

- Competition against other power sources – In some regions, coal remains a low-cost generator, while in others, NG-based power is typically more economical due to the availability of low-cost NG (e.g., in North America, NG is about half the cost of elsewhere), although the potential for changes in relative fuel prices is possible. Regardless, new coal power will need to have the lowest cost of electricity possible.

- Drive towards low carbon – Internationally, the Paris Agreement aims to reduce greenhouse gas emissions. In the U.S., multiple states have enacted low-carbon initiatives, including several that have committed to >90% reductions by 2040. Coal, as a fossil fuel, and one that produces double the CO_2 per MWh that NG does, is therefore a bigger target towards reducing CO_2.

- Energy security – In some regions, coal is an abundant natural resource, representing energy security and reducing the need for reliance on fuels or energy from foreign countries. Finding ways to use it more effectively can be critical for these regions.

- Environmental regulations – Coal emission regulations vary globally, but coal universally remains harder to permit than NG. Uncertainty in regulations increases risk, which makes coal power projects more difficult to finance and generators more reticent to build them.

- Financing – Financing is becoming more challenging for larger plants as the future power market has uncertainties, especially around carbon. Coal power plants are hence a particular challenge. Smaller plants are thought to be lower risk since they require less capital, and hence have a better opportunity for financing.

- Meeting a changing market – The energy market is changing, largely due to the growth of variable renewable energy (VRE). Intermittency requires grid protection provided by dispatchable sources. In some regions, coal power is providing such grid support, requiring more flexible operation than plants were designed for, which is deleterious to performance. Such operating behavior will likely continue to grow, reducing the need for base-load fossil power, while putting extra importance on their ability to provide grid resilience.

The system was designed to improve its commercial potential by addressing these factors in the following ways:

- Adaptability – Indirect-fired sCO_2 power cycles are heat-source agnostic. Lessons learned from this project on the power island are directly adaptable to other applications, including non-coal power ones. These cycles can also use a variety of coal generators, including fluidized beds, which could increase the system's fuel flexibility.

- Costs – sCO_2 systems have the potential to be lower cost than conventional coal power plants with lower maintenance costs, less fuel use, and a projected lower cost of electricity.

- Efficiency – sCO_2 power cycles are more efficient than comparable steam-Rankine cycles by 2–4% points for sizes greater than 300 MW, and up to 8% points for smaller sizes. Higher efficiency also reduces emissions (including CO_2) on a per MWh basis.

- Operational flexibility – The system has inherent operational flexibility that is superior to conventional coal power plants. Mainly this is due to the sCO_2 turbomachinery being significantly smaller on a relative basis compared to that of steam-Rankine cycles, which lends itself to improved flexibility. The flexibility provided by the system, particularly lower turndown and faster startup, could be key in the future marketplace and provides the ability to not include energy storage for cases where the cost-benefit analysis is not positive.

- Size – The system can be made smaller (100 MW net or less) and still maintain high efficiency and flexibility (unlike steam-Rankine cycles). This reduces the financing hurdle and makes the system a better fit in locations with uncertain future power demand growth.

Potential commercial markets for this system include:

- One of the short-term markets will be niche areas where NG supply is limited or unavailable without significant infrastructure investment, where coal can be supplied. In the U.S., this is largely in the West. Opportunities may also exist in Mexico and areas in Asia and Eastern Europe. These applications will be small, likely <100 MW, which is doable with this system.

- In regions where NG is more expensive (e.g., Africa and Asia), or if NG prices should rise in North America, the system will be competing directly with more established systems for coal. In these cases, the system must have costs and performance that are superior in general, especially given that it might be perceived to be higher risk (although its field experience will help mitigate this). Based on techno-economic assessments, this system will improve efficiency and reduce cost, especially at smaller sizes.

- In regions where there is more explosive projected VRE growth (e.g., Korea), the potential to add energy storage to this system may provide additional opportunities.

- In regions where there is a need or economic reason to be low-carbon, post-combustion capture can be readily applied to this system even as a retrofit.

CONCLUSIONS

An existing facility was chosen for the FEED study of an indirect-fired sCO_2 primary power cycle technology. MU's CCHP is a well-established district-energy system with the necessary facilities, infrastructure, and staffing talent to effectively demonstrate and showcase this emerging power generation technology. Although the project did not progress to the operating phase, the CCHP offered a promising environment for obtaining valuable operational and reliability data which could be shared with university students and researchers, the DOE, and the utility industry.

As an existing plant, the MU CCHP presented opportunities and challenges in retrofitting existing space for the new pilot system. Much existing infrastructure was planned for use by the pilot project, including fuel and auxiliary systems, control rooms, switch gear, a utility interconnect, and the plant stack. Relocation was to be required for some existing infrastructure, including power, control, and communication conduits and wiring. The FEED study scope included identifying solutions for the these and other challenges associated with designing the pilot for construction within the CCHP plant's spatial constraints.

The power cycle was designed with a modification of the standard RCBC architecture to maximize overall plant efficiency with a combustion byproduct as the thermal resource. The addition of an sCO_2 economizer enabled the fired heater to be designed with an 84.3% efficiency, which is comparable to that of a steam boiler with equivalent combustion technology. With a power cycle efficiency of 35.8% and an expected plant efficiency of 30.2% at 10 MW_e, the sCO_2-based cycle demonstrates superiority to steam-Rankine systems. At this scale, a successful pilot program would advance the technology to TRL 7, allowing for financing and investment in future plants.

The sCO_2 power cycle was designed for demonstration using a coal-fired CO_2 primary heater with stoker combustion technology. The fired heater was designed with CO_2-cooled walls in a configuration readily scalable for future applications. Commercially available environmental control systems were designed for mitigating emissions including NOx, SO_2, and particulate matter.

The sCO_2 power technology has the potential to be lower cost than conventional coal power plants and is adaptable to a wide range of heat sources other than coal. Additional potential commercial advantages include superior thermal efficiency as well as flexibility in system sizes and operating profiles compared with conventional steam-Rankine based systems. Finally, potential markets for this technology have been identified and summarized.

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DISCLAIMER

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