Pre-FEED – Final Report

A Low Carbon Supercritical CO_2 Power Cycle / Pulverized Coal Power Plant Integrated with Energy Storage:

Compact, Efficient and Flexible Coal Power

Contract No. 89243319CFE000022

Recipient Organization:

Echogen Power Systems (DE), Inc.
365 Water Street
Akron, Ohio 44308-1044

Prepared By:

Jason D. Miller
Engineering Manager
jmiller@echogen.com
234-542-8037

Principal Investigator:

Dr. Timothy J. Held
Chief Technology Officer
theld@echogen.com
234-542-8029 (office)
330-379-2357 (fax)

Project Partners

Mitsubishi Heavy Industries

Riley Power Inc.

Electric Power Research Institute

Louis Perry and Associates, A CDM Smith Co.

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1. Integrated Plant Concept

Echogen Power Systems, Inc. (EPS), Louis Perry and Associates, A CDM Smith Co. (CDMS), Electric Power Research Institute, Inc. (EPRI), Mitsubishi Heavy Industries (MHI), and Riley Power Inc. (RPI) have partnered to design an advanced coal-fired power plant, integrating innovative technologies to deliver key characteristics of compactness, high efficiency, modular construction, operational flexibility and a low-carbon footprint: supercritical CO_2 (sCO_2) power cycles, air-fired pulverized coal (PC) fired heater, amine-based post combustion capture (PCC), and CO_2-based electrothermal energy storage (ETES). This combination, shown in Figure 1, produces a coal-fired power plant with favorable attributes that will be more competitive than state-of-the-art steam power cycles and natural gas combustion turbines (areas where cost of natural gas is high) in the future power market. The plant will have a base peak power output of 120.7 MW_e with an additional generation of up to 30 MW_e for 8 hours available through the energy storage system giving the plant a maximum generation capacity of 150.7 MW_e. The proposed plant is expected to achieve the United States Department of Energy (DOE) flexibility targets while achieving an efficiency of 29.9% HHV net with 83.6% CO_2 capture or 40.3% HHV without. At this scale, the estimated installed cost, including all contingencies and overhead, of the sCO_2 power cycle is $1,175/kW_e$ and the predicted energy storage system has a levelized-cost-of-storage of $135/MWh. The costs of the PCC (including CO_2 compression and drying) is $1,527/kW_e$ and the air-fired PC and it associated air quality control system (AQCS) is $3,755/kW_e$. The total plant cost (TPC) is $1,045M and the levelized cost of electricity (LCOE), expressed in 2019 dollars, is $212.8/MWh. Total plant costs including all required auxiliary equipment are shown in Section 7.

It has been shown that sCO_2 cycles are 4% points (550 MW_e plants) to 8% points (90 MW_e plants) higher in efficiency on an “apples-to-apples” basis when compared with steam cycles integrated with atmospheric oxy-combustion, chemical looping combustion and air fired PC heaters without capture (DE-FE0025959). The 90 MW_e plants were studied with the air-fired PC heaters and similar results for net plant efficiency (without carbon capture) were achieved (40.3% HHV versus 41.0%).

sCO_2 power cycles also offer a potential cost advantage over comparable steam-Rankine cycles. The high fluid density of sCO_2 greatly reduces the physical size of its turbomachinery. And because the condensing pressure of CO_2 is well above atmospheric pressure, vacuum systems are unnecessary, and air infiltration is eliminated, which also removes the need for components such as deaerators and condensate polishers. This same high condensing pressure increases the vapor density by four orders of magnitude (decreasing the volumetric flow rate requirement of the condenser by the same) compared to steam, making air-cooled condensers a much more practical and cost-effective alternative to water-cooled condensers that dominate steam-based systems.

To reduce technical risk and achieve commercialization by 2030 an air-fired PC heater was chosen. The combustion process is proven, as it has been in use since the early 20th-century and the heater design, which has been adapted to heat CO_2 instead of water, is similar to a traditional utility steam boiler. State-of-the-art combustion process and AQCS will allow for efficient use of the coal while still meeting strict environmental requirements. The amine-based PCC process chosen has been commercially proven and shown to be an economical choice for CO_2 capture.

The ramp rate and turndown capabilities of the system will be significantly improved through the addition of a flexible energy storage system. This system can capture and store excess thermal energy and excess electrical power generation capacity in cold and hot thermal reservoirs that can be discharged when power demand exceeds baseload capacity. EPS has been developing a CO_2-based ETES system that has the potential to integrate with electrical and direct thermal energy storage, which are both being explored as part of this plant concept.

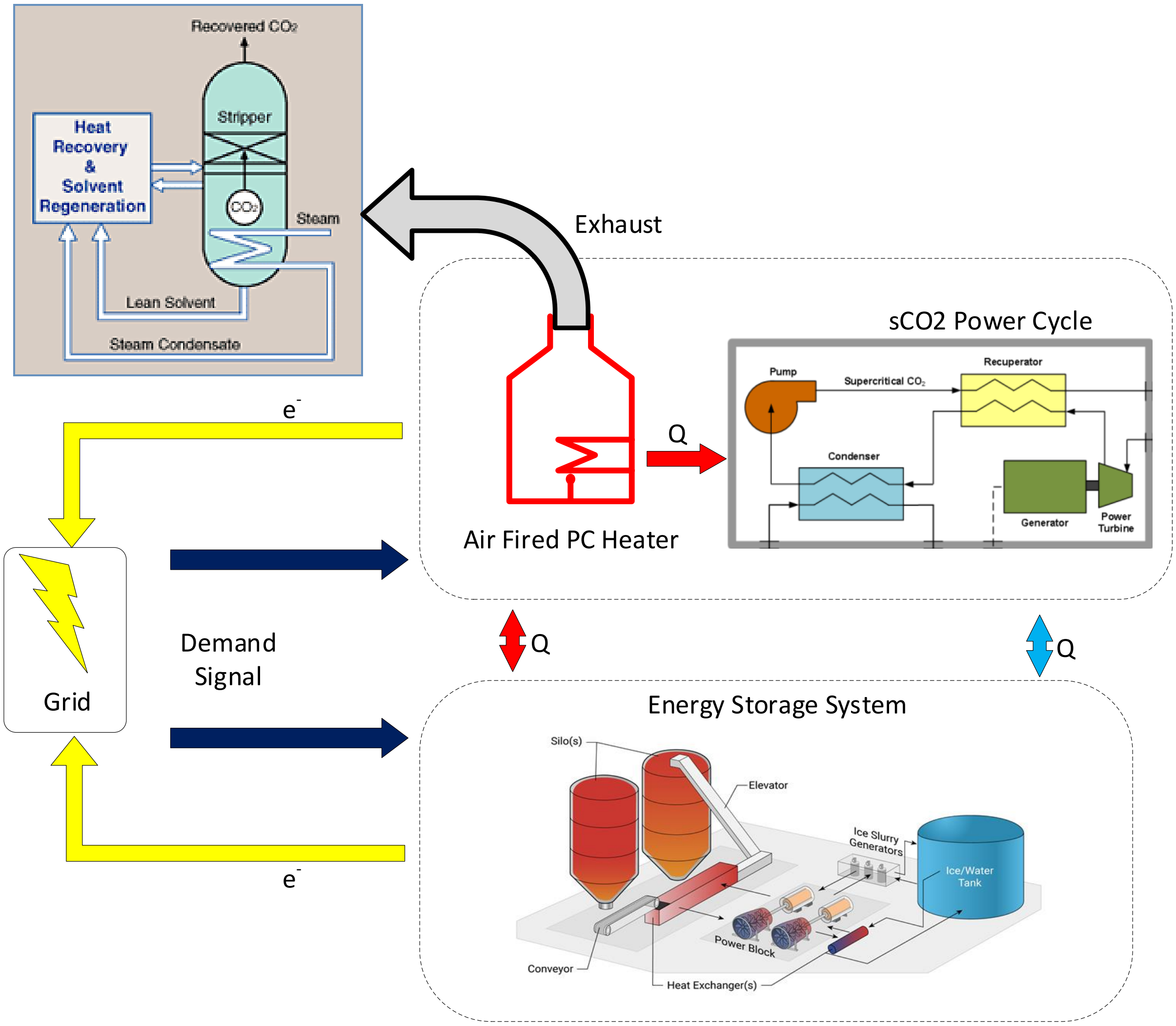

Figure 1 Integrated plant concept, sCO_2 Power Cycle, Air-fired PC, Amine-Based PCC, ETES

sCO_2 Power Cycles

sCO_2 power cycles were first proposed in the 1960s[1,2] and studied extensively during the past decade due to their potential for delivering transformational improvements in power cycle efficiency. The compact nature of sCO_2 turbomachinery also offers potential capital cost and footprint advantages, and the water-free power cycle can significantly reduce operation and maintenance (O&M) costs over traditional steam-Rankine systems. sCO_2 power cycles for waste heat recovery and gas turbine combined cycle power plant applications (turbine inlet temperatures 425°C to 525°C) are commercially available from EPS in the 1–10 MW_e range, and larger units are planned. A substantial body of design literature has been developed over the past 20 years,[3] with numerous ongoing R&D programs under private, DOE, and non-U.S. governmental funding.

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[1] Feher, E. G., 1968, "The Supercritical Thermodynamic Power Cycle," Energy Convers., **8**, pp. 85–90.

[2] Angelino, G., 1968, "Carbon Dioxide Condensation Cycles for Power Production," ASME J. Eng. Power, **90**(3), pp. 287–296.

[3] Brun, K., Friedman, P., and Dennis, R., eds., 2017, *Fundamentals and Applications of Supercritical Carbon Dioxide (SCO_2) Based Power Cycles*, Elsevier Lt

The basis for the sCO_2 power cycle is the recompression Brayton (RCB) cycle, shown in Figure 2. The RCB cycle employs two compressors in parallel. The low-temperature compressor (LTC) receives low-temperature, high-density CO_2 from the cooling/condensing heat exchanger (CHX). The high-temperature compressor (HTC) receives comparatively high-temperature, low-density CO_2 that bypasses the CHX and high-pressure side of the low-temperature recuperator (LTR). Via the CHX bypass, the HTC flow avoids heat rejection to the extent that it optimizes recuperation (internal heat exchange) in the power cycle. The cycle uses both an LTR and a high-temperature recuperator (HTR). The LTC operates in parallel with the HTC and the flow split between the two is chosen to minimize the exergy destruction associated with the recuperation. The HTR is used to pre-heat the sCO_2 entering the primary heat exchanger (PHX; air-fired PC), which transfers heat from the thermal resource to the sCO_2 working fluid. Heated sCO_2 flows to three turbines arranged in parallel. Two are drive turbines (DT), powering the LTC and HTC and the largest is the power turbine (PT), which produces electrical power via a synchronous generator.

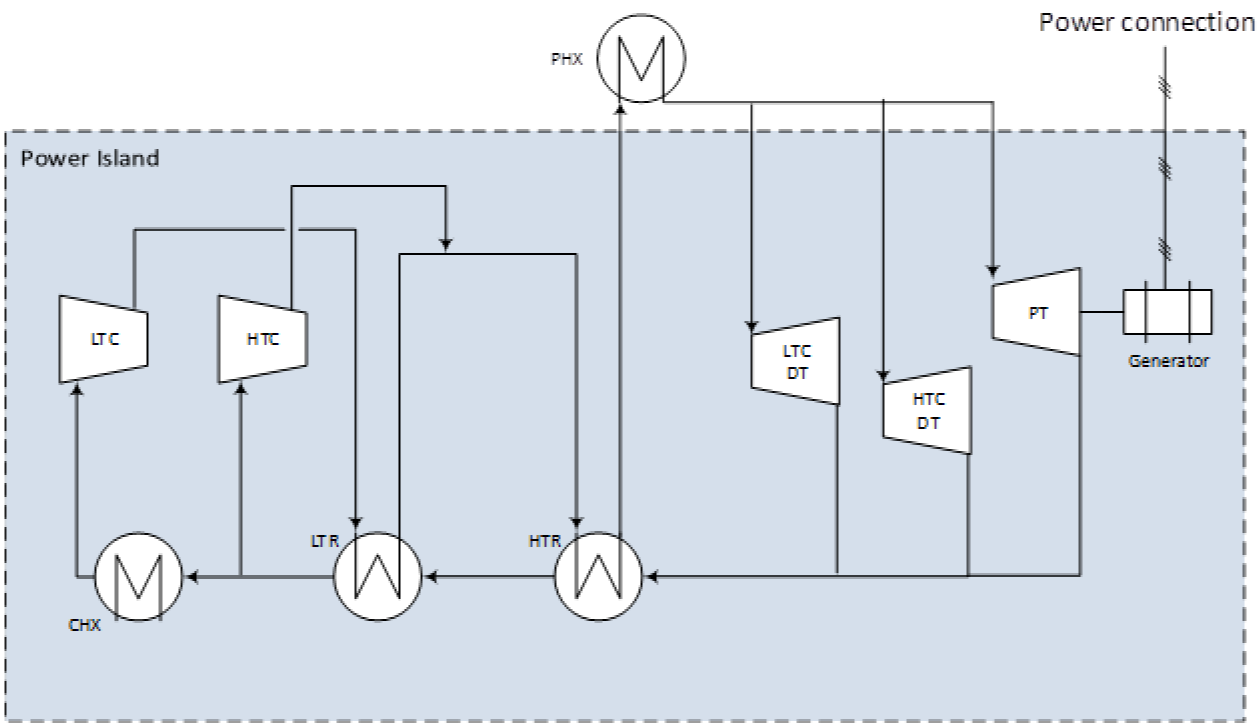

Figure 2 RCB flow diagram

The RCB configuration provides the highest cycle efficiency due to its internal recuperation and resultant small temperature difference across the PHX. Due to the high amount of recuperation, the temperature of the CO_2 entering the PHX is greater than 500°C. While this is beneficial from a cycle perspective, this high temperature limits the flue gas cooling and would be problematic for downstream equipment and suboptimal for the efficiency of the thermal resource (air-fired PC). To optimize the overall plant design, modifications have been made to the RCB cycle.

The modified recompression Brayton (mRCB) cycle, shown in Figure 3, is an RCB variant that incorporates low-grade heat addition using a second primary heat exchanger (PHX-2) installed in the exhaust ducting downstream of the radiant section of the air-fired PC heater (PHX-1). PHX-2 essentially acts as an economizer section of the fired heater for the sCO_2 power cycle. This variation was developed and optimized by EPS under DOE funding (DE-FE0025959) in a collaborative project led by EPRI, which included contributions from The Babcock & Wilcox Company, GE-Alstom, Howden, Siemens, and Doosan Heavy Industries. Adding low-grade heat to the power cycle presents an efficiency tradeoff. Low-grade heat addition to the working fluid improves the efficiency of the thermal resource by extracting more heat from the exhaust gas. However, low-grade heat addition simultaneously penalizes the thermal efficiency of the sCO_2 power cycle by reducing the average temperature of the heat available to the CO_2 in the PHX and by limiting amount of heat from the power cycle than can be used for internal recuperation. Based on previous trade studies the mRCB cycle was chosen, as the incremental loss in power cycle efficiency (> 1%) is made up for in gains in fired heater efficiency (5-10%).

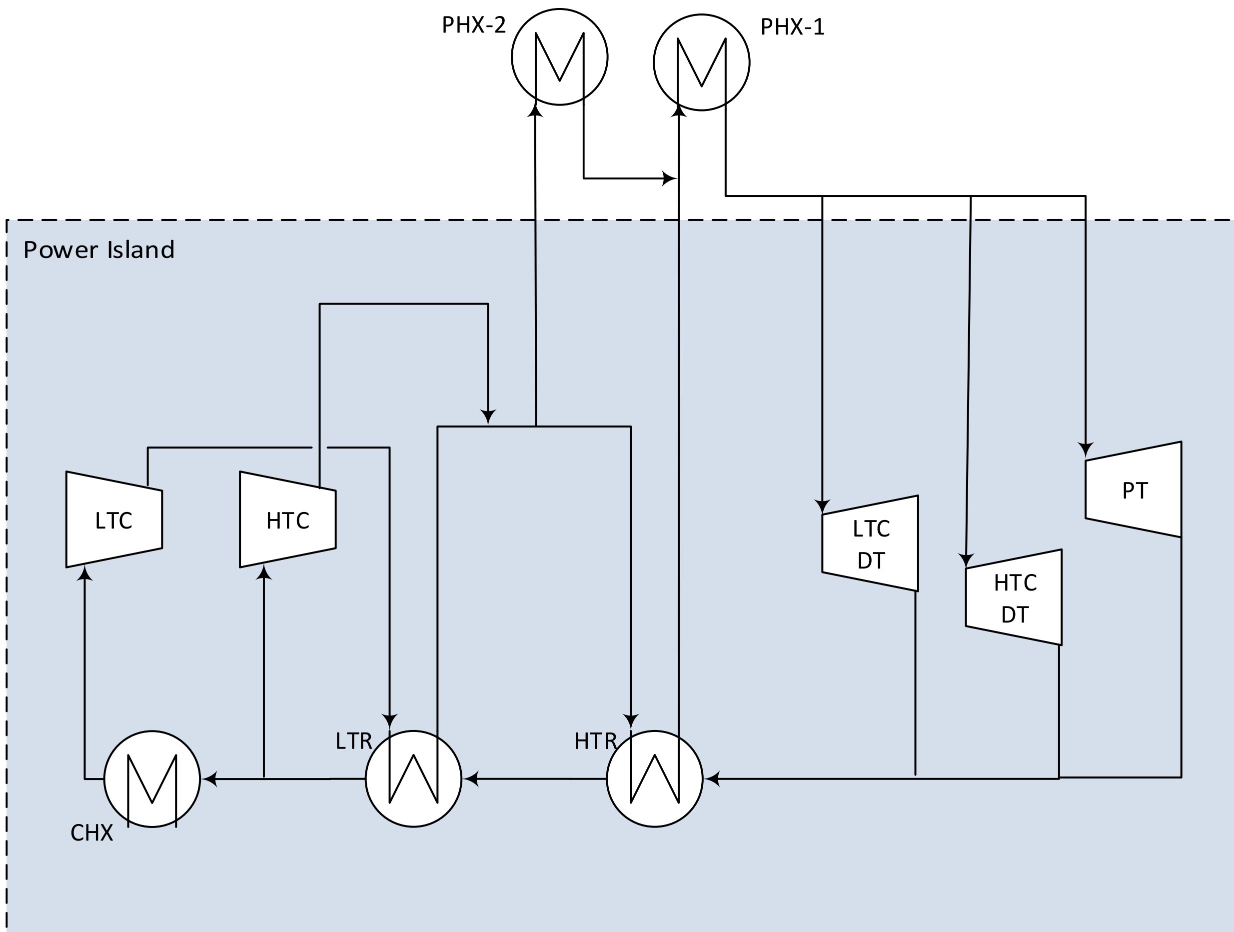

Figure 3 mRCB cycle flow diagram

Air-Fired PC sCO_2 Heater

RPI is providing the air-fired PC heater for indirect heating of the CO_2 for the power cycle. The proposed system closely resembles, in design and function, a traditional utility steam boiler. The fired heater is equipped with a dual fuel system capable of firing pulverized coal or NG. This system was designed for fuel flexibility and has the capability to fire coal or NG for base load operation, of NG as needed for off-design loads. Because the fired heater is capable of up to 100% NG firing, there is potential to operate this plant during times when coal is unavailable or economically non-competitive when compared to NG.

The coal handling equipment, pulverizers, and combustion system are identical to traditional steam boiler systems. The fired heater section (PHX1) provides heat input to the CO2 through radiant heat transfer and the furnace walls are CO_2 cooled. An economizer section (PHX2) is used to provide "low-grade" heat to the CO_2 through convective heat transfer. Leaving the last stage of the economizer (PHX2) the flue gas is cooled in a regenerative air-preheater. The air preheating increases the temperature of the combustion air, thereby increasing the overall fired heater efficiency. Finally, the flue gas is sent through a selective catalytic reduction system (SCR) for NO_x removal, a circulating dry scrubber (CDS) for SO2/HCl removal and a bag house (particulate matter) before an induced draft (ID) fan provides the motive force to pull the flue gas through the PCC system.

Fuel System

Coal Systems - RPI has considered a coal system scope terminating at the coal bunkers and carrying through to the burners. This system includes the coal feeders, coal mills, and coal piping. Bulk coal handling equipment, including coal bunkers is by others.

Burners - RPI has included 12 burners, in three rows on the front wall of the heater. These burners are dual fuel designs and are capable of achieving full load on either coal or NG or burning any combination of the fuels. Burners include high energy spark ignitors, and flame scanners. The burners can be individually tuned to achieve proper air flow and good combustion.

NG System - RPI has developed indicative pricing for the natural gas system, including the primary pressure and flow regulating skid, local block and bleed skids at the burners, and gas piping.

Combustion Air Systems - The proposed burner systems include two combustion air streams. Each system consists of a dedicated fan, air preheater, and ductwork. The primary air system supplies hot air to the mills for coal dryout and transport of the pulverized fuel. The secondary air system supplies hot air to the burner windbox and overfire air systems.

Heater Design

RPI has designed the CO_2 heater to achieve the design load firing 95% coal and 5% natural gas by heat input. This system considers overall efficiency, metal temperatures, material optimization, and fabrication of the elements and tubing.

Efficiency of the CO_2 heater is determined by several factors. The main goal of efficiency optimization is reducing heat losses. The largest loss in the fired heater is the heat lost in the flue gas at the fired heater exit. Other losses consist of radiant heat loss to the environment, moisture loss from hydrogen combustion, ash loss, etc. 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 ~40°C. For a counter flow element this approach temperature is the gap between the coldest fluid at the surface 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 40°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. This sCO_2 fired heater includes an equivalent surface to an economizer, based on pulling a small portion of the sCO_2 process stream at a low temperature to minimize the flue gas losses. The economizer is trading sCO_2 cycle efficiency for fired heater efficiency and must be balanced to maximize overall plant efficiency.

Additional efficiency is gained by adding a combustion air preheater to the unit. This system recovers waste heat into the combustion air, reducing fuel firing rate. Considering the above constraints, the unit achieves a CO2 heater efficiency of 84%, with a heat input of 297 MW_{th}.

Surface Layout

RPI has developed a conceptual design which mimics the layout of a traditional steam boiler. Wall mounted burners fire into a tube and membrane furnace section. The radiant region of the furnace includes a set of platens maximizing the amount of radiant surface while minimizing the overall footprint and materials required. Despite the addition of the platens, the furnace is still larger than an equivalent steam boiler. The larger size allows the unit to maintain reasonable radiant flux, reducing metal temperatures in the furnace and resulting wall thickness requirements. Flue gas leaves the radiant section of the furnace and is then passed through a convective backpass. This region of the heater includes serpentine elements for both the primary fluid, as well as the economizer sections.

Tube Sections
Fluid temperatures and furnaces fluxes result in a peak mid-wall metal temperature of approximately 740°C. Considering the high design pressure of this unit, this requires advanced materials for the furnace tubing. Riley has designed the unit with Inconel 740 furnace wall tubes, providing adequate margin for fluid temperature and radiant flux variation within the walls. The convective elements see both significantly lower flux, as well as colder fluid temperatures, and can be made from more traditional Super 304 stainless. The economizer tubing is proposed as T22 materials.

Air Preheater
The CO_2 heater will be equipped with two tubular air preheaters. These systems will be designed to achieve a maximum combustion air temperature of 370°C on the primary air and 290°C for the secondary air. Flue gas temperatures will be controlled by a partial air bypass around the air preheaters. This bypass is primarily to maintain SCR catalyst temperature during low load operation. The air preheater will be composed of carbon steel tubes and must be provided with air flow at all times due to the high flue gas inlet temperatures.

AQCS

SCR
RPI has included a system typical for coal fired combustion systems. This high dust SCR reactor is arranged for vertical flow down through multiple catalyst layers at gas temperatures in the range from 600-700°F.

The Selective Catalytic Reduction process works by reducing the oxides of nitrogen (NOx) contained in the flue gas into nitrogen (N2) and water (H2O) with the use of ammonia (NH3) as the reduction agent. The basic reactions are the following:

$$4NO + 4NH3 + O2 > 4N2 + 6H2O$$
$$2NO2 + 4NH3 + O2 > 3N2 + 6H2O$$

To achieve sufficient reaction rate, the gas stream must be heated to between 500ºF and 800ºF. A specially formulated catalyst is used. The NOx reduction efficiency of the catalyst increases with rising temperature. At very high gas temperatures, above ~800ºF, the catalyst can be damaged.

Before the flue gas enters the SCR catalyst, ammonia is added and mixed in such a way that a homogeneous distribution of ammonia and flue gas is achieved. In addition, the gas temperature and flue gas distribution are also made uniform. After mixing, the flue gas and ammonia mixture then flows through the catalyst where the NOx is converted in accordance with the reaction equations described above.

CDS
A circulating dry scrubber (CDS) is proposed to remove the acid gas constituents from the flue gas, primarily SO2 but also SO3, 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 reactions are as follows:

$$Ca(OH)2 + SO2 > CaSO3 \bullet \frac{1}{2}H2O + \frac{1}{2}H2O$$

$$Ca(OH)2 + SO3 > CaSO4 \bullet \frac{1}{2}H2O + \frac{1}{2}H2O$$

$CaSO_3 \cdot ½H_2O + ½O_2 > CaSO_4 \cdot ½H_2O$

$Ca(OH)_2 + CO_2 > CaCO_3 + H_2O$

$Ca(OH)_2 + 2HCl > CaCl_2 + 2H_2O$

$Ca(OH)_2 + 2HF > CaF_2 + 2H_2O$

The CDS system also removes a high percentage of mercury in the flue gas. Figure 4 shows an overview of the CDS process.

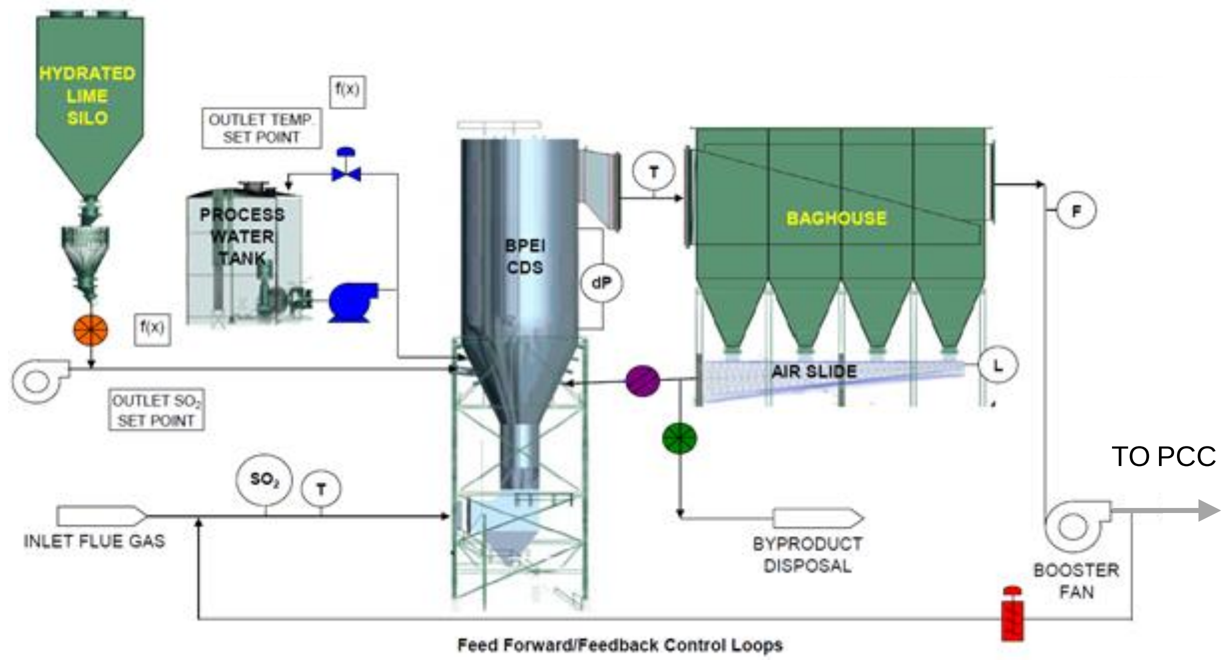

Figure 4 Overview of Circulating Dry Scrubber and Fabric Filter System

Flue gas from the secondary air preheater is directed to the inlet of the CDS reactor, the flue gas passes through a horizontal duct and takes a 90° vertical turn. Turning vanes in the bend are designed to keep fly ash from dropping out and to distribute flue gas evenly to the venturi section. A reactor bottom solids removal system in this area removes any byproduct that may fall out during upsets and shutdowns.

Once flowing in the vertical direction, the flue gas passes through a venturi. The venturi section accelerates the flue gas just prior to the injection of high-pressure water, recycled solids, and hydrated lime. The venturi creates a fluidized bed assuring maximum contact between the pollutants in the flue gas and the hydrated lime. The flow in the reactor is turbulent with high chemical and physical heat and mass transfer rates.

The injected water brings the flue gas closer to the saturation temperature where SO_2 absorption is most effective. The water is injected at 3.4 to 4.1 MPa through the injection lances and each lance includes a “spill-back” nozzle. “Spill-back” refers to the design of the nozzle wherein part of the water pumped to the nozzle is returned to the supply tank. The rate of water injected into the CDS reactor is controlled by throttling the return flow. The nozzle provides a consistent spray up to a 10 to 1 turndown of flow.

Particulate Control – Fabric Filter

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. A constant baghouse pressure drop maintains removal of the circulating byproduct. The pressure drop across the baghouse is maintained by cleaning the bags with compressed air. A pulse of compressed air cleans the bags row by row in a sequence until the baghouse pressure drop returns to set point. The compressed air pulse knocks the cake of byproduct off the filter bags. The byproduct falls to a hopper below each compartment. The hoppers include startup heaters and vibrators to enhance byproduct flow from the hoppers to the air slides below. If required for turndown a clean gas recirculation duct from the positive discharge of the induced draft fan 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.

Fired Heater Auxiliary Equipment

Fired Heater Fans

Induced Draft Fan - The unit will be provided with an induced draft fan at the discharge of RPI's scope of supply, capable of meeting the required flue gas flow, while providing adequate draft to maintain negative furnace pressure. This fan will be controlled by inlet vanes or VFD.

Forced Draft Fan - This fan will take ambient air and provide flow to the air preheat systems prior to combustion in the furnace. This fan will be controlled by inlet vanes, with VFD control turndown loads.

Primary Air Fan - RPI has included a separate primary air fan. This fan takes ambient air and provides the required pressure and flow to preheat the air and then transport the pulverized coal to the burners. This fan operates at a significantly higher pressure than the FD fan to allow for this coal transport.

Ash Handling Equipment

Ash is removed from the heater at the furnace bottom, backpass hoppers and air preheater hoppers. CDS byproduct is removed from the reactor bottom and from the air slides.

Air Slides - The CDS byproduct, which is a mixture of particulate, unreacted lime, and CaSO3, CaSO4, CaCO3, CaCl2, CaF2, and inert material exits the reactor, and is removed from the flue gas with the baghouse. The byproduct removed by the baghouse is cycled back to the reactor at a high rate through air slides. The byproduct circulation flow establishes a fluidized bed in the CDS reactor.

Byproduct Silo - The byproduct inventory in the CDS is maintained by intermittently removing the byproduct from the solids recycle stream with the byproduct removal system. The byproduct is then transported to a byproduct disposal system.

Furnace Bottom Ash System - The proposed system includes a fully dry bottom ash system. This system consists of a conveyor spanning the full width of the boiler. Ash drops onto this conveyor, and as it is pulled to the side of the unit, the low pressure of the furnace pulls a continuous stream of air across the hot ash. This results in completing any residual combustion, as well as recovery of the heat in the ash, improving overall efficiency of the unit. This system also requires minimal water to maintain only the furnace seal, and the ash is never wetted eliminating the need for ash de-watering or other processing before disposal.

Post Combustion Capture System

MHI's KM CDR Process™ is an amine-based CO_2 capture process that uses MHI's KS-1™ solvent. The CO_2 capture system is capable of recovering 90 to 95% of the CO_2 from the flue gas and compressing the treated CO_2 to pipeline requirements.

The CO_2 recovery facility consists of four main sections shown in Figure 5: (1) flue gas pretreatment, (2) CO_2 recovery, (3) solvent regeneration, and (4) CO_2 compression and dehydration.

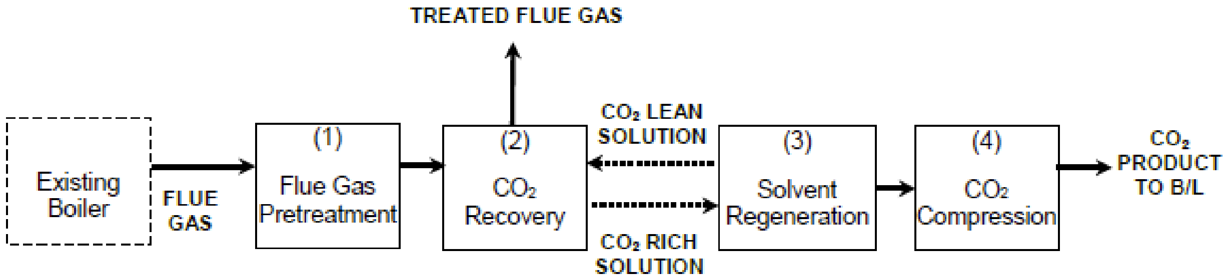

Figure 5 Block flow diagram of the CO_2 recovery plant

Flue Gas Pretreatment

Flue gas from the host plant first enters the Flue Gas Quencher, which is a cylindrical tower with structured packing that has two important functions: (1) flue gas cooling and (2) SO_2 removal.

The flue gas temperature from the power plant is too high to supply directly to the CO_2 Absorber, and a lower flue gas temperature is preferred due to the exothermic reaction of CO_2 absorption. The efficiency of CO_2 absorption increases with lower temperatures, so the flue gas is cooled before it enters the CO_2 Absorber. This cooling generates large amounts of condensate that accumulates in the tower bottom. Excess flue gas condensate is discharged to maintain a stable liquid level in the tower bottom and can be supplied to other water users reduce makeup water.

To reduce the concentration of SO_2 in the flue gas, the water circulated back to the flue gas quencher is pH controlled by injecting caustic soda. Controlling how much SO_2 enters the system is an important part of reducing solvent consumption.

The Flue Gas Blower draws the flue gas from the existing plant and overcomes the pressure drop across the Flue Gas Quencher and CO_2 Absorber. The Flue Gas Blower is installed downstream of the Flue Gas Quencher.

CO_2 Absorption

The CO_2 Absorber is a cylindrical tower with dimensionally configured structured packing. It has two main sections: (1) the CO_2 absorption section in the lower part and (2) the treated flue gas washing section in the upper part. The CO_2 Absorber uses structured packing in order to reduce the pressure drop of flue gas as it passes through the tower and improve gas-liquid contact.

CO_2 Absorption Section - The cooled flue gas from the Flue Gas Quencher is first introduced into the bottom of the CO_2 Absorber. The flue gas moves upward through the packing while the CO_2-lean solvent is supplied at the top of the absorption section packing. The flue gas contacts with the solvent on the surface of the packing where 90% of the CO_2 in the flue gas is absorbed by the solvent. The CO_2-rich solvent in the bottom of the CO_2 Absorber is pumped through the Solution Heat Exchanger to the Regenerator by the Rich Solution Pump.

Washing Section - As the flue gas exits the absorption section, it continues upward into the washing section of the CO_2 Absorber. The treated gas is washed and cooled by water in order to remove vaporized solvent and also to maintain the water balance within the system. The water wash is a combination of packing sections and demisters. One of the demisters is a special type developed by MHI. The system configuration is MHI's proprietary design and is already in use at several operating commercial plants. Finally, the treated flue gas is exhausted directly to the atmosphere from the top of the CO_2 Absorber.

Solvent Regeneration

The Regenerator is a cylindrical column with structured packing. Its purpose is to recover the KS-1TM solvent by removing the CO_2 using steam-stripping.

The CO_2-rich solvent is pre-heated in the Solution Heat Exchanger by the hot CO_2-lean solvent extracted from the bottom of the Regenerator. The heated CO_2-rich solvent is then introduced into the upper section of the Regenerator and flows down over the packing where it contacts with hot vapor (water and CO_2) that desorbs CO_2 from the solvent. The vapor is produced by the Regenerator Reboiler, which uses LP steam to boil the CO_2-lean solvent. The lean solvent from the bottom of the Regenerator is sent back to the CO_2 Absorber. After the CO_2-lean solvent exchanges heat with the cold rich solvent in the Solution Heat Exchanger, it is cooled to the optimum temperature by the Lean Solution Cooler just before re-entering the CO_2 Absorber. The overhead vapor leaving the Regenerator is cooled in the CO_2 Gas Cooling Unit, and the condensed liquid from this unit is then returned to the system. The cooled CO_2 is then sent to the CO_2 Compression Unit.

CO_2 Compression and Dehydration

The CO_2 Compression Unit consists of the compressor and its interstage coolers. The compressor is electric motor driven with multiple stages of compression split into a low pressure (LP) side and a high pressure (HP) side. The Dehydration Unit and Oxygen Removal Unit are located in series at the outlet of the LP section, and the dried CO_2 then moves to the HP section where the pressure is increased up to 15 MPa. The CO_2 is then cooled by the Final Stage Discharge Cooler before it is ready for transportation.

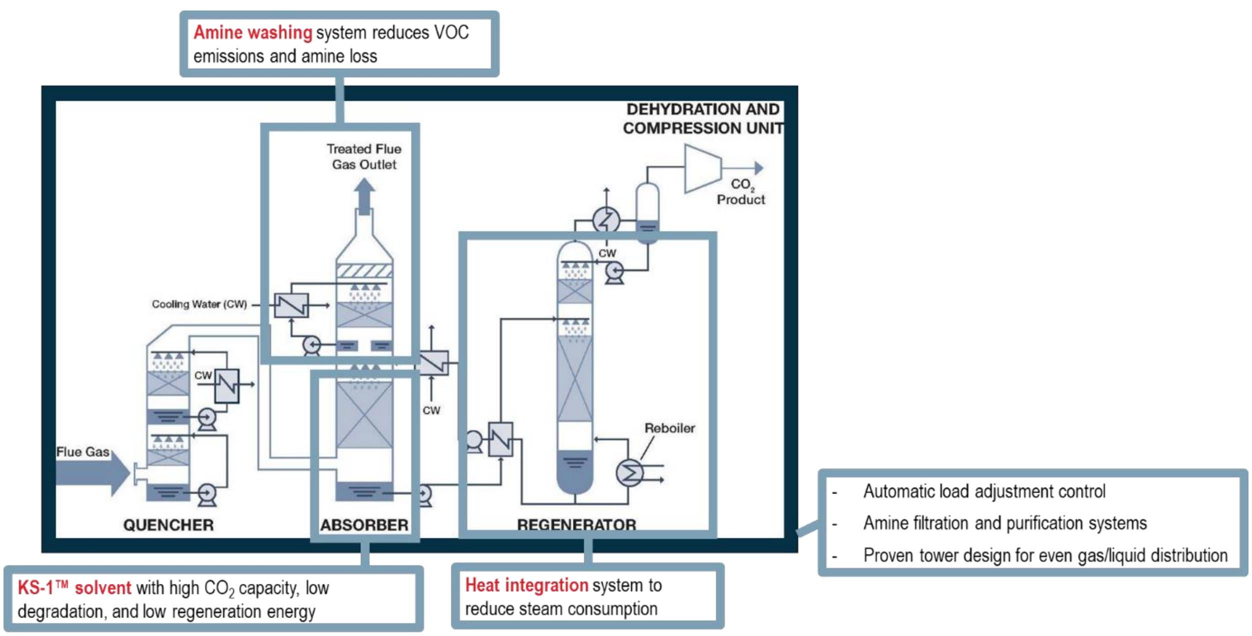

Figure 6 Key features of MHI's KM CDR Process®

A few key features set MHI's KM CDR Process™ apart from other PCC technologies including the following:

1. **High-performing amine solvent KS-1™** – KS-1™ is a sterically hindered amine that offers several advantages as compared to the conventional mono-ethanol-amine process, including reduced thermal energy consumption for regeneration, lower required solvent/CO_2 ratios, lower solvent degradation (no corrosion inhibitor required), and lower solvent consumption due to resistance to oxygen and high temperature. KS-1™ has been used on all of MHI's commercial projects and has performed as designed for various applications and flue gas conditions.

2. **Amine emissions reduction system** – MHI was the first to discover that solvent emissions increased significantly with the presence of SO_3 mist. As a countermeasure, a proprietary amine emission reduction system with a proprietary demister was developed to reduce these emissions.

3. **Heat integration system** –MHI designed a heat integration system to reduce the amount of thermal energy needed to regenerate the solvent.

4. **Amine purification system** – Impurities introduced from the flue gas can degrade CO_2 capture performance. MHI has successfully demonstrated a particulate control system and reclaiming process to prevent accumulation of unwanted impurities.

5. **Automatic load adjustment system** – MHI has developed a control system that is able to adjust operating set points based on inlet flue gas CO_2 concentration and flow rate to optimize plant performance at various conditions.

6. **Proven tower design** – Understanding the need to scale the technology to very large capacities, MHI tested various liquid distribution malfunctions at one of its research facilities. Based on this testing, MHI created a design and installment plan that ensures reliable flue gas pretreatment and CO_2 absorption performance.

PCC Steam Supply

One of the plant requirements is that any proposed concept must fire at least 70% coal (by HHV heat input). Amine-based PCCC systems require a heat input for the CO_2 stripping process. This is typically provided through a low-pressure auxiliary steam supply. To supply the required steam, the air-fired PC heater would need to be supplemented with an auxiliary steam supply system. The use of CO_2 as the heat source for this process is prohibitive for several reasons. First the temperature range of the stripping process is relatively tight, and because the CO_2 is in a supercritical state heat rejection to the PCC system would be challenging (there is no constant temperature phase change in the temperature range required for the stripping process) and would require complex attemperation controls. Second, the PCC stripping process has been commercially shown to work with steam and introducing the technology development requirements of using CO_2 would require significant R&D to prove the system. Third, and most importantly, the amount of heat required for the stripping process is significant and would greatly penalize the sCO_2 cycle efficiency if taken from heat sources internal to the power cycle. This heat input represents a significant portion of the heat available in the sCO_2 power cycle for recuperation.

Two options for this auxiliary steam supply have been studied: a natural gas (NG) combustion turbine (CT) and heat recovery steam generator (HRSG) combined heat-and-power (CHP) plant (using a Solar Turbine and an HRSG sized to meet the steam requirement of the PCC system), providing both electrical power and auxiliary steam; and a gas-fired package boiler, providing steam only. Table 1 summarizes the parameters used to define the possible solution space. In either case, the main power plant (sCO_2 power cycle + fired heater) net electrical efficiency is 40.3% HHV (after accounting for all fired heater and sCO_2

power cycle related parasitic loads), with a net electrical output of 120 MW_e. The PCC auxiliary loads vary based on the gas flow rate and CO_2 capture rate. The gas temperature leaving the HRSG is assumed to be 180°C. Without duct burner firing, the combined efficiency (turbine electrical and HRSG thermal) is 69.4% HHV. Duct burning is assumed to be 100% efficient on an LHV basis (90.2% on an HHV basis). The amount of duct burner firing is varied to demonstrate the tradeoff between thermal efficiency and carbon capture efficiency. The package boiler thermal efficiency is assumed to be 83%. Exhaust gas flows are based on excess air levels of 20% (fired heater) and 15% (package boiler). The CO_2 portion of the exhaust gas flows are 20.3–21.0% by mass fraction (fired heater, varying with the amount of NG co-firing), 4.7-10.2% (CHP, varying with the amount of duct burner firing), and 13.4% (package boiler). For both the CHP and package boiler arrangements, the amount of steam required for the stripping process was provided by MHI. The steam is assumed to enter the boilers as a saturated liquid and exit the boilers as a saturated vapor with a 5 bar(g) supply pressure to the PCC system.

Figure 7 displays the possible solution space for a minimum of 70% coal firing (based on HHV heat input). The auxiliary steam source is the CHP or the package boiler. The coal-fired sCO_2 heater co-fires 0-10% NG (depending on what is assumed to be required for CO_2 temperature control). Some CHP scenarios are unable to achieve 90% carbon capture since the CHP requires too much NG for the overall plant to achieve both 90% carbon capture and 70% coal firing. In the CHP scenarios, the optimum efficiency points represent no duct burner usage and the optimum carbon capture points represent duct burners used to tilt the heat absorption split of the CHP system toward steam (up to the point where either 90% carbon capture or 30% overall natural gas heat input are reached). Note that the 0% co-firing cases for the fired heater are shown as an opportunity. RPI has requested the ability to keep a minimum of 5% NG co-firing capability in the fired heater for temperature control.

Table 1 Assumptions for the CHP and package boiler trade study

	Parameter	**CHP**	**Package Boiler**
Power	Power cycle net power (MW_e)	120	120
	Overall plant net power (MW_e)	119.8 – 126.3	104.6 – 111.0
Efficiency	Fired heater net electrical HHV efficiency (%)	40.3	40.3
	Aux. gross HHV efficiency (%)	69.4, 90.2 (1)	83.0
Flue gas flow	Fired heater total gas flow (kg/s-MW_{th}) (2)	0.43	0.43
	Aux. total gas flow (kg/s-MW_{th}) (2)	0.50 – 1.09	0.38
CO_2 gas flow	Fired heater CO_2 gas flow (% wt.) (3)	20.3 – 21.0	20.3 – 21.0
	Aux. CO_2 gas flow (% wt.)	4.7 – 10.2	13.4
NG – Aux.	NG heat input range auxiliary system NGHRSG / PkgBlr (MW_{th} – HHV)	51.7 – 104.4	14.9 – 87.4
NG – Fired Heater	NG heat input range fired heater (MW_{th} – HHV)	0 – 26.0	0 – 29.8
Coal – Fired Heater	Coal heat input range fired heater (MW_{th} – HHV)	234.4 – 260.4	267.9 – 287.6
Steam	PCC steam/CO_2 ratio (kg/kg)	Provided by MHI – proprietary information	

Fuel	Fuel flow is varied between the cases always respecting 70% minimum heat input from coal. Coal analysis and NG composition are found in Table 5 and Table 7 respectively.

(1) Gas turbine (electrical + thermal) and duct burner (thermal), respectively
(2) Flow rate per MW_{th} heat input
(3) Varies based on coal/NG fuel split

Table 2 Economic assumptions for LCOE contributions for each case

Parameter	**Value**	**Basis**
NG Cost ($/MMBtu)	4.42	QGESS Fuel Prices for Selected Feedstocks in NETL Studies (Jan. 2019) - NG 30 year levelized
Coal Cost ($/MMBtu)	2.23	QGESS Fuel Prices for Selected Feedstocks in NETL Studies (Jan. 2019) - NPRB coal 30 year levelized cost
CO_2 Price ($/tonne)	38.6	Assumed based on business case
Capacity Factor (CF)	0.85	Baseload operation
Fired Heater Cost Baseline ($M)	177.9	Fired Heater Cost (RPI)
Fired Heater Flue Gas Ref. Flow (kg/s)	737	Heater Flow (RPI)
Heater Scaling Exp	0.69	QGESS Capital Cost Scaling Methodology (Jan. 2013)
PCC Cost Baseline ($M)	482	Case B11B [4] - Cansolv Process
PCC Flue Gas Ref. Flow (kg/s)	989.1	Case B11B[4] - Cansolv Process
PCC Scaling Exp.	0.79	QGESS Capital Cost Scaling Methodology (Jan. 2013)
Plant Life (yrs.)	30	Plant design criteria
FCR	0.0707	Based on economic factors supplied by DOE. Details found in Section 3 Cost Design Basis

[4] "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity," NETL-PUB-22638, September 2019.

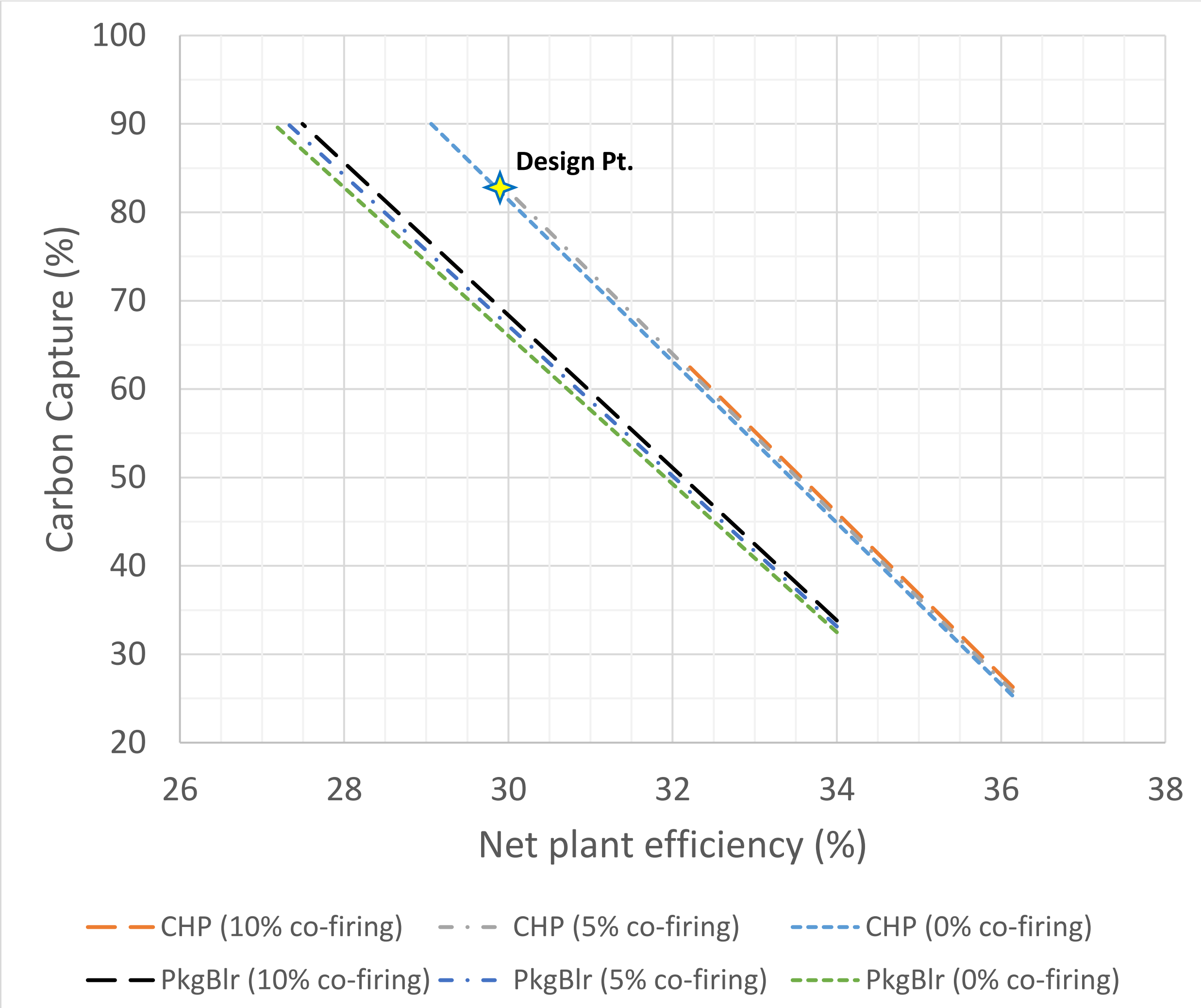

Figure 7 Plant solution space for minimum 70% coal heat input

To determine the most economical plant design, the contribution to the LCOE was determined for each of the cases as shown in Figure 8. Three components of LCOE were considered for this analysis, holding all other contributions constant. The components were: the contribution of the LCOE associated with the fired heater; the contribution of the capital cost associated with the change in size of the PCC system depending on carbon capture efficiency and exhaust flow; and the contribution of the variable O&M cost associated with amount of fuel (NG and coal) minus the value of the captured CO_2.

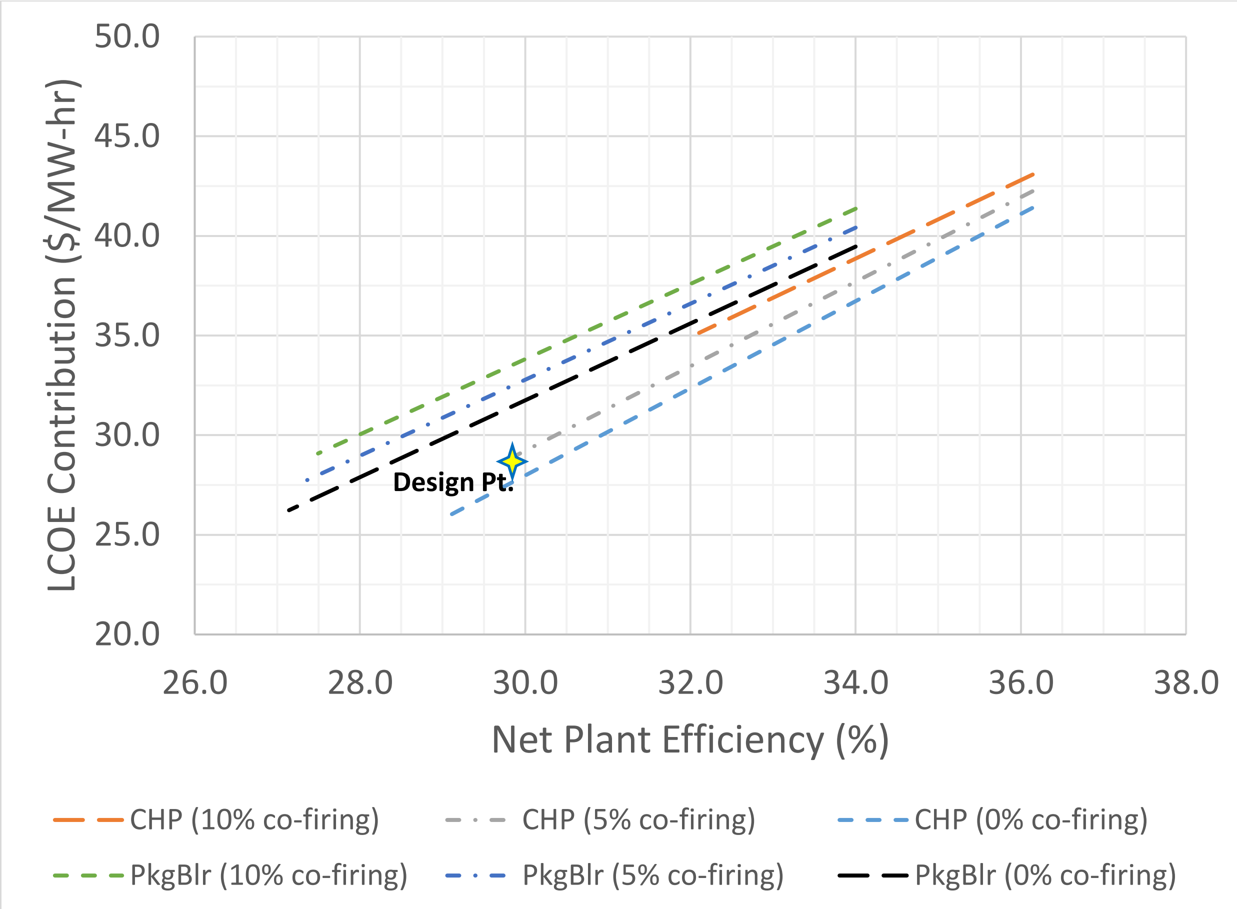

Figure 8 LCOE contribution of fired heater, PCC, and O&M costs for considered plant configurations

The assumptions and scaling parameters for the LCOE contribution are summarized in Table 2. The value of CO_2 was assumed at $38.6 / tonne. It is important to note here that the value of CO_2 does have a significant impact on the LCOE contribution. At CO_2 values of $30.3/tonne the LCOE contribution of the package boiler equals that of the CHP (package boiler is 2.6% points less efficient than the plant using the CHP at the design point). With a CO_2 value of $35/ton, the COE contribution of the CHP is slightly more ($1.29/MWh), but with the efficiency being 2.6% points higher. The expected LCOE for the plant is between $120/MWh to $140/MWh, meaning the difference in LCOE contribution between the two options is approximately 1%. While this analysis does show the potential benefit of utilizing a package boiler for steam production, this solution is well within the error of the analysis and therefore choosing the higher efficiency option was considered prudent.

ETES

To accommodate plant turn-down and ramp rate requirements, an energy storage system is proposed. EPS is developing a novel ETES that utilizes CO_2 as the working fluid for long-duration energy storage. The system builds on EPS's existing expertise and leverages the sCO_2 cycle development work that has been completed in waste heat recovery and primary power cycle design and integration. Utilizing CO2 as the working fluid for this system offers the same advantages that are present in power cycles (compact turbomachinery and plan foot-print, potential for water free operation) and the allows for the use of moderate temperatures in the thermal reservoirs. The proposed ETES system converts alternating current (AC) power taken from the grid or generation equipment and converts it to a thermal potential (hot and cold reservoirs). When power is then needed, the system then converts the thermal potential back to AC power to be supplied back to the grid.

In its simplest version, ETES consists of a reversible heat pump cycle, where thermal energy is transferred between two storage reservoirs, one at high temperature and the other at low temperature, as shown in Figure 9. During the "charging" phase (taking AC power in) of operation, thermal energy is upgraded from a low-temperature storage reservoir (LTS) to a high-temperature storage reservoir (HTS) by using the heat pump cycle in the nominally forward direction. During this process, an electrical motor is used to drive a gas compressor, which increases the CO_2 temperature to 350°C. The thermal energy contained in the fluid is transferred to the HTS (heating its thermal medium to 325 - 350°C) using an indirect heat exchanger (HTX). An internal recuperator (RCX) is used to increase the compressor inlet temperature. This internal heat addition through the RCX reduces the amount of required compression work in the charging cycle. The compressor inlet heating allows the compressor to operate over a smaller compression ratio (reducing the amount of compression work), while still maintaining the desired 350°C outlet temperature. The fluid is then expanded through a turbine, which produces shaft work used to help drive the compressor, reducing the electrical auxiliary load. The fluid at the turbine exit is lower pressure and much lower temperature. Heat is transferred from the LTS (which is slightly below the freezing point of water) to the CO_2, which brings it back to the initial state at the compressor inlet.
During the "generating" phase of operation, the directions of fluid and heat flows are reversed. The CO_2 exiting the low-temperature reservoir (0°C) is pumped to 30 MPa, as the pump inlet and outlet temperatures are considerably lower than during the charging cycle. As is typical with CO_2 power cycles an internal recuperator (the same RCX used in the charging cycle) is used to preheat the CO_2 going to the HTX. The CO_2 is then heated close to the high temperature reservoir temperature and expanded through a turbine, producing shaft work used to drive a synchronous generator for electric power generation.

One metric of overall cycle performance is the "round-trip efficiency" (RTE). This parameter defines the amount of electrical energy (kW-hr) that can be produced during the generating cycle divided by the amount of electrical energy that was consumed during the charging cycle. The other key performance parameter is system capital cost, which can be defined in terms of generating capacity, or in terms of storage capacity. For the proposed plant, fixed generation and charging capacities of 30 MW_e are assumed (meaning 30 MW_e can be taken off or added to the grid), with 8 hours of storage potential (240 MWh electrical) and a 15-hour charging time.

The concept of ETES can be accomplished by a number of methods, primarily characterized by choices of working fluid and thermal reservoir temperatures and materials. EPS has performed a detailed comparison of two leading ETES concepts—an air-Brayton (AB) cycle, using molten nitrate salt (at 565°C) and hexane (at -70°C) as the high- and low-temperature reservoir materials, respectively, and the proposed CO_2 transcritical-Rankine (CTR) cycle, using conventional heat transfer oil, sand, or concrete (at < 350°C) and water/ice (at 0°C) as the reservoir materials. Both cycles can achieve RTE values in the 55-60% range at utility scale. However, the more extreme temperatures of the AB cycle result in significantly higher projected reservoir costs due to the extensive use of stainless and cryogenic steels, while the CTR cycle can be constructed of lower-cost carbon steel. In addition, the low pressure of the AB cycle requires much larger heat exchangers and pipe components, at increased overall system cost. Finally, the AB cycle performance is more sensitive to compressor and heat exchanger pressure drop than the CTR cycle. And while the AB cycle can utilize derivatives of GT components for its turbomachinery, the CTR cycle will use commercial industrial components and derivatives of EPS's power cycle equipment. For these reasons, the CTR cycle offers a more reliable and lower-risk path to commercialization than does the AB cycle.

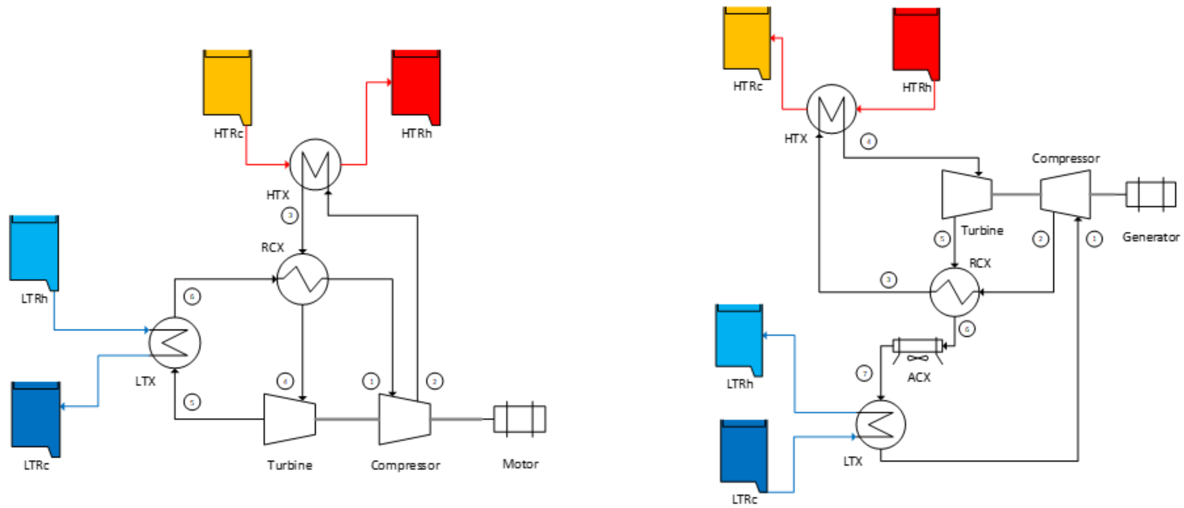

Figure 9 ETES process flow diagrams for the charging (on the left) and generating (on the right) cycles. (numbers in circles are state point designations)

Lithium ion batteries represent the incumbent technology (outside of pumped hydroelectric energy storage, which is geographically limited) for energy storage. RTEs of lithium ion battery installations are estimated to be around 86%,[5] although operational system data has shown a typical RTE of 78% in the field.[6] The industry standard for cost comparison for energy storage systems is the levelized cost of storage (LCOS), which accounts for the capital cost, O&M cost, and the cost of the electricity used to charge the storage to compute an average cost of the power produced later. Using similar assumptions to those used in the Lazard's Levelized Cost of Storage Analysis—Version 3.0 report,[7] it is anticipated that CO_2-based ETES systems will deliver an LCOS that ranges from 25% to 50% less than a lithium ion battery system (even considering that ETES has lower RTE) with storage capacity ranging from 4-8 hours, respectively. An example chart showing the breakdown of LCOS into its component parts is given in Figure 10 for a 50 MW_e system with 10 hours capacity, assuming $0.03/kWh electricity cost during charging, and using lithium ion system cost assumptions from Lazard's NYISO distribution case. Because of the low cost of storage capacity, ETES systems are increasingly cost advantaged (upwards of 50%) for applications that require longer storage and generation time scales projected to be required by utility scale systems.

As is clear in Figure 10, while the generation equipment (e.g., the inverter system) cost and RTE of a lithium ion system are better than the ETES example, the low incremental storage cost of the ETES system provides a clear advantage in LCOS. This can also be seen in Figure 11, as the hours of storage increases the $/kW-hr for an ETES system decreases, while in turn the cost for batteries asymptotes. In addition, the long-term degradation associated with battery performance versus age represents a significant O&M cost that does not occur with the more conventional, longer-life equipment of the ETES system. Furthermore, the controls required to manage the performance and safety of battery systems represent a significant added balance-of-plant (BOP) cost and operational cost that is absent from the ETES system. Environmental and disposal issues are another detriment to batteries that ETES does not suffer from.

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[5] "Energy Storage Technology and Cost Characterization Report," PNNL-28866 Hydrowires, July 2019.

[6] Pinsky, N., and O'Neill, L., 2017, *Tehachapi Wind Energy Storage Project - Technology Performance Report #3*.

[7] Wilson, M., 2017, *Lazard's Levelized Cost of Storage Analysis—Version 3.0*.

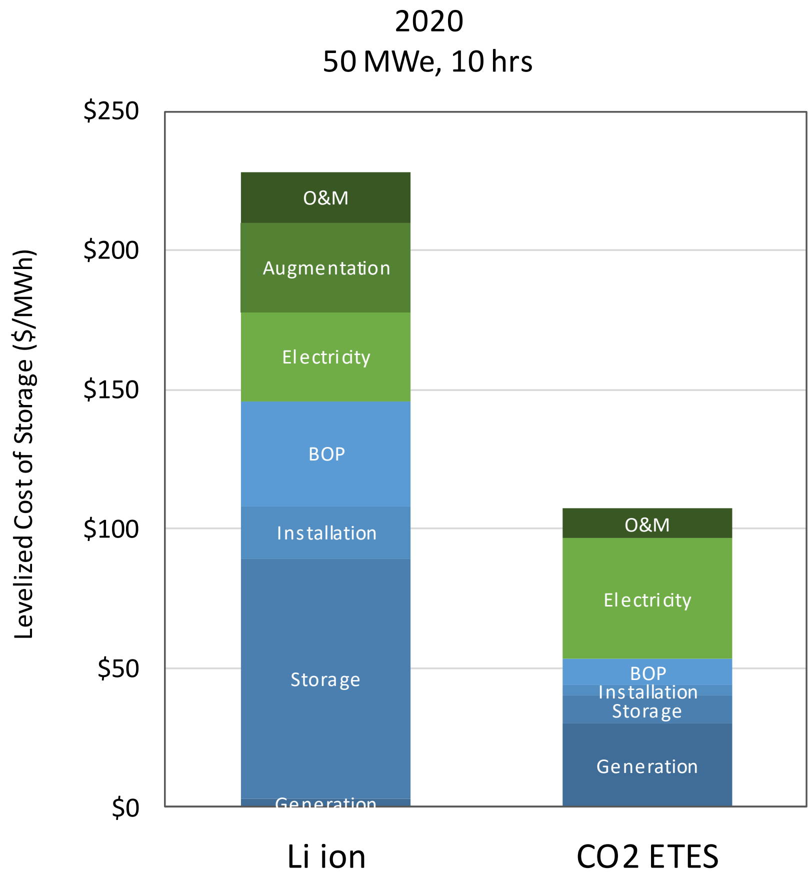

Figure 10 Comparison of LCOS for CO_2 ETES vs lithium ion battery systems. The bars shaded in blue represent investment cost items, while those in green represent annualized operating costs.

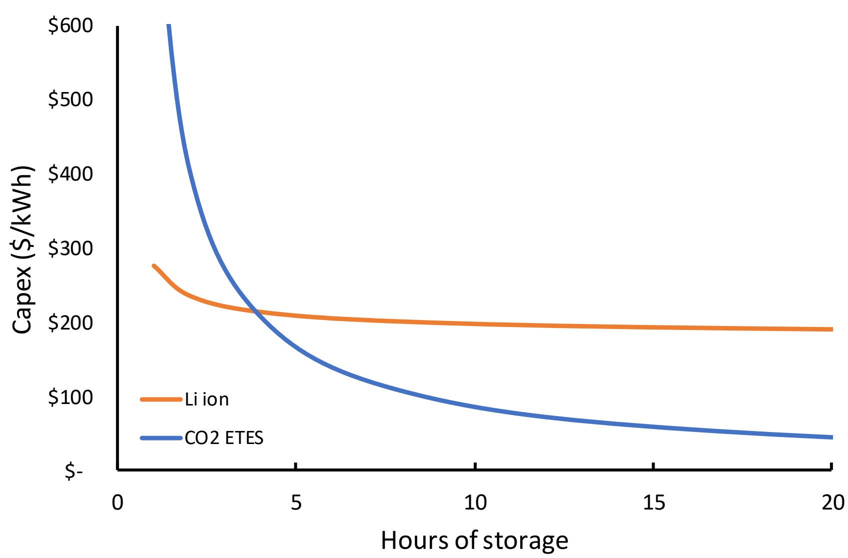

Figure 11 Capex comparison of CO_2 ETES vs lithium ion battery systems as storage time is varied

System Summary

The plant block flow, diagram, with energy flows is shown in Figure 12. The plant has a net power output of 120.7 MWe and consists of an indirect heated sCO_2 power cycle generating 128.6 MW_e at the generator terminals with auxiliary loads of 4.7 MW_e for the fired heater, 2.7 MW_e for the air-cooled-condenser, and 1.1 MW_e for the sCO_2 power cycle, building loads and transformer losses. A 297.6 MW_{th} air-fired PC heater provides the heat input to the sCO_2 power cycle. The fired heater is fed with (on an HHV heat input basis) 95% coal and 5% natural gas. The AQCS, consisting of a catalyst for NO_x reduction, a scrubber for SO_2 and HCl reduction, and a bag house for particulate management is used to meet emissions limits. Carbon capture is performed in an amine-based PCC that captures 83.6% of the total plant CO_2 in the flue gas (90% of the flue gas through in the PCC system) and provides pipeline ready CO_2 at a rate of 26.7 kg/s. The PCC system requires saturated steam at 5 bar(g) for the stripping process. This is provided by a CHP plant (NGCT and HRSG) designed to provide steam and electricity for all PCC auxiliaries (cooling tower, boiler feed pumps, condensate pumps, CO_2 stripping). The CHP on a net basis will take in 106.3 MW_{th} (NG, HHV) and produce 0.7 MW_e after all auxiliary and steam loads are served. A cooling tower provides cooling for the PCC and CO_2 compression systems. The ETES system is rated for 30 MW_e charging/generating and has 8 hours of generation capacity when fully charged. This provides the plant with a peak output of 150.7 MW_e, and the ability to turn down the plant electrical output by 25%, while holding the fired heater heat input constant and maintaining full load plant efficiency. The plant has an overall efficiency of 29.9% HHV, including the PCC system and 40.3% HHV if PCC is not utilized.

A summary of the system's ability to meet design criteria is presented below.

- **Greater than/equal to 4% ramp rate:** The system is expected to achieve the 4% ramp rate. The plant ramp rate will be limited by the fired heater. The fired heater is designed to fire both NG and coal at 100% load. Heat input to the system through NG firing allows for heat input (fuel feed rate) changes at rates greater than 4% and trimmed as coal the coal feed rate is adjusted to meet demand. To minimize the thickness of the pressure parts, decreasing thermal inertial and increasing flexibility, advanced nickel alloys (740-H) are being used in the high temperature sections. During detailed design of the fired heater material optimizations to minimize wall thickness, flexibility analysis to determine cycling fatigue and expected component life, and FEA analysis of problem areas will be conducted to verify the fired heater ramping capabilities. MHI has indicated the PCC system has ramping capabilities of up to 5% per minute. Due to the compact nature and small thermal mass of the sCO_2 power cycle (turbines and internal heat exchangers), the power cycle will adjust to changes in heat input quickly as compared to the fired heater. If the energy storage block is considered, during the generating cycle, up to 30 MW_e can be brought on from cold metal in less than 30 minutes (potentially adding 0.8% to the overall ramp rate of the plant). The ability to use the ETES system is limited, as the generating potential is only available for 8 hours at full power before the system will require recharging.

- **Cold/Warm start – less than 2 hours:** The fired heater is not capable of meeting the 2-hour start time, as typical start profiles would be to ramp the heater at 40°C/hour. This would imply a start time of > 17 hours. With energy storage, the system will be able to bring up to 30 MWe onto the grid in 30 minutes, but there is still a significant warm up time associated with the air-fired PC heater.

- **5:1 turndown with full environmental compliance:** The system can meet the 5:1 turndown requirement. Turndown of the heater is dependent on two factors, ability to control heat input, and ability to maintain adequate cooling flow through the pressure parts across the load range. RPI has a large install base of burners capable of achieving the targeted turndown rate, particularly with the ability to co-fire natural gas. Control of the total heat input to the system is not anticipated to be a challenge with the dual burner configuration. Cooling flow, provided by the CO2, will be the critical factor to achieve turndown. The power cycle design will allow for control of the supply temperature of the CO2 to the fired heater through a combination of HTC, recuperator, and PHX2 bypass and attemperation during low load operation. An additional 30 MW_e (25% plant output) of excess power can be taken by the ETES system during the charge cycle, while still operating the fired heater at 100% load. There are limits of ETES operation due to the thermal reservoir sizes. The ETES system will be fully charged in 15 hours, and once this point is reached the fired heater will have to begin to turndown.

- **CO_2 capture ready:** The air-fired PC system is carbon capture ready. An amine-based PCC system was chosen to provide 83.6% carbon capture of the plant (capture efficiency is limited by requirement of 70% minimum plant heat input by coal). Other PCC systems could be utilized, such as using membranes or any technology that can be installed downstream of the fired heater.

- **Zero liquid discharge:** The sCO_2 power cycle utilizes dry cooling (air) and hence requires no water for operation or cooling. The ETES system, while utilizing an ice slurry and air cooling for cold storage and cooling sink, does not discharge any liquids. The AQCS system will use a circulating dry scrubber technology to eliminate any liquid discharge associated with sulfur removal. The PCC system Waste-water from the cooling tower could be treated using evaporation and crystallization process to removed dissolved solids for water re-use.

- **Solids disposal that is mostly salable with limited landfill:** All ash is untreated, and its value for sale will depend on the fuel being burned. Byproduct of the CDS reactor is a mixture of particulate, unreacted lime, and CaSO3, CaSO4, CaCl2, CaF2, and inert material. This system can be collected independently of the other ash, and either be sold or disposed accordingly.

- **Dry bottom and fly ash discharge:** All ash leaving the system will be fully dry, whether from the furnace bottom ash system or through fly ash collection points.

- **40% net plant efficiency for maximum load range without carbon capture:** The proposed plant exceeds the requirement by achieving 40.3% HHV efficiency without carbon capture, and 29.9% HHV with the MHI PCC system (with 83.6% carbon capture efficiency).

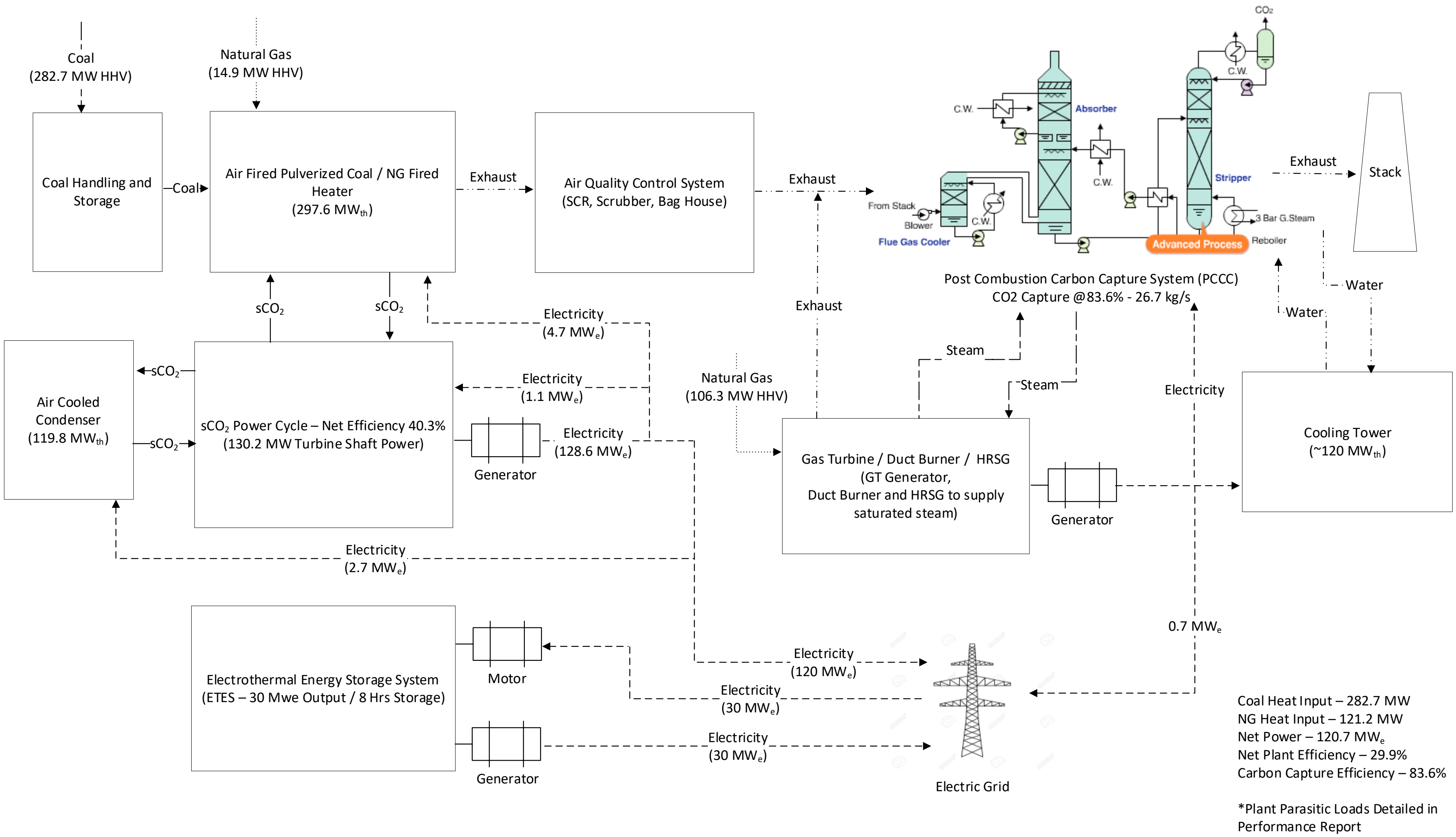

Figure 12 Integrated Plant Block Diagram

2. Business Case

Introduction

This section describes the circumstances around the current coal power marketplace and how the proposed technology will be designed to respond to varying market scenarios. Factors include:

- Coal type(s)
- CO_2 constraint and/or price
- Domestic and/or international market applicability
- Estimated cost of electricity (and ancillary products) that establishes competitiveness
- Market advantage of the concept
- NG price
- Renewables penetration

The current marketplace 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 typically more economical due to the availability of low-cost NG (e.g., in the U.S., NG is about half the cost of elsewhere).
- **Drive towards low carbon –** 179 countries have signed the Paris Agreement, whose goal is to reduce greenhouse gas (GHG) emissions (typically, countries have pledged to reduce CO_2 emissions on the order of 20–40% from 2012 levels). While the U.S. has not signed the agreement, multiple states have enacted low-carbon initiatives including several that have committed to 80-90% (or higher) reductions by the 2040 to 2050 timeframe. Coal, as a fossil fuel, and one that produces double the CO_2 per MWh than NG does, is therefore a bigger target related to 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 – 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. Coal power plants are 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, which largely comes from fossil-based units. In the U.S., some coal power plants are providing such grid support, requiring them to operate more flexibly than they were designed for, which is deleterious to performance. Such operating behavior will likely also occur in other regions as VRE grows, reducing the need for base-load fossil power, while putting extra importance on their ability to provide grid resilience and dispatchable, synchronous (firm) power.

United States

New coal power has stagnated in the U.S., where coal is often not competitive with NG, or presents future environmental risk. There are no known larger-scale new-build coal power projects advancing in the U.S. and some utilities have back-burnered coal or pledged to eliminate it. Several things are likely needed for a significant resurgence in new coal:

- **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 its use in other industrial market grows.
- **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. Governmental programs like 45Q 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 the case in most circumstances. Hence, the value must increase (perhaps by regulation) and/or the cost must decrease for coal CCS projects to be more viable.
- **Regulatory certainty –** Uncertainty in future regulations increases risk, which makes coal power projects difficult to finance and generators more reticent to build them. Recent revisions to the Clean Air Act section 111(b) have been proposed to alter the definition of best system of emission reduction for new coal units to the most efficient demonstrated steam cycle in combination with best operating practices, instead of requiring partial CCS as was the case in the previous version. Getting this in place and adding certainty around the low-carbon future may be important for growth in coal power.

Outside the U.S.

Outside the U.S., different regions have different appetites for coal. A summary is given 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 slowing electricity demand. As a result, some coal plants have been operating at reduced capacity factors. Due to this, and growing environmental concerns, the Chinese government has announced it will postpone building some coal plants that have received approval and halt construction of others. 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 (a key criterion) and smaller will likely be of appeal. CO_2 utilization for EOR and enhanced gas recovery are also growing possibilities.
- **Europe –** In Western Europe, following the Paris Agreement, several countries announced plans to end coal-fired generation within their borders or set in place emissions reductions 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 in the region. In Eastern Europe, there is more potential for new coal as brown coal resources are abundant and cheap. Efficiency and cleanliness will be keys in this region. CCS may be a challenge, however, 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 GW of coal capacity in 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 supercritical units as India has imposed a carbon tax on coal, which is about \$6.25/tonne-CO_2, making efficiency important in the region. Work has also been done to locate reservoirs for CCS.
- **Japan –** As of 2018, Japan had over 44 GW of coal plants in operation, with over 6 GW 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 space is an issue. Japan is very interested in novel coal power cycles, including sCO_2 power cycles.
- **Korea –** Coal produces over 40% of Korea's power and the country still has plans for additional coal power, despite having a climate pledge with a 30% reduction in GHG emissions by 2030. Efficiency

is also important in Korea, and they have strong interest in sCO_2 power cycles, having invested in the DOE's STEP program.

- **Others –** Coal is growing in some regions in Africa (e.g., Kenya and Zimbabwe) and Southeast Asia (e.g., Indonesia and Vietnam), which presents opportunities, although low-cost coal power will be critical in these areas. Smaller-scale plants will be a definite plus.

Advantages of the Proposed Technology

- This system can be made smaller (100 MW_e net or less) and still maintain high efficiency and flexibility. This reduces the financing hurdle and makes the system a better fit for niche locations that lack a low-cost NG supply, where power demands are typically lower.

- Indirect-fired sCO_2 power cycles have been factory-tested,[8] lowering the risk of the technology. The first commercial installation of an sCO_2 power system by Siemens using EPS technology was recently announced,[9] and is scheduled to begin operation in 2021.

- This technology is well designed for energy storage, which can be readily integrated using a system based on concept already being studied under a separate ARPA-E grant. Energy storage is growing in importance as the penetration of VRE increases, as it could allow the coal unit to operate near continuously, putting power on the grid when needed and storing energy when not. This allows the unit to run more often at its design conditions, avoiding ramping and turndown, which have negative impacts on efficiency, emissions output on a per MWh basis, and unit lifetime. 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 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 unit's competitiveness.

- In addition to the potential for integrated energy storage, the proposed cycle will have improved operational flexibility characteristics, meeting those specified by DOE. Mainly this is due to the sCO_2 cycle 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 technology, particularly lower turndown and faster startup times, could be key in the future marketplace even if energy storage is included, and provides the ability to not include energy storage for cases where the cost-benefit analysis is not positive.

What Is Needed for the Technology to be Competitive

DOE performed a techno-economic analysis for coal power plants using Powder River Basin (PRB) coal with and without CCS, as shown in Table 3, with total plant cost (TPC), levelized cost of electricity (LCOE), and CO_2 captured cost adjusted to 2019 $ by EPRI.

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[8] Held, T. J., 2014, "Initial Test Results of a Megawatt-Class Supercritical CO_2 Heat Engine," *The 4th International Symposium - Supercritical CO_2 Power Cycles*, Pittsburgh, Pennsylvania.

[9] TransCanada, 2019, "Capturing the Power of Hot Air" [Online]. Available: https://www.transcanada.com/en/stories/2019/2019-02-28-capturing-the-power-of-hot-air/. [Accessed: 21-Mar-2019]

Table 3 Techno-economics of various coal plants using PRB coal

Technology	Case	Size, MW_e	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	---
PC with CCS (supercritical)	S12B	650	27.0	4243	181.4	52

Based on these data from DOE, EPRI determined:

- TPC for the proposed technology to equal the LCOE of PC with CCS is $3914/kW
- TPC for the proposed technology to get the cost of CO_2 captured to $40/tonne is $2926/kW

Note that these numbers are all for larger-scale power plants and hence do not account for any diseconomies of scale when reducing to 100 MW_e. SaskPower's Boundary Dam Unit 3 installed PCC for EOR in 2014. The resulting unit produces 110-MW_e net. The CCS retrofit cost ~$C800M and $C500M was used to upgrade steam conditions to 124 bar and 565°C. Add to this the cost of the original components, estimated to be $C200M, and the capital cost for a new build is roughly $10,200/kW. While this number should be taken with a grain of salt (SaskPower has stated that the next CCS unit will be 65% cheaper), it acts as a cautionary tale, illustrating the higher cost of CCS at smaller scales for more conventional technology.

Another example of importance is the most recent coal power plant built in the U.S.: an 84-MW_{th} combined-heat-and-power plant at the University of Alaska Fairbanks for $248M, which equates to a TPC of ~$8000/kW. 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/kW would be appealing. EOR opportunities will also be important in such cases.

Based on this high-level review, for the proposed system to be competitive, beyond achieving the performance characteristics that have been set for this project, Table 4 below provides cost targets for the technology in various regions and scenarios.

Table 4 Cost targets for various coal technologies in several regions and scenarios

Case	Region	Scenario	Competition	Cost Targets
1	U.S.	NG not available, coal and EOR / 45Q available	Small coal (100 MW_e)	TPC < $6000/kW
2	U.S.	NG < $4.4/MBtu (coal $2.2/MBtu) and CO_2 value of $50/tonne	Coal or NG with CCS	TPC < $3000/kW; CO_2 cost < $40/tonne
3	Africa, Asia, Europe	NG > $11.6/MMBtu (coal $2/MBtu)	Coal with CCS	LCOE< $160/MWh; TPC < $3900/kW
4	Anywhere	CO_2 value of $50/tonne	Any CCS	CO_2 cost < $50/tonne
5	Anywhere	Non-base load operation with CCS	Coal FIRST technologies	TPC < $3900/kW; CO_2 cost < $50/tonne; value for energy storage

The first 4 cases in Table 4 assume a base-load unit with 85% capacity factor and ~1M tonnes of CO_2 captured annually. The $50/tonne value for CO_2 is roughly a summation of EOR with 45Q credits (or 45Q credits for storage only). So, the cost targets for the technology are TPC = $3900/kW, LCOE = $160/MWh, and CO_2 cost = $50/tonne, with stretch goals of TPC = $3000/kW, LCOE = $120/MWh, and CO_2 cost = $40/tonne. Several additional comments:

- 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. These applications will be small, perhaps smaller than 100 MW_e net (which is doable with this technology). In these cases, the capital costs must be lower than $8000/kW. The other potential short-term market is in regions where there is an EOR play, e.g., Texas and Wyoming. Generally, EOR projects must provide ~1M tonnes of CO_2 annually to be considered, which is about what 100 MW_e net produces. This size is likely a better fit in oil & gas markets than larger plants.

- In regions where NG is more expensive (e.g., Africa, Asia, and Eastern Europe), or if NG prices should rise in North America, the technology will be competing directly with more established PCC systems for coal. In these cases, the proposed technology must have capital costs and COE that are comparable, and preferably superior (given it might be perceived to be higher risk), to this option.

- Another factor is if the value of CO_2 is increased (either by a CO_2 price or value) in comparison to the cost of CO_2 captured, then this proposed CCS technology will have more opportunities. On the flip side, since this current system does not have inherent CCS, if the region does not have a significant CO_2 policy or utilization opportunities (e.g., India or South Africa), or is not focused on low carbon but rather just cheaper power production (e.g., developing nations like Kenya), this technology could still be an option, especially at smaller scales.

3. Plant Design Basis

Site-Related Conditions

The assumed site location for this project is a generic plant site in Midwestern U.S. The site is typical of Midwestern power generation facilities and has access to rail or highway transportation. The site is assumed to be clear and level with no special problems; however, 30-m pile foundations are required. The site is in Seismic Zone 0 at an elevation of 180 m above mean sea level.

For all cases, it is assumed that a raw water supply is available within 10 km of the site. Ash disposal is assumed to be off-site. The design is based on indoor construction.

Site Ambient Conditions

Annual average ambient air conditions for material balances, thermal efficiencies, and equipment sizing are:

- Average dry-bulb temperature 15°C (*)
- Average wet-bulb temperature 10.8°C (*)
- Atmospheric pressure 0.101 MPa (*)
- Elevation 0 m (*)
- Cooling water temperature 15.6°C (*)
- Minimum dry-bulb temperature
  - (1% coldest month) -6.7°C
  - (99% cold day) -18.9°C
  - (Record cold day, record low design limit) -35°C
- Maximum dry-bulb temperature
  - (0.4% hot day) 32°C
  - (1% hot day) 30°C
  - (2% hot day) 28°C
- Relative humidity 60% (*)

(*) Reference air conditions for plant performance evaluation. The site dry air composition is listed in

Table 6.

Technical Data

Common technical data include:

- The nominal net power production of the plant is 120 MW_e.
- The design fuel is Montana Rosebud sub-bituminous coal with the characteristics and analyses presented in Table 5.
- The backup and startup fuel is NG. The characteristics of the NG are presented in Table 7.
- The main products and by-products of the plant are the following:

<u>Electric Power</u>

- Voltage: 345 kV
- Frequency: 60 Hz

Captured Carbon Dioxide

- CO_2 characteristics at plant battery limits are the following:
- Status: supercritical
- Pressure: 152 bar(g)
- Temperature: 31°C
- Purity: >99.0 % wt. min
- Moisture: < 0.1 PPM_v

- Typical water quality is shown in Table 8.
- Coal is delivered to the site by rail.
- The coal storage pile is sized for 45 days of storage.
- Onsite emergency ash storage is sized for 90 days. Final disposal is off site.

Other BOP criteria are shown in Table 9.

Table 5 Montana Rosebud Subbituminous Design Coal Analysis

Proximate Analysis	**Dry Basis, %**	**As Received, %**
Moisture	0.0	25.77
Ash	11.04	8.19
Volatile Matter	40.87	30.34
Fixed Carbon	48.09	35.70
Total	*100.0*	*100.0*
Ultimate Analysis	**Dry Basis, %**	**As Received, %**
Carbon	67.45	50.07
Hydrogen	4.56	3.38
Nitrogen	0.96	0.71
Sulfur	0.98	0.73
Chlorine	0.01	0.01
Ash	10.91	8.19
Moisture	0.00	25.77
Oxygen (By Difference)	15.01	11.14
Total	*100.0*	*100.0*
Heating Value	**Dry Basis**	**As Received, %**
HHV, kJ/kg	26,787	19,920
LHV, kJ/kg	25,810	19,195
Hardgrove Grindability Index	57	
Ash Mineral Analysis		**%**
Silica	SiO_2	38.09
Aluminum Oxide	Al_2O_3	16.73
Iron Oxide	Fe_2O_3	6.46
Titanium Dioxide	TiO_2	0.72
Calcium Oxide	CaO	16.56

Magnesium Oxide	MgO	4.25
Sodium Oxide	Na_2O	0.54
Potassium Oxide	K_2O	0.38
Sulfur Trioxide	SO_3	15.08
Phosphorous Pentoxide	P_2O_5	0.35
Barium Oxide	Ba_2O	0.00
Strontium Oxide	SrO	0.00
Unknown	---	0.84
	Total	*100.0*
Trace Components		**PPM_d**
Mercury (Mean plus one std. dev.)	Hg	0.081

Table 6 Typical Site Air Composition, Dry

Component	Unit	Value
Nitrogen (N_2)	% mass	72.429
Oxygen (O_2)	% mass	25.352
Argon (Ar)	% mass	1.761
Water (H_2O)	% mass	0.382
Carbon Dioxide (CO_2)	% mass	0.076

Table 7 NG Composition

Components		Volume Percentage
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
Methanethiol	CH_4S	5.75×10^{-6}
Total		*100.0*
Units	**LHV**	**HHV**
kJ/kg	47,454	52,581
kJ/m^3	34.71	38.46

Table 8 Typical Raw Water Quality

Components	mg/l	mg/l as equivalent $CaCO_3$
Silica (SiO_2)	6.8	—
Calcium (Ca)	76.0	189.0
Magnesium (Mg)	16.0	66.0
Sodium (Na)	20.0	44.0
Potassium (K)	2.9	3.7
Bicarbonate (HCO_3)	246.0	202.0
Sulfate (SO_4)	56.0	58.0
Chloride (Cl)	26.0	37.0
Nitrate (NO_3)	6.9	5.6
Total Dissolved Solids	457.0	—
Total Hardness	—	255.0
pH	8.0	
Ionic Strength, meg/l	9.2×10^{-3}	
Temperature Range, °C	4.4–26.7	
Reference Temperature, °C	15.6	

Table 9 BOP Criteria

Cooling System	**Description**
Cooling System	Forced-Draft Cooling Tower
Plant Distribution Voltage	**Description**
Motors below 745 W	110/220 volts
Motors 186 kW and below	480 volts
Motors above 186 kW	4160 volts
Motors above 3.7 MW	13,800 volts
Steam and Gas Turbine Generators	24,000 volts
Grid Interconnection Voltage	345 kV
Large Motors	**Description**
CO_2 Compressor Drive Motors	Rated output to be delivered at the maximum ambient temperature of 28°C 2% hot day. Compressors are designed for reduced voltage starting.
Water and Wastewater	**Description**
Makeup Water (raw water)	Makeup for process and de-ionized water is drawn from a nearby lake.

Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5678 liters/day.
Water Discharge	Wastewater is partly treated and recycled to process units, partly discharged according to the permit limits.

4. Performance Summary

Performance Summary Metrics

This section details the calculation methodologies for the metrics reported in the performance summary.

Fired Heater Efficiency

The fired heater efficiency is equal to the amount of heat transferred to the CO_2 in the fired heater divided by the thermal input of the coal and natural gas (HHV basis). It is represented by the following equation:

$$\eta_{FE} = \frac{Q_{CO2}}{Q_{Coal} + Q_{NG}}$$

Where:

- η_{FE} – Fired heater efficiency
- Q_{CO2} – Heat transferred to the CO_2
- Q_{Coal} – Heat input of coal
- Q_{NG} – Heat input of natural gas into the fired heater

sCO₂ Power Cycle Efficiency

The power cycle efficiency is calculated by taking the gross power generated by the power turbine, subtracting the power cycle auxiliary loads, and dividing by the heat transferred to the CO_2 in the fired heater. It is represented by the following equation:

$$\eta_{PC} = \frac{W_{PT} - W_{cycle\ auxiliary}}{Q_{CO2}}$$

Where

- η_{PC} – Power cycle efficiency
- W_{PT} – sCO_2 power turbine gross power generated at generator terminals (MW_e)
- $W_{cycle\ auxiliary}$ – Auxiliary loads associated with the power cycle and fired heater (MW_e)

Generation Efficiency

The plant generation efficiency is calculated by taking the gross power generated by the power turbine adding the gross power generated by the combustion gas turbine, subtracting the power cycle and post combustion capture (PCC) auxiliary loads, and dividing by the heat transferred to the CO_2 in the fired heater and the heat input to the combustion gas turbine and heat recovery steam generator. It is represented by the following equation:

$$\eta_G = \frac{W_{PT} - W_{cycle\ auxiliary} + W_{GT} - W_{PCC\ auxiliary}}{Q_{CO2} + Q_{GT}}$$

Where

- η_G – Generation efficiency
- W_{GT} – Gas turbine gross power generated at generator terminals (MW_e)
- $W_{PCC\ auxiliary}$ – Auxiliary loads associate with the power cycle, fired heater, and the PCC system (MW_e)
- Q_{CO2} – Heat transferred to the CO_2 (MW_{th})
- Q_{GT} – Heat input of natural gas to the gas turbine and steam generator (MW_{th})

Overall Plant Efficiency

The overall plant efficiency is calculated by adding the gross electric power produced sCO_2 turbine and gas turbine and subtracting all plant auxiliary loads then dividing by the total heat input into the plant. It is represented by the following equation:

$$\eta_{Plant} = \frac{W_{PT} + W_{GT} - W_{PCC\ auxiliary} - W_{cycle\ auxiliary}}{(Q_{coal} + Q_{NG}) + Q_{GT}}$$

Where

- η_{Plant} – Net plant efficiency

Electrothermal Energy Storage (ETES) System Round Trip Efficiency

The round-trip efficiency of the ETES system is calculated by dividing electrical energy produced during the generating process by the electrical energy consumed during the charging process. It is represented by the following equation:

$$RTE = \frac{W_{generated}}{W_{charge}}$$

Where

- RTE – Round trip efficiency
- $W_{generated}$ – Electricity generated in generating cycle (MWh)
- W_{charge} – Electricity consumed in the charging cycle (MWh)

Key System Assumptions

Table 10 shows key sCO_2 power cycle equipment performance values. Note, these values do not represent a solution that is optimized for only power cycle efficiency. Power cycle costs are considered during the cycle design and performance and cost are traded. There is potential to get approximately 0.5% points in power cycle efficiency if the heat exchangers are allowed to grow in size (UA). EPS typical design practices limit the effectiveness of the recuperators to 98% and both the low temperature recuperator (LTR) and high temperature recuperator (HTR) are below this limit. Turbomachinery efficiencies are scaled from vendor supplied data and based on shaft power (smaller sizer or shaft power corresponds to lower efficiency).

Table 10 sCO_2 Power Cycle Equipment Performance Assumptions

Power Turbine	
Inlet Pressure (MPa)	27.4
Inlet Temperature (°C)	700
Isentropic Efficiency (%)	91.8
Low Temperature Compressor	
Inlet Pressure (MPa)	6.5
Inlet Temperature (°C)	21.7
Isentropic Efficiency (%)	88.3
Low Temperature Compressor Drive Turbine	
Inlet Pressure (MPa)	27.4
Inlet Temperature (°C)	700
Isentropic Efficiency (%)	86.4
High Temperature Compressor	
Inlet Pressure (MPa)	27.4
Inlet Temperature (°C)	700
Isentropic Efficiency (%)	86.6
High Temperature Compressor Drive Turbine	
Inlet Pressure (MPa)	27.4
Inlet Temperature (°C)	700
Isentropic Efficiency (%)	87.5
Low Temperature Recuperator	
Effectiveness (%)	97.1
Min. Approach Temperature (°C)	6.4
Overall Thermal Conductance, UA (kW/°C)	17,807
High Temperature Recuperator	
Effectiveness (%)	96.6
Min. Approach Temperature (°C)	11.2
Overall Thermal Conductance, UA (kW/°C)	14,136

Table 11 defines the assumptions applied to the fired heater, air quality control system (AQCS) equipment, and the post combustion carbon capture (PCC) systems.

Table 11 Fired Heater, AQCS, and Post Combustion Capture Equipment Assumptions

Fired Heater	
Coal	Montana Rosebud subbituminous (95% heat input)
Natural Gas	Natural Gas (5% heat input)
Fired Heater Efficiency (%)	84
Stack Temperature (°C)	33

AQCS Equipment	
SO_2 Control	Circulating Dry Scrubber (CDS) and PCC flue gas pretreatment
SO_2 Removal Efficiency (% before / after PCC system)	92.2 / 99.9
NOx Control	Low NOx burners, over-fire air, and selective catalytic reduction (SCR)
SCR Efficiency (%)	70.7
Ammonia Slip (ppm) (end of catalyst life)	5
Particulate Control	Fabric filter
Fabric Filter Removal Efficiency (%)	99.8
Ash Distribution (% fly / bottom)	80 / 20
SO_3 Removal Efficiency (%)	> 99% of SO3 is captured within the CDS
Mercury Control	Carbon injection at CDS
CO_2 Control	MHI KM CDR process ®
Overall Carbon Capture (%)	83.6

sCO_2 Fired Heater and PCC Heat and Mass Balance

The following section describes the sCO_2 fired heater and PCC system performance. The fired heater and air quality control system (AQCS) is described by the process flow diagram (PFD) shown in Table 12 sCO2 Fired Heater - HMB and the heat-and-mass balance (HMB) is summarized in (line number therein corresponds to the stream number in the PFD). The flue gas constituents are summarized in

Table 13. A dual-fuel system capable of firing pulverized coal and natural gas 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 combustion air. The system is designed to operate under full load with a 95% heat input from coal and 5% heat input from natural gas. The natural gas heat input is used for temperature trimming of the sCO_2, as attemperation typical in steam systems is not utilized in this design.

The AQCS includes NO_x control using SCR, SO_2 control using a CDS and particulate control using a fabric filter. Tubular air preheaters are proposed for combustion air heater, and there is no air leakage present in the preheater.

The PCC system PFD and HMB are shown in Figure 14. Note only flue gas inlet and CO_2 capture conditions are shown.

Table 12 sCO2 Fired Heater - HMB

Line	Media	Temp.	Pressure	Draft	Mass Flow Fluid	Mass Flow Solid	Volume Flow Fluid	Volume Flow Solid	Enthalpy Fluid	Enthalpy Solid
#		°C	bar(a)	mm H20	kg/hr	kg/hr	(A) L/min	(S) L/min	kJ/kg	kJ/kg
1	Coal	15	N/A	N/A	0	50,954	N/A	N/A	N/A	2.1
2	Coal / Primary Air	66	N/A	508	104,033	50,954	3,202,437	1,414,933	39.5	50.9
3	Natural Gas	15	3.4	N/A	1,040	N/A	14,314	21,219	4.1	N/A
4	Primary Air (Cold)	15	N/A	1,270	104,033	N/A	1,424,242	1,414,933	-10.1	N/A
5	Primary Air (Hot)	371	N/A	1,143	104,033	N/A	3,183,600	1,414,933	358.4	N/A
6	Secondary Air (Cold)	15	N/A	381	312,299	N/A	4,275,477	4,247,532	-12.0	N/A
7	Secondary Air (Hot)	288	N/A	254	312,299	N/A	8,374,645	4,247,532	270.9	N/A
8	Secondary Air (Hot)	288	N/A	254	83,266	N/A	2,232,879	1,132,493	270.9	N/A
9	Secondary Air (Hot)	288	N/A	254	229,033	N/A	6,141,766	3,115,039	270.9	N/A
10	CO_2	209	295.1	N/A	281,656	N/A	N/A	N/A	583.8	N/A
11	CO_2	520	292.1	N/A	281,656	N/A	N/A	N/A	993.2	N/A
12	CO_2	503	292.1	N/A	3,124,457	N/A	N/A	N/A	970.1	N/A
13	CO_2	700	275.1	N/A	3,124,457	N/A	N/A	N/A	1221.6	N/A
14	Flue Gas / Fly Ash	414	N/A	-127	464,168	3,742	15,092,199	6,371,377	432.2	378.1
15	Flue Gas / Fly Ash	346	N/A	-203	464,168	3,742	12,844,424	6,371,377	352.6	302.1
16	Flue Gas / Fly Ash	346	N/A	-318	464,375	3,742	13,804,717	6,374,210	352.6	302.1
17	Flue Gas / Fly Ash	174	N/A	-406	464,375	1,339	9,921,255	6,374,210	158.2	127.6
18	Flue Gas / Fly Ash	79	N/A	-533	488,097	198,385	5,898,350	6,699,840	55.1	43.3
19	Flue Gas	79	N/A	-762	488,097	5	8,878,460	6,699,840	55.1	44.2
20	Flue Gas	88	N/A	25	488,097	5	8,422,022	6,699,840	64.7`	50.8
21	Byproduct (Ash/Lime)	79	N/A	-533	0	197,041	N/A	N/A	N/A	43.3

22	Byproduct (Ash/Lime)	79	N/A	-406	0	195,701	N/A	N/A	N/A	43.3
23	Water	15	5.9	N/A	23,723	N/A	N/A	N/A	-41.8	N/A
24	Lime	15	1.4	N/A	0	1,339	N/A	N/A	N/A	2.0
25	Ammonia	15	6.6	N/A	206	N/A	N/A	N/A	-32.4	N/A

Table 13 sCO_2 Fired Heater - Flue Gas Constituents

Line	**N_2**	**O_2**	**CO_2**	**H_2O**	**SO_2**	**SO_3**	**HCl**	**NO_x as NO_2**	**Ash**	**NH_3**
#	**vol % (wet)**	**vol % (wet)**	**vol % (wet)**	**vol % (wet)**	**PPM_v (wet)**	**PPM_v (wet)**	**PPM_v (wet)**	**PPM_v (wet)**	**g/m^3**	**PPM_v (wet)**
14	71.52	3.13	11.60	13.65	723.6	5.8	9.2	187.6	4.28	0.00
15	71.52	3.13	11.60	13.65	723.60	5.80	9.20	187.6	4.28	0.00
16	71.53	3.15	13.63	11.61	721.3	7.2	9.2	56.1	4.27	5.00
17	71.53	3.15	13.63	11.61	721.3	7.2	10.4	56.1	5.13	4.6
18	68.72	2.96	10.82	17.23	105.9	1.7	1.0	56.1	441.7	4.3
19	68.75	3.03	10.85	17.17	53.0	0.3	1.0	56.1	0.01	0.8
20	68.75	3.03	10.85	17.17	53.0	0.3	0.8	56.1	0.01	0.8

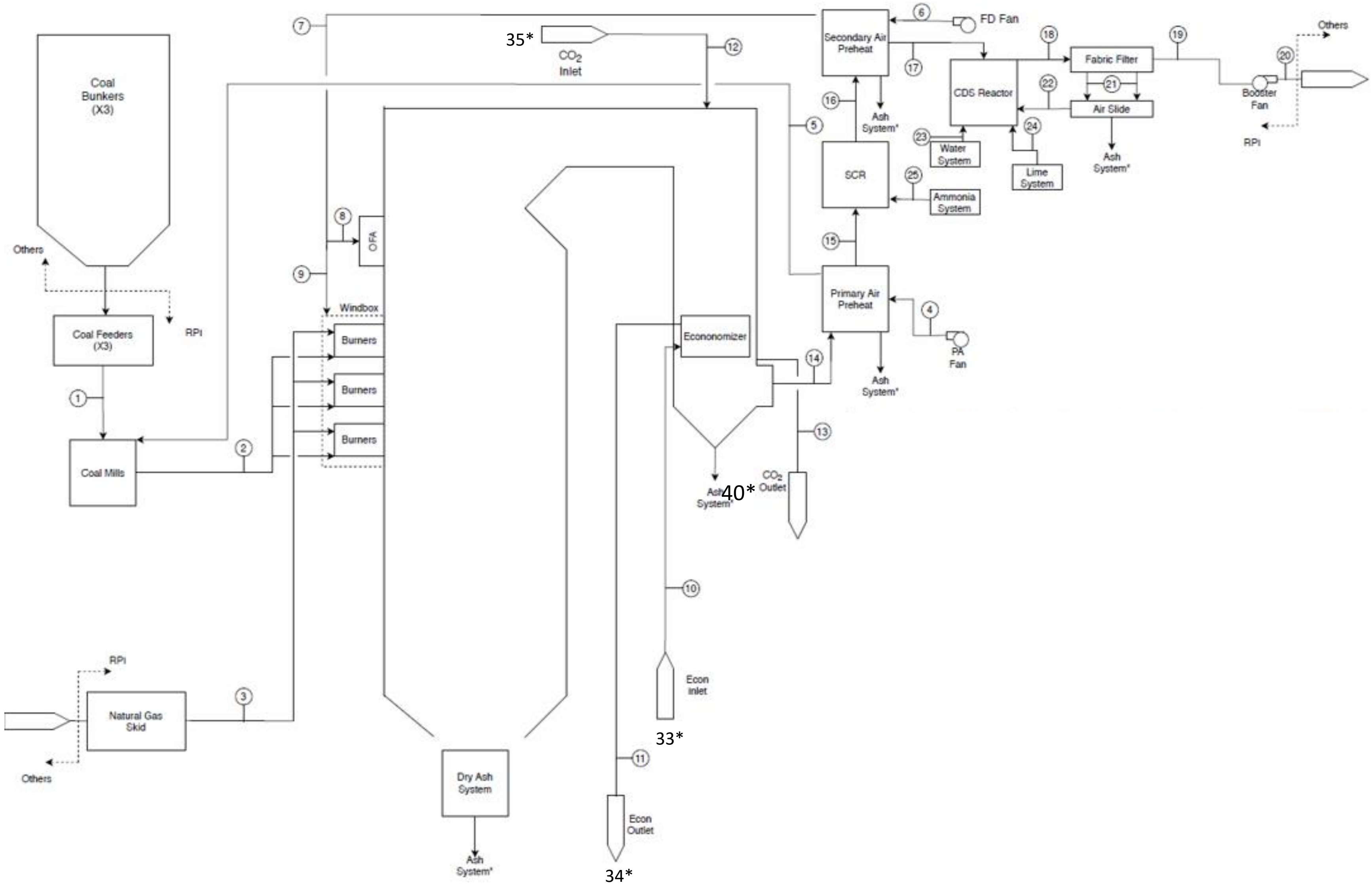
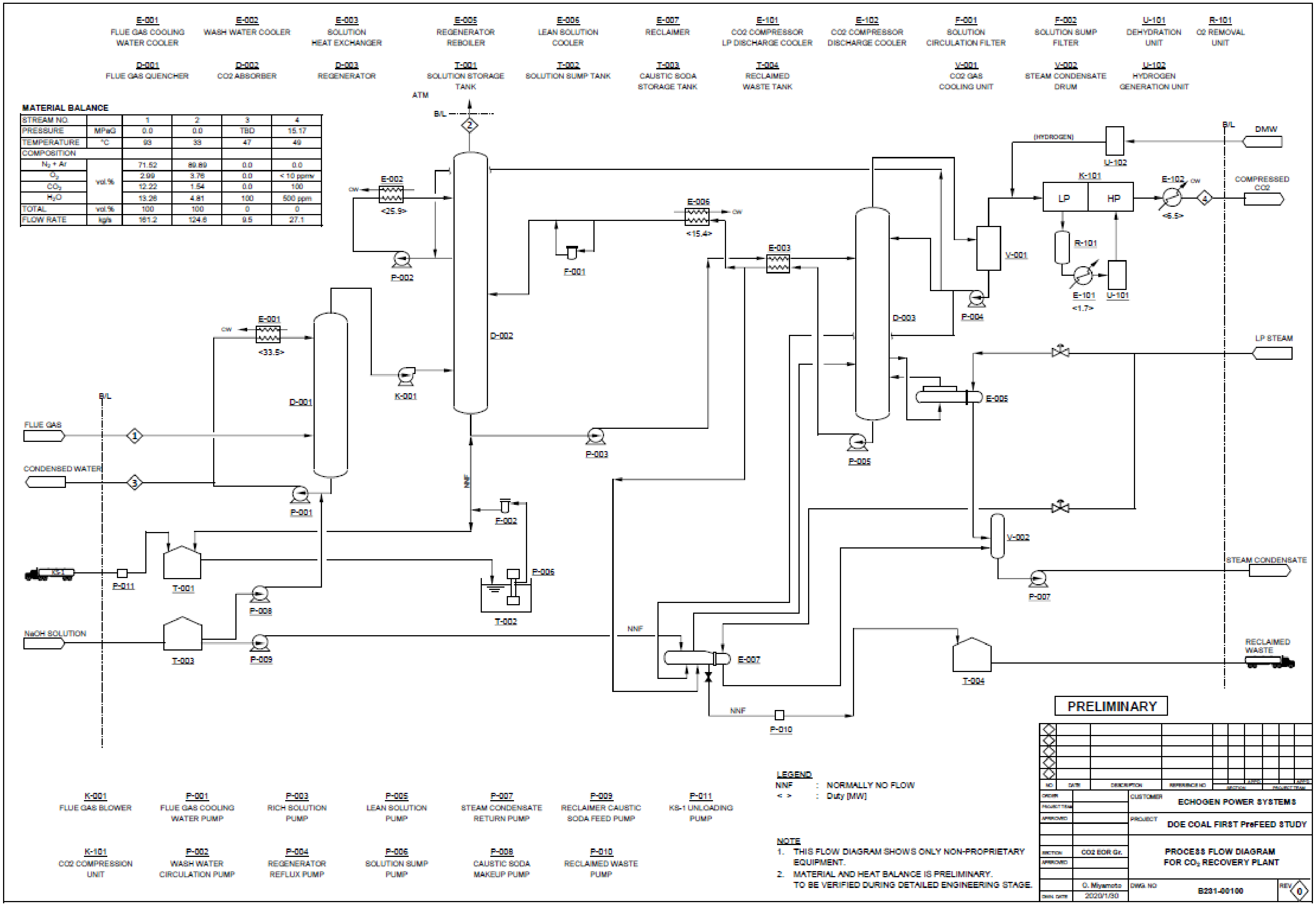


*Figure 13 sCO2 fired heater PFD (note; streams marked with * correspond to stream numbers from sCO2 power cycle)*



MATERIAL BALANCE

STREAM NO.		1	2	3	4
PRESSURE	MPaG	0.0	0.0	TBD	15.17
TEMPERATURE	°C	93	33	47	49
COMPOSITION					
N_2 + Ar	vol.%	71.52	89.89	0.0	0.0
O_2		2.99	3.76	0.0	< 10 ppmv
CO_2		12.22	1.54	0.0	100
H_2O		13.26	4.81	100	500 ppm
TOTAL	vol.%	100	100	0	0
FLOW RATE	kg/s	161.2	124.6	9.5	27.1

Figure 14 MHI PCC HMB

sCO_2 Power Cycle Heat and Material Balance

The sCO_2 power cycle and plant performance are summarized in the following section. The modified recompression Brayton (mRCB) cycle described in the Design Basis Report is used for the power cycle. This cycle allows for more efficient use of the heat produced in the fired heater, with little effect on power cycle performance (approximately 0.1% change in power cycle efficiency). The specific state points for the proposed cycle are based on a cycle optimization in which both fired heater an sCO_2 power cycle performance and sCO_2 power cycle costs are considered. This combined optimization results with the HTC and LTR high pressure outlets having slightly different temperatures. The power cycle PFD is shown in Figure 15, with the HMB summarized in Table 14.

Plant electrical loads are summarized in Table 15. These loads encompass the main power generation portion of the plant, but do not include the ETES system. Generating loads include both the sCO_2 power cycle and combustion turbine (CT) generators. The total net generating capacity of the plant is 120.7 MW_e. Auxiliary loads for the fired heater include fans, coal pulverizers, and atomizers. sCO_2 power cycle auxiliary loads include gearbox and generator losses, air-cooled condenser fans and turbomachinery auxiliaries. Also included were transformer losses and a balance-of-plant allowance for buildings, coal conveying, ammonia pumps and vaporizers, and ash transport systems. The PCC system auxiliary loads and CT electrical generation have been combined into a single line item (NG CT – PCC parasitic loads). The auxiliary loads associated with this include the following: cooling tower fans, cooling water pumps, condensate return and HRSG boiler feedwater pumps, make-up water pumps, CO2 compression, and all loads associated with the CO_2 stripping process.

A summary of the power cycle component size and performance is shown in Table 16.

The plant performance summary for both the plant without and with PCC is shown in Table 17 and Table 18, respectively. In both cases the fired heater efficiency is 84% and the power cycle has a gross thermodynamic efficiency of 48%. Without PCC the net plant efficiency, excluding CT generating and PCC auxiliary loads as shown in Table 15, is 40.3% HHV. With PCC the net plant efficiency is 29.9% HHV.

Table 14 sCO_2 power cycle heat and mass balance

State	Description	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Enthalpy (kJ/kg)
10	CHX Outlet - LTC Inlet	21.7	6.52	568.0	258.3
20	LTC Outlet	50.2	30.00	568.0	290.3
21	HTC Outlet	201.7	29.58	318.1	573.8
22	Turbomachinery Bearings	50.2	30.00	18.0	290.3
23	LTR High Pressure Inlet	50.2	29.97	550.0	290.3
30	LTR High Pressure Outlet	214.2	29.58	550.0	592.4
31	HTR High Pressure Inlet	209.5	29.50	789.9	585.6
32	HTR High Pressure Outlet	500.9	29.29	789.9	967.3
33	PHX-2 Inlet	209.5	29.51	78.3	585.6
34	PHX-2 Outlet	520.0	29.21	78.3	991.4
35	PHX-1 Inlet	502.6	29.21	868.2	969.5
40	PHX-1 Outlet	700.0	27.51	868.2	1220.9

41	LTC Turbine Inlet	700.0	27.41	91.7	1220.9
42	HTC Turbine Inlet	700.0	27.41	156.8	1220.9
43	Power Turbine Inlet	700.0	27.41	619.7	1220.9
50	HTR Low Pressure Inlet	523.5	7.02	868.2	1013.8
51	LTC Turbine Outlet	531.3	7.12	91.7	1023.1
52	HTC Turbine Outlet	529.3	7.12	156.8	1020.6
53	Power Turbine Outlet	521.0	7.12	619.7	1010.7
54	HTR Low Pressure Outlet - LTR Low Pressure Inlet	220.6	6.92	868.2	666.5
60	LTR Low Pressure Outlet	60.4	6.77	868.2	475.1
61	CHX Inlet	56.2	6.69	568.0	469.3
62	HTC Inlet	59.8	6.69	318.1	475.1
A1	Air Inlet	15.0	0.101	9868.2	288.4
A2	Air Outlet	27.1	Fan dP (20.3 mm H_2O)	9868.2	300.6

Table 15 Summary of plant auxiliary and generating loads

Plant Electrical Loads	**Value (kW_e)**
Generating Loads	
sCO_2 Power Turbine	130,212
NG CT – PCC parasitic loads	700
Gross Power	**130,912**
Auxiliary Loads	
Gearbox & Generator Losses	1,666
ACC Fan (CHX)	2,707
Primary Air Fan	1,147
Forced Draft Fan	875
Induced Draft Fan	1,860
Pulverizer Seal Air Fan	110
Pulverizers	513
Atomizer	238
Turbine Auxiliaries (Dry gas seal conditioning and lube oil)	156
Transformer Losses	440
Miscellaneous Balance of Plant	500

Total Auxiliary Power	**10,212**
System Net Power (with PCC)	**120,700**

Table 16 sCO_2 power cycle equipment summary

Component	**Duty (kW) - (kW/°C)**	**Efficiency / Effectiveness**
LTC - Shaft Power (T – C)	18,135	86.4% – 88.3%
HTC - Shaft Power (T – C)	31,392	87.5% – 86.6%
PT - Shaft Power	130,212	91.8%
CHX - Heat Transferred – UA	119,788 – 16,426	90.3%
HTR - Heat Transferred – UA	301,498 – 14,136	96.6%
LTR - Heat Transferred – UA	166,183 – 17,807	97.1%
PHX1 - Heat Transferred to CO_2	218,244	84% Fired Heater Efficiency
PHX2 - Heat Transferred to CO_2	31,756	

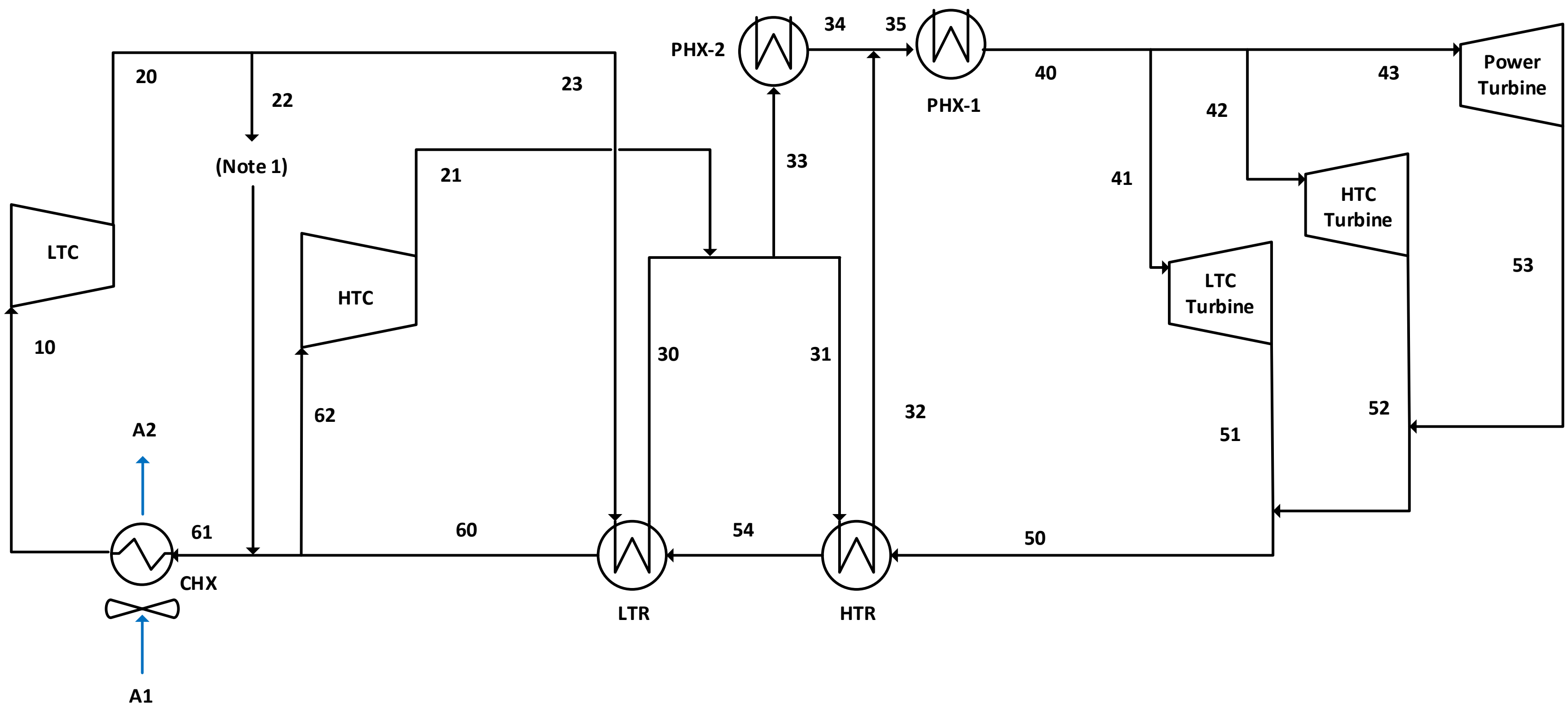


Figure 15 sCO_2 Power Cycle Process Flow Diagram

LTC – Low temperature compressor

HTC – High temperature compressor

PHX-2 – Fired heater convective section

PHX-1 – Fired heater radiant section

HTR – High temperature recuperator

Note 1 – Estimated parasitic CO_2 flow for turbomachinery auxiliaries

LTC Turbine – Low temperature compressor drive turbine

HTC Turbine – High temperature compressor drive turbine

Power Turbine – Power turbine, coupled to synchronous generator

CHX – Air cooled CO_2 condenser/chiller

LTR – Low temperature recuperator

Table 17 Plant efficiency summary without PCC

System (without PCC)	Energy In (kW)	Energy Out (kW)	Efficiency
Fired Heater	297,619	250,000	84.0%
Power Cycle	250,000	120,000	48.0%
Overall Plant (without PCC)	297,619	120,000	40.3%

Table 18 Plant efficiency summary including PCC

System (with PCC)	Energy In (kW)	Energy Out (kW)	Efficiency
Fired Heater	297,619 (Thermal)	250,000 (Thermal)	84.0%
Power Cycle (incl. PCC Aux.)	250,000 (Thermal)	120,000 (Electric)	48.0%
Combustion Gas Turbine and Duct Burner and PCC	106,292 (Thermal)	600 (Electric)	n/a
Overall Plant (with PCC)	403,912 (Thermal)	120,600 (Electric)	29.9%

ETES System Heat-and-Mass Balance

The following section summarizes the performance of the ETES system. The PFD's for the generating and charging cycles are shown in Figure 16 and Figure 17, respectively. The ETES system utilizes CO_2 as the working fluid. Concrete is used as the high temperature storage medium and Duratherm HF ® is used as the heat transfer fluid (HTF) between the concrete and CO_2. The cold storage uses an ice-on-coil system in which a large storage tank has a tube bundle installed inside. Cold CO_2 flows through the tubes and freezes a water/glycol mixture in the tank during the charge cycle and warm CO_2 (> 0°C) and melting the ice slurry mixture.

The ETES system is represented as two separate cycles (generating and charging), but share the following components:

- High temperature storage cold reservoir (HTSc)
- High temperature storage intermediate reservoir (HTSi)
- High temperature storage hot reservoir (HTSh)
- High temperature oil to CO_2 heat exchangers (HTX1 and HTX2)
- Recuperator (RCX)
- Low temperature ice slurry to CO_2 heat exchanger and slurry storage (LTX/ISG)

The generating cycle (Figure 16) is a simple recuperated power cycle, with a recompression step occurring at an intermediate pressure in the power turbine expansion. Liquid CO_2 is pumped to a high pressure from the cold state at the discharge of the low temperature heat exchanger (LTX/ISG) and heated with the RCX using heat that is not used during the expansion of the CO_2 across the turbine. HTF heated from the high temperature concrete reservoir is then used to heat the CO_2 in the high temperature heat exchangers (HTX1 and HTX2) before it is expanded across the high pressure and low-pressure stages of the power turbine. A small split stream is taken at an intermediate pressure in the power turbine expansion and recompressed and added back to cycle between the RCX and HTX2. The low-pressure CO_2 leaving the lower pressure section of the power turbine passes through the RCX before finally rejecting heat through the LTX/ISG . The generating cycle state points are described in Table 19 and the associated major equipment performance summary is shown in Table 20.

The charging cycle (shown in Figure 17), used to generate the hot and cold potential for the generating cycle, is a modified heat pump cycle. It takes AC power in and converts it to potential thermal energy that can be stored in the HTS (concrete) and LTX/ISG (ice slurry) reservoirs. A CO_2 compressor compresses (and heats) the CO_2 to 22.6 MPa. The high temperature CO_2 leaving the compressor rejects heat to the HTF and the HTS. The CO_2 then goes through the RCX to pre-heat the CO_2 at the compressor inlet. An air-cooled chiller (Chg ACC) is used to reject heat prior to expansion across a low temperature turbine (LT turbine). The Chg ACC is used to balance the hot and cold storage and decrease the temperature going into the turbine expansion. From the LT Turbine cold CO_2 enters the LTX/ISG and generates the ice slurry mixture and then goes through RCX prior to entering the charge compressor. The charging cycle state points are described in Table 21 and the associated major equipment performance summary is shown in Table 22.

This system utilizes a three-tank high temperature storage system, consisting of a hot tank (HTSh), an intermediate temperature tank (HTSi), and a cold tank (HTSc). This is done because of the mismatch and curvature of the specific heat between CO_2 and the HTF (Figure 18). The addition of a third tank allows for tight approach temperatures between the CO_2 in both the charging and generating cycles (shown in Figure 19).

The ETES system performance is summarized in Table 23. The system is designed to charge and discharge at 30 MW_e, with a 15-hour charge time and 8-hour discharge time. The generating cycle has an efficiency of 30.4%, and the charging cycle has a coefficient of performance (COP) of 1.73. The overall RTE for the ETES system is 52.7%.

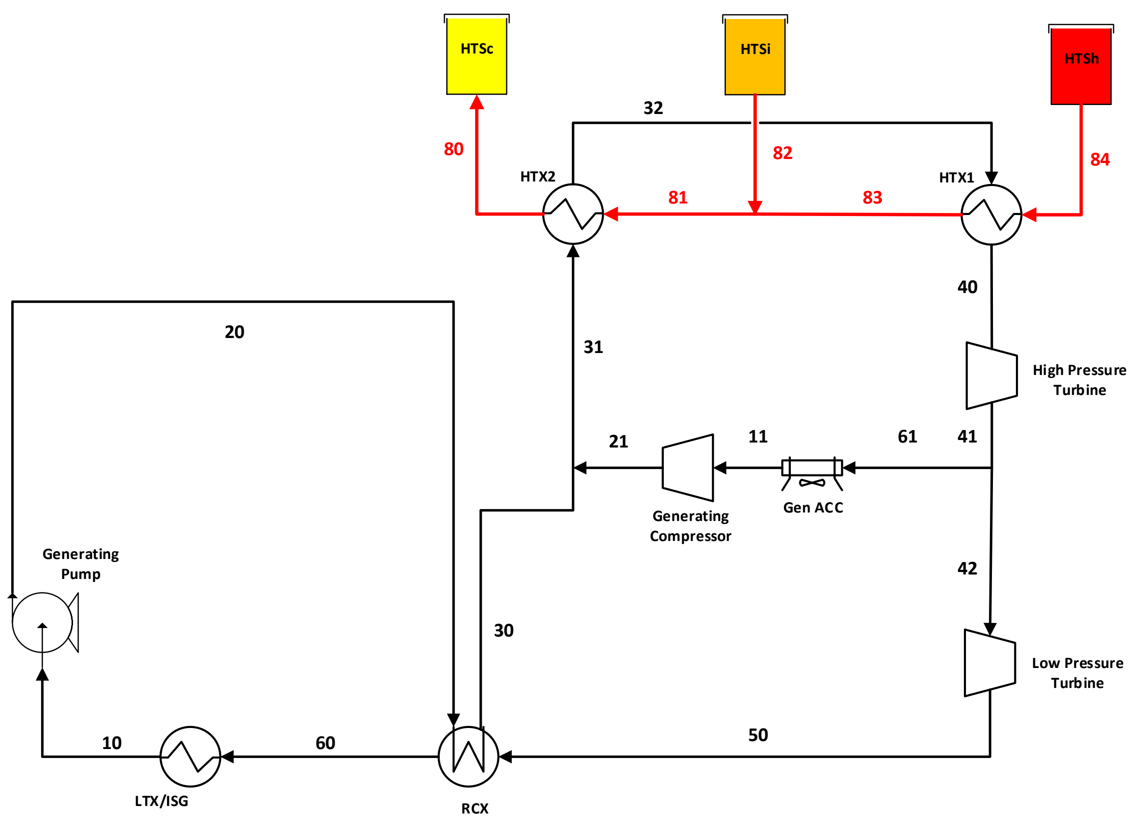


Figure 16 ETES system power generating cycle

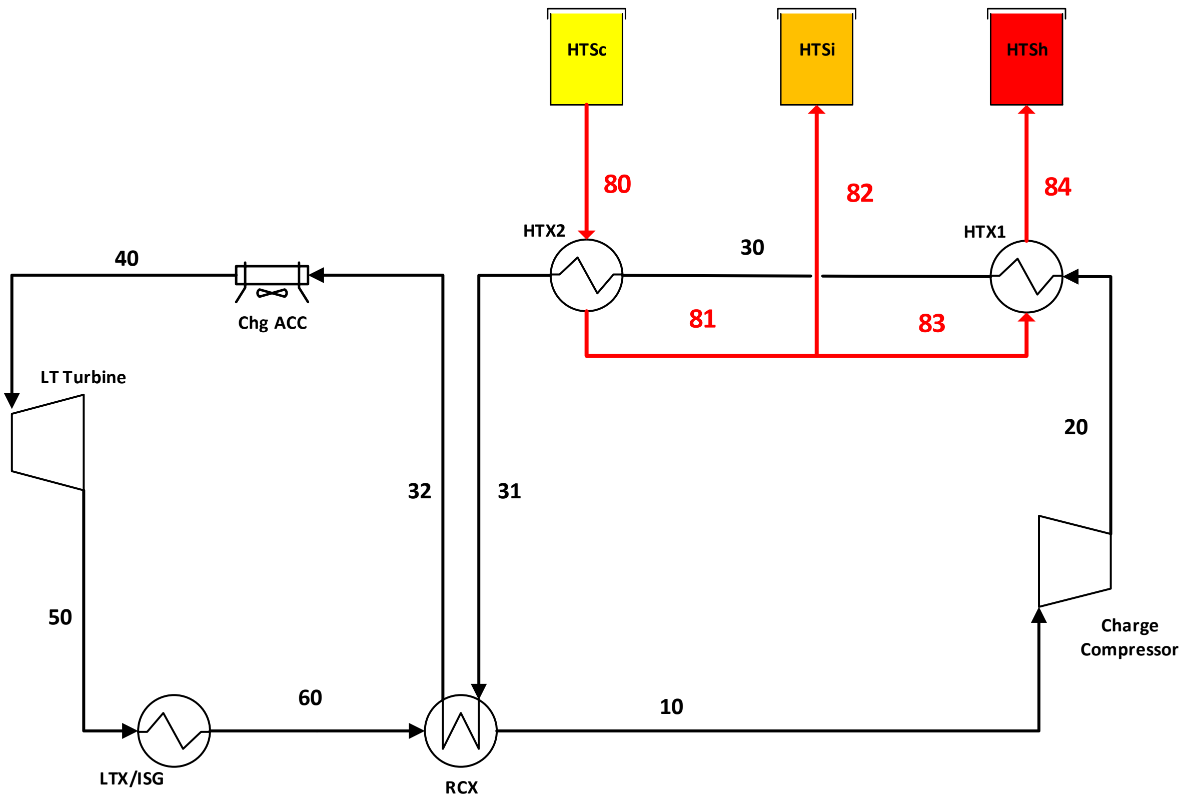


Figure 17 ETES system charging cycle

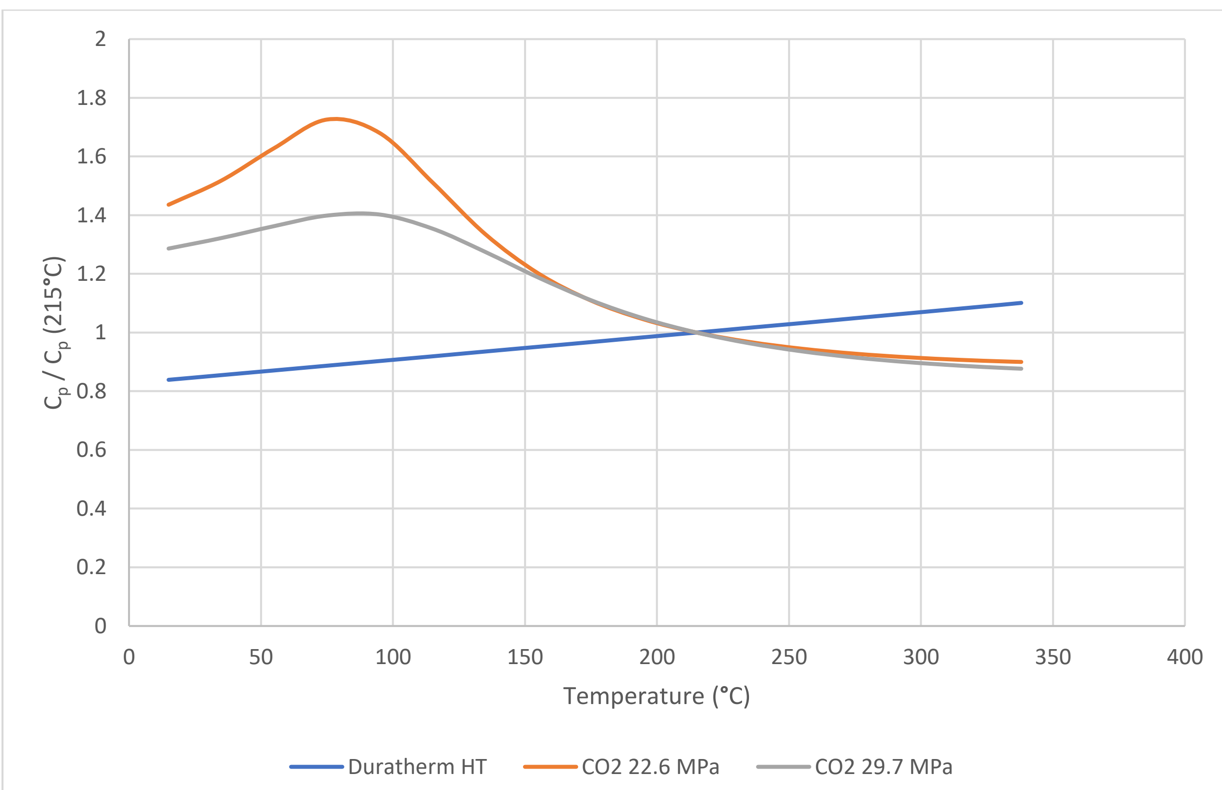


Figure 18 Specific Heat Variation of CO_2 and Duratherm HF® (215°C Reference)

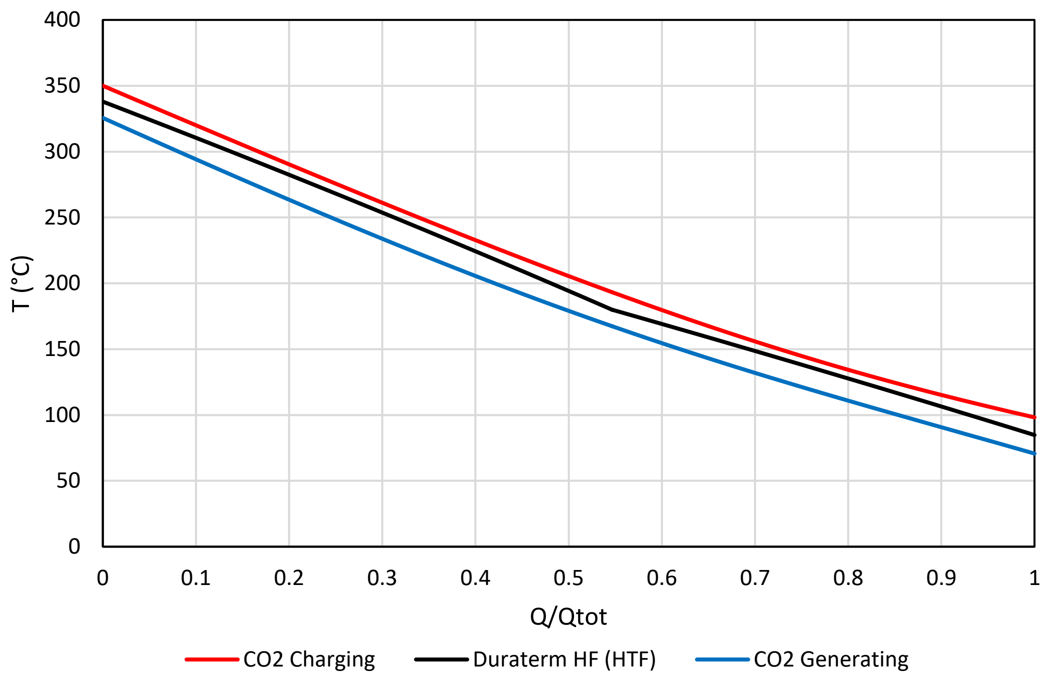


Figure 19 Temperature - Heat Transfer (T-Q) Plot of HTX1 and HTX2

Table 19 State point table for ETES power generating cycle, Figure 16

State	Description	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Enthalpy (kJ/kg)
10	LTX Outlet - Pump Inlet	-6.1	3.1	214.8	185.5
20	Pump Outlet - RCX HP Inlet	13.1	30.0	214.8	218.6
30	RCX Outlet	72.1	29.9	214.8	334.4
31	HTX2 Inlet	70.7	29.9	237.9	331.7
32	HTX2 Outlet - HTX1 Inlet	167.4	29.8	237.9	332.4
40	HTX Outlet - HPT Inlet	325.6	29.7	237.9	744.2
41	HPT Outlet	185.4	7.0	237.9	627.0
42	LPT Inlet	185.4	7.0	214.8	627.0
50	LPT Outlet - RCX LP Inlet	123.0	3.3	214.8	576.9
60	RCX LP Outlet - LTX Inlet	15.9	3.2	214.8	461.0
61	Gen ACC Inlet	185.4	7.0	23.1	627.0
11	Gen ACC Outlet - Gen Comp Inlet	25.0	6.9	23.1	269.7
21	Gen Comp Outlet	58.1	30.0	23.1	306.1

84	HTSh Outlet - HTX1 HTF Inlet	338.0	0.3	149.9	702.5
83	HTX1 HTF Outlet	180.0	0.2	149.9	344.6
82	HTSi Outlet	180.0	0.2	79.3	344.6
81	HTX2 HTF Inlet	180.0	0.2	229.2	344.6
80	HTX2 HTF Outlet - HTSc Inlet	84.8	0.1	229.2	150.5

Table 20 ETES power generating cycle equipment summary, Figure 16

Component	Duty (kW) – (kW/°C)	Efficiency / Effectiveness (%)
Generating Pump	7,103	82.0
HP Turbine	27,883	88.0
LP Turbine	10,758	
Generating Compressor	840	79.0
HTX1	54,347 - 9,639	93.4
HTX2	43,488 - 8,358	90.1
RCX	25,029 - 1,722	97.0
Gen ACC (thermal / electric)	8,265 / 64	-
LTX	59,184	-
Hot Oil Pumps	99.6	80.0

Table 21 State point table for ETES charging cycle, Figure 17

State	Description	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Enthalpy (kJ/kg)
10	RCX LP Outlet - Chg Comp Inlet	95.8	2.3	139.6	555.0
20	Chg Comp Outlet - HTX1 Inlet	350.0	22.6	139.6	785.3
30	HTX1 Outlet	193.3	22.4	139.6	580.7
31	HTX2 Inlet - RCX HP Inlet	98.2	22.2	139.6	410.9
32	RCX HP Outlet - Chg ACC Inlet	49.4	22.1	139.6	295.5
40	Chg ACC Outlet - LTT Inlet	20.0	22.1	139.6	233.1
50	LTT Outlet - ISG Inlet	-13.5	2.4	139.6	168.7
60	ISG Outlet - RCX LP Inlet	-12.5	2.3	139.6	439.6

80	HTSc Outlet - HTX2 HTF Inlet	84.8	0.3	122.1	150.5
81	HTX2 HTF Outlet	180.0	0.2	122.1	344.6
82	HTSi Inlet	180.0	0.2	42.2	344.6
83	HTX1 HTF Inlet	180.0	0.2	79.8	344.6
84	HTX1 HTF Outlet - HTSh Inlet	338.0	0.1	79.8	702.5

Table 22 ETES charging cycle equipment summary, Figure 17

Component	**Duty (kW) – (kW/°C)**	**Efficiency / Effectiveness (%)**
Charge Compressor	32,644	84.0
LT Turbine	2,647	84.3
HTX1	28,467 - 3,282	95.5
HTX2	22,779 - 2,718	93.5
RCX	5,339 - 795	98.0
Charge ACC (thermal / electric)	8,717 / 116	-
ISG	31,517	-
Hot Oil Pumps	54	80

Table 23 ETES performance summary

Generating Cycle	Heat Input (kW_{th})	98,146
	Heat Rejected (kW_{th})	59,184
	Electricity Generated (kW_e)	29,833
	Net Cycle Efficiency (%)	30.4
	Time to Full Discharge (hrs)	8
Charge Cycle	Electricity Consumed (kW_e)	30,167
	Heat Generated (kW_{th})	52,269
	Cooling Generated (kW_{th})	31,517
	COP	1.73
	Time to Full Charge (hrs)	15
Round Trip Efficiency (%)		**52.7**

Environmental Performance

The plant emissions of SO_2, NO_x, particulate matter (PM), Hg, HCl, and CO_2 are presented in Table 24.

Table 24 Air emissions

Emission	lb/MMBTU	lb/MWh (gross)	ton/year
SO_2	1.69E-03	.013	7.3
NO_x	0.074	0.700	335.2
PM	9.50E-03	0.090	43.1
Hg	3.16E-07	3.00E-06	1.4E-03
HCl	1.10E-03	0.010	5.0
CO_2	30.52	290.5	184,634

SO_2 emissions (as well as SO_3, HCl, and HF) are controlled using a CDS that requires a dedicated hydrated lime injection, water injection, byproduct ash recycle and flue gas recirculation. This system achieves a removal efficiency of 92.2%. The byproduct of this process is “dry ash”, which will have calcium content and cannot be used for typical beneficial uses and hence will need to be disposed off-site. SO_2 is further removed during the carbon process bringing the overall removal rate to 99.9%.

NO_x heater emissions are controlled to 0.3 lb/MMBtu using low NOx burners and over fire air. An SCR is then used to further reduce the NO_x concentration to 0.074 lb/MMBtu.

Particulate emissions are controlled using a pulsed jet fabric filter, operating with a removal efficiency of 99.8%.

The total reduction in mercury emission through the combined control equipment (SCR, fabric filter, and CDS) brings the overall emissions to 3.16E-07 lb/MMBtu.

83.6% of the CO_2 present in the flue gas is removed in the PCC process with the remainder being emitted at a rate of 30.52 lb/MMBtu.

Table 25 shows the overall water balance for the plant. The water demand represents the amount of water required for a particular process. The difference between the demand and what is recycled in the process is water withdrawal. Raw water consumption is defined as what is removed from the source and not returned. There are 4 processes that require water: the CDS, evaporative cooling tower, boiler feedwater make-up, and the PCC process.

Cooling tower water losses considered are evaporative (2.3% of circulating flow), drift (0.1% of circulating flow), and blowdown (EL + drift / (cycles of concentration – 1)).

Because of sensitivities to proprietary information, the boiler feedwater and PCC process water use has been grouped together.

Table 25 Water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	L/min	L/min	L/min	L/min	L/min
CDS	395	0	395	0	395
Cooling Tower (Drift, Evaporation, and Blowdown)	124	0	124	31	93
Boiler Feedwater and PCC process	723	0	723	0	723

5. Equipment Summary and Technology Gap Analysis

The PC/sCO_2/ETES power plant makes extensive use of proven technologies to limit technical risk and provide a clear path to commercialization. An inventory of key plant components and subsystem is shown in Table 26, along with an identification of commercial availability.

Table 26 Key plant components TRL summary

Subsystem	Component	Availability	TRL	Source
	Non-commercial components			
Power cycle				
	130 MW_e power turbine	Scale-up from 100 MW	6	Siemens
	30 MW HT compressor	Scale from 4 MW	4	Barber Nichols
	18 MW LT compressor	Scale from 3 MW	5	EPS100, Barber Nichols
	Operation and control	Scale from 10 MW	4	Echogen
	High temperature turbine stop valve	Scale from 10 MW	4	Flowserve, Baker Hughes
Primary heat exchanger				
	Heat exchanger design	Scale from 10 MW	3	LSP
Energy storage system				
	Charging system turbine	Derivative	6	Ebara, Flowserve, Cryostar
	Generating system turbine	Scale-up from 10 MW	6	EPS100, Barber Nichols
	High-temp. exchanger (sand-to-CO_2)	Derivative	6	Solex
	Low-temperature reservoir	Derivative	6	Liquid Ice, BAC
	Commercial components			
Power cycle				
	15 MW LT compressor (alternate)	Liquid pump	9	Sulzer, Flowserve
	Recuperators	Commercial	9	Heatric, VPE
	Water-cooled cooler	Commercial	9	Heatric, VPE
	High temperature materials	Commercial	9	Special Metals, Haynes
	All others	Commercial	9	Various
Pulverized coal and natural gas combustor				
		Commercial	9	Riley Power
Primary heat exchanger				
	High-temperature materials	Commercial	9	Special Metals, Haynes

Subsystem	Component	Availability	TRL	Source
Emissions control system				
	NOX reduction catalyst	Commercial	9	Riley Power
	SO2/HCl scrubber	Commercial	9	Riley Power
	Particulate management (baghouse)	Commercial	9	Dustex or equivalent
Carbon capture system				
		Commercial	9	Mitsubishi
Energy storage system				
	Charging system compressor	Commercial	9	Siemens, Hanwha, etc.
	Recuperators	Commercial	9	Heatric, VPE
	High temp. exchangers (liquid-to-CO_2)	Commercial	9	Heatric, VPE
	Low-temp. exchangers	Commercial	9	Tranter, Alfa Laval
	High-temp. reservoir	Commercial	9	Silo or tank manuf.
	Generating system pump	Liquid pump	9	Sulzer, Flowserve

The components and subsystems that are not directly commercially available are discussed further, along with the technical development and risk abatement activities that are in place or planned.

Non-Commercial Components and Subsystems

130 MW_e power turbine

The sCO_2 power turbine is a modest scale-up of the 100 MW_e, 730°C inlet temperature turbine designed by Siemens during the DOE-funded "High-Efficiency Thermal Integration of Closed Supercritical CO_2 Brayton Power Cycles with Oxy-Fired Heaters" project[10] (DE-FE0025959). The turbine features a dual barrel design due to the high turbine inlet temperature with an axially split outer barrel. A technology gap and risk assessment analysis were conducted by Siemens during the program. The two highest ranking risks were:

1) Rotating blade failure due to high unsteady/alternating stresses due to fluid density and pressure.
2) Materials long-term compatibility with sCO_2.

The identified risk mitigation strategy for these two items was:

1) Detailed transient CFD and forced response analyses to assess alternating stresses and update the design as necessary.
2) Review literature to select best candidate materials and perform additional material compatibility testing, if required.

[10] Jason D. Miller et al., "Comparison of Supercritical CO_2 Power Cycles to Steam Rankine Cycles in Coal-Fired Applications," in *Proceedings of ASME Turbo Expo 2017: Turbomachinery Technical Conference and Exposition* (Charlotte, North Carolina, USA: American Society of Mechanical Engineers, 2017), GT2017-64933; Andrew Maxson et al., "High-Efficiency Thermal Integration of Closed Supercritical CO_2 Brayton Power Cycles with Oxy-Fired Heaters," 2017; Andrew Maxson et al., "Integration of Indirect-Fired Supercritical CO_2 Power Cycles with Coal-Based Heaters," in *The 6th International Symposium - Supercritical CO_2 Power Cycles* (Pittsburgh, Pennsylvania, 2018).

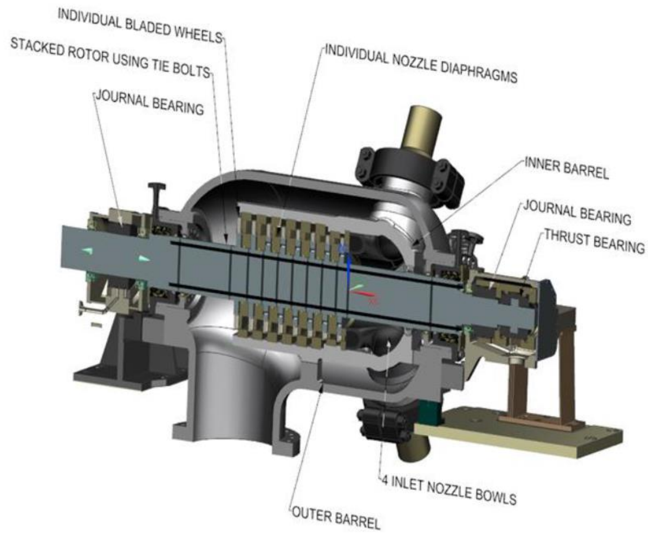


Figure 20: Siemens-designed 100 MW_e sCO_2 turbine (from DE-FE0025959).

Both these risk mitigation activities would be initiated at the next stage of the design process, which would occur once funding were assigned to develop the Coal FIRST system. We anticipate that Siemens or another OEM would be contracted to perform the design and fabrication of the power turbine.

18 MW Low Temperature Compressor (LTC)

The LTC compresses CO_2 from the water-cooled heat exchanger (CHX) outlet to the low-temperature recuperator (LTR) high-pressure inlet. The fluid properties at the LTC inlet are high density and low compressibility—very similar to an incompressible fluid. Thus, the operating characteristics of the LTC are similar to that of a liquid CO_2 pump. EPS has previously designed, built and successfully tested the equivalent of a 3 MW LTC in their EPS100, which would require a relatively modest scaling to 18 MW for the current program.

Alternatively, the fluid properties are sufficiently liquid-like that EPS has approached pump suppliers such as Sulzer, Flowserve and Ebara regarding the use of a conventional barrel-case style pump for LTC service. Provided sufficient suction margin is provided, this approach also appears feasible. The predicted isentropic efficiency of these pumps ranged from 76-84% at the design point, which is similar to the predicted and measured EPS100 compressor/pump performance (78-82%).

30 MW High Temperature Compressor (HTC)

Sometimes called the "bypass compressor" or "re-compressor", the HTC compresses CO_2 from the low-pressure outlet of the HTR to the high-pressure outlet of the LTR (effectively bypassing the LTR and CHX). The HTC operates over fluid conditions that are intermediate between the liquid-like properties at the LTC inlet and true ideal gas properties. The primary design path for the Coal FIRST HTC is a scaled version of a turbine-driven compressor that is being designed for the Large-Scale Pilot program, which in turn is a derivative of the LTC design.

Alternate designs are also being considered. At these conditions, the compressor could also be an industrial-style barrel-case or integrally-geared multistage design. As these are commercial devices, the technical risk of this approach is low. However, typical isentropic efficiency values of these compressors are in the 80-82% range, vs the predicted 86.4-87.3% range for the high-speed single-stage design. The efficiency of the power cycle would be approximately 1-2 percentage points lower with the industrial compressor design than the high-speed approach.

High temperature turbine stop valve

The turbine stop valve (TSV) is a key component to the sCO_2 power cycle. It is exposed to the highest CO_2 temperature and pressure and must close quickly in response to system trip signals, such as the loss of generator load, to avoid a power train overspeed situation. EPS has successfully demonstrated a Flowserve high-speed TSV in their EPS100 testing at lower CO_2 temperature. The work in cast valve bodies discussed below also applies to the TSV, and Baker Hughes is developing a CO_2 TSV for the STEP program. In addition, the work that the AUSC program has conducted includes steam TSV development work that is directly relevant here. Much of the necessary development in this area consists of code modifications to permit the use of advanced materials such as Haynes 282 and Inconel 740H at the temperatures used herein.

Operation and control

EPS has extensive experience in the operation and control of single turbo-compressor sCO_2 power cycles through its EPS100 development and test program[11]. The RCB cycle has one unusual feature relative to most existing Rankine and Brayton cycles—the use of two compressors in parallel. The first (and to date only) operating RCB configuration was the Sandia loop. In their experience, starting the two compressors represented operating challenges, and required simultaneous starting of the LTC and HTC to avoid driving the compression system into surge. While this process could be used here, analysis of the Sandia configuration shows that the starting challenges could have also been resolved through the use of independent bypass (or "anti-surge") and isolation valves and controls, such as are planned for the current project. In addition, the transient modeling simulations that have been developed for the LSP and current projects allow for detailed operability modeling throughout the start and other operating modes.

In EPS's previous design studies and simulations, the heat source has most frequently been natural gas-fired combustion turbine (CT) exhaust for combined-cycle applications. The differences between that heat source and the coal-fired heater are two-fold. First, the heat source time constants are very long in both cases, but for the CT exhaust the sCO_2 cycle had no control over the heat source, while for the coal-fired system the heat source firing rate can be controlled by the sCO_2 cycle. Second, the heat source temperature for the coal-fired case is much higher than the CT exhaust, thus requiring continuation of CO_2 flow following a system trip in order to maintain primary heat exchanger material temperatures to stay within limits. EPS is experienced in developing and executing Failure Modes, Effects and Criticality Analysis (FMECA) processes that are used to develop response plans for all foreseen failure modes.

We do not expect that the presence of the post-combustion carbon capture system will have a significant effect on the operation and control of the power cycle. Similarly, the planned implementation of the energy storage system allows for less maneuvering of the main power plant, with little to no effect on the main power plant control system.

Primary heat exchanger

The PHX has two technology development requirements. The materials used for the heat exchanger tubes and other components are already addressed in the "Materials, piping, tubing and valves" section above. The same materials are used in steam boilers, thus reducing the risk of unexpected problems with fire-side corrosion.

Due to the high working temperatures and pressures of the fluid, RPI has elected to design the majority of the heater components using Inco 740H. This material is a nickel-based alloy and has excellent strength in this operating region. This material is substantially more expensive than traditional tube materials, such as stainless steels, but allows for workable tube thicknesses and diameters.

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[11] Timothy J. Held, "Initial Test Results of a Megawatt-Class Supercritical CO_2 Heat Engine," in *The 4th International Symposium - Supercritical* CO_2 *Power Cycles* (Pittsburgh, Pennsylvania, 2014).

The heat transfer design of the PHX is relatively challenging due to the higher volumetric flow rate required for an sCO_2 power cycle for the same power rating as a steam Rankine cycle. In addition, the lower pressure ratio of the sCO_2 cycle increases its sensitivity to pressure drop in the PHX relative to a steam Rankine cycle. The simultaneous management of the pressure drop, and heat transfer design requires an integrated cycle-level optimization process. EPS and RPI are presently collaborating in the LSP program including development and refinement of this optimization process. The learnings from that program will directly impact the design process for this program.

The LSP program is presently in the Front-End-Engineering-Design (FEED) phase of the program and RPI has completed the preliminary design of the coal fired – sCO_2 heater. The FEED study will be completed in August of 2020, and a competitive down select of projects will be undertaken by the DOE for Phase III awards with announcements expected October of 2020. Detailed design of the fired heater (power cycle and balance of plant) will commence in January 2021, with material procurement and fabrication beginning in the 2^{nd} quarter. Commissioning of the system is expected to begin in January 2023, with full load operation beginning in June. With operational data being available in 2023 to support the design of the commercial scale fired heater, a 2030 commercial deployment is easily achievable and could be as soon as 2026 if financing becomes available.

The proposed heater design is based on a traditional utility scale steam boiler, with a furnace and a separate convective backpass. The element design of the backpass is a series of serpentine elements, designed to be fully drainable. These elements are stringer supported, with the coldest fluid cooling the stringers to provide maximum strength. Economizer elements are in-line with the primary convective elements and can share the same stringers for support.

Economizer tubes are finned to maximize heat transfer and minimize the amount of material required. Bare tube economizers may be considered following additional fuel analysis to reduce potential for ash buildup and soot-blowing requirements. Due to the lower working temperatures of the economizer elements, these will be fabricated of a stainless alloy to reduce overall project cost.

RPI anticipates no significant issues with the fabrication of the convective elements, though care will be taken to ensure welding procedures and heat treatment as adequate for the Inco 740H materials.

The furnace and backpass walls are CO_2 cooled, and will be the highest temperature components of the heater. Tube size and spacing has been selected to match known fabrication standards, but RPI has not fabricated membrane walls using Inco 740 materials. This will require additional development, to ensure the panels can be effectively welded without significant warping or cracking. Field welds for this material will be minimized, due to the strict welding requirements.

To improve overall efficiency and maximize radiant absorption, RPI is including platens in the upper section of the furnace. These platens are fully drainable and are on wide spacing to prevent issues with ash bridging due to the high metal temperatures, as well as maximizing the radiant exposure. RPI does not anticipate issues with fabrication of these elements.

Because of the relatively large volumetric flow rates require, large diameter piping for headers may be required to maintain the low target pressure drop. RPI currently plans to use Inco 740, though this is under review for possible cost reduction. The high pressures will require thick walls for all of these components, and fabrication and welding will need to be closely monitored for this material.

Energy Storage System

The electro-thermal energy storage (ETES) system is a new technology that EPS is developing in part through DOE ARPA-E funding. Many of the key components are commercially available or are derivatives of those developed for sCO_2 power cycles. EPS is presently designing a 10 MW_e, 8-hour ETES demonstration plant that is anticipated to be in operation in the 2022-time frame. This demonstration plant will provide significant risk abatement for the ETES system proposed here.

Charging system turbine

The turbine in the charging cycle is a hydraulic turbine, where the liquid "flashes" to vapor near the turbine exit. Although CO_2 turbines of this type are not commercially available, in the last 25 years, hydraulic turbines have been introduced into the natural gas liquification process and are regularly employed to improve the overall process efficiency[12]. Initial discussions with Ebara Turbine indicate that the charging system turbine is a relatively simple modification to their product line, thus reducing the risk for this component.

Generating system turbine

The turbine is a derivative of the sCO_2 power cycle turbines described above. The inlet temperature of 300°C is modest, allowing for low-cost materials of construction.

High temperature reservoir and heat exchangers

Three alternative reservoir and heat exchanger technologies are being developed for the ETES system. One, discussed below, is a commercial system. The non-commercial alternatives are described here.

One approach uses a stationary concrete thermal mass[13] as the thermal storage medium while using a much smaller quantity of HTF (Duratherm HF) as an intermediate medium between the CO_2 and concrete. As with the commercial approach, the heat exchanger between the HTF and CO_2 is a conventional PCHE. The concrete thermal masses include cast-in fluid passages, enabling direct-contact heat transfer between the HTF and concrete. The HTF tanks, pumps and controls are all commercially available components. EPS is partnered with Westinghouse Nuclear under ARPA-E program DE-AR0000996 to conduct design and techno-economic optimization of the concrete-based solution.

Another approach uses silica sand as both the heat transfer and storage medium. The storage containers would be conventional concrete silos or dome structures[14]. The sand transport process is a combination of conventional and high-temperature conveyors[15]. The heat exchanger between CO_2 and sand is planned to be either a moving-bed heat exchanger (MBHE)[16] or fluidized bed heat exchanger (FBHE)[17]. The MBHE is a commercially-available technology[18], although not at the pressures required for CO_2-based power cycles—however, development work on a CO_2-capable MBHE is underway under two DOE-funded

[12] Hans E Kimmel and Simon Cathery, "Thermo-Fluid Dynamics and Design of Liquid-Vapour Two-Phase LNG Expanders," in *Gas Processors Association-Europe, Technical Meeting, Advances in Process Equipment,* (Paris, France, 2010).

[13] Cory Stansbury, Energy storage device, US PTO US 2018/0372423 A1, filed May 15, 2018, and issued December 27, 2018.

[14] Benjamin Davis, "Holcim New Zealand Cement Terminal," *Shotcrete Mag.* 19, no. 1 (2017): 26–30.

[15] "The Magaldi Superbelt Conveyor | Magaldi Group," accessed January 9, 2020, https://www.magaldi.com/en/about-us/the-magaldi-superbelt-conveyor.

[16] Pedro Isaza, W. David Warnica, and Markus Bussmann, "Thermal Performance and Sizing of Moving Bed Heat Exchangers," in *ASME 2014 International Mechanical Engineering Congress and Exposition*, (Montreal, Quebec, Canada: American Society of Mechanical Engineers, 2014); Philipp Bartsch and Stefan Zunft, "Heat Transfer in Moving Bed Heat Exchangers for High Temperature Thermal Energy Storage," in *SOLARPACES 2016: International Conference on Concentrating Solar Power and Chemical Energy Systems* (Abu Dhabi, United Arab Emirates, 2017).

[17] K Schwaiger et al., "SandTES-A Novel Thermal Energy Storage System Based on Sand," in *21st International Conference on Fluidized Bed Combustion,* (Naples, Italy, 2012); Martin Haemmerle et al., "Saline Cavern Adiabatic Compressed Air Energy Storage Using Sand as Heat Storage Material," *Journal of Sustainable Development of Energy, Water and Environment Systems* 5, no. 1 (March 2017): 32–45.

[18] "Solex Thermal Sciences | Energy Efficient Heat Exchanger Technology," Solex Thermal Sciences, accessed January 9, 2020, https://www.solexthermal.com/.

programs, for CSP applications[19] and EPS's ETES program in partnership with Solex Thermal Sciences under DE-AR0000996. The FBHE is based on well-known heat transfer principles and design methods from fluidized bed combustion. EPS is also partnered with TU Wien on DE-AR0000996.

At the conclusion of the first phase of DE-AR0000996, scheduled for mid-year 2020, EPS will down-select between the concrete- and sand-based high-temperature reservoirs to test in their laboratory-scale (200 kW_{th}) ETES system. Following successful lab-scale testing in 2021, EPS plans to scale the high-temperature reservoir to the 10 MW_e demonstration plant for further design validation testing. The concrete/HTF system is inherently modular and thus freely scalable. The two sand solutions also are modular in nature, in that multiple heat exchangers in parallel are frequently employed in industrial applications.

Low-temperature reservoir (LTR) and heat exchangers

Similar to the high-temperature reservoir, EPS is evaluating two different LTR configurations, both using water-ice phase change as the reservoir material. The first, lower-risk approach is to use a stationary ice-on-coil thermal reservoir[20] with either direct heat transfer to and from CO_2 in embedded heat exchangers, or by using a separate HTF system to transfer heat between the LTR and CO_2. The second approach uses an ice slurry generator (ISG) to create a fluid ice/water mixture that can be stored in a separate tank and pumped similarly to a liquid up to approximately 30% ice fraction, which is the storage system design target[21]. The advantage of this approach is that the heat exchanger scaling is decoupled from the storage medium and containment, which improves the scalability of the LTR. ISGs are commercially available, but generally using conventional F-gas and similar refrigerants[22]. EPS is partnered with Liquid Ice Technologies, a commercial provider of ice slurry generators, to develop a prototype CO_2-based ISG as part of DE-AR0000996. A down-selection to the final configuration based on a full techno-economic analysis and the results of the ARPA-E program testing will be made in mid-2021.

Because the slurry formation process is different from the melting process, a separate low-temperature heat exchanger is used during the generating process. Provided that the ice particle size within the slurry is appropriately maintained, conventional plate-based heat exchangers can be used with slurries[23].

Commercial Components and Subsystems

Recuperators and CHX

These heat exchangers are all of the "Printed Circuit Heat Exchanger" (PCHE) type[24]. The developer and first supplier of PCHEs is Heatric, a division of Meggitt, who has supplied them to the oil and gas industry for over 40 years. Additional suppliers, such as Vacuum Products Engineering (VPE) and CompRex have recently entered the market, helping to diversify the supply chain and provide pricing

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[19] Clifford K Ho et al., "Evaluation of Alternative Designs for a High Temperature Particle-to-SCO_2 Heat Exchanger," in *Proceedings of the ASME 2018 12th International Conference on Energy Sustainability* (Lake Buena Vista, Florida, USA: ASME, 2018).

[20] Michael Rutberg et al., "Thermal Energy Storage," *ASHRAE Journal* 55, no. 6 (June 2013): 62--66.

[21] Michael Kauffeld, Masahiro Kawaji, and Peter W. Egolf, eds., *Handbook on Ice Slurries—Fundamentals and Engineering* (International Institute of Refrigeration, 2005)

[22] Michael Kauffeld and Sebastian Gund. 2019. "Ice Slurry – History, Current Technologies and Future Developments." *International Journal of Refrigeration* 99:264–271.

[23] Beat Frei and Tahsin Boyman, "Plate Heat Exchanger Operating with Ice Slurry," in *PCM.2003 Phase Change Material and Slurry, Scientific Conference and Business Forum*, (Yverdon, Switzerland, 2003).

[24] Renaud Le Pierres et al., "Impact of Mechanical Design Issues on Printed Circuit Heat Exchangers," in *Supercritical* CO_2 *Power Cycle Symposium* (Boulder, Colorado, 2011).

competition. EPS and others have used PCHEs from Heatric and VPE in sCO_2 power cycles at scales up to 10 MW_e. Heat exchangers of these types are extremely modular, and thus scalability is straightforward.

Materials, piping, tubing and valves

Extensive studies of material compatibility with CO_2 have been conducted by Oak Ridge National Laboratory (ORNL)[25], University of Wisconsin Madison (UWM)[26] and others[27]. EPS has direct contact with the researchers at these and other labs. In general, CO_2 does not create unique corrosion problems with most commonly used piping and heat exchanger materials in the temperature ranges they would normally be used due to their material strength and creep properties. At the highest temperatures used in this project (700-730°C), appropriate materials have been developed under the auspices of the Advanced Ultra Super-Critical (AUSC) steam development program[28] and their performance with CO_2 verified in ORNL testing.

A key remaining development activity is the qualification of Haynes 282 as a cast material for components such as valve bodies. This work is presently being performed under the STEP program[29]. EPS has discussed the use of the combined turbine throttle/stop valve with GE and has received a favorable response to extending their development work to this program.

Note that EPS has worked with Haynes and Special Metals on previous programs, including the use of Inconel 740H in the high-temperature sCO_2 heater developed under the DOE-funded TCES program, "sCO_2 Power Cycle with Integrated Thermochemical Energy Storage Using an MgO-Based sCO_2 Sorbent in Direct Contact with Working Fluid" (DE-EE0008126).

Fuel systems

RPI proposes using Atrita ® pulverizers. These are standard components and are widely used for smaller scale plants.

The firing system be designed with dual fuel burners, capable of achieving full load on pulverized coal and natural gas. These are standard RPI designs and are deployed in multiple existing utility boilers. These burners will provide fuel flexibility throughout the life of the unit.

RPI has extensive experience designing and supplying natural gas combustion systems, and will include a pressure regulating skid, as well as double block and bleed skids for each burner. The natural gas system will meet all standards, such as NFPA 85.

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[25] B.A. Pint, R.G. Brese, and J.R. Keiser, "Supercritical CO_2 Compatibility of Structural Alloys at 400°-750°C," in *NACE Corrosion 2016 Conference and Expo*, 2016; Bruce A. Pint, Kinga A. Unocic, and James R. Keiser, "Effect of Impurities on Supercritical CO_2 Compatibility," in *Proceedings of 3rd European Supercritical CO_2 Conference* (Paris, France, 2019).

[26] Jacob Mahaffey et al., "Effect of Oxygen Impurity on Corrosion in Supercritical CO_2 Environments," in *The 5th International Symposium - Supercritical* CO_2 *Power Cycles* (The 5th International Supercritical CO_2 Power Cycles Symposium, San Antonio, Texas, 2016); Kumar Sridharan et al., "Corrosion of Candidate Alloys in High Temperature Supercritical Carbon Dioxide," in *Supercritical* CO_2 *Power Cycle Symposium* (Boulder, Colorado, 2011).

[27] Julie D Tucker et al., "Supercritical CO_2 Round Robin Test Program," in *The 6th International Symposium - Supercritical CO_2 Power Cycles* (Pittsburgh, Pennsylvania, 2018).

[28] Paul S Weitzel, "A Steam Generator for 700 C to 760 C Advanced Ultra-Supercritical Design and Plant Arrangement: What Stays the Same and What Needs to Change," in *The Seventh International Conference on Advances in Materials Technology for Fossil Power Plants* (Waikoloa, Hawaii, 2013).

[29] Marion et al., "The STEP 10 MW_e SCO_2 Pilot Plant Demonstration," in *The 6th International Symposium - Supercritical CO_2 Power Cycles* (Pittsburgh, Pennsylvania, 2018).

Emissions control system

The emissions controls for this plant are conventional and are commercially available. RPI will supply the emission control system for this plant.

RPI is a leading supplier of SCR technology and has a wide install base on standard units. The design of this unit will meet all RPI standards for flue gas flows and temperatures and will utilize standard catalysts to achieve the target emissions.

RPI has multiple installed circulating dry scrubbers (CDS), across a range of boiler sizes. This unit will achieve the target emissions values, using a proven technology. As a Dry scrubber, all water injected into the system is converted to vapor, eliminating the need for slurry systems and other water handling equipment that would be seen on a traditional wet scrubber.

A fabric filter is an integral part of the CDS system. The operating conditions for the fabric filter are typical, and this equipment will be sourced from a well-known vendor such as Dustex or equivalent. Air slides will also be utilized for ash and byproduct recirculation. RPI has developed a pneumatic conveyor, which will be used to transport ash from the fabric filter to the CDS reactor.

CO_2 capture system

The PCC system for this plant is a commercial product from MHI, a partner in this program.

ETES components: Charging system compressor

The compressor is a key component of the charging heat pump cycle. The operating conditions are conventional for a non-intercooled industrial gas compressor, and several commercial suppliers can provide equipment that meets the specification requirements. At the approximately 30 MW_e power rating of this program, the compressor would likely be of the integrally-geared type [30]. Commercial suppliers of this type of compressor have indicated that single compressors of up to 50 MW_e are within the current range of their product line. EPS has had direct discussions with both Siemens and Hanwha for similar compressor applications

Generating system pump

The pump inlet conditions are subcritical, with a true liquid CO_2 phase. The operating conditions are well within the capability of commercial pump suppliers such as Sulzer and Flowserve, both of whom have provided quotations for EPS on similar projects.

Recuperator

The operating conditions for the recuperator are similar to those used in the sCO_2 power cycle—thus the same comments as provided in the previous section also apply here.

High temperature reservoir and heat exchangers

The lowest technical risk HTR is a two-tank system using a conventional heat transfer fluid (HTF, such as Duratherm HF, Therminol or DowTherm) as both the heat transfer and thermal storage medium. The heat exchanger for this system would be a conventional PCHE, similar to the recuperator and CHX heat exchangers described above. The storage containers are conventional insulated oil tanks. The capital expense of this approach is the highest of the three alternatives.

[30] Christian Wacker and René Dittmer, “Integrally Geared Compressors for Supercritical CO_2,” in *The 4th International Symposium - Supercritical* CO_2 *Power Cycles* (Pittsburgh, Pennsylvania, 2014).

6. Costing Methodology and Assumptions

Capital Cost Estimating Basis

Capital costs are reported in June 2019 dollars (base-year dollars) to put them on a consistent and up-to-date basis. Construction costs at the reference site were based on union labor.[31]

For cost-estimating purposes, the plants are generally assumed to be in a “mature” state of development meaning that no extra equipment or costs are included to account for unit malfunction or extra equipment outages.

As illustrated in Figure 21, this study will report capital cost at four levels: Bare Erected Cost (BEC), Total Plant Cost (TPC), Total Overnight Cost (TOC), and Total As-spent Capital (TASC). BEC, TPC, and TOC are “overnight” costs and are expressed in “base-year” dollars. The base year is the first year of capital expenditure, which for this study is 2019. TASC is expressed in mixed-year, current-year dollars over the entire capital expenditure period, which is assumed to last five years for coal plants (2019 to 2023).

BEC comprises the cost of delivered process equipment, on-site facilities, and infrastructure that support the plant (e.g., shops, offices, labs, roads), and the direct and indirect labor required for its construction and/or installation. The cost of engineering, procurement, and construction (EPC) services and contingencies are not included in BEC. BEC is an overnight cost expressed in base-year dollars.

TPC comprises the BEC plus the cost of services provided by the EPC contractor and project and process contingencies. EPC services include: detailed design, contractor permitting (i.e., permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included), and project/construction management costs. TPC is an overnight cost expressed in base-year dollars.

TOC comprises the TPC plus owner’s costs. TOC is an “overnight” cost, expressed in base-year dollars and as such does not include escalation during construction or interest during construction. TOC is an overnight cost expressed in base-year dollars. TOC is calculated using a on TPC. The multiplier used for this study was 1.21. This multiplier was calculated using the methodology described in Table 29 to calculate the owners cost for the plant. It was found to be the same across all cases considered in this study.

TASC is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction. Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period. TASC is also calculated using a simple multiplier, this time on TOC. The multiplier of 1.154 used for this study was taken from U.S. Department of Energy (DOE) / National Energy Technology Laboratory (NETL) guidelines for five-year construction projects.[32]

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[31] NETL economic studies typically assume non-union labor rates. Union labor rates were chosen to better match up with conditions in 2019 and based on other studies performed by EPRI.

[32] “Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance,” NETL-PUB-22580, September 2019.

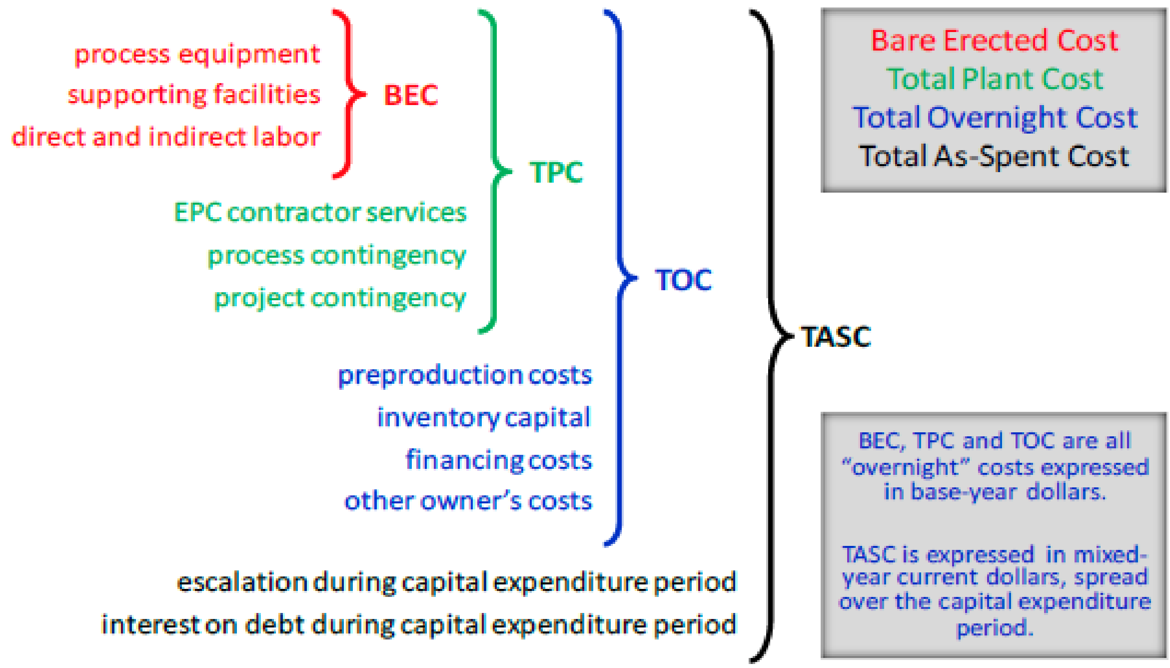

Figure 21 Capital Cost Levels and Their Elements

Cost Estimate Classification

The capital cost estimate completed for this study is consistent with DOE/NETL QGESS guidelines[32] and is classified as a Class 4 cost estimate. The accuracy range for a Class 4 estimates is -15% on the low side, and +30% on the high side. Table 27 describes the characteristics of an Association for the Advancement of Cost Engineering (AACE) Class 4 Cost Estimate.[33]

Table 27 DOE/NETL QGESS Class 4 Cost Estimate Description

Estimate Class	**Degree of Project Definition** % of complete definition	**End Usage** Purpose of Estimate	**Methodology** Typical Estimating Method	**Expected Accuracy Range** Typical variation in low and high ranges
Class 4	1% - 15%	Study or Feasibility	Equipment factored or parametric models	-15% - 30%

System Code of Accounts

The costs are grouped according to a process/system-oriented code of accounts. Consistent with other DOE/NETL economic studies, 14 accounts are used for the power plant plus one additional account (15) for the energy storage system. Note, because this is a supercritical CO_2 (sCO_2) power cycle, Account 8 has been modified to account for the differences between a steam and sCO_2 power cycle. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process, so they are included in the specific system account. In addition, each code of account is further broken down into major equipment cost, material cost, and labor cost. Labor cost includes both direct and indirect costs.

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[33] "Cost Estimate Classification System – As Applied In Engineering, Procurement, and Construction for the Process Industries," AACE International Recommended Practice No. 18R-97.

Plant Maturity

Cost estimates in this report reflect the cost of the next commercial offering for plants that include technologies that are not yet fully mature and/or which have not yet been deployed in a commercial context. These cost estimates for next commercial offerings do not include the unique cost premiums associated with first-of-a-kind plants that must demonstrate emerging technologies and resolve the cost and performance challenges associated with initial iterations. However, these estimates do utilize currently available cost bases for emerging technologies.

Contracting Strategy

The estimates are based on an EPC approach utilizing multiple subcontracts. This approach provides the owner with greater control of the project, while minimizing, if not eliminating, most of the risk premiums typically included in an EPC contract price.

In a traditional lump sum EPC contract, the contractor assumes all risk for performance, schedule, and cost. However, as a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. Rather, the current trend appears to be a modified EPC approach, where much of the risk remains with the owner. Where contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

This approach is anticipated to be the most cost-effective approach for the owner. While the owner retains the risks, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Battery Limits for Capital Cost Estimate

The estimates represent a complete power plant facility on a generic site located in the Midwestern U.S. The plant boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system but terminating at the high-voltage side of the main power transformers. Coal transportation cost is not included in the reported capital or operations and maintenance (O&M) costs (storage and coal handling maintenance are, however). CO_2 transport and storage (T&S) cost is also not included in the costs for the cases that capture CO_2 but is treated separately and added to the cost of electricity (COE) by adding \$10/tonne-CO_2.

Labor Rates

The all-in union construction craft labor rate for the generic Midwestern U.S. site is assumed to be \$81.28/hour[34]. This rate is based on EPRI's Technical Assessment Guide[35].

The estimates are based on a competitive bidding environment with adequate skilled craft labor available locally. Labor is based on a 50-hour work week (five x 10-hour days).

[34] "High-Efficiency Thermal Integration of Closed Supercritical CO_2 Brayton Power Cycles with Oxy-Fired Heaters", DE-FE002595, 2018

[35] "Technical Assessment Guide (TAG®) for Power Generation and Storage Technologies; 2016 Topics". EPRI, Palo Alto, CA: 2016. 3002008947.

Exclusions

The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (engineering and construction management), and contingency. The following items are excluded from the capital costs:

- All taxes except for payroll and property
- Site specific considerations – including, but not limited to, seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.
- Labor incentives
- Additional premiums associated with an EPC contracting approach.

Contingency

Process and project contingencies are included in estimates to account for unknown costs that are omitted or unforeseen due to a lack of complete project definition and engineering. Contingencies are added because experience has shown that such costs are likely, and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared. Capital cost contingencies do not cover uncertainties or risks associated with:

- Changes in labor availability or productivity
- Changes in regulatory requirements
- Delays in equipment deliveries
- Performance of the plant after startup (e.g., availability and efficiency)
- Scope changes
- Unexpected cost escalation.

Process Contingency

Process contingency is intended to compensate for uncertainty in costs caused by performance uncertainties associated with the development status of a technology. Process contingency is applied to each component based on its current technology status. The majority of the proposed plant is made up of commercially available systems and equipment that is in use commercially. For all of these plant sections 0% process contingency is applied to the bare erected costs (BEC). However, several systems are presently under development and have not been commercially deployed at full scale and as such process contingencies have applied. These are summarized in Table 28.

Table 28 Process Contingency as Applied to Plant Cost Categories

Plant System or Equipment	Process Contingency (% of Bare Erected Costs)
(4.1) Fired heater furnace and radiant platens, convective and economizer elements, air preheaters, dry ash system, soot blowers, heater intimate steel	10
(8B.1 & 8B.4) sCO_2 Power Cycle Turbomachinery	15
(15.1) ETES Generating and Charging Systems	15
(15.2) ETES Storage Systems	20

Project Contingency

Project contingencies were added to each capital account to cover project uncertainties and the cost of additional equipment that would be identified in a detailed design. The project contingencies represent costs that are expected to occur but were not identified in the individual cost accounts. The project contingencies are applied to the BEC, engineering fees, and process contingencies. The project contingencies used for each individual cost account in the NETL Case B12B[36] were also used for the proposed plant. These contingencies ranged from 10–20%. For new equipment, the contingencies were either set to 15% or based on the contingency used in DOE Case B12B for similar equipment. The total project contingency for this was 13.3% - slightly less than the total project contingency of the NETL supercritical PC Case B12B (13.9%).

Owner's Costs

Owner's costs include:

- Initial cost for catalyst and chemicals
- Inventory capital (fuel storage, consumables, etc.)
- Land
- Prepaid royalties or license fees
- Preproduction (or startup) costs. For this plant, the initial fill of CO_2 is considered as part of the startup costs and is factored into the TPC to TOC multiplier.

Royalty charges or license fees may apply to some portions of generating units incorporating new technologies. If known, royalty charges must be included in the capital requirement.

Preproduction costs cover operator training, equipment checkout, major changes in unit equipment, extra maintenance, and inefficient use of fuel and other materials during startup. For this project's purposes, pre-production costs were estimated as follows:

- One month fixed operating costs (O&M labor, administrative and support labor, and maintenance materials). In some cases, this could be as high as two years of fixed operating costs due to new staff being hired two years before commissioning.
- One to three months of variable operating costs (consumables) at full capacity, excluding fuel. (These variable operating costs include chemicals, water, and other consumables plus waste disposal charges.)
- 25% of full-capacity fuel cost for one month. This charge covers inefficient operation that occurs during the startup period.
- 2% of TPC. This charge covers expected changes and modifications to equipment that will be needed to bring the unit up to full capacity.

The following should be included:

- Value of inventories of fuels, consumables, and by-products was capitalized
- An allowance for spare parts of 0.5% of the TPC

[36] "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity," NETL-PUB-22638, September 2019.

- The initial cost of any catalyst or chemicals contained in the process equipment (but not in storage, which is covered in inventory capital)
- A nominal cost of $7413/hectare ($3000/acre) for land.

Table 29 summarizes the procedure for estimating owner's costs. The methodology is defined by the U.S. Department of Energy (DOE) / National Energy Technology Laboratory (NETL) guidelines[37] and mostly follows the guidelines from Sections 12.4.7 to 12.4.12 of AACE International Recommended Practice No. 16R-90.[38]

Table 29 Estimation Method for Owner's Costs

Owner's Cost	Estimate Basis
Prepaid Royalties	Any technology royalties are assumed to be included in the associated equipment cost, and thus are not included as an owner's cost.
Preproduction (Start-Up) Costs	• 6 months operating labor • 1-month maintenance materials at full capacity • 1-month non-fuel consumables at full capacity • 1-month waste disposal • 25% of one month's fuel cost at full capacity • 2% of TPC. Compared to AACE 16R-90, this includes additional costs for operating labor (6 months vs. 1 month) to cover the cost of training the plant operators, including their participation in startup, and involving them occasionally during the design and construction.
Working Capital	Although inventory capital is accounted for, no additional costs are included for working capital.
Inventory Capital	• 0.5% of TPC for spare parts • 60-day supply (at full capacity) of fuel. Not applicable for natural gas (NG). • 60-day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site. Does not include catalysts and adsorbents that are batch replacements such as water-gas shift, carbonyl sulfide, and selective catalytic reduction catalysts and activated carbon. AACE 16R-90 does not include an inventory cost for fuel.
Land	• $3000/acre (300 acres for coal; 100 acres for NG) • Note: This land cost is based on a site in a rural location.
Financing Cost	• 2.7% of TPC This financing cost (not included by AACE 16R-90) covers the cost of securing financing, including fees and closing costs but not including interest during construction (or Allowance for Funds Used During Construction). The "rule of thumb" estimate (2.7% of TPC) is based on a communication with Black & Veatch.

[37] "Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance," NETL-PUB-22580, September 2019

[38] "Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries," AACE International Recommended Practice No. 16R-90, 1991.

Other Owner's Costs	• 15% of TPC This additional lumped cost is not included by AACE 16R-90. The "rule of thumb" estimate (15% of TPC) is based on a communication with Black & Veatch. The lumped cost includes: • Preliminary feasibility studies, including a front-end engineering design study • Economic development (costs for incentivizing local collaboration and support) • Construction and/or improvement of roads and/or railroad spurs outside of site boundary • Legal fees • Permitting costs • Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors) • Owner's contingency (sometimes called "management reserve" — these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, and unplanned labor incentives in excess of a five-day/ten-hour-per-day work week. Owner's contingency is not a part of project contingency) This lumped cost does not include: • EPC risk premiums (costs estimates are based on an EPC Management approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule, and cost) • Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar • Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes • Unusual site improvements: normal costs associated with improvements to the plant site are included in the BEC, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, and noise regulations.

O&M Costs

O&M costs are to be estimated for a year of normal operation and presented in the base-year dollars. O&M costs for a generating unit are generally allocated as fixed and variable O&M costs.

Fixed O&M costs are essentially independent of actual capacity factor, number of hours of operation, or number of kilowatts produced, and are expressed in $/kW-year. Fixed O&M costs are composed of the following components:

- Operating labor
- Total maintenance costs (may also have a variable component)
- Overhead charges.

Taxes and insurance are considered as fixed O&M costs and are estimated as 2% of the TPC.

Variable O&M costs and consumables are directly proportional to the number of kilowatts produced or tonnes of CO_2 captured. They are generally in mills/kW-hour.

The estimation of these cost components is discussed below.

Operating Labor

Operating labor is based on the number of personnel required to operate the plant per shift. The total operating cost is based on the labor rate, supervision, and overhead. For this study, a fully loaded cost of $213,500 per person per year was assumed.

Total Maintenance Costs

Annual maintenance costs for the plant are estimated as a percentage of the TPC of the facilities for this study it was 2% of the TPC. Estimates are expressed separately as maintenance labor and maintenance materials. A maintenance labor-to-materials ratio of 40% labor cost and 60% material cost was used for this breakdown.

Overhead Charges

The only overhead charge included in this study is a charge for administrative and support labor, which is taken as 30% of the O&M labor.

Consumables

Consumables are the principal components of variable O&M costs. These include water, catalysts, chemicals, solid waste disposal, and other materials that are consumed in proportion to energy output. Costs for consumable items are shown in Table 30.

Table 30 Cost Data for Consumable Items

Consumables and Variable Cost Items	Unit Cost
H_2O and Chemicals	
Raw Water, $/1000 liters	0.45
Ammonia (aqueous 29.4% weight), $/tonne	194
Sorbent (Delivered)	
Lime, $/tonne	155
Limestone, $/tonne	45
Dry Disposal	
Bottom and Fly Ash, $/tonne	15
Other	
Activated Carbon, $/tonne	1455

Financial Structure Section

The financial structure for this study was based on a 5-year capital expenditure period, as specified in the DOE/NETL guidelines.[39] The financial structure for is shown in Table 31.

[39] "Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance," NETL-PUB-22580, September 2019.

Table 31 Nominal and Real Rates Financial Structure for Investor-Owned Utility

Type of Security	% of Total	Current-Dollar Cost	Weighted Average Cost of Capital	After-Tax Weighted Average Cost of Capital
Nominal				
Debt	55%	5%	2.75%	2.04%
Equity	45%	10%	4.50%	4.50%
Total			7.25%	6.54%
Real (based on 2.01% average real Gross Domestic Product deflator, 1990–2018[40])				
Debt	55%	2.94%	1.61%	1.20%
Equity	45%	7.84%	3.53%	3.53%
Total			5.14%	4.73%

Global Economic Assumptions

Table 32 summarizes the global economic assumptions that were used for evaluating the economic performances of the cases in this study. The assumptions are specified in the DOE/NETL guidelines.

Table 32 Global Economic Assumptions

Parameter	Value
Taxes	
Income Tax Rates	21% federal, 6% state (effective tax rate of 25.74%)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
Contracting and Financing Terms	
Contracting Strategy	EPC Management (owner assumes project risks for performance, schedule, and cost)
Type of Debt Financing	Non-recourse (collateral that secures debt is limited to the real assets of the project)
Repayment Term of Debt	Equal to operational period in formula method
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Analysis Time Periods	
Capital Expenditure Period	NG plants: 3 years; Coal plants: 5 years
Operational Period	30 years
Economic Analysis Period	33 or 35 years (capital expenditure period plus operational period)
Treatment of Capital Costs	
Capital Cost Escalation During Capital	0% real (3% nominal)

[40] "Real Gross Domestic Product [GDPC1]," U.S. Bureau of Economic Analysis, Federal Reserve Bank of St Louis. https://fred.stlouisfed.org/series/GDPC1/.

Expenditure Period	
Distribution of Total Overnight Capital over the Capital Expenditure (before escalation)	5-year period: 10%, 30%, 25%, 20%, 15%
Working Capital	Zero for all parameters
% of Total Overnight Capital Depreciated	100% (actual amounts are likely lower and do not influence results significantly)
Escalation of Operating Costs and Revenues	
Escalation of COE (revenue), O&M Costs	0% real (3% nominal)[41]
Fuel Costs[42]	Natural Gas (Reference Case) – \$15.08/MWh Coal (Midwest PRB) – \$42.12/tonne

Levelized Cost of Electricity

The cost metric used in this report is the levelized cost of electricity (LCOE) reported in real 2018 dollars, which is the revenue that must be received by the generator per net MWh produced to meet the desired return on equity after meeting all debt and tax obligations and operating expenses.

The approach used to calculate the LCOE is described below.

Estimating LCOE Using Formulas

The following simplified equation can be used to estimate COE as a function of TASC, fixed O&M, variable O&M, fuel costs, capacity factor, and net output. The equation requires the application of fixed charge rates (FCR), which are based on the capital recovery factors (CRF). These FCRs and CRFs are valid only for scenarios that adhere to the global economic assumptions listed in Table 32 and utilize the stated finance structure listed in Table 31 and the stated capital expenditure period. The formulas for calculating FCR and CRF values based on other assumptions are shown below in the equations below. The formulas for calculating the FCR values include an adjustment to the CRF value to account for depreciation.:

$$LCOE = [(FCR)(TASC) + OC_{FIX} + (CF)\ OC_{VAR}] / (CF)\ (MWh)$$

where:

- LCOE = revenue received by the generator (\$/MWh) during the power plant's first year of operation (expressed in 2019 dollars), if the LCOE escalates at a nominal annual rate equal to the general inflation rate; i.e., that it remains constant in real terms over the operational period of the power plant
- FCR = fixed charge rate based on CRF values that matches the finance structure and capital expenditure period. The interest rate used in the formula must by necessity be the after tax weighted average cost of capital

[41] "The Handy-Whitman Index of Public Utility Construction Costs, 1912 to January 1, 2018," Whitman, Requardt & Associates, LLP, 2018.

[42] "Quality Guidelines for Energy Systems Studies Fuel Prices for Selected Feedstocks in NETL Studies," NETL-PUB-22458, Januaury 2019.

- TASC = total as spent capital expressed in on-line year cost in 2019 dollars
- OC_{FIX} = the sum of all fixed annual operating costs in 2019 dollars
- OC_{VAR} = the sum of all variable annual operating costs, including fuel at 100% capacity factor, in 2019 dollars
- CF = plant capacity factor, assumed to be constant over the operational period, for this study a CF = 0.85 was assumed
- MWh = annual net megawatt-hours of power generated at 100% capacity factor.

Based on the economic factors specified by the DOE, the FCR for a five-year capital expenditure period is 0.0707.

Cost of CO_2 Captured and Avoided

The cost of CO_2 captured was calculated both from the standpoint of the cost of CO_2 removed and the cost of CO_2 avoided.

The cost of CO_2 captured or removed in $/tonne is given by:

$$\text{Cost of } CO_2 \text{ Captured} = (LCOE_{\text{with removal}} - LCOE_{\text{w/o removal}}) / (CO_2 \text{ Captured})$$

where:

- LCOE = cost of electricity ($/$MWh_{net}$)
- CO_2 Captured = CO_2 captured for case (tonnes/MWh_{net})

Note that for cost of CO_2 captured, the LCOE does not include the cost of CO_2 T&S.

The equation used to calculate the cost of CO_2 avoided in $/ton or $/tonne is given by:

- $\text{Cost of } CO_2 \text{ Avoided} = (LCOE_{\text{with removal}} - LCOE_{\text{w/o removal}}) / (CO_{2\text{w/o removal}} - CO_{2\text{with removal}})$

where:

- LCOE = cost of electricity ($/$MWh_{net}$)
- CO_2 = CO_2 emissions for case (tonnes/MWh_{net}). Note The difference in CO_2 emissions (with removal or without removal) is not equal to CO_2 captured (previously defined) since the addition of CO_2 capture technology may increase CO_2 generation (if gross power generation is increased) and/or may reduce MWh_{net} (if gross generation is not increased to maintain net power generation).

Costs of CO_2 Transport and Storage

The cost of CO_2 T&S is included in the LCOE to derive the complete cost of capturing and storing CO_2. The updated DOE Bituminous Baseline Report[36] specified the conditions and T&S costs to be used for DOE system studies. The costs are based on transporting high-pressure (15.17 MPa) CO_2 from the power plant through a 100-km pipeline to the sequestration or enhanced oil recovery site. The CO_2 leaves the pipeline at a pressure of 8.27 MPa still in a supercritical state. For the Midwest location used for this study, the T&S value specified by DOE is $10/tonne-$CO_2$.

Levelized Cost of Storage

To quantify the value of storage and compare different electrical storage technologies, "Levelized Cost of Storage" (LCOS) is used. This calculated system parameter combines the economic costs of storing and later generating electrical energy. There are several formulas that can be used to calculate LCOS. For this study, following LCOS equation was used[43]:

$$LCOS = \frac{I_0 + \sum_{t=1}^{n} \frac{C_{ESS_t}}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_{ESS_t}}{(1+r)^t}}$$

where

I_0	Initial investment cost
C_{ESS}	Total annual cost, year t
E_{ESS}	Total net energy produced, year t
r	Discount rate (assumed 10%)
t	Year
n	Plant life (assumed 30 years)

Initial investment cost is calculated as:

I_0=Generation system cost ($/kW) + Capacity cost ($/kWh) + BOP ($/kW) + Installation ($/kW)

These costs are summarized in item 15 (ETES System) in Table 37. The generation system cost, balance-of-plant (BOP), and installation costs are shown in 15.1, 15.3, and 15.4. The Capacity (storage) costs are shown in line 15.2. Note that "Capacity cost" is evaluated in terms of the electrical output ($/kW$_e$), rather than thermal energy stored ($/kW$_{th}$).

The total annual energy produced (E_{ESS}) is calculated assuming a generating duty cycle of 33% (8 hours per day)—the fraction of time the system is operating in generating mode. The Depth-of-Discharge (DoD) for ETES systems is 1. Other technologies, such as lithium ion systems are limited to 80% due to the impact of high DoD values on battery life.

E_{ESS}=Power output (kW) · Duty cycle · 8760 hrs/yr · DoD

The total annual cost is calculated as:

C_{ESS}=Net electricity cost + O&M cost

Electricity cost is the electrical power used to charge the system during the assumed annual usage profile, which is calculated as function of E_{ESS}, round-trip-efficiency (RTE), and purchased price of power:

Net electricity cost = E_{ESS} (kWh) · (1 - 1/RTE) · purchased price of power ($/kWh)

For electricity cost, $0.025/kWh was assumed, which is consistent with the ARPA-E DAYS[44] program assumptions, and roughly consistent with the median EIA wholesale price of electricity for 2017, implicitly assuming utility-scale plants would be operated by utilities. This assumption does <u>not</u> take advantage of negative pricing as seen in the California ISO markets during high solar PV production periods.

7. Economic Analysis

This section provides details on how the specific costs were estimated for the plant and highlights key components with individual cost estimates for: fired heater, post-combustion capture system (PCC),

[43] Lai, C. S., and McCulloch, M. D., 2017, "Levelized Cost of Energy for PV and Grid Scale Energy Storage Systems," Appl. Energy, **190**(C), pp. 191–203.

[44] "Duration Addition to Electricity Storage (DAYS)," Funding opportunity DE-FOA-0001906, May 2018.

sCO_2 power cycle, and electrothermal energy storage (ETES) system. Based on equipment and system data provided by the team, CDMS developed a cost estimate for plant installation, piping, foundations, and balance-of-plant (BOP) equipment. EPS provided equipment cost estimates for the sCO_2 power cycle and ETES systems. RPI provided equipment costs for the fired heater, fuel system, and air quality control system (AQCS). MHI provided installed cost estimates for the PCC system. These descriptions are followed by the presentation of the capital and O&M costs for the plant along with LCOE, and CO_2 captured and avoided costs.

Fired Heater and Air Quality Control System

Details on the cost estimates provided by RPI for the fired heater (air-fired pulverized coal heater) and its associated air quality control systems (AQCS) are given in this section. RPI developed a heat-and-mass balance for the fired heater and AQCS and subsequently designed them for this plant. A conceptual layout, shown in Figure 22 and Figure *23,* was developed to support the equipment and installation cost estimate. A summary of the costs and the corresponding bases are shown in Table 33.

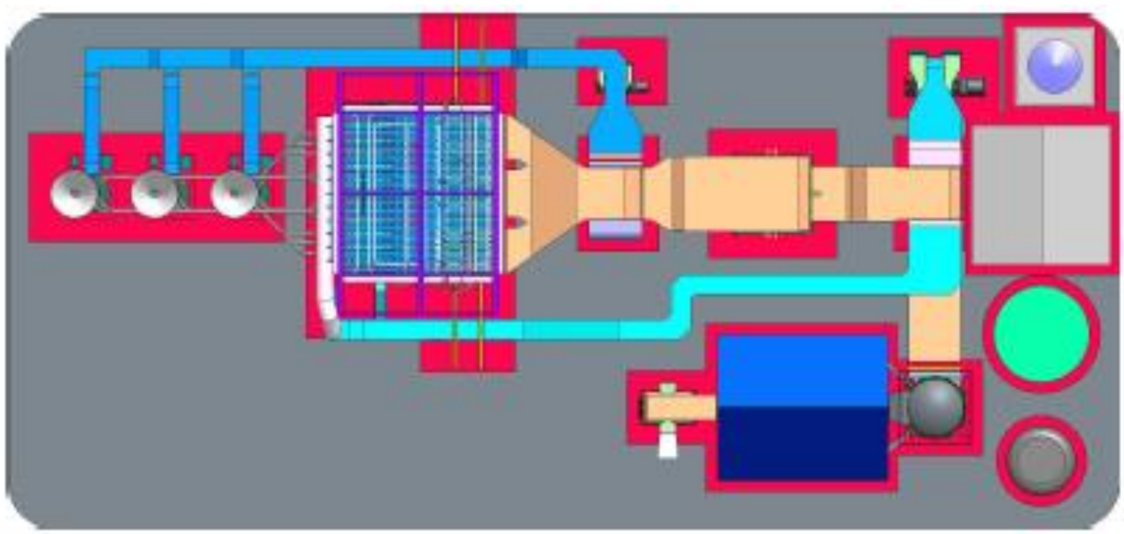

Figure 22 Conceptual Layout of RPI's Air Fired Heater and AQCS Equipment – Top-Down View for layout

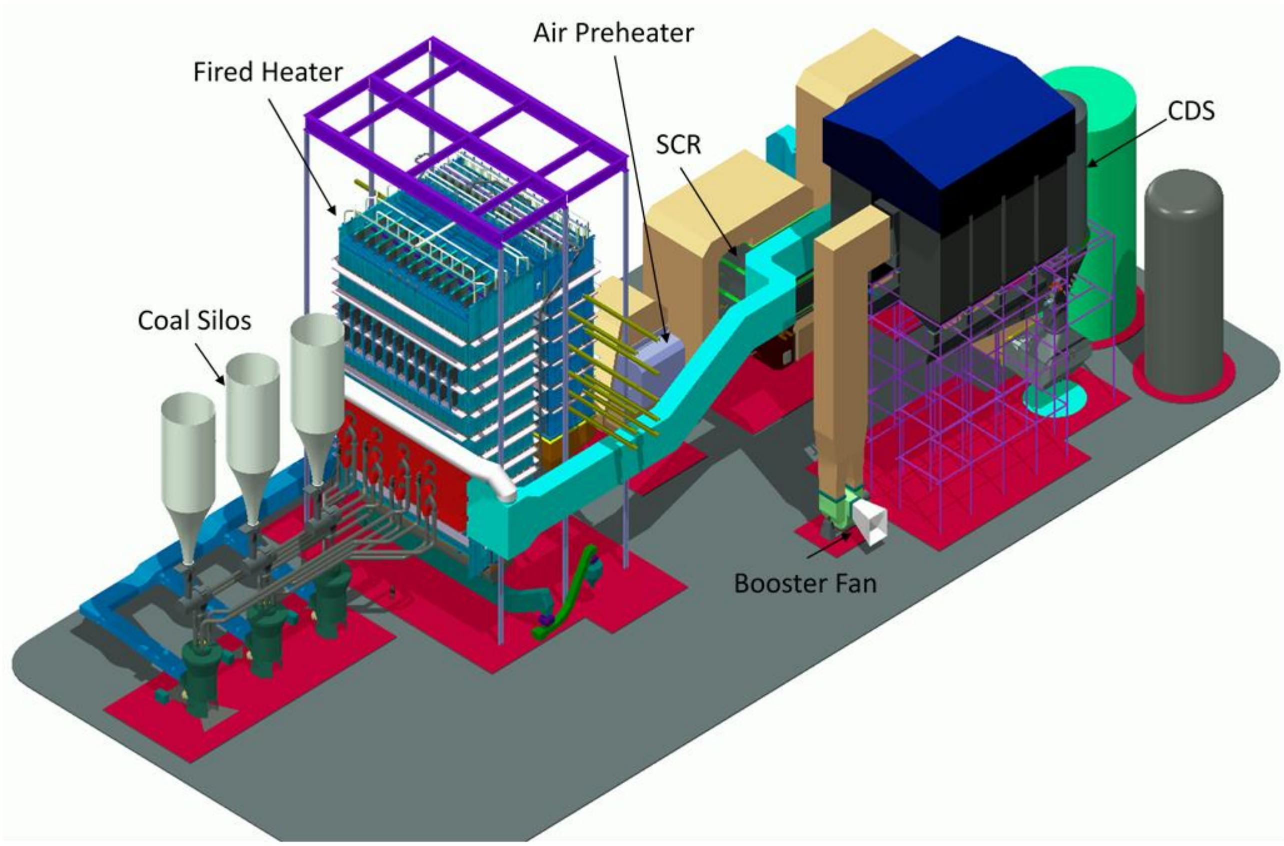

Figure 23 RPI's, Fired Heater and AQCS Conceptual 3D Arrangement - Circulating Dry Scrubber (CDS), Selective Catalytic Reduction (SCR)

Table 33 RPI's Fired Heater and AQCS Cost Summary

Major Equipment	Subsystems	Cost Basis	Cost ($)
Fired Heater	Furnace and Radiant Platens	Scaling from similar equipment	177,875,500
	Convective Elements	Scaling from similar equipment	
	Economizer Elements	Scaling from similar equipment	
	Hot and Cold Air Preheaters	Scaling from similar equipment	
	Dry Ash System	Budget quotation	
	Sootblowers	In house allowance	
	Heater and Intimate Steel	In house take off and unit pricing	
Fuel System	Coal Feeders	Scaling from similar equipment	10,011,100
	Coal Mills	Scaling from similar equipment	
	Coal Pipe	In house take off and unit pricing	

	Burners	Scaling from similar equipment	
	Natural Gas Skids	Scaling from similar equipment	
Selective Catalytic Reactor	SCR Casing	In house take off and unit pricing	4,788,600
	Catalyst	Scaling from similar equipment	
	Ammonia System	Scaling from similar equipment	
Circulating Dry Scrubber	Scrubber Vessel	In house take off and unit pricing	8,770,600
	Lime System	Scaling from similar equipment	
	Water System	Scaling from similar equipment	
	Air System	Scaling from similar equipment	
	Air Slide - Product Recirculation	In house take off and unit pricing	
Pulse Jet Fabric Filter		Scaling from similar equipment	5,881,100
Instrument and Controls		In house allowance	1,414,800
Fans	Forced Draft Fan	Scaling from similar equipment	3,233,000
	Primary Air Fan	Scaling from similar equipment	
	Induced Draft Fan	Scaling from similar equipment	
Ductwork	Combustion Air	In house take off and unit pricing	6,332,000

PCC System

MHI provided capital cost estimates for the PCC system. These estimates assume a turn-key delivery of MHI's complete scope of supply and are consistent with an AACE Class 4 estimation. MHI's scope of supply ends at the breaching interface to the induced draft fan, the outlet of the CO_2 compressor discharge cooler and the tie points to their required plant utilities. The scope of supply includes the following:

1. KM CDR Process™ license
2. Engineering
3. Procurement
    a. Mechanical Equipment
    b. Piping
    c. Instrumentation
    d. Electric
    e. Structural Assemblies
    f. Process
        i. KS-1™ Solvent (initial fill through end of commissioning)
        ii. Catalyst/Chemicals
        iii. Laboratory Equipment
4. Logistics and Transportation
5. Site Construction
6. Start-up Spares
7. Commissioning Support

8. EPC Indirects

Excluded from the capital costs are any atypical site preparation (e.g. removal of existing obstructions and foundations) and owners costs (e.g. land, engineering studies, delivery of utilities to CO_2 capture plant boundary, permitting, etc.). A summary of the costs provided by MHI is shown in Table 27. Note the CO_2 compression unit costs include the hydrogen generation unit, low-pressure/high-pressure compressor, low-pressure compressor discharge cooler, CO_2 compressor discharge cooler, piping, CO_2 gas cooling unit, and the dehydration unit.

To support the plant design and layout a 2-D layout was developed by MHI, shown in Figure 24.

Table 34 PCC and Compression System Cost Summary

System Description	Cost Basis	Estimated Cost ($)
CO_2 Capture Unit	Equipment factored and similar equipment	135,000,000
CO_2 Compression Unit	Equipment factored and similar equipment	30,000,000
Total		165,000,000

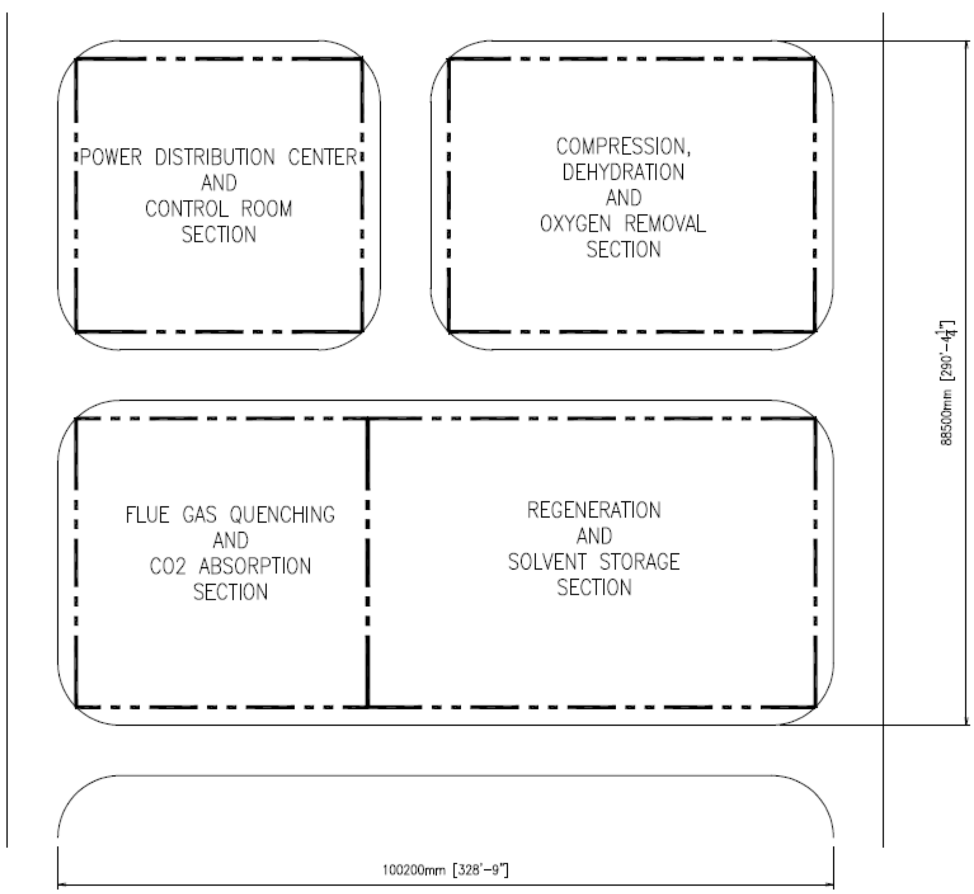

Figure 24 MHI, Layout and Footprint for PCC System

sCO_2 Power Cycle

Details on the cost estimates provided by EPS for the sCO_2 power cycle are provided in this section. Note that a special Account 8B was created to capture the sCO_2 power cycle costs as the system has intrinsic differences from a steam-Rankine power cycle and hence required a different set of sub-accounts as presented in Table 37.

Turbomachinery Costs
Power turbine, drive turbines, and compressor costs are based on EPS cost models. Budgetary estimates for turbines and compressors ranging in shaft power from 3 MW to 750 MW with turbine inlet temperatures up to 730°C are used as the basis for the models and estimate.

Recuperator Costs
Both the high and low temperature recuperator are printed circuit heat exchangers. Cost models for these are based budgetary on estimates provided to EPS by Vacuum Process Engineering in support of an EPRI led DOE study on the integration of sCO_2 power cycles with advanced coal combustion.[34] Costs are scaled with the overall thermal conductance (UA) of the heat exchanger. Design differences between the high and low temperature recuperators are considered and costs per UA is adjusted based on temperature conditions.

Air Cooled Condenser
The air-cooled condenser (ACC) is finned tube type heat exchanger. ACC costs are also scaled with UA. The cost model is based on budgetary quotes for ACCs with UA's in the range of 11.7 MW/°C to 81.7 MW/°C. The UA of the ACC used in the proposed design is 16.3 MW/°C.

The CO_2 inventory control system cost is included in cost category 8.6B along with foundations and utility racks. All other cost categories are self-explanatory. Table 35 shows the major equipment cost summary for the sO2 power cycle.

Table 35 sCO_2 Power Cycle Major Equipment Cost Summary

<table>
<tr><th>Equipment</th><th>Cost ($K)</th><th>Basis</th></tr>
<tr><td>Low Temperature Compressor</td><td>7,839.4</td><td>EPS Turbine Driven Compressor Cost Models</td></tr>
<tr><td>High Temperature Compressor</td><td>11,200.8</td><td>EPS Turbine Driven Compressor Cost Models</td></tr>
<tr><td>Power Turbine</td><td>15,694.7</td><td>EPS axial turbine costs models - Based on supplier budget quotes (15-720 MW shaft power)</td></tr>
<tr><td>High Temperature Recuperator</td><td>15,109.7</td><td rowspan="2">EPS Cost Models - Based on supplier budget quote for utility scale recuperators (90 MW_e plant)</td></tr>
<tr><td>Low Temperature Recuperator</td><td>7,662.0</td></tr>
<tr><td>ACC</td><td>4,282.8</td><td>EPS Cost Models</td></tr>
</table>

ETES System

ETES equipment costs were scaled using EPS cost models for sCO_2 equipment (turbomachinery and heat exchangers) and supplier data for the hot and cold thermal storage.

Balance of Plant and Installation Costs

CDMS developed a conceptual plant layout based on equipment information (geometric sizes and weights) provided by EPS, MHI, and RPI. This layout is shown in Figure 25 and was used as the basis for estimating material, labor, and installation costs for the plant. The full-asize print is attached in Section 9 Plant Layout / Plot Plant. Note that MHI provided costs for a turn-key installation of their scope so CDMS only carried the footprint in the site layout.

Coal Handling Equipment Cost Basis
Costs are based on Stock Equipment Company budget estimates for the equipment depicted on the layout. Installation costs are based on the estimated support bents and pits for the system, as well as a factored equipment cost.

Feedwater and BOP Systems
Based on Kansas City Deaerator and Flowserve pump budget quotation from a previous project then scaled for the heat recovery steam generator (HRSG) flow requirements. Cranes and compressed air equipment, as well as piping based on estimating software and conceptual material takeoffs. Fire water tank are based on a budget estimate from Advance Tank.

Fired Heater and Accessories
Foundations and steel costs are based on the layout lineal feet (LF), volumes, and density assumptions. The installation cost is based on a budget estimate from Babcock and Wilcox Construction Co. for a similarly sized coal-fired boiler and AQCS equipment. Electrical costs are based on estimating software and conceptual material takeoffs.

Gas Fired Generator / HRSG
Costs are based on budgetary estimates from Solar Turbines and Victory Energy.

sCO_2 Power Cycle
Piping costs are based on estimating software and conceptual material takeoffs. Foundations and steel costs are based on the layout LF, volumes, and density assumptions. The installation cost is based on person-hour estimates. Electrical costs are based on estimating software and conceptual material takeoffs.

Cooling Tower
Costs are based on EvapTech and Flowserve budgetary estimates. Foundations and steel costs are based on the layout LF, volumes, and density assumptions. Electrical costs are based on estimating software and conceptual material takeoffs.

Ash Systems
Costs are based on budgetary estimates provided by Tank Connection. Installation costs are based on the layout and preliminary material takeoff for the piping. Foundations and steel costs are based on the layout LF, volumes, and density assumptions.

Plant Electrical Systems and Plant I&C
Electrical system costs are based on the total electrical generation capacity, estimating software and conceptual material take off. Plant I&C costs are based on creating a business and control network for the site with equipment costs based on commercially available hardware and software.

Site Civil
Costs are based on conceptual material takeoff and estimating software. Stormwater management costs are based on a 100-year storm, with the first flush and the entire coal pile going to the wastewater treatment plant.

Buildings
Costs are based on pre-engineered metal buildings with utilities factored into the building costs. The Gas turbine/HRSG and the fired heater buildings are assumed to be stick-built structures.

ETES System

Piping costs are based on estimating software and conceptual material takeoffs. Foundations and steel costs are based on the layout LF, volumes, and density assumptions. The installation cost is based on person-hour estimates. Electrical costs are based on estimating software and conceptual material takeoff

Water Treatment and Wastewater Treatment Plant

Water treatment system costs are based on assuming that river water is pumped to the plant site for use as fire and service water. Treatment equipment costs are based on budgetary estimates from Monroe Environmental and Flowserve. Wastewater treatment system costs are based on two systems, one for the waste stream from the PCC island, and the other for storm water from the coal pile and plant roadways. Treatment equipment costs are based on budgetary estimates from Evoqua.

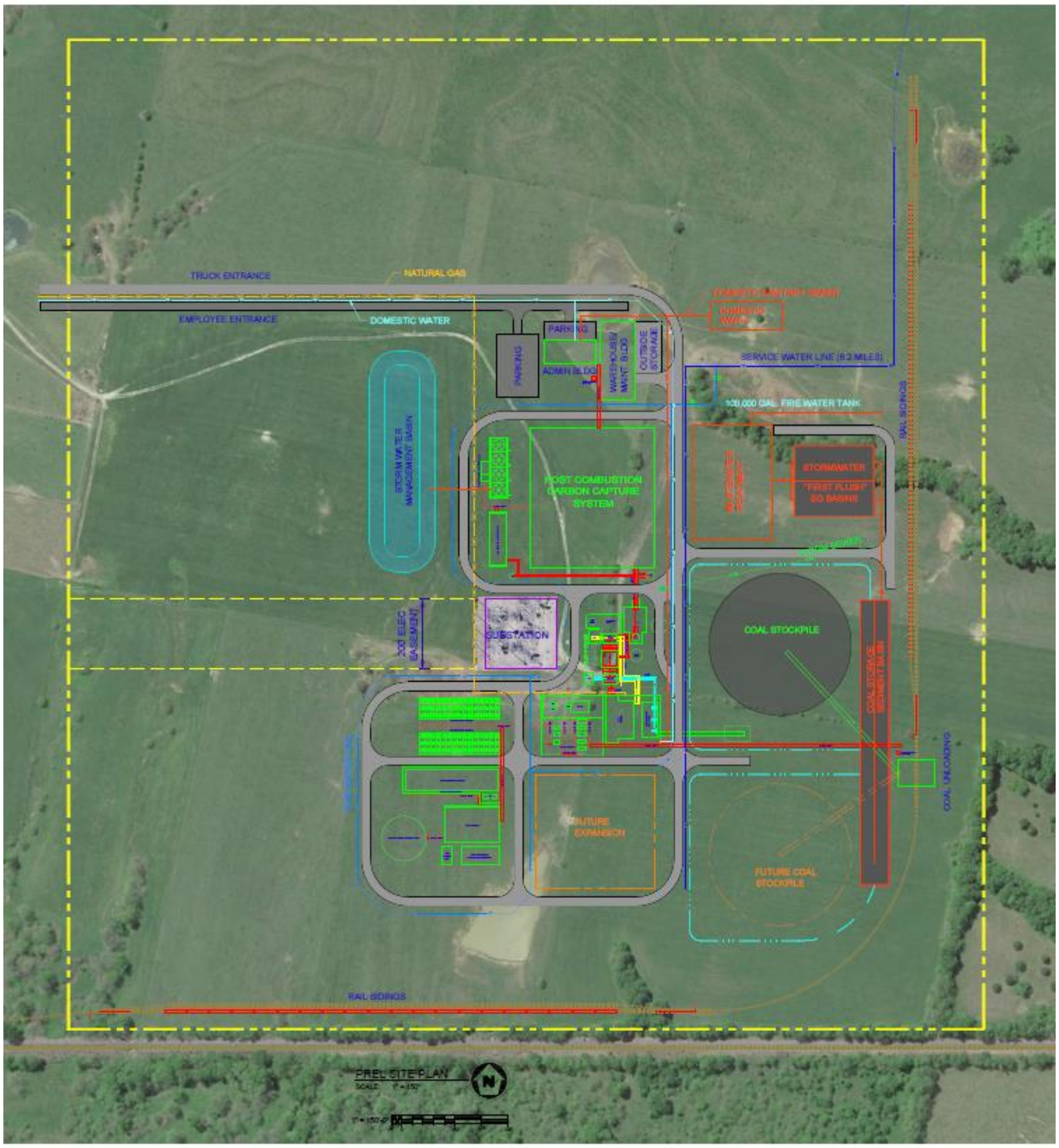

Figure 25 CDM Smith Conceptual Plant Layout

Summary

A detailed breakdown of the capital costs for the proposed Coal FIRST plant, a 120.7 MW_e air-fired pulverized coal plant utilizing an sCO_2 power cycle with turbine inlet conditions of 700°C and 27.4 MPa, an amine-based PCC system, and a novel ETES system is shown in Table 37. Unique costs for each of the plant major subsystems were developed by the program partners: EPS – sCO_2 power cycle and ETES system; RPI – air fired heater and AQCS; MHI – PCC system. CDMS provided installation, piping, foundation, electrical, and BOP estimates that are based on the conceptual layout (shown in Figure 25) and equipment definition provided by EPS, MHI, and RPI. A capital cost comparison of the proposed plant, the proposed plant (air-fired heater, sCO_2 power cycle, and ETES system) without carbon capture, and the proposed plant without carbon capture and the ETES system is shown in Table 38. To determine costs for the plant without carbon capture; the fired heater, AQCS, sCO_2 power cycle, and ETES system are all assumed to be identical and the systems required for the PCC system have been removed (water treatment, combustion gas turbine, cooling tower, feedwater, and CO_2 removal). Note, the sCO_2 power cycle, fired heater, and AQCS portions of the plant are identical across each of the plant iterations, the difference in net power (120.7 MW_e w/ carbon capture and 120 MW_e without) is due to the addition of the combustion gas turbine used to supply electricity and steam to the PCC plant.

Table 39 shows the O&M cost breakdown for the proposed plant with and without carbon capture and the plant without carbon capture and ETES. Table 40 shows the first-year power costs, TPC, TOC, TASC, CO_2 costs, and LCOS again for the proposed plant with and without carbon capture.

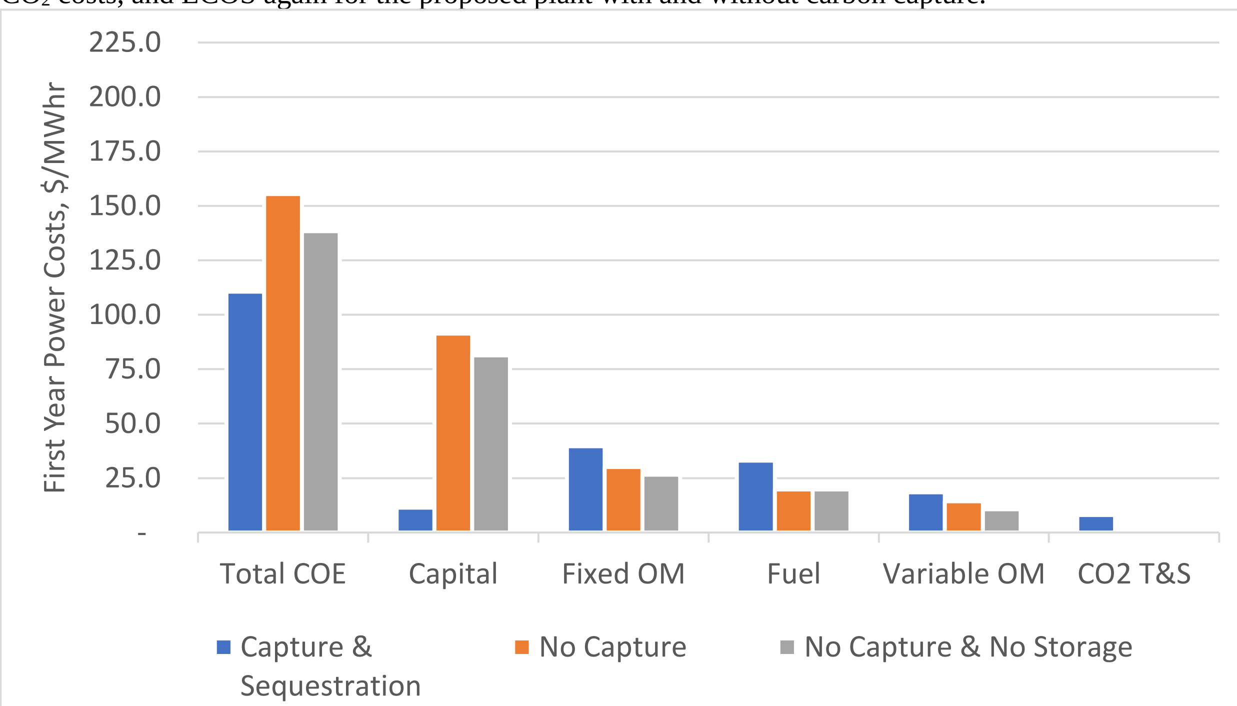

Figure 26 compares the first-year power costs, broken down into their components, of the proposed plant, the proposed plant carbon capture, and the proposed plant without carbon capture and ETES.

Table 41 summarizes the decrease in LCOE if a credit similar to the 45Q tax credit and if revenue from enhanced oil recovery can be applied to the plant economics. The assumed CO_2 credit for sequestration and EOR and the sale price of CO_2 is summarized in Table 36 was applied directly as defined in Table 36. Note when applying the sequestration credit only, the cost for CO_2 T&S is included in the LCOE calculation.

Table 36 Assumed CO_2 Credits and Sale Price

Application	**CO_2 Value ($/tonne)**
Sequestration	55 (credit)
Enhanced Oil Recovery (EEOR)	38 (credit), 40 (sale price)

Table 37 Plant Cost Summary

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
1 COAL & SORBENT HANDLING													
1.1 Coal Receive & Unload	$0	$930	$1,344	$0	$2,274	20.0%	$455	0%	$0	15%	$409	$3,138	26.0
1.2 Coal Stackout & Reclaim	w/ 1.1	w/ 1.1	w/ 1.1	$0	$0	0.0%	$0	0%	$0	15%	$0	$0	0.0
1.3 Coal Conveyors	$0	$961	$984	$0	$1,945	20.0%	$389	0%	$0	15%	$350	$2,684	22.2
1.4 Other Coal Handling	$0	$882	$1,323	$0	$2,205	20.0%	$441	0%	$0	15%	$397	$3,043	25.2
SUBTOTAL 1.	$0	$2,773	$3,651	$0	$6,424		$1,285		$0		$1,156	$8,865	73.4
2 Fired Heater Fuel System													
2.1 Fuel System: Coal Feeders, Coal Mills, Coal Pipe, Burners, Natural Gas Skids	$10,011	*Included in 4.1 Material	*Included in 4.1 Direct	$0	$10,011	0.0%	$0	0%	$0	15%	$1,502	$11,513	95.4
2.2 Fired Heater Fuel System Foundations	w/ 4.4	$0	$0	$0	$0	0.0%	$0	0%	$0	15%	$0	$0	0.0
SUBTOTAL 2.	$10,011	$0	$0	$0	$10,011		$0		$0		$1,502	$11,513	95.4
3 FEEDWATER & MISC. BOP SYSTEMS													
3.1 Feedwater System	$11	$632	$22	$0	$665	20.0%	$133	0%	$0	15%	$120	$917	7.6
3.2 Water Makeup & Pretreating	$1	$400	$6	$0	$407	20.0%	$81	0%	$0	20%	$98	$586	4.9
3.7 Waste Treatment Equipment	$0	$3,224	$3,136	$0	$6,360	20.0%	$1,272	0%	$0	20%	$1,526	$9,158	75.9
3.8 Misc. Equip. (Cranes, Air Comp., Comm., Fire Protection, Utility Piping)	$785	$754	$348	$0	$1,887	20.0%	$377	0%	$0	20%	$453	$2,717	22.5
SUBTOTAL 3.	$797	$5,010	$3,511	$0	$9,318		$1,864		$0		$2,196	$13,378	110.8
4 PC FIRED HEATER & ACCESSORIES													
4.1 Furnace and Radiant Platens, Convective and Economizer Elements, Air Preheaters, Dry Ash System, Sootblowers, Heater Intimate Steel.	$177,875	$1,415	$110,000	$0	$289,290	20.0%	$57,858	10%	$28,929	15%	$47,733	$423,810	3,511.3
4.2 Fans – Forced Draft, Primary Air, and Booster Fan	$3,233	w/4.1 Material	w/4.1 Direct	$0	$3,233	0.0%	$0	0%	$0	15%	$485	$3,718	30.8
4.3 Major Component Rigging	w/ 4..1	w/ 4..1	w/ 4..1	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
4.4 Fired Heater & Accessories Foundations and Support Steel	$0	$773	$1,036	$0	$1,809	20.0%	$362	0%	$0	0%	$0	$2,171	18.0
4.5 Fired Heater Ducting: Combustion Air, Flue Gas	$6,332	w/ 4.1	w/4.1	$0	$6,332	0.0%	$0	0%	$0	15%	$950	$7,282	60.3
SUBTOTAL 4.	$187,440	$2,188	$111,036	$0	$300,664		$58,220		$28,929		$49,168	$436,980	3,620.4
5 FLUE GAS CLEANUP													
5.1 Circulating Dry Scrubber: Scrubber Vessel, Lime System, Water System, Air System, Air Slide – Product Recirculation	$8,770	w/ 4.1 Material	w/ 4.1 Direct	$0	$8,770	0.0%	$0	0%	$0	15%	$1,316	$10,086	83.6
5.2 Selective Catalytic Reduction (SCR)	$4,788	w/ 4.1 Material	w/ 4.1 Direct	$0	$4,788	0.0%	$0	0%	$0	15%	$718	$5,506	45.6
5.3 Bag House & Accessories	$5,881	w/ 4.1 Material	w/ 4.1 Direct	$0	$5,881	0.0%	$0	0%	$0	15%	$882	$6,763	56.0
5.4 Installation, foundations, stack, and support steel	$0	$2,682	$1,262	$0	$3,945	20.0%	$789	0%	$0	15%	$710	$5,443	45.1
SUBTOTAL 5.	$19,439	$2,682	$1,262	$0	$23,384		$789		$0		$3,626	$27,798	230.3

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
5B CO2 REMOVAL & COMPRESSION													
5B.1 CO2 Removal System	$121,500	w/5B.1 Equipment	w/5B.1 Equipment	$0	$121,500	11.1%	$13,500	0%	$0	15%	$18,225	$153,225	1,269.5
5B.2 CO2 Compression & Drying	$27,000	w/ 5B.2 Equipment	w/ 5B.2 Equipment	$0	$27,000	11.1%	$3,000	0%	$0	20%	$5,400	$35,400	293.3
SUBTOTAL 5B.	$148,500	$0	$0	$0	$148,500		$16,500		$0		$23,625	$188,625	1,562.8
6 COMBUSTION TURBINE/ACCESSORIES													
6.1 Combustion Turbine Generator	$7,500		$28	$0	$7,528	20.0%	$1,506	0%	$0	10%	$903	$9,937	82.3
6.2 Combustion Turbine Accessories	w/ 6.1												0.0
6.3 Compressed Air Piping	w/ 6.1												0.0
6.4 Combustion Turbine Foundations	w/ 6.1												0.0
SUBTOTAL 6.	$7,500	$0	$28	$0	$7,528	$0	$1,506	$0	$0	$0	$903	$9,937	$82
7 HRSG													
7.1 Flue Gas Recycle Heat Exchanger	$0	$0	$0	$0	$0	0.0%	$0	0%	$0	15%	$0	$0	0.0
7.3 Ductwork	$0	$765	$2,295	$0	$3,060	20.0%	$612	0%	$0	15%	$551	$4,223	35.0
7.4 Stack	$35	$397	$24	$0	$456	20.0%	$91	0%	$0	10%	$55	$602	5.0
7.9 HRSG, Duct & Stack Foundations	$6,000	$185	$6,247	$0	$12,432	20.0%	$2,486	0%	$0	20%	$2,984	$17,902	148.3
SUBTOTAL 7.	$6,035	$1,347	$8,566	$0	$15,948		$3,190		$0		$3,589	$22,727	188.3
8B sCO2 POWER CYCLE													
8B.1 Compressor (High and Low Temperature)	$21,339	$5	$12	$0	$21,356	20.0%	$4,271	15%	$3,203	15%	$4,325	$33,155	274.7
8B.2 Internal Recuperation (HTR and LTR)	$22,772	$10	$19	$0	$22,801	20.0%	$4,560	0%	$0	15%	$4,104	$31,465	260.7
8B.3 CO2 Air-Cooled Condenser	$4,283	$1,645	$1,638	$0	$7,566	20.0%	$1,513	0%	$0	15%	$1,362	$10,441	86.5
8B.4 CO2 Power Turbine (Includes 130 MW generator and turbine throttle valve)	$19,895	$25	$18	$0	$19,938	20.0%	$3,988	15%	$2,991	15%	$4,037	$30,953	256.4
8B.5 System Piping and Valves	$0	$5,312	$21,254	$0	$26,566	20.0%	$5,313	0%	$0	15%	$4,782	$36,661	303.7
8B.6 CO2 System Foundations, Storage Tanks, and Utility Rack	$685	$552	$777	$0	$2,014	20.0%	$403	0%	$0	15%	$363	$2,780	23.0
SUBTOTAL 8.	$68,973	$7,549	$23,719	$0	$100,241		$20,048		$6,194		$18,972	$145,455	1,205.1
9 COOLING WATER SYSTEM													
9.1 Cooling Towers (Field Erected)	$1,720	w/ Equipment Cost	w/ Equipment Cost	$0	$1,720	0.0%	$0	0%	$0	15%	$258	$1,978	16.4
9.2 Circulating Water Pumps	$420	$10	$7	$0	$437	20.0%	$87	0%	$0	15%	$79	$603	5.0
9.4 Circ. Water Piping	$0	$315	$230	$0	$545	20.0%	$109	0%	$0	15%	$98	$752	6.2
9.9 Circ. Water System Foundations and Utility Rack	$0	$228	$392	$0	$620	20.0%	$124	0%	$0	20%	$149	$893	7.4
SUBTOTAL 9.	$2,140	$553	$629	$0	$3,322		$320		$0		$584	$4,226	35.0

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
10 ASH/SPENT SORBENT HANDLING SYS													
10.6 Ash Storage Silos	$0	$420	$171	$0	$591	20.0%	$118	0%	$0	15%	$106	$816	6.8
10.7 Ash Transport & Feed Equipment	$0	$240	$62	$0	$302	20.0%	$60	0%	$0	15%	$54	$416	3.5
10.9 Ash/Spent Sorbent Foundations and Steel	$0	$372	$498	$0	$870	20.0%	$174	0%	$0	20%	$209	$1,253	10.4
SUBTOTAL 10.	$0	$1,032	$731	$0	$1,763		$353		$0		$370	$2,485	20.6
11 ACCESSORY ELECTRIC PLANT													
11.1 Generator Equipment	$6,804	$0	$4,925	$0	$11,729	20.0%	$2,346	0%	$0	15%	$2,111	$16,186	134.1
11.3 Switchgear & Motor Control	$6,107	$0	$7,194	$0	$13,301	20.0%	$2,660	0%	$0	15%	$2,394	$18,356	152.1
11.5 Wire & Cable	$620	$0	$531	$0	$1,151	20.0%	$230	0%	$0	15%	$207	$1,589	13.2
11.8 Main Power Transformers	$8,500	$0	$6,534	$0	$15,034	20.0%	$3,007	0%	$0	15%	$2,706	$20,747	171.9
11.9 Electrical Foundations	w/ 11.1, 11.3, 11.8	$0	$0	$0	$0	20.0%	$0	0%	$0	20%	$0	$0	0.0
SUBTOTAL 11.	$22,031	$0	$19,184	$0	$41,215		$8,243		$0		$7,419	$56,877	471.2
12 INSTRUMENTATION & CONTROL													
12.1 Fired Heater Control Equipment	$1,414	w/ Equipment Cost	w/ Equipment Cost	$0	$1,414	0.0%	$0	0%	$0	15%	$212	$1,626	13.5
12.2 Combustion Turbine Control	w/6.1	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.3 sCO2 Power Cycle Control	w/8B.4	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.4 Signal Processing Equipment	w/12.1, 6.1, 8B4	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.6 Distributed Control System Equipment	w/12.1, 6.1, 8B4	$0	$0	$0	$0	0.0%	$0	0%	$0	0%	$0	$0	0.0
12.8 Other I & C Equipment	$0	$886	w/ 11.5	$0	$886	20.0%	$177	0%	$0	15%	$160	$1,223	10.1
SUBTOTAL 12.	$1,414	$886	$0	$0	$2,300		$177		$0		$372	$2,849	23.6
13 IMPROVEMENTS TO SITE													
13.1 Site Preparation	$1,119	$861	$850	$0	$2,830	20.0%	$566	0%	$0	20%	$679	$4,075	33.8
13.2 Site Improvements	$286	$2,041	$254	$0	$2,581	20.0%	$516	0%	$0	20%	$619	$3,717	30.8
13.3 Site Facilities (Utilities and Roadways)	$1,524	$2,654	$1,865	$0	$6,043	20.0%	$1,209	0%	$0	20%	$1,450	$8,702	72.1
SUBTOTAL 13.	$2,929	$5,556	$2,969	$0	$11,454		$2,291		$0		$2,749	$16,494	136.7

Acct No. Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost $	Eng'g CM H.O.& Fee %	Eng'g CM H.O.& Fee Total	Process Contingency %	Process Contingency Total	Project Contingency %	Project Contingency Total	TOTAL PLANT Cost	TOTAL PLANT COST $/kW
14 BUILDINGS & STRUCTURES													
14.1 Boiler Building	$0	$9,982	$2,924	$0	$12,906	20.0%	$2,581	0%	$0	15%	$2,323	$17,811	147.6
14.2 Turbine Building (Gas Turbine)	$0	$2,582	$2,366	$0	$4,948	20.0%	$990	0%	$0	15%	$891	$6,828	56.6
14.3 Administration Building	$0	$2,625	w/ Material Cost	$0	$2,625	20.0%	$525	0%	$0	15%	$473	$3,623	30.0
14.4 Circulation Water Pumphouse	$0	$376	w/ Material Cost	$0	$376	20.0%	$75	0%	$0	15%	$68	$519	4.3
14.5 Water Treatment Buildings	$0	$4,200	w/ Material Cost	$0	$4,200	20.0%	$840	0%	$0	15%	$756	$5,796	48.0
14.7 Warehouse	$0	$4,014	w/ Material Cost	$0	$4,014	20.0%	$803	0%	$0	15%	$723	$5,539	45.9
14.8 Other Buildings & Structures (ETES System / sCO2 Power Cycle)	$0	$3,913	w/ Material Cost	$0	$3,913	20.0%	$783	0%	$0	15%	$704	$5,400	44.7
SUBTOTAL 14.	$0	$27,692	$5,290	$0	$32,982		$6,596		$0		$5,937	$45,515	377.1
15 ETES System													
15.1 Generating Equipment Cost (Charge and Generating Cycles)	$31,670	*Included with Equipment	*Included with Equipment	$0	$31,670	20.0%	$6,334	15%	$4,751	15%	$6,413	$49,168	407.4
15.2 Storage Equipment Cost (HTS and LTS)	$12,261	*Included with Equipment	*Included with Equipment	$0	$12,261	20.0%	$2,452	20%	$2,452	15%	$2,575	$19,740	163.5
15.3 ETES Foundations	$0	$1,568	$2,342	$0	$3,909	20.0%	$782	0%	$0	15%	$704	$5,394	44.7
15.4 ETES Installation and Piping Costs	$0	$2,130	$505	$0	$2,635	20.0%	$527	0%	$0	15%	$474	$3,636	30.1
SUBTOTAL 15.	$43,931	$3,698	$2,847	$0	$50,475		$10,095		$7,203		$10,166	$77,939	645.7
TOTAL COST	$521,140	$33,273	$178,134	$0	$765,529		$131,476		$42,326		$132,333	$1,071,664	8,878.7

Table 38 Cost Summary - Proposed Plant, Plant without Carbon Capture, and Plant without Carbon Capture and ETES

Cost Category	Base Plant[1] ($/kW)	Base Plant w/out CC[2] ($/kW)	Base Plant w/out CC and ETES ($/kW)
1 COAL & SORBENT HANDLING	73.4	73.9	73.9
2 FIRED HEATER FUEL SYSTEM	95.4	95.9	95.9
3 FEEDWATER & MISC. BOP SYSTEMS	110.8	0.0	0.0
4 PC BOILER & ACCESSORIES	3620.4	3641.5	3641.5
5 FLUE GAS CLEANUP	230.3	231.7	231.7
5B CO2 REMOVAL & COMPRESSION	1562.8	0.0	0.0
6 COMBUSTION TURBINE/	82.3	0.0	0.0
7 HRSG	188.3	0.0	0.0
8B sCO2 POWER CYCLE	1205.1	1212.1	1212.1
9 COOLING WATER SYSTEM	35.0	0.0	0.0
10 ASH/SPENT SORBENT HANDLING	20.6	20.7	20.7
11 ACCESSORY ELECTRIC PLANT	471.2	419.6	322.8
12 INSTRUMENTATION & CONTROL	23.6	23.7	23.7
13 IMPROVEMENTS TO SITE	136.7	137.4	137.4
14 BUILDINGS & STRUCTURES	377.1	379.3	379.3
15 ETES SYSTEM	645.7	649.5	0.0
Total	8878.7	6885.4	6139.1

(1) Based on 120.7 MWe net plant output
(2) Based on 120.0 MWe net plant output

Table 39 O&M Cost - Proposed Plant, Plant without Carbon Capture, and Plant without Carbon Capture and ETES

O&M Costs	Base Plant	Base Plant w/out Carbon Capture	Base Plant w/out Carbon Capture and ETES
Total Operating Jobs per Shift	14	8	6
Fixed O&M Costs ($K)			
Administrative and Support Labor	2,572	1,983	1,768
Operating Labor Costs	2,989	1,708	1,281
Maintenance Labor Costs	8,573	6,610	5,893
Property Taxes and Insurance	21,433	16,525	14,734
Total Fixed O&M Costs	35,568	26,826	23,676
Variable O&M Costs ($K)			
Maintenance Material Cost	12,860	9,915	8,840
Consumables ($K)			
Ash Disposal	724	724	724
Chemical	w/ other consumables	w/ other consumables	w/ other consumables
Water	160	-	-
Other Consumables	5,858	2,169	-
Total Variable O&M Costs	19,603	12,809	9,565

Table 40 First-Year Power Cost, TPC, TOC, TASC, CO_2 Captured and Avoided Cost, and LCOS - Proposed Plant, Plant without Carbon Capture, and Plant without Carbon Capture and ETES

Summary	Base Plant	Base Plant w/out Carbon Capture	Base Plant w/out Carbon Capture and ETES
Net Plant Output (MW_e)	120.7	120	120
Efficiency (%)	29.9	40.4	40.4
CO_2 Capture (%)	83.6	0	0
CO_2 Captured, tonne/MWh (net)	0.81	0	0
CO_2 Emitted, tonne/MWh (net)	0.16	0.97	0.97
Fuel Type (Dual Fuel)	Montana Rosebud Subbituminous / NG		
Fuel Cost[42]	Natural Gas (Reference Case) – $15.08/MWh Coal (Midwest PRB) – $42.12/tonne		
Total Plant Cost, Total Overnight Cost, and Total as Spent Capital Costs			
TPC ($/kW)	8,879	6,885	6,139
TOC ($/kW)	10,743	8,469	7,551
TASC ($/kW)	12,398	9,773	8,714
First-Year Power Cost			
Capital ($/MWh)	117.7	91.3	81.4
Fixed OM ($/MWh)	39.6	30.0	26.5
Variable OM ($/MWh)	18.5	14.3	10.7
Fuel Cost ($/MWh)	33.0	19.8	19.8
CO_2 T&S Cost ($/MWh)	8.1	-	-
First-Year Power Cost ($/MWh)	216.9	155.4	138.4
CO_2 Costs			
Cost of CO_2 Captured ($/tonne)	66.07	-	-
Cost of CO_2 Avoided ($/tonne)	82.34	-	-
Levelized Cost of Storage			
LCOS ($/kWh)	0.135	0.135	-

Table 41 LCOE Benefit of Carbon Credits through 45Q and Enhanced Oil Recovery (EEOR)

Category	Proposed Plant Capture (Sequestration)	Proposed Plant No Capture	Proposed Plant No Capture & No Storage	Proposed Plant Capture & 45Q Credit (Sequestration)	Proposed Plant Capture & 45Q credit (EOR)
Total LCOE ($/MWh)	216.9	155.4	138.4	172.4	145.4
Capital ($/MWh)	117.7	91.3	81.4	117.7	117.7
Fixed OM ($/MWh)	39.6	30.0	26.5	39.6	39.6
Fuel ($/MWh)	33.0	19.8	19.8	33.0	33.0
Variable OM ($/MWh)	18.5	14.3	10.7	18.5	18.54
CO_2 Value ($/MWh)	8.1	-	-	(36.3)	(63.4)

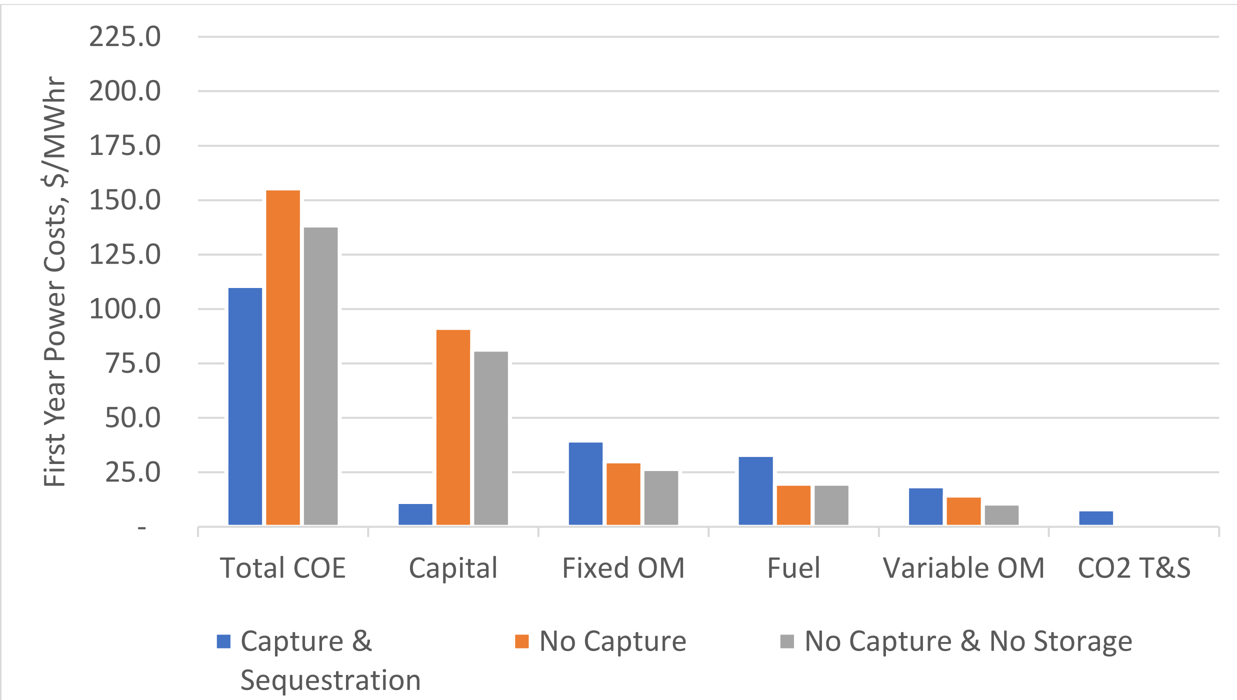

Figure 26 First Year Total and Component Power Cost – Base Plant with and without Carbon Capture

Discussion and Sensitivities

Based on the results of the techno-economic study preformed, the goal of this section to identify ways to improve the overall economics. The following design constraints were identified as key drivers in system economics:

1. *Employ efficiency improving technologies that maintain greater than 40% net plant cycle efficiency for a maximum load range without carbon capture.*

   40% HHV net plant efficiency at the plant scale proposed (120 MW_e) is achievable with sCO_2 power cycles. Even for high efficiency sCO_2 power cycles, to meet this criterion, high turbine inlet temperatures (700°C) are required. This produces significant cost in the fired heater and sCO_2 power cycle (radiant and convective tubes, sCO_2 turbines, sCO_2 high energy piping and valves) mainly due to the need to use stronger, but expensive, nickel-based alloys. Previous studies have shown that moving from 700°C to 600°C greatly reduces plant cost with only a marginal effect on plant efficiency. A 3.5 – 5.0% improvement in LCOE is expected by moving to lower turbine inlet temperature even if the net efficiency is decreased from 40.3% to 36.5% HHV (not considering carbon capture). Table 42 summarizes the potential improvement in LCOE if the net plant efficiency requirement is reduced from 40% to 36.5%. This is a result of the fired heater and sCO_2 power cycle representing a significant portion of the TPC (50.9% for the fired heater and 17.5% for the sCO_2 power cycle) and moving to lower temperatures reduces the amount and grade of expensive nickel alloy that is required for the higher turbine inlet temperatures. A 25% reduction fired heater cost and a 19% reduction in sCO_2 power cycle cost is expected when moving from 700 to 600°C.

Table 42 Summary of Effect of Turbine Inlet Temperature on Efficiency and LCOE for Proposed Plant without Carbon Capture

	Proposed Plant w/out Carbon Capture	**Lower Temperature Plant w/out Carbon Capture**
Turbine Inlet Temperature (°C)	700	600
NET Plant Efficiency HHV (%)	40.3	36.5
LCOE Contribution ($/MWh)		
Fired Heater Cost	33.3	25.0
sCO_2 Power Cycle Cost	11.4	9.2
Fuel Cost	19.8	21.7
LCOE	155.4	146.8

2. *The carbon capture process shall be integrated with the power generating plant to maximize the overall power plant system efficiency. The carbon capture plant shall be designed as close as possible to the DOE goal of 90%, or higher, CO_2 capture efficiency.*

   When considering available technical paths to meet this requirement, options with low technical risk were favored. This led to the decision to consider amine-based PCC as the leading technical choice as there are several commercially operating plants in service today. One key thing to consider regarding these types of PCC systems is the heat input required for the stripping process. Typically, in steam power plants heat for the stripping process is pulled from medium/low pressure stream at an intermediate point in the expansion turbine. The stripping process also requires a relatively tight temperature range to achieve optimal performance, and steam is ideal for this as it can be supplied at saturation conditions. In sCO_2 cycles there is not an ideal place to pull heat for this stripping process. In fact, any heat pulled from the power cycle greatly reduces cycle efficiency. Also, CO_2 is in a supercritical state and holding a narrow temperature range for the stripping process will require complex heating or mixing of CO_2 streams.

The additional equipment required to operate the PCC system (combustion GT and HRSG, water treatment, cooling tower) increases the cost for CO_2 captured. To achieve a cost of CO_2 captured of \$50/tonne, a reduction in the TPC of the equipment required for CO_2 capture of 65-70% is required. Options to consider outside of amine-based PCC are oxy-combustion and membrane post combustion capture. Oxy-fired heaters come with more technical risk, but do not require additional heat for CO_2 capture (a plus if integrating with sCO_2 cycles). Membrane CO_2 capture also does not require heat input, but to get over 80-85% capture efficiency requires large membranes and flue gas recirculation. While both options come with some additional technical risk, these should be considered as potential avenues to cost reduction and potential performance improvements for integration with sCO_2 power cycles.

8. Project Execution Plan Presentation

A Low Carbon Supercritical CO_2 Power Cycle / Pulverized Coal Power Plant Integrated with Energy Storage:
Compact, Efficient and Flexible Coal Power

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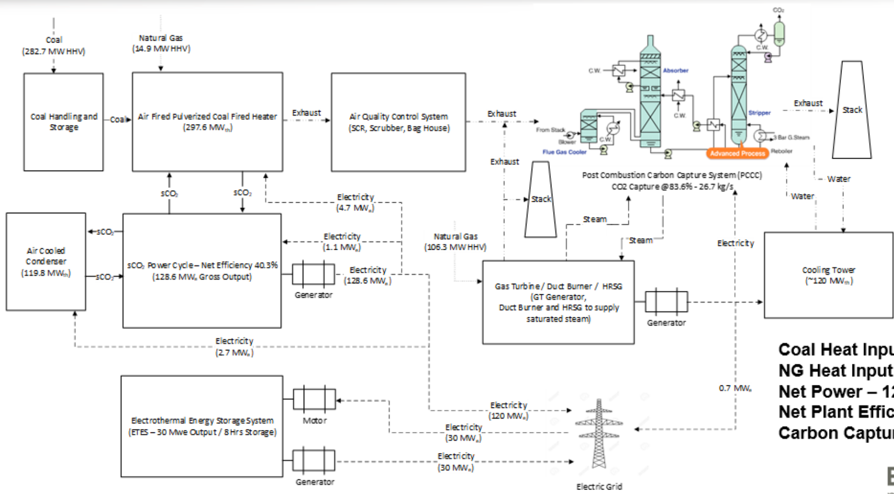
Project Execution Plan
89243319CFE000022

March 4, 2020

Plant Overview – Block Flow Diagram



Coal Heat Input – 282.7 MW$_{th}$
NG Heat Input – 121.2 MW$_{th}$
Net Power – 120.7 MW$_e$
Net Plant Efficiency – 29.9%
Carbon Capture Efficiency – 83.6%

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Technology Development Overview

- sCO2 Power Cycle
  - EPS100 Waste Heat Recovery – 8.5 MWe commercially available power cycle
  - Large-Scale Pilot program
  - STEP facility component development
- Coal Fired Heater
  - Large-Scale Pilot program
- ETES System
  - ARPA-E DAYS
  - 10 MW / 8-hour Pilot plant under development
- Post Combustion Carbon Capture, AQCS, Gas Turbine-HRSG, Process Cooling
  - Commercially available components – all TRL 9

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Large-Scale Pilot Program – US DOE-Funded Project

Award: DE-FE0031585

- 10 MWe large-scale pilot plant using coal-fired combustor with sCO_2 power cycle
- Mizzou CHP plant host site
- Phase I feasibility study complete
- Phase II (FEED study) in process
- Phase III – Build and Operation (2021-2025)

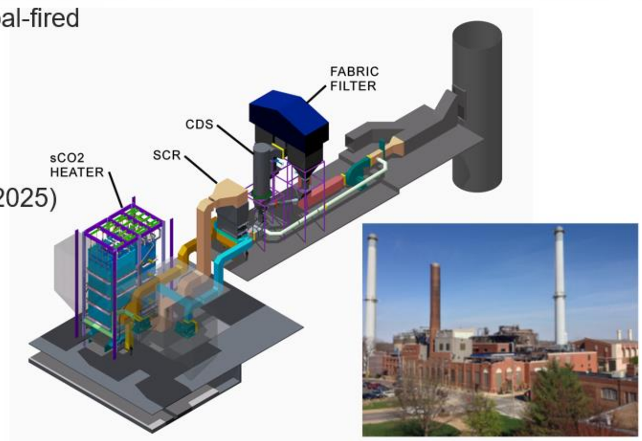
Program lead, power cycle

CDM Smith EPC

EPRI TEA, industry voice

Host site

RileyPower Coal-fired heater, AQCS



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TransCanada / Siemens project - sCO_2 Commercial Deployment

- Announced by TransCanada in March 2019
- EPS120 (uprated EPS100) on an RB211
- Partially-funded by ER Alberta
- TC investigating potential for 25-30 additional WHRUs in Western Canada

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https://www.tcenergy.com/stories/2019/2019-02-28-capturing-the-power-of-hot-air/

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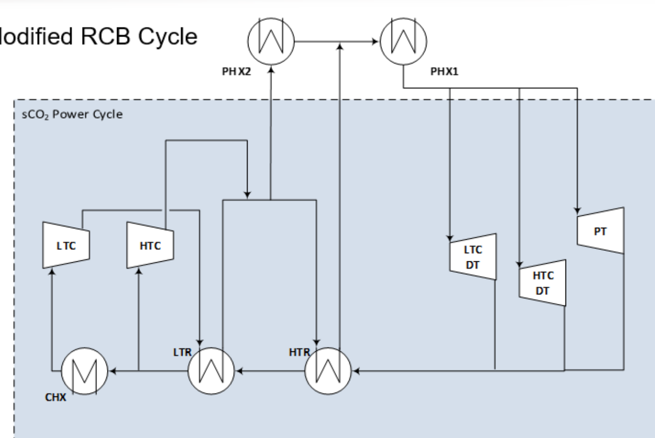
sCO2 Power Cycle - Overview

Modified RCB Cycle



- System uses parallel compressors - EPS100 uses single compressor
- System designed for higher temperatures than EPS100, 600-700°C versus 400-500°C
- Only one two-compressor system operated to date – Sandia test loop
- Operational challenges include heat source thermal management during start-up, shutdown and ramping.

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High and Low Temperature Recuperators (HTR & LTR)

- Commercially available from several suppliers
  - Heatric - provided PCHEs for EPS100 at lower operating temperatures
  - VPE – supplied lab scale PCHEs up to 600°C to Echogen (performance tests have been completed)
  - Both suppliers are engaged in the LSP program
- Presently TRL – 9 commercially available component even for "higher temperature" Coal FIRST plant

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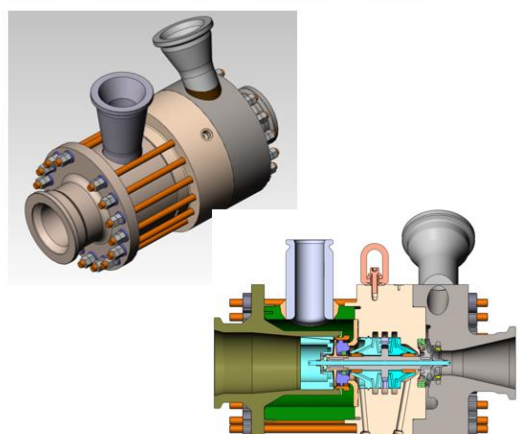
High and Low Temperature Compressors (HTC & LTC)

Low Temperature Compressor (18 MW)

- Fluid Conditions similar to liquid pump
- 2.5 MW hermetically sealed design tested (EPS100)
- Conventional barrel case pump feasible if sufficient NPSH margins

High Temperature Compressor (31 MW)

- Fluid conditions between ideal gas and liquid
- Primary design path: scaled version of LSP turbine driven compressor (3.6 MW)
- Alternate design path: barrel style or Internally-geared compressor multistage designs commercially available (lower efficiency)



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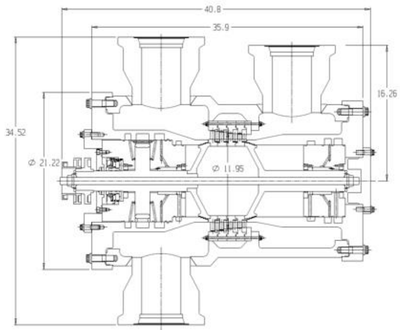
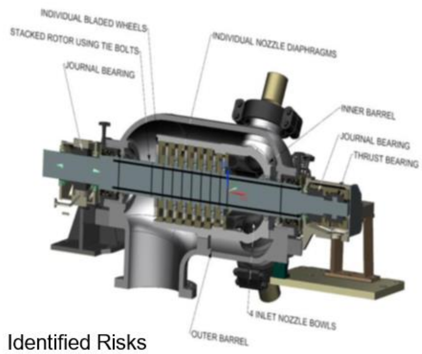
Power Turbine (PT)

LSP Power Turbine Design



- 3 or 4 stage axial design
- T_{in} = 600°C
- Based on STEP Conceptual Design

Coal FIRST Baseline
Siemens 100 MW 730°C Turbine



Identified Risks
- Blade failure risk – high unsteady alternating stresses
- Material compatibility with CO2

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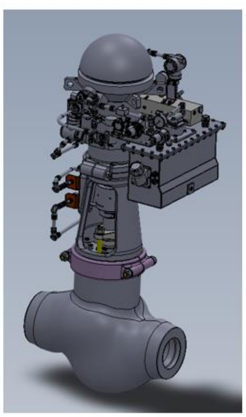
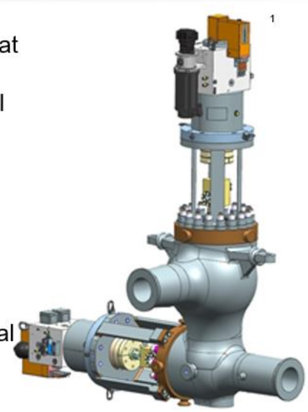
High Energy Turbine Valves (TSV)



- Flowserve TSV has been demonstrated at lower temperatures (485°C)
- ASME Code approved material – Inconel 740H
  - Not castable, requires forged valve bodies (very expensive)
- Haynes 282 – Code qualification underway
  - Castable material – potential for cost reduction
- High budget risk – low/moderate technical risk
- Flowserve and GE suppliers being considered for LSP – nickel alloys being considered



[1]

[1]Marion, J., Kutin, M., McClung, A., Mortzheim, J., Ames, R.; "The STEP 10 MWe sCO2 Pilot Plant Demonstration", ASME Turbo Expo 2019

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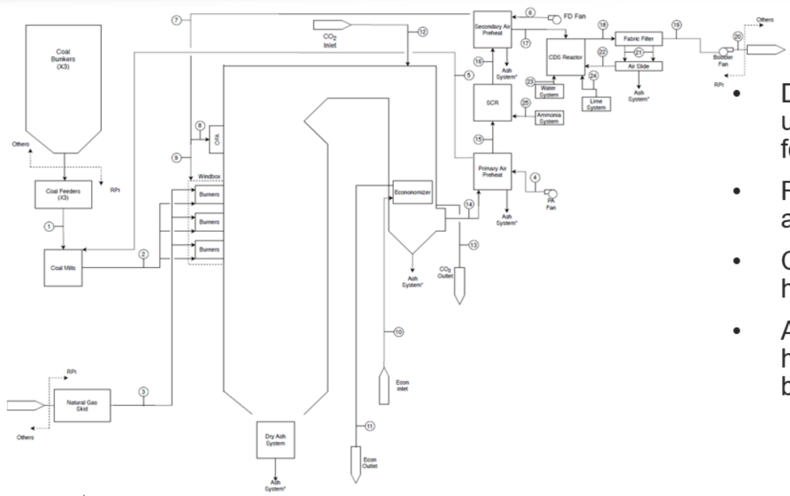
Air Fired PC Heater - Overview



- Designed similarly to a traditional utility steam boiler (CO_2 is utilized for wall cooling)
- Radiant furnace for combustion and final CO_2 heating (to 700°C)
- Convection pass for initial CO_2 heating – PHX2
- Air delivery system, AQCS, ash handling, fuel delivery and burners commercially available

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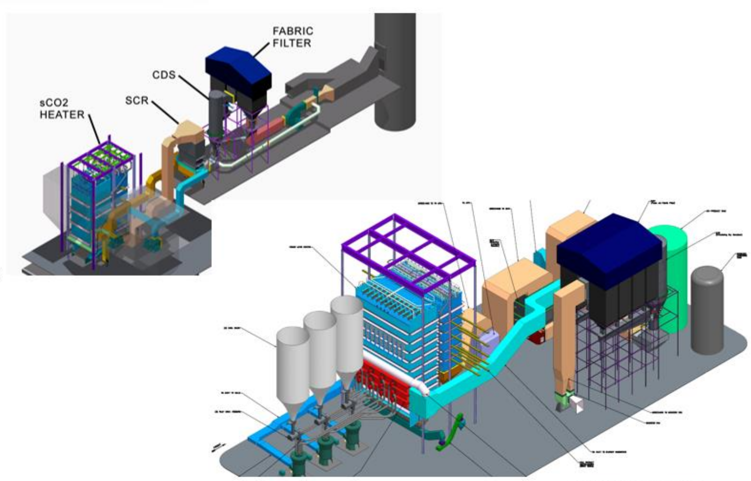
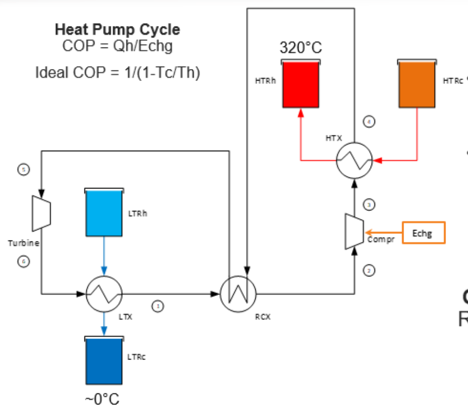
Fired Heater Risk Mitigated - LSP

- Operational
  - Design does not use traditional attemperation for CO2 temperature control – relies on firing rate (NG co-firing for trim) and excess air.
- Design
  - Furnace heat flux profile – LSP program is stoker fired furnace, Coal FIRST plant is Air Fired PC. Both units are CO2 wall cooled designs. Verification of radiant heat transfer models
  - Empirically-based margins in tube wall design due to better understanding of furnace heat flux profiles through LSP testing
  - Ability to meet low pressure drop requirement (compared to steam boiler) – flow distribution



power systems

Electrothermal Energy Storage Overview



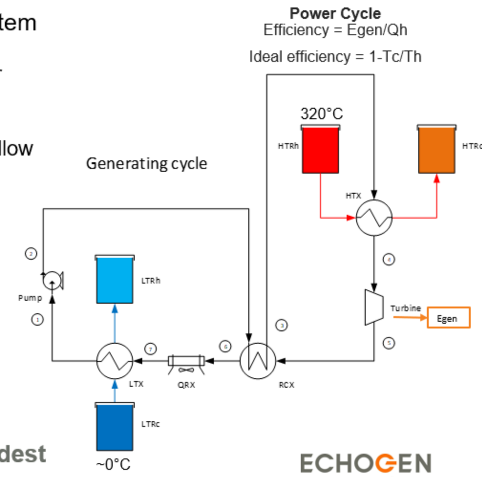
CO2 based ETES system

- Leverages sCO2 power cycle development
- Modest temperatures allow for low cost materials

Overall Process

RTE = Egen/Echg

= COP x Efficiency



Ideal cycle RTE = COP_{Carnot} x η_{Carnot} = 100%

Non-ideal processes result in RTE ~60%, even at modest temperature ratio

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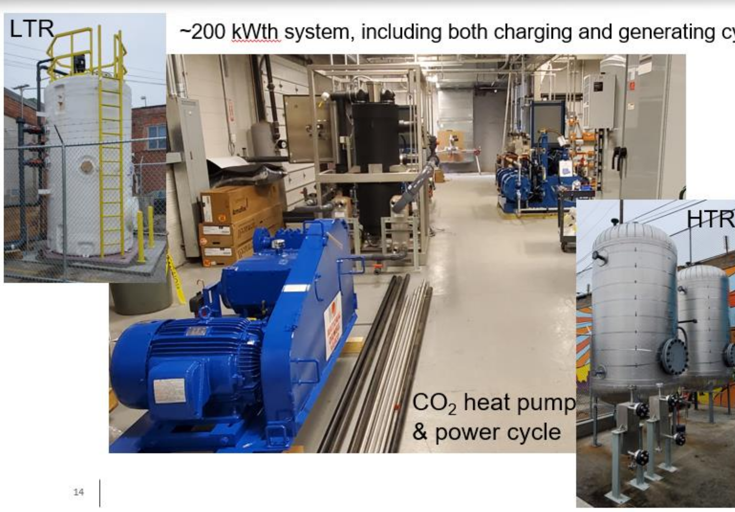
ARPA-E DAYS Program – ETES Proof of Concept

~200 kWth system, including both charging and generating cycles



Initial build
- 2-tank heat transfer fluid HTR
- Ice slurry LTR
- Complete July - 2020

BP 2
- Build and test sand or concrete HTR system
- Complete July - 2021

Primary developmental focus:
- HTSR and heat exchanger (TRL 4)
- LTSR performance (TRL 4)
- Operation and controls

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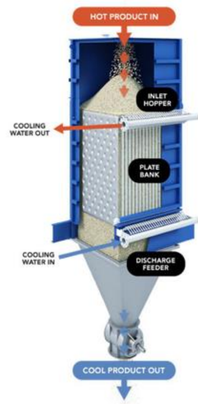
High temperature heat exchanger and reservoir

- Version 1: Heat transfer fluid with PCHE heat exchangers
  - Commercially-available products
  - Lowest risk, but higher-cost
- Next versions being designed and evaluated under ARPA-E program:
  - Concrete + HTF (Westinghouse)
  - Sand + MBHE (Solex)
  - Sand + FBHE (TU Wien)



Solex MBHE

Westinghouse

TU Wien FBHE

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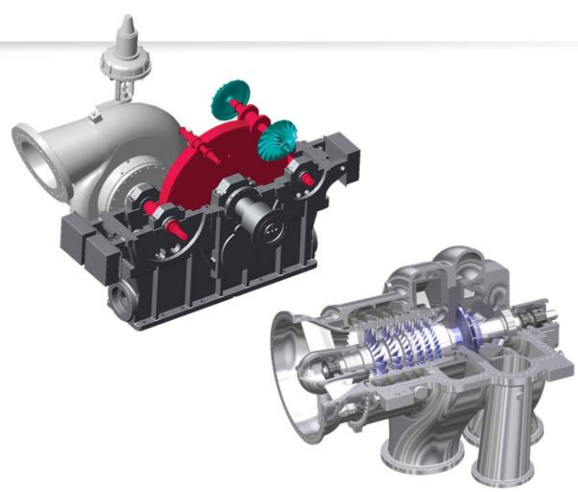
Charge compressor

- 5-50 MWe – Commercially Available
  - Integrally-geared (IG) compressor
  - Multiple suppliers (Siemens, Hanwha, Howden, Atlas Copco…)
- 50+ MWe
  - Parallel IG compressors
  - Developing large axial compressor technology with Barber-Nichols, University of Cincinnati & Notre Dame



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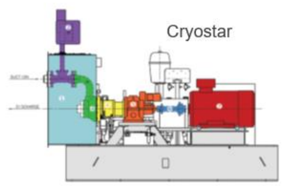
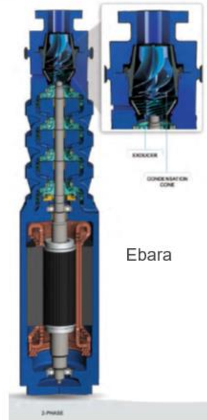
Charge cycle hydraulic turbine

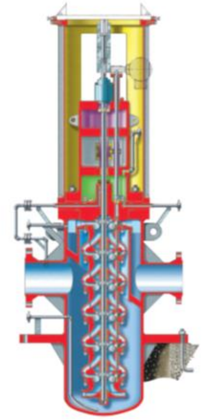
- Similar to LNG expanders used in liquefaction
- Pressure, power within experience range
- Multiple manufacturers
  - Cryostar
  - Ebara
  - Flowserve



Cryostar



Ebara



Flowserve

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ETES 10 MW / 8-hour Pilot Plant

- Pilot plant utilizes low risk components
  - Commercial charge compressor
  - Scaled EPS100 turbomachinery for generating cycle
  - 2 – Tank heat transfer fluid HTSR with commercial PCHE for HTX
  - ISG or ice on coil solution for LTSR and LTX
  - 2-year program to operation from funding release (Expected operation late 2022)
  - Will bring ETES system to TRL 7
- Roadmap for lower cost, higher performance technology
  - Advanced HTSR/HTX (ARPA-E Days)
  - ISG (ARPA-E), passive slurry generation (TBD)
  - Hydraulic Turbine (vendor development – derivative design)
  - Pilot system provides testbed for technology improvement

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Technology Developers

Echogen's current commercial partnerships include Siemens (Oil and Gas) and GE (Marine) in Waste Heat Recovery Applications

Power Cycle

Turbomachinery
- Barber Nichols, Inc.
- Siemens

- Printed Circuit Heat Exchangers
  - Vacuum Process Engineering
  - Heatric

- High Energy Valves
  - Flowserve and GE (LSP)

ETES

Thermal Reservoirs and HX
- Concrete HTSR
  Westinghouse Electric Corp.
- Sand Fluidized Bed HX
  Technische Universität Wien
- Sand Packed Moving Bed HX
  Solex Thermal Science
- Ice Slurry Generator
  Liquid Ice Technologies

Turbomachinery
- Siemens / Barber Nichols, Inc.
- Ebara, Flowserve, Cryostar

- High Energy Valves
  - Flowserve and GE (LSP)

Plant Systems

Fired Heater and AQCS
- Riley Power, Inc.

High Temperature Materials
- Special Metals Company
- Haynes International, Inc.

Post Combustion Carbon Capture
- Mitsubishi Heavy Industries

EPC
- Louis Perry and Associates, A CDM Smith Company

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Project Financing Requirements and Challenges

- What would be required for securing financing?
  - Minimize technical risk – pilot operation of equipment will be required
  - Minimize financial risk – well defined revenues (long term PPA, CO2 credit/revenue with high likelihood of certainty such as 45Q)
  - EPC contractor to provide a full project wrap
- What are the biggest challenges?
  - Many banks have forsworn providing capital for coal projects[1]
  - Political and public perception of funding coal projects

[1]https://www.banktrack.org/page/list_of_banks_which_have_ended_direct_finance_for_new_coal_minesplants

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ECHOGEN power systems

Permitting Scenarios

- Scenario 1 – Non-Attainment Area
  - Subject to more rigorous air quality standards, Public backlash would be high
  - This would make permitting almost impossible – AVOID
- Scenario 2 and 3 – Greenfield and Brownfield Site (Netting not available)
  - New Construction > 250 MMBtu/hr Heat source or 100 tons of any criteria
  - PSD and BACT would be required
  - 12 – 18 months for construction permitting
  - Would trigger PSD, public notice mandatory (potential to slow down 12 months or more)
  - Oversight by EPA
- Scenario 4 – Brownfield Site using Netting (replacing present emissions source with lower one)
  - Using this method for LSP permitting at University of Missouri
  - 6 – 9 months for construction permitting
  - State has more autonomy in issuing permits

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Approach to Site Selection

- Heavily dependent on project financing
  - Well defined revenue stream – Long Term PPA and CO2 credit/revenue
  - Enhanced Oil Recovery for CO2 revenue – Petra Nova Model
- Avoidance of plants in Non-Attainment Areas
  - Permitting would be near impossible
- Through EPRI's support several US utilities have committed funds to LSP
  - AEP and Southern Company are supporting Echogen's LSP program
  - Others have expressed interest in the program
  - Leverage existing relationships to determine potential interest in US based site
- International market

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Detailed Design Plan and Timeline

Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
System																								
sCO2 Power Cycle Detailed Design	Preliminary Design (FEED)									Detailed Design														
Power Turbine		Preliminary Design								Detailed Design														
High Temperature Compressor		Preliminary Design								Detailed Design														
Low Temperature Compressor		Preliminary Design								Detailed Design														
High Energy Valves		Preliminary Design								Detailed Design														
ETES System	Preliminary Design (FEED)									Detailed Design														
Fired Heater	Preliminary Design (FEED)									Detailed Design														
Air Quality Control System			Preliminary Design (FEED)							Detailed Design														
Post Combustion Carbon Capture System	Preliminary Design (FEED)									Detailed Design														
Plant Engineering (Piping, Foundations, Buildings, Steam Supply)			Preliminary Design (FEED) Conclusion - Notice To Proceed										Detailed Design											
Site Permitting Scenario 2 or 3							Permitting (No Netting)																	
Site Permitting Scenario 4																	Permitting (Netting)							

Assumes Notice to Proceed at FEED conclusion (Performance and Cost Determined)

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9. Plant Layout / Plot Plan