Cover Page – Coal Plants of the Future (Coal FIRST)

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Project Title: Coal-Based Power Plants of the Future—Hybrid Coal / Gas Combustion Boiler Concept with Post Combustion Carbon Capture (HGCC)

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1 Business Case

Traditional coal-based power plants were designed for base-load, always-on operation. However, as renewable energy sources become more cost effective and a larger part of energy production, coal-based generation will need greater flexibility to rapidly cycle on and off. The proposed plant design, a Hybrid Gas/Coal Concept (HGCC), focuses on achieving power generation with high-efficiency and load cycling capability combined with carbon dioxide (CO_2) capture. The HGCC concept consists of combining an 88 MWe gas combustion turbine and a 263 MWe ultra-supercritical (USC) coal boiler with 51 MW of energy storage capacity as batteries. The HGCC concept is unique and presents a strong business case because it is:

- **Flexible**
  - Combination of technologies and battery capacity provides high turndown (7.6:1)
  - Battery storage enables system to provide 51 MW nearly instantly for one hour.
  - Combustion turbine can achieve 30 minute ramp up to 88 MWe from initial firing
  - Redesigned coal firing allows for smooth boiler ramp rates and lower minimum load.
  - Combination of gas turbine and coal boiler technologies boosts efficiency to 37% including CO_2 capture and compression. In peak time operation, this efficiency can be increased up to 43.5% by using the ESS system.
- **Innovative**
  - Novel coal boiler firing reduces or eliminates time constraint associated with ramp-up.
  - Three power source components (gas turbine, steam turbine, and batteries) provide an instant response with increasing output as slower starting components ramp up.
- **Resilient**
  - Turbine and boiler technologies are well developed and reliable.
  - Utility-scale application of battery technology continues to improve and provide immediate response to demand.
  - Coal properties variability is managed using on-line analyzers, fireside performance indices, and condition-based monitoring.
- **Small with the potential for Brownfield Retrofits**
  - Boiler/steam turbine, combustion turbine, and batteries provide 350 MWe net output.
  - Aligns coal as a cost-effective and diversified backup to less reliable renewables.

Key Findings from the study are listed below:

- The COE from the HGCC is competitive with both USCPC and IGCC even though those plants are larger and have a natural economy of scale advantage
- HGCC offers significant improvement in the areas of ramp rate, turndown, and start up flexibility (cold and warm) compared to USCPC and IGCC
- HGCC components are commercially available today, the PreFEED and FEED studies will detail how these are to be best integrated
- Redesigned coal boiler firing allows improved ramp rates and turndown when compared to the USCPC

The opinion of probable cost for capital and O&M provided in this report is made on the basis of Barr's experience and qualifications and represents our best judgment as experienced and qualified professionals familiar with the project. The cost opinion is based on project-related information available to Barr at this time and includes vendor quotations, similar past projects, and factoring literature data (DOE-NETL Costing Study[i]) to 2019 values. The factoring approach is based upon using the "Exponent 0.6 rule". In relevant instances, the MW_e/MW_{th} capacity ratio between the NETL study cases and the proposed concept then raised to the exponent 0.6 was used to adjust costs. The opinion and accuracy of cost may change as more information becomes available. In addition, since we have no control over the cost of labor, materials, equipment, or services furnished by others, or over the methods of determining prices, competitive bidding, or market conditions Barr cannot and does not guarantee that proposals, bids, or actual costs will not vary from the opinion of probable cost.

1.1 Market Advantage - Cycling Attributes

Renewable energy sources are less reliable than combustion-based power. As renewables become more cost effective and a larger part of the generation mix, additional cycling requirements are being imposed on historically base load coal units. This was not anticipated when coal units were designed. Utilities meet the expected demand by using a day-ahead projection of electrical demand to develop a generation resource stack. Resource stacks start with the lowest operating cost and add resources until the demand is met. As more, non-dispatchable renewables are added to the generation portfolio, utilities respond by adjusting the commitments to combustion type generating resources. This has required coal units to transition from base load operation to frequent cycling at certain times of the year.

The Hybrid Gas/Coal Concept (HGCC) utilizes three distinct and unique approaches to maximizing cycling flexibility (turndown and ramp rate). In order of decreasing flexibility, the concept incorporates the following features:

- Energy Storage System (ESS) (batteries) – 51 MW gross
- Combustion Turbine (GE 6F.03) – 88 MW gross
- USC Boiler/Steam Turbine Cycle – 263 MW gross

The combustion turbine can operate independently from the USC Boiler as needed during the startup process. From a cold start, the full exhaust of the combustion turbine will be directed to a bypass stack. As the USC Boiler is warmed, routing of exhaust gas from the combustion turbine will be gradually transitioned to the boiler until all the exhaust is routed to the USC Boiler and the bypass to the stack is closed. It is anticipated that the bypass will be utilized for approximately two hours during a warm start until the steam turbine is synchronized to the grid. The bypass stack will be used during cold start times for up 6-8 hours until the steam turbine in synchronized to the grid. It should be noted that it is not necessary to start the combustion turbine in advance of firing the boiler. If output from the combustion turbine is not needed the USC boiler can start independently. Provisions will be included in the air permit, which will allow the combustion turbine to operate using the bypass stack for a specified period of time before the exhaust is routed into the USC boiler. The combustion turbine comes standard with burners that minimize CO and NOx emissions.

The USC Boiler is equipped with a redesigned coal firing system not found on current coal fired boilers. The new firing system allows the boiler minimum load to be reduced by 20%.

When the plant is called upon to begin operation from a cold start, the following start-up order is envisioned:

- ESS: immediate
- Combustion turbine: 30 minutes to full load

- USC Boiler Steam Cycle: 6-9 hours to full load from cold start, approximately 3 hours and 40 minutes from warm start

Anticipated start up times and ramp rates are summarized in Table A1.1 located in the supporting documents in Attachment A. The overall plant turndown when ESS is considered is approximately 7.6 to 1.

Renewables are often touted as having a cheaper cost of electricity than competing technologies like coal combustion. This comparison is somewhat misleading, as it discounts the value of other necessary services that the transmission system requires to fully function, such as load following, turndown, voltage support, and spinning reserve. Unfortunately, the value of these additional services is not well monetized for combustion-type generation. Table A1.2 in supporting documentation in Attachment A compares the types of services offered by different technologies.

1.2 Business Development Pathway

Coal based technology faces a challenging future given environmental constraints (emissions and carbon capture), low natural gas prices, and declining cost of renewable resources. Given these realities, the most applicable and cost effective application of HGCC technology will likely be in retrofitting either existing or retired coal fired power plants. It is unlikely that a utility or project developer would initiate this technology at a green field site. Therefore, one of the base cost assumptions is that a minimum set of infrastructure will be available and reduce the capital cost of this technology. A sensitivity analysis will assume that the following at a retired plant is available: cooling tower/circulating water, exhaust gas stack, coal processing, boiler/turbine building, water/waste water treatment, ash handling, in plant electrical breakers/motor control centers, and substation. The retired boiler, turbine, high energy piping, feedwater heaters, etc. would be removed as part of the HGCC retrofit.

1.3 Market Scenario Baseline

The current Energy Information Administration (EIA) data on coal and natural gas costs suggests that natural gas will cost \$3.00/MMBtu and coal will cost \$2.00/MMBtu. EIA also provides data for heat rate and variable O&M cost/MWh. Those results are used in Table 1.1 to compare variable fuel plus O&M costs for a projected HGCC plant versus other combustion forms of generation. The table provides a sensitivity analysis for \$6/MMBtu natural gas. Variable costs are used by utilities to decide the order in which generation units are brought on line to serve load (lower is better). At \$3/MMBtu, estimated HGCC costs are very close to those of a USC Boiler/Steam turbine but higher than those of a Combined Cycle unit. In contrast, at \$6/MMBtu, the HGCC is more expensive to operate than the USC Boiler/Steam turbine but less expensive to operate than the Combined Cycle unit. The economics of the HGCC will improve once the market evolves to account for the value of load following, voltage support, and spinning reserve.

Table 1.1 Market Scenario Baseline – Fuel plus O&M cost/MWH Comparisons

Generation Type	Heat Rate (BTU/kWh)	Variable O&M ($/MWh)	Fuel Cost ($/MWh) Coal - $3/MMBtu		Total Variable Cost	Total Variable Cost
			($3/ NG)	($6/ NG)	($3/ NG)	($6/ NG)
HGCC with PCC	**9,199**	**15.2**	**21.4**	**30.5**	**36.6**	**45.7**
USC Boiler Steam Turbine with PCC	10,508	16.8	21.0	21.0	37.8	37.8
CC with PCC	7,466	4.6	22.5	44.9	27.0	49.5

Total Cost of Electricity are compared in Table 1.2 using fuel costs of $2/MMBtu for coal and $3/MMBtu for natural gas. The HGCC cost is close the USC Boiler/Steam Turbine and higher than combined cycle due to capital cost considerations which are summarized in Table 1.3.

HGCC's business case is comparable to existing coal technologies using current metrics, and also provides better turndown, faster start-up times at warm or cold conditions, better spinning reserve capability, and higher ramp rates than either the USC Boiler/Steam turbine or the Combined Cycle. In addition, the HGCC can be retrofitted within a retired coal fired facility of the proper size (300-400MW). Use of existing infrastructure and systems can reduce capital cost by up to 30%. Under this scenario, the Total Cost of Electricity would be approximately **$115/MWh.** The capital cost provided in Table 1.3 has a comparable cost at $3,303/kW.

Table 1.2 Total Cost of Electricity (2019 Dollars)

Generation Type	Capital Cost ($/MWh)	Fixed O&M ($/MWh)	Variable O&M Cost ($/MWh)	Fuel Cost ($/MWh)	Total Cost of Electricity ($/MWh)
HGCC Base (350 MWe Net)	**77.1**	**22.1**	**15.2**	**21.4**	**135.8**
USC Boiler Steam Turbine with PCC[i]	82.7	17.6	16.8	21.0	**138.1**
IGCC with PCC[ii]	83.5	20.1	11.9	22.5	**137.3**

Table 1.3 Total Plant Cost and output (2019 dollars)

Generation Type	MWe Net	Total Plant Cost	Plant Cost ($/kW)
HGCC (Peak)	**350**	**$1,156,000,000**	**$3,303**
USC Coal w/PCC	550	$1,939,137,000	$3,525
NGCC w/PCC	559	$827,924,000	$1,481
IGCC w/PCC	497	$1,580,585,000	$3,181

1.3.1 Coal Types & Cost

In 2017, the mine average sales prices were:

- Subbituminous: $14.29 per short ton (2,000 lbs.)
- Bituminous: $55.60 per short ton,
- Lignite: $19.51 per short ton, and
- Anthracite: $93.17 per short ton.

Though lignite is a cheaper coal, it is less efficient and requires additional coal drying processes. As a result, while the national average sales price of coal at coal mines was $33.72 per short ton, the average delivered coal price to the electric power sector was $39.09 per short ton.[iii]

1.3.2 Natural Gas Price

The EIA report shows that natural gas prices are expected to be between $3/MMBtu and $8/MMBtu based on the Low and High Oil and Gas Resource and Technology cases, respectively.

1.3.3 Renewables Penetration

In the *Annual Energy Outlook 2019 with Projects to 2050*, the U.S. Energy Information Administration (EIA) predicts increasing share of both renewables and natural gas in electricity generation. Primary causes are lower natural gas prices and decreasing renewable capacity costs influenced by tax credits that will continue into the mid-2020s.

1.3.4 CO_2 Market Prices

It is anticipated, U.S. energy-related CO_2 emissions will need to decrease by 2.0% in 2019 and by 0.9% in 2020[iv]. Carbon taxes have been suggested to help achieve this reduction[v]. No credit for CO_2 has been taken for the purposes of cost comparison. 45Q tax credit is estimated at $10-$20 per ton stored CO_2. The C_2PH concept compresses CO_2 at a purity of greater than 95% which, today, can be sold for $15-$40 / ton CO_2.

1.4 O&M Analysis

The O&M costs for the HGCC are very similar for the USCPC as shown previously in Table 1.1. This is expected since the equipment line up for the HGCC is very similar to the USCPC. The exception is the use of the General Electric F6.03 combustion turbine as part of the HGCC configuration. Fixed and variable O&M costs for the combustion turbine have been included in the O&M cost calculations.

O&M cost increases from increased cycling operation are a concern for the existing coal fired fleet for base load operation. In the case of the HGCC cycling duty parameters are known at the beginning of the design process and will be addressed in the preFEED study and refined during the FEED study. The design approach in the preFEED and FEED studies will explore upgraded materials, improved machine design, component flexibility to allow greater thermal movements, advanced sensors to monitor equipment, and artificial intelligence to aid in predictive maintenance.

1.5 Domestic & International Market Applicability

The EIA's Annual Energy Outlook 2019[vi] projects renewable energy growth through 2050. Renewable energy is expected to reach 48% of US installed generation, led by wind and solar. In 2018, coal provided 27% of the energy for the U.S. but is projected to reduce to only about 17% in 2050.

As more renewable resources are added, there will be an additional need for combustion resources such as the HGCC to provide for grid reliability when the output of renewable generation is low or zero.

2 Plant Concept

2.1 Proposed Design

The proposed HGCC plant combines a state-of-the-art ultra-supercritical (USC) coal power plant with a natural firing gas turbine and energy storage system (ESS). The typical role of the heat recovery steam generator (HRSG) in a normal natural gas firing combined cycle (NGCC) power plant will be replaced by a coal boiler. The plant is proposed to have a combination of a USC boiler/ steam turbine, a combustion turbine, and an ESS battery storage system for a net total of 350MW. This configuration is expected to reach 45.5% plant efficiency based on higher heating value (no CO_2 capture) with less than 30% natural gas use.

Two unique features of this power plant design will enable rapid start-ups and load changes. The first is a redesigned coal preparation and firing system. The second feature is utilizing the traditional gas turbine, which has an inherently fast start-up and ramp rate capability.

The combined system will effectively handle variable power demand driven by the increased use of renewable power plants. The exhaust gas from the 88 MW gas turbine will feed the 263 MW USC coal boiler furnace. An economizer gas bypass system is incorporated to increase the gas temperature over 300°C at low load for effective selective catalytic reduction (SCR) operation. Should power demand be lower than minimum load, the remaining electricity will be stored in an ESS, which will assist in initial ramp-up during load ramp-ups such as morning or evening peaks.

Modern digital twin and remote monitoring service will assist operation and maintenance to reduce O&M cost. The HGCC plant will be modeled as digitally twined, which can simulate integrated static and dynamic performance at any time by using DHI's integrated plant performance calculation tool, UniPlant and dynamic analysis tool. DHI's RMS (Remote Monitoring Service) will support operation and maintenance by using real-time monitoring of operational information, predictive diagnostics, and performance monitoring diagnostics. Optimum operation parameters can be advised using an optimized action plan when the coal and operation conditions are changed.

The proposed concept meets the specific design criteria in the RFP per the following details:

- Near-zero emissions using a combination of advanced air quality control systems (electrostatic precipitator - ESP, wet flue gas desulfurization system - wet FGD, selective catalytic reduction for NOx control - SCR) that make the flue gas ready for traditional post combustion carbon capture technology.
- High ramp rate capability (expected 6% vs RFP 4%) and Low minimum loads (expected 7.6:1 turndown vs 5:1 target). The Hybrid Gas/Coal Power Plant's preliminary operation scenario is demonstrated in Figure A2.1 in Attachment A.
- Integrated ESS with 51 MW vanadium redox flow batteries.
- Minimized water consumption by the use of a cooling tower vs. once through cooling, and internal recycle of water where possible.
- Reduced design and commissioning schedules from conventional norms by utilizing state-of-the-art design technology, such as digital twin, and 3D modeling and dynamic simulation. Utilizing a modular approach in the FEED study stage will reduce construction cost and schedule.
- Enhanced maintenance features to improve monitoring and diagnostics such as coal quality impact modeling/monitoring, advanced sensors, and controls.
- Integration with coal upgrading or other plant value streams (co production). Potential for rare earth element extraction in the raw coal feed stage.

- Natural gas co-firing as an integral part of the design with the gas turbine responsible for nearly a quarter of direct power output, as well as use of the gas turbine exhaust to assist with heating the coal fired steam boiler.

2.2 Block Flow Diagram

Figure 2.1 includes the simplified block flow diagram focusing on the boiler, gas turbine, steam turbine, and emission controls.

2.3 Process Blocks

2.3.1 Coal Fired Boiler

The proposed coal fired boiler will be a Doosan variable pressure once-through USC boiler. This boiler is an opposed wall-fired, once-through, ultra-supercritical boiler with supercritical steam parameters over 250 bar and 603℃ at the outlet. It is a two-pass, radiant-type boiler with a drainable superheater and capable of firing the coals specified in the RFP (throughout the boiler load range, enabling fast start-up times and maximizing ramp rates). The boiler will incorporate advanced low NO_x axial swirl pulverized coal burners in the furnace's front and rear walls. The advanced low NO_x burners come complete with auxiliary fuel burners for start-up and low-load combustion support.

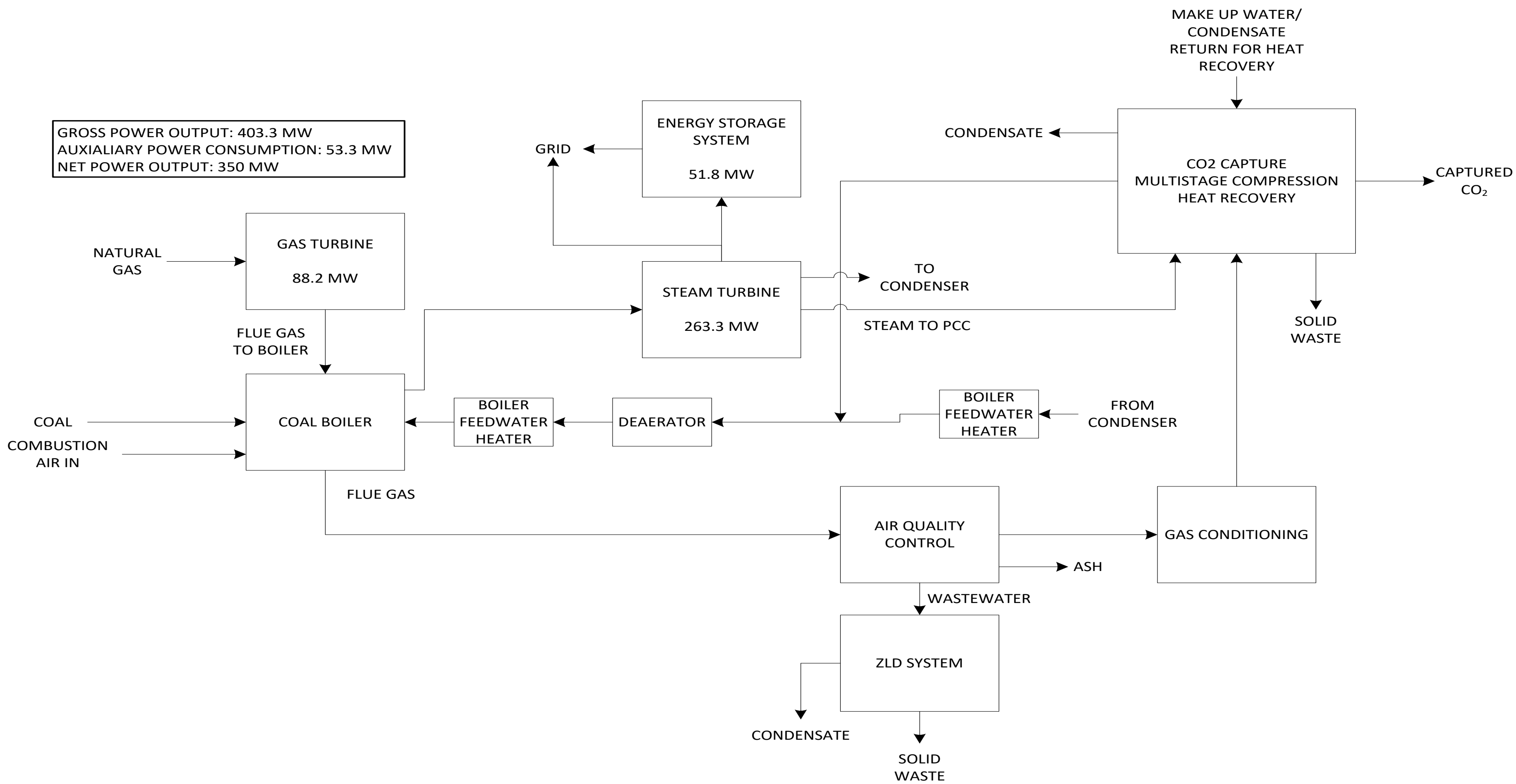
During start-up and low loads (below the minimum specified stable-operating load), two-phase flow is maintained in the furnace with the assistance of a recirculation pump. The pump increases economizer inlet water flow and maintains a sufficient water flow through the furnace tubes to provide adequate cooling. The recirculation pump is a standard design featuring suspended, in-line configuration with wet stator motor. The pump extracts an amount of water from the separator and storage vessel system and recirculates it to the economizer inlet to combine with the feedwater such that the total water flow to the furnace tubes is at or above the minimum flow requirement. For start-up, the recirculation pump system offers fast start-up times, low firing rates, and low auxiliary fuel consumption. As limited hot water is dumped to flash tanks, system heat loss and feedwater inventory requirements are minimal. The heating surface arrangement is selected to maintain desired steam conditions throughout the required operating load range.

Lime is injected into the flue gas ahead of the SCR for SO_3 reduction before it goes to flue gas heat exchangers to minimize corrosion potential. This is important to the heat transfer surface integrity.

2.3.2 Steam Turbine

The proposed steam turbine will be a Doosan DST-S20 condensing steam turbine with reheat. The steam conditions are 3,500 psi and 1,112°F main steam/1,112°F reheat steam at steam turbine inlet. The steam turbine will be configured as a tandem compound two-flow machine featuring a combined HP-IP casing with a two-flow low-pressure turbine. The HP-IP casing has a horizontally split design with two shells. Steam entering into the HP inner casing is conducted into the circular duct or nozzle chambers, which are cast in the inner casing. The HP steam flows toward the front bearing pedestal. The inlet connections are sealed in the inlet section of the nozzle chambers with special sealing rings.

Figure 2.1 Simplified Block Flow Diagram – Hybrid Gas/Coal Power Plant



The reheat steam enters the IP inner casing via two inlet connections in the lower and in the upper half of the outer casing. Steam entering into the IP inner casing is conducted into the circular duct. The IP steam flows toward the low pressure (LP) casing. The inlet connections are sealed in the inner casing in a similar way as the live steam inlet into the HP section of the turbine. The LP casing is a double-flow, double-shell design. The outer and inner casings are of welded design. Steam from the IP turbine is introduced through two cross-over pipelines into the inlet equipped with the expansion joint and into a circular duct in the inner LP casing. The walls of the outer LP casing form a rectangular exhaust hood. The LP casing lower half is welded on to the exhaust neck. Welded brackets are on the periphery of the outer casing and enable the casing to be set up on the foundation.

The extraction branches are situated in the lower half of the inner turbine casing and they are led out through the condenser neck to regenerative heaters. The exhaust annulus is equipped with a spray cooling system, which is used when the quantity of steam passing through the rear section is low and the associated ventilation losses of the blades increase the temperature to about 194^{o}F (typically during low-load or no-load operation).

2.3.3 Gas Turbine

The proposed gas turbine has an 88 MW power output capability with the configuration of a single shaft, bolted rotor with the generator connected to the gas turbine through a speed-reduction gear at the compressor or “cold” end. This feature provides for an axial exhaust to optimize the plant arrangement for combined cycle. An 88 MW class GE 6F03 model would be applied for the concept development and preFEED study. The major features of the gas turbine are described below. The compressor is an 18-stage axial flow design with one row of modulating inlet guide vanes and a pressure ratio of 15.8:1 in ISO (Standard) conditions. Inter-stage extraction is used for cooling and sealing air (turbine nozzles, wheel spaces) and for compressor surge control during startup/shutdown.

A reverse-flow six-chamber second-generation dry low NO_x (DLN-2.6) combustion system is standard with six fuel nozzles per chamber. Two retractable spark plugs and four flame detectors are a standard part of the combustion system. Crossfire tubes connect each combustion chamber to adjacent chambers on both sides. Transition pieces are cooled by air impingement. Thermal barrier coatings are applied to the inner walls of the combustion liners and transition pieces for longer inspection intervals. Each chamber, liner, and transition piece can be replaced individually.

The turbine section has three stages with air cooling on all three nozzle stages and the first and second bucket stages. The first stage bucket has an advanced cooling system to withstand the higher firing temperature. It utilizes turbulated serpentine passages with cooling air discharging through the tip, leading, and trailing edges. The buckets are designed with long shanks to isolate the turbine wheel rim from the hot gas path, and integral tip shrouds are incorporated on the second and third stages to address bucket fatigue concerns and improve heat rate. The first stage has a separate, two-piece casing shroud that permits reduced tip clearances. The rotor is a single-shaft, two-bearing design with high-torque capability incorporating internal air cooling for the turbine section.

2.3.4 Energy Storage System (ESS)

The proposed energy storage system is a 51 MW modular redox flow battery system using a vanadium ion. The ESS will be designed to store energy from the nearby renewable power generation source as well as surplus power from HGCC plant. The ESS will also be designed to take care of the frequency control function for stabilization of the grid when renewable generation fluctuates. The Vanadium redox flow battery has longer storage durations and longer life cycle and easier to scale up than a lithium ion battery. The 51 MW ESS will have 51 MWh capacity with a 1-hour discharge and charge time. It will effectively cover the initial startup and load following when renewable power is lost and before gas turbine ramp up is complete - a 30-minute duration. The ESS is expected to have a 20-year life and the operation capability is expected to be 8,000 cycles.

2.3.5 Environmental

The following sections describe the environmental control systems anticipated for the HGCC.

2.3.5.1 Air Quality Control Systems (AQCS)

A combination of advanced AQCS components will reduce the pollutant emissions dramatically. A NL (Non Leakage)-GGH (Gas Gas Heater) Cooler is proposed, followed by dry ESP (Electrostatic Precipitator). Greater than 99% dust reduction efficiency is targeted for the ESP. The ESP has the best efficiency at 194^{o}F-212^{o}F. For this reason, the NL GGH cooler is placed before the ESP.

An SCR-deNO$_x$ system, with > 90% NO$_x$ reduction efficiency, is installed before the GAH (Gas Air Heater). The optimum operating temperatures for SCR units using a base-metal oxide catalyst ranges from 600 to 750°F[2]. The inlet flue gas temperature to the SCR unit at the minimum load should be higher than 572°F. SO_2 emission will be controlled by a wet limestone FGD and SO_3, PM_{10}, and Hg_{PM} will be controlled by an EME (Electrostatic Mist Eliminator) in combination with a wet limestone FGD absorber. The NO$_x$ and SO_2 flue gas concentrations are 10 ppm and 4 ppm, respectively.

Additional DeSOx control with a one stage sieve tray and one stage vortex™ tray, newly developed by Doosan Lenjtes, will be added to meet the 4 ppm SO_2 target. The SO_2 to SO_3 conversion rate is expected to be less than 1%. The EME (Electrostatic Mist Eliminator), which is developed by DHI, applies wet ESP technology. The EME's installed after a one stage ME (Mist Eliminator) on top of the absorber. EME is compact with higher efficiency, lower operating cost and greater than 90% reduction efficiency. The EME has 95% removal efficiency for PM greater than 0.7μm and 70% for PM of 0.3μm or less. Therefore, the EME has the same performance as a bag house for PM10 removal. Since the non-leakage GGH cooler is located before the dry ESP, this is a cold ESP (flue gas temperature ranges from 194 to 212^{o}F), which has better mercury removal efficiency. In addition to this, the majority of mercury in bituminous-fired boilers exists as Hg^{2+}, which is soluble[xi]. Therefore, most Hg^{2+} is removed by the Wet FGD and the EME, using wet ESP technology to remove particle-bound mercury. Elemental mercury in subbituminous is difficult to remove but a catalyst in this system oxidizes Hg^0 to Hg^{2+} for removal and simultaneously reduces NO to N_2.

Additional equipment will be installed in the FGD to meet the SOx reduction target. This eliminates the need for lime injection that is known to lower fly ash resistivity. Using the above AQCS train, PM10 and PM2.5 can be effectively reduced to 0.5 mg/Nm3.

Bituminous coal is the base case for this study, however, the AQCS proposed method is applicable to each coal type listed in Table 2.5. Details of all the parameters related to the AQCS have not been evaluated for this phase and will be addressed in the preFEED study.

2.3.5.2 Carbon Capture

The proposed concept for carbon capture will evaluate the amine-based PCC (Post Combustion Carbon) capture as the base case. Current Technical Specifications for PCC are provided by Doosan Babcock and are used to evaluate the performance impact on the conceptual design. Alternatives to reduce the performance decrease by the PCC process will be investigated. A detailed performance, cost, and operational impact study on the USC PP heat balance would be conducted during the preFEED stage for this concept.

2.3.5.3 Carbon capture plant requirements and performance

Preliminary amine-based PCC plant requirements include an absorber with an inlet temperature of 95^{o}F and outlet temperature of 113^{o}F. The system also includes a 2.5 MJ/kg CO_2 reboiler with a steam requirement of 125.7 lb/s, an inlet temperature of 510.8^{o}F, and outlet temperature of 303.8^{o}F. The

Upstream ESP and FGD efficiencies are expected to be 99% and 90% respectively and the carbon capture rate is assumed to be 90%. To avoid solvent degradation, it is assumed that the maximum allowable SO_2 inlet is 4ppmv. The resulting CO_2 product will be greater than 99.9% Vol. CO_2 and 0.1% Vol. H_2O at a flow rate of 119 lb/s, a temperature of 104°F and a pressure of 2,200 psi. A key aspect of the flexible operation of post-combustion capture plants is steam availability and conditions, necessary to regenerate the solvent.

Uncontrolled steam extraction (floating pressure) to supply the reboiler is preferred over controlled extraction by throttling the low pressure turbine inlet since it improves full and part load performance. However, there are limitations for regeneration at partial load, since the floating pressure integration leads to steam pressures at partial load that are too low for additional solvent regeneration. The insertion of a butterfly valve in the IP-LP crossover downstream of the steam extraction point enables steam throttling at reduced loads, which provides steam with enough energy to continue capture operations at full capacity. This increases the operational flexibility of the power plant by allowing it to respond to load demand changes but has a negative impact on overall system efficiency. This design technology is adopted for the HGCC concept. A more detailed performance, cost, and operational impact study on the USC PP heat balance will be conducted during the preFEED stage for this concept.

The required reboiler steam flow at 30% load is 62.9 lb/s with an inlet temperature of 501.7°F, which is about 50% of design flow and 100% of design temperature. This unbalanced load steam requirement can be met in the current proposed boiler and turbine concept design. However, more detailed analysis will be conducted at preFEED stage, especially for turbine stability.

2.3.5.4 Requirement from AQCS to PCC connection

The PCC plant requires some flue-gas upstream processing in coal-fired applications due to the detrimental impact of acid gas components on the solvent life. These components in the flue gas, such as SO_2, SO_3, NO_2, and halides, react with the solvents to produce unreactive heat stable salts (HSS), which have to be removed or converted back to amine. It is normally recommended that inlet SO2 concentration of the PCC plant must be less than 4 ppmv. NOx reduction technologies are anticipated to be sufficient to minimize the impact of nitrate salt formation. Optimal PCC performance is achieved at relatively low flue-gas temperature (i.e., 86°F to 104°F), with a typical operating temperature of 95°F. A direct contact cooler (DCC) is installed downstream of the FGD to cool the flue gas from the typical main FGD outlet temperature to achieve the required PCC inlet temperature.

2.3.5.5 Carbon capture integration & technology options

Among the various carbon capture technologies, the amine base absorption technology is the most proven technology but it requires a significant amount of heat for absorbent regeneration. Calcium/sorbent looping adsorption technologies such as CACHYS™ have some technological benefit, such as low energy penalties because it includes an exothermic carbonation reaction. But it has much lower TRL than amine base PCC. Cryogenic Distillation technology requires CO_2 concentration and high cooling energy. At this moment, an advanced amine base absorption PCC technology with reduced energy consumption will be applied for HGCC plant. The reboiler energy consumption is reduced to 2.5 MJ/kg CO_2 level by applying the Doosan Babcock internal integration technologies. Steam for the reboiler is extracted from the LP cross over pipe. Unused energy from the reboiler will be recovered at the deaerator. CO_2 compression heat will be recovered by heating feed water to increase plant efficiency. A detailed performance, cost, and operational impact study on the USC PP heat balance will be conducted during the preFEED stage for this concept. Alternative integration options to reduce the performance decrease by the PCC process will be investigated.

2.3.5.6 Water Use

Water consumption is estimated at 2 million gallons per day. Most of the consumptive use is for cooling tower make up, with blowdown routed to treatment discussed in the next section.

2.3.5.7 ZLD System

Wastewater from the flue gas cleanup and cooling tower blowdown are collected and sent to a zero liquid discharge system or ZLD. The thermal ZLD system reuses most of the treated water and dispose of only a small amount of solid waste. The ZLD system is divided into softening/ultra-filtration pretreatment, reverse osmosis (RO) for brine concentrating, and a mechanical vapor recompression crystallizer requiring a small amount of startup steam initially. The RO permeate and distillate from the crystallizer are sent back as part of condensate return. Softening solids from a filter press and concentrated solids from the crystallizer are landfilled. The RO system will include pretreatment for hardness removal eliminating scaling concerns due to high sulfates.

2.3.5.8 Solid Waste

Solid waste includes fly ash and gypsum which are saleable. Precoat (amine system) waste from flue gas clean up and solids from the ZLD are collected and landfilled.

2.4 Design, Construction, and Commissioning Schedule Optimization – Modularization & Retrofit Opportunities

Tactics to reduce design, construction, and commissioning schedules from conventional norms include:

- Complete boiler modularization characteristics (e.g., shop fabrication of equipment or subsystems, or laydown area pre-assembly, in whole or part)
  - Combustion turbine – ships as a complete unit
  - Boiler and accessories
  - Environmental control systems – each system is composed of modules
  - ESS Battery system – ships as a complete unit for assembly in the field
- CFD and 3D modeling
- Advanced process engineering such as using heat balances to optimize the thermal efficiency
- Retrofit existing power plants and repurpose existing infrastructure, such as coal handling and cooling water systems.
- Continuous analysis of coal delivered to the plant using a full stream elemental analyzer to blend coals based on projected impacts on plant performance.
- One equipment manufacturer to streamline commissioning

2.4.1 Modularization

State-of-the-art design technology such as digital twin and 3-D modeling and dynamic simulation at the design stage will be applied to improve power plant reliability and reduce construction time. Field welding points of high pressure component will be reduced as much as possible and a standard size boiler will be applied to reduce construction cost. Additionally, a modularization approach will be used as much as possible during the FEED study stage to reduce the construction time. The energy storage system batteries are a modular concept to reduce installation costs and easily increase storage capacity.

Many existing power plants or prospective plant sites are on or near major waterways. Using barges where possible will allow large pieces of equipment such as vessels, boiler components, etc. to be fabricated off site and shipped in large pieces.

2.5 Basic Performance Criteria / Specification

Table 2.1 provides the overall plant performance including total plant efficiency, ramp rate, start time, and turndown while Table 2.2 provides criterial design parameters for the plant equipment.

Table 2.1 Overall Plant Performance

Process/Equipment	Value	Unit
Total Plant Efficiency	37.1	%
Total Plant Natural Gas % Feed	< 30	%
Total Plant Ramp Rate Target	10	%
Total Plant Ramp Rate Expectation	6	hrs
Total Plant Cold/Warm Start Time	Estimated 30 min for Gas Turbine is full load, estimated 220 min for Steam Turbine is full load in warm start-up	--
Total Plant Turndown with Full Environmental Compliance Target	7.6:1	--

Table 2.2 Critical Design Parameters for Coal & Gas Boiler Turbine

Process/Equipment	Operating Parameter	Value	Unit
Boiler (Opposed wall-fired, once through supercritical, 2-pass radiant-type boiler with drainable superheater) Turbine (tandem compound two-flow machine with High Pressure (HP)-Intermediate Pressure (IP))	Supercritical Steam Pressure	3500	psi
	Super Heat Steam Temperature	1112	°F
	Reheat Steam Temperature (at Turbine inlet)	1112	°F
	Coal % Feed Fuel Usage – Coal	43.9	lb/sec
	Coal % Feed Fuel Usage – Air	210.5	lb/sec
	Efficiency/MW – Boiler	89.3	%
		603 (503 from coal combustion, 100 from GT exhaust gas)	MWth
Gas Turbine (GE 6F03)	Natural Gas Usage	9.3	lb/sec
	Air Usage	398.6	lb/sec
	Exhaust Gas Temperature	1112	°F
	Efficiency/MW	36.04	%
		88	MW
ESS (Vanadium Redox flow battery)	Charge/discharge duration	1	hr
	Storage duration	Limitless	
	Efficiency/MW/MWh	60-80 (DC-DC)	%
		51	MW
		51	MWh
	Life/Cycle	20/8,000	Yr/cycles
SCR	Inlet Gas Temperature (at min load)	Over 572	°F
	Inlet NOx (bituminous/sub-bituminous /lignite)	150/147/141	ppm
	Concentration (at O_2 6% dry vol.)	10	ppm
Sorbent Injection	Hydrated lime	9,259	lb/hr
Electrostatic Precipitator	Dust reduction efficiency	99	%
FGD with Non-leakage gas-gas heater and Electrostatic Mist Eliminator (EME)	Concentration (at O_2 6% dry vol.)	4	ppm
	Exit PM10	2	mg/m^3
	SO_2 removal efficiency	99.7	%

Process/Equipment	Operating Parameter	Value	Unit
Carbon Capture / Compression System	CO_2 capture efficiency (Assume <10 ppm SO_2 Inlet)	90	%
		24	MW
ZLD Treatment System	RO / Crystallizer	1000	GPM
		1	MW
Efficiency and Reliability Improvement Technologies - Full stream elemental coal analysis combined (FSEA) combined with combustion system operational performance indices (CSPI) to optimize coal properties and plant operations- Note: all values are dependent upon fuel composition, system design, and operating parameters	Wall slagging/Strength Index	TBD	°F
	Water Wall Slagging Deposit build up rate (DBR)	TBD	lb/ft^{2}s
	High Temperature Fouling (Furnace exit gas temperature <less than T_{IST})	< T_{IST}	°F
	High Temperature Fouling (DBR)	TBD	lb/ft^{2}s
	Low Temperature Fouling – Sulfation Temperature	TBD	°F
	Low Temperature Fouling (DBR Sulfation)	TBD	lb/ft^{2}s

2.6 Plant Efficiency

Table 2.3 lists the plant properties at different load rates. The Hybrid Gas/Coal Concept (HGCC) has a high predicted plant efficiency of 37.1% with PCC by using the DHI's integrated plant performance calculation tool, UniPlant, which can simulate the integrated performance of boiler, turbine and CO_2 compression with PCC. In case of peak time operation, this efficiency can be increased up to 43.5% by using the ESS system. For charging the ESS, additional power is required, but surplus power used during low demand time can increase power and efficiency during peak time.

Table 2.3 Plant Properties

Total plant load	MCR	71%	57%	45%	30%	Units
Coal power plant load	**MCR**	**92%**	**67%**	**49%**	**28%**	
Ambient dry bulb temperature	59.0	59.0	59.0	59.0	59.0	Deg F
Ambient relative humidity	60.0	60.0	60.0	60.0	60.0	%
Barometric pressure	14.7	14.7	14.7	14.7	14.7	psi
Gas turbine load	100.0	0.0	0.0	0.0	0.0	%
Gas turbine power output	88.2	0.0	0.0	0.0	0.0	MW
ST power output	263.3	242.9	177.6	128.5	72.6	MW
ESS power output	51.8	51.9	51.9	51.9	51.9	MW
Plant gross power output	403.3	294.8	229.5	180.4	124.6	MW
Auxiliary power consumption	53.3	45.5	30.9	21.4	12.2	MW
Plant net power output	350.0	249.3	198.6	159.0	106.4	MW
Natural gas heat input	265.0	0.0	0.0	0.0	0.0	MW
Coal heat input	539.8	613.2	462.2	339.2	205.0	MW
Plant gross eff. (HHV)	50.1	48.1	49.6	53.2	60.8	%
Plant net eff. (HHV)	43.5	40.7	43.0	46.9	54.7	%
Plant net eff. without ESS (HHV)	37.1	32.2	31.7	31.6	29.4	%

Total plant load	**MCR**	**71%**	**57%**	**45%**	**30%**	**Units**
Coal power plant load	**MCR**	**92%**	**67%**	**49%**	**28%**	

Table 2.4 lists the auxiliary power requirements at different load rates. These are estimates and will be further refined during the preFEED study.

Table 2.4 Auxiliary Power Summary for Plant Properties

Total plant load	**MCR**	**71%**	**57%**	**45%**	**32%**	**Units**
Coal power plant load	**MCR**	**92%**	**67%**	**49%**	**28%**	
BFPM	8,213	8,192	3,984	2,024	709	kW
Condensate Pump	402	337	246	183	116	kW
CO2 Compressor	17,044	14,985	11,229	8,200	4,915	kW
SCR	199	149	105	75	45	kW
Dry ESP	2,988	2,235	1,569	1,120	672	kW
Wet FGD including NL GGH, ZLD, EME	4,681	3,502	2,458	1,755	1,053	kW
Ash handling system	700	700	490	350	210	kW
Coal handling system	201	201	140	100	60	kW
Pulverizers	952	952	666	476	286	kW
Primary & Forced Air Fans	1,273	952	668	477	286	kW
Other Fans	643	479	336	240	144	kW
Induced Draft Fans	4,144	3,100	2,176	1,554	932	kW
Circulating Water Pumps	2,212	2,212	1,548	1,106	664	kW
Ground Water Pumps	228	228	160	114	68	kW
Cooling tower Fans	1,145	1,145	801	572	343	kW
PCC	6,500	4,863	3,413	2,438	1,463	kW
Miscellaneous Balance of Plant	912	682	479	342	205	kW
Transformer Losses	830	621	436	311	187	kW
Total	53,268	45,536	30,903	21,439	12,358	kW

2.6.1 Plant Monitoring & Forecasting

In the constantly fluctuating landscape of the electricity grid, new strategies will utilize advanced computational systems in order to continuously adjust operations to yield the greatest efficiency possible in the moment. The coal industry has been well-positioned for this constant fluctuation by learning from one of its largest challenges - heterogeneous, constantly fluctuating fuel properties. The lessons learned from dynamic optimization of operations with respect to fuel properties may be extended to the challenges of load following in the new era.

Microbeam Technology Inc. (MTI)'s state-of-the-art condition-based monitoring (CBM) tool for coal-fired power plants is designed to actively monitor and manage coal quality and overall boiler conditions. Coal properties impact the performance, reliability, and availability of electricity generation units as well as increase maintenance costs. A study by EPRI found that the minimum annual economic impact of ash behavior to the US coal-fired power industry was 1.2 billion dollars.[vii]

The Combustion System Performance Indices (CSPI) and coal tracker (CT) tools provide a means to maximize availability and maintain generating capacity while reducing cost.[viii,ix] The tool will forecast and alert plant operators and engineers of poor boiler conditions, which may occur as a result of incoming coal and/or current power plant parameters. The coal quality information that has shown the best prediction is derived from full stream elemental analyzers (FSEA) based on prompt gamma neutron activation analysis (PGNAA) that provides online analysis of key coal quality parameters. The integration of the CBM based control system with the coal combustion plant of the future is illustrated in Figure A2.2 in Attachment A.

In addition to FSEA, coal quality information can be derived from a range of coal handling and blending facilities including in-mine analysis. The CT program is tailored for each plant and is used to track the coal from the point of delivery to the burner. The CT is integrated with CSPI (CSPI-CT) to forecast coal quality delivered to each burner or set of burners. This allows for better prediction of combustion stoichiometry, wall slagging, convective pass fouling, and erosion. This software is currently in operation at a coal fired power plant and is integrated with CBM. The CSPI-CT can be integrated with a PGNAA, fireside sensors measuring parameters such as temperature, gas composition, heat flux, etc. This data is combined with plant operation setpoints for burner operation (air, fuel, and steam flows), soot blower cycling, pollution control equipment, etc. In addition, the CSPI-CT program integrated with CBM provides an assessment of overall plant performance as a function of coal properties and boiler operations. Fine-tuned projections of coal properties and plant performance are developed using a combination of operational expertise, traditional data analysis, and machine learning. . The aim of the efforts is to provide a tailored tool that will integrate the operations of the CSPI-CT into the plant control systems. Currently, Microbeam is leading a project funded by the US DOE National Energy Technology Laboratory (NETL), a coal company, and utilities entitled “Improving Coal Fired Plant Performance through Integrated Predictive and Condition-Based Monitoring Tools” Award No. DE-FE00031547. The overall goal of this project is to demonstrate at a full-scale coal-fired power plant the ability to improve boiler performance and reliability through the integrated use of condition-based monitoring (CBM) and predictions of the impacts of coal quality on boiler operations.[x,xi]

At a current installation of CSPI-CT, MTI monitors changes in heat rate, coal properties, and load conditions. The CSPI-CT is currently being used for coal selection and blending matching with specific plant component performance in order to reduce these peaks. The impacts of ash deposition increase heat rate in the new plant in the same way as an existing system. The preFEED phase would intend to incorporate Performance Indices-Coal Tracker programs to manage fuel properties. Managing fuel properties and tailoring operating conditions will improve heat rate and improve overall plant efficiency. A lignite-fired plant experienced numerous reductions in output during a period of 12 days of challenging operations. Root cause analysis found that fuel properties were a primary factor in the operational challenges. Proper use and projection of fuel quality at the burner may have avoided heat rate excursions. During these conditions, the plant may obtain a calculated 1.35% heat rate improvement over traditional operations by accurately forecasting and circumventing challenges associated with changing fuel properties.

The challenge of maintaining efficiency during cycling will be solved in part through the CSPI-CT’s fuel classification/sorting capabilities. Furthermore, by accurately forecasting the impacts of fluctuating coal quality on performance, the CSPI-CT enables a new form of efficiency improvement: harmonizing supply-demand fluctuations in the boiler.

2.7 Alternative Coal and Other Fuels Thermal Performance

The Hybrid Gas/Coal Concept (HGCC) can use various kind of coals as well as natural gas. This feature can help energy security and flexibility during future fuel market fluctuation. Bituminous and sub-bituminous coal can be burned in a same boiler design with a well proven coal blending technology. Lignite coal requires a larger boiler but it also can be used if it is considered during the design stage. Regarding modularization, an HGCC power plant would be better suited for bituminous and sub-bituminous with advanced coal blending technology and a real time coal quality measurement system. This advanced coal blend technology can help apply the same size power plant to the sub-bituminous and bituminous coals, which can reduce a CAPEX investment. Table 2.5 below summarizes the output specifications for the bituminous and sub-bituminous coals and lignite coals. In case of lignite firing, the net power output is reduced to 312.4MW in compare to the 350MW of bituminous and sub-bituminous.

Plant efficiency using lignite coals is expected to be approximately 2% lower than a bituminous firing plant. To mitigate slagging and fouling problem caused by lignite sodium-rich ash, horizontal furnace exit temperature will have to be reduced, which leads to larger furnace volume for the same power output. With the same boiler furnace size, power output should be reduced. In addition, increased tube spacing in the convective pass to allow for cleaning of fouled tube surfaces. Eliminating alternative superheater and reheater tube panels by using the same wall tube spacing for a bituminous boiler can allow for a lignite modification model. Considering the wall tube structure is more important to boiler price, these modifications would prevent boiler price increase and make a modularization concept relevant to a lignite boiler. However, the smaller steam turbine is a disadvantage for modularization. Using the bigger lignite boiler with same steam turbine would provide better economics. At the preFEED stage, the optimum MW size for modularization will be reviewed.

Table 2.5 Output Specifications for Different Coal Types

	Lignite MCR	**Sub-bituminous MCR**	**Bituminous MCR**	**Units**
Ambient dry bulb temperature	59.0	59.0	59.0	Deg F
Ambient relative humidity	60.0	60.0	60.0	%
Barometric pressure	14.7	14.7	14.7	psi
Gas turbine load	100.0	100.0	100.0	%
Gas turbine power output	88.2	88.2	88.2	MW
ST power output	229.9	261.3	263.3	MW
ESS power output	45.2	56.7	51.8	MW
Plant gross power output	363.4	406.2	403.3	MW
Auxiliary power consumption	51.0	56.2	53.3	MW
Plant net power output	312.4	350.0	350.0	MW
Natural gas heat input	265.0	265.0	265.0	MW
Coal heat input	496.4	554.5	539.8	MW
Plant gross eff. (HHV)	47.7	49.6	50.1	%
Plant net eff. (HHV)	41.0	42.7	43.5	%
Plant net eff. without ESS (HHV)	35.1	35.8	37.1	%

Table 2.6 below summarizes the auxiliary power requirement comparison for the different coals. This concept phase has determined the auxiliary power for sub-bituminous coal to be greater than bituminous. Lignite auxiliary power should be higher than sub-bituminous, but in this conceptual study the reduced power output for lignite is the result of using the same physical boiler size as bituminous and sub-bituminous as discussed earlier in the previous paragraph.

Table 2.6 Auxiliary Power Summary for Different Coal Types

Total plant load	**Lignite**	**Sub-Bit**	**Bit**	**Units**
Coal power plant load	**MCR**	**MCR**	**MCR**	
BFPM	7,095	8,245	8,213	kW
Condensate Pump	339	387	402	kW
CO2 Compressor	17,210	17,217	17,044	kW
SCR	199	210	199	kW
Dry ESP	2,992	3,143	2,988	kW
Wet FGD including NL GGH, ZLD, EME	4,687	4,924	4,681	kW
Ash handling system	634	700	700	kW
Coal handling system	182	201	201	kW
Pulverizers	862	1,344	952	kW
Primary & Forced Air Fans	1,274	1,889	1,273	kW
Other Fans	704	643	643	kW
Induced Draft Fans	4,150	5,445	4,144	kW
Circulating Water Pumps	2,002	2,212	2,212	kW
Ground Water Pumps	206	228	228	kW
Cooling tower Fans	1,036	1,145	1,145	kW
PCC	5,884	6,500	6,500	kW
Miscellaneous Balance of Plant	826	912	912	kW
Transformer Losses	751	830	830	kW
Total	51,034	56,175	53,268	kW

2.8 Process Hazard Analysis

Redesigning the coal firing system creates potentially dangerous conditions. A detailed process hazard analysis (PHA) would be conducted to identify the hazards and implement the appropriate technologies to mitigate/eliminate them. The technologies to reduce hazards such as explosions or fires are well known, including CO monitors, explosion suppression canister systems, and fast acting dampers/explosion panels to name a few. A preliminary PHA will be part of the preFEED study for the pulverizing system, but also the HGCC concept as a whole.

3 Technology Development Pathway

3.1 Present Solution

The HGCC utilizes typical state of the art power plant equipment and systems, including:

- USC pulverized coal boiler
- USC steam turbine
- Feedwater heater and condenser
- Pumps and fans
- AQCS consisting of and SCR, ESP, Wet FGD and EME
- PCC system and CO2 compression
- Breakers, buses, and switchgear
- Process controls
- GE F6.03 combustion turbine
- ESS with storing capability from HGCC and nearby renewable source

There are four unique aspects of this design. The major engineering challenge will be to integrate the four systems into the already commercially available hardware.

- Redesigned Coal Firing System –The advantage of this system is that the boiler turndown and ramp rate are improved when compared to a traditional pulverized coal boiler.
- Combustion Turbine Integration – The exhaust from the combustion turbine will be introduced into the boiler in the furnace proper and the overfire air system. CFD modeling will need to be performed to optimize the performance of the burner/OFA system for NOx emission and combustion completion and to calculate heat transfer rates for the various sections of the boiler (waterwalls, superheater, reheater, etc.).
- Flue Gas/Air Heater Heat Recovery – The introduction of the combustion turbine exhaust upsets the flue gas/combustion air flow balance in the air heater (there is an excess of flue gas). The engineering approach will be to divert some of the flue gas and recover the heat in the flue gas with two external heat exchangers. The heat from these exchangers will be directed into the condensate system and the feedwater system. These pieces of hardware are typical in their design for this application, but the integration in the boiler/feedwater cycle is new.
- ESS (batteries) – The ESS (vanadium redox flow battery) currently exists but the integration into the boiler/combustion turbine electrical system will be new.
- Advance coal property monitoring and management system designed to minimize impact on performance and reliability.

3.2 Technical Gaps and Ways to Address Them

The Hybrid Gas/Coal Concept (HGCC) key technical gaps/risks and well as proposed approaches to address them are discussed in the following subsections.

3.2.1 Boiler Combustion Gaps

The USC technologies are well proven up to 1,000 MW and have shown high reliability. However, a typical USC power plant is normally configured with a capacity of over 400 MW to take advantage of economies of scale. The 263 MW–class USC coal power plant, featuring rapid start and low-load operation, will require a thorough design study and analysis. The boiler combustion characteristics with gas turbine exhaust gas should be checked for the technical feasibility of this concept.

Figure A3.1 in Attachment A shows the flame and temperature distribution by CFD simulation on Doosan Clean Coal Test Facility furnace environment. The flame shape is similar for all cases and the temperature is relatively low for the gas turbine flue gas case. This is the effect of gas components with high heat capacity, such as CO_2 and H_2O, which constitute a larger fraction of the flue gas than in pure air combustion. However, from the viewpoint of stability of the flame, it is assumed that the flame is attached to the flame holder.

Figure A3.2 in Attachment A shows the oxygen concentration distribution. As shown in the previous temperature distribution, the flame is stable, so oxygen is rapidly exhausted from the front end of the burner, and the oxygen concentration drops sharply. Since most of the oxygen is consumed before OFA is supplied, it can be judged that most of the fuel is burned. Oxygen concentration around the OFA rises sharply as additional combustion air is fed through the OFA downstream of the furnace, but the oxygen concentration decreases as additional burnout proceeds. It can be concluded that some combustion delay is caused by GT exhaust gas, but there is no significant problem in combustion.

As mentioned above, it was confirmed that the option of mixing the GT flue gas with the combustion air and supplying the mixture to the burner has no significant problem in terms of flame stability. However, as the oxygen partial pressure decreases, combustion delay is inevitable, and the temperature of the mixed gas supplied is also high, so that the draft loss of the burner air register becomes large. The retention time in the furnace is reduced by the increased volume of the GT exhaust gas. All of these conditions are reflected in the increased unburned carbon content. Therefore, additional development is required for the burner, OFA system, and burner size.

USC heat transfer surfaces operate at higher temperatures and may be prone to increased fireside ash material sticking and rapid deposit growth. Studies on these issues need to be conducted in order to optimize materials of construction, operating temperatures, cleaning technologies, and cleaning cycles. Furnace heat absorption change due to the large volume of hot gas injection should also be investigated. An optimization study of the configuration and design parameters of coal and gas would be required to maximize the benefits and minimize the risks for the RFP requirements.

The necessity of a small-scale test will be determined in the preFEED stage. If it is required, the test will be conducted in the FEED stage. If the test is conducted, it is expected that a 3MWth DHI test facility will be used.

3.2.2 Risks

The key technical risk associated with the HGCC is the integration of the combustion turbine into the boiler. Introduction of the turbine exhaust into the boiler requires that the following areas be redesigned when compared to a traditional pulverized coal boiler (Refer to Section 3.1):

- Furnace windbox and burners
- Overfired air system
- Flue gas/air heater and external heat exchangers

The design issues are anticipated to cover the following:

- Heat transfer for the various boiler sections
- Expected tube metal temperatures and their variation as load changes
- NOx emissions reductions from the overfired air system
- Flue gas temperature entering the SCR system at all boiler loads
- Minimum load considerations

3.3 Approach for Advancement

The proposed plant consists of well-proven technologies except coal combustion testing and analysis under a gas turbine exhaust gas environment. Therefore, if appropriate and feasible, a small-scale coal combustion test should be conducted before 2022. A full FEED study for the retrofit demonstration would be possible in the 2022 time frame. A retrofit base demonstration would reduce investment and risk and be implemented in the 2022-2025 time frame. A full FEED study and full scale implementation would occur in the 2025-2030 time frame.

Table 3.1 lists the steps that will be taken to bring the HGCC into commercial operation by 2030 and their associated costs.

Table 3.1 Cost and Time of Commercial HDCC Operation - Combustion concept (CFE000017)

Task	Cost	Timeframe
Concept Study (completed)	$190,000	2019
Pre-FEED Study • Doosan and Barr; Contractor to be selected for FEED Study Support and Construction	$1 MM	2020
FEED Study Critical Components		
• Large Pilot Testing and Modeling	$3 MM	2022-2023
• Full Scale FEED Study (Doosan, Barr, and Contractor selected during pre-FEED)	$10 MM	2024-2025
Full Scale Commercial Project Demonstration		
• Detailed Design Engineering	$90 MM	2026-2027
• Full Scale Commercial Project Demonstration (350MW) • Construct USC boiler, Gas Turbine, Pulverized coal storage & CO2 Capture	$1,200 MM	2027-2030

The new build project cost was estimated at $1.156 billion for business case simulation to compare to other technologies at the same condition. However, the commercial plant cost of this concept can be reduced to about $890 million by using an existing Plant BOP and infrastructure such as coal/site preparation, cooling Tower system, ash storage/handling, building and electric system. It is a real virtue of a Coal FIRST project that transforms an old coal power plant to a modern one to reduce cost.

Table 3.2 provides items to be addressed during the FEED and PreFEED stages of the project

Table 3.1 Technical Pathway

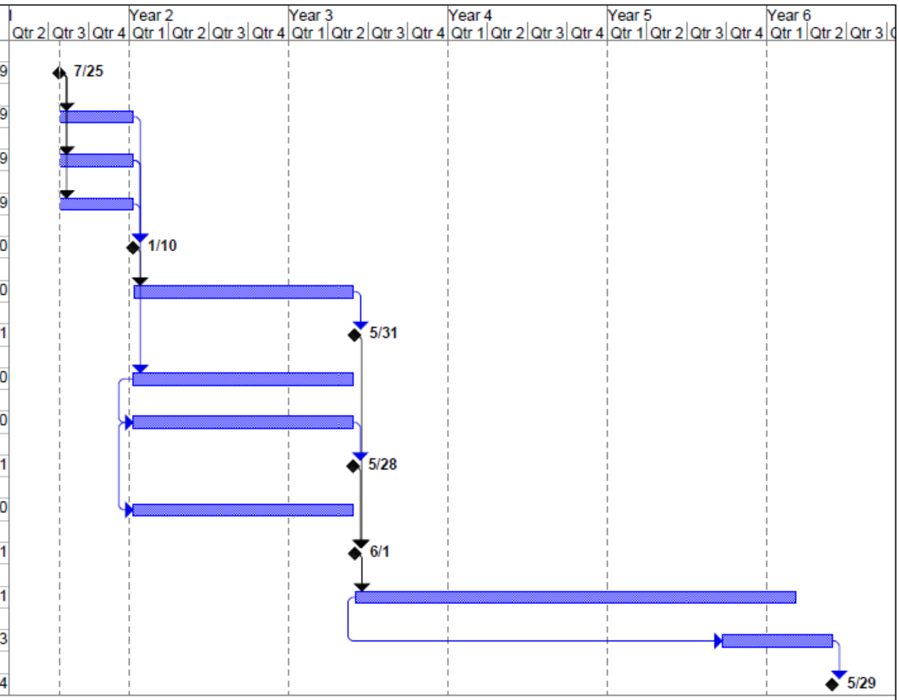
Technical pathway	Technical agendas	Key activities	Target
PreFEED Study	Technical feasibility of coal combustion system with Gas turbine exhaust gas	Various cases combustion CFD analysis for combustion system feasibility and design optimization	Confirm the technical possibility and identity optimum combustion system configuration
	Aux. power reduction and performance improvement	Basic design, process optimization and maker confirmation for 40% efficiency without ESS - Aux. power 10% (5.3MW) reduction - 12.4 MW power increase at same heat input - 2.0 MJ/kg CO2 PCC Reboiler duty R&D plan	Identify plant design configuration realize 40% plant efficiency without ESS including R&D which can be completed during FEED Study
	Cost optimization	Cost reduction by modularization and capacity combination study between gas, coal, and ESS. PCC cost reduction	Identify the CAPEX level of FEED stage
	Flexibility improvement-Minimum load	Steam turbine and boiler design improvement to reduce the minimum load under the PCC using condition	Steam plant minimum load 20%(52.6 MW)
FEED	Retrofit and new build project feasibility	Basic design and critical component detail design for the targeted Plant Retrofit and new build power plant	Confirm the technical and economic feasibility of retrofit and new project
	Flexibility improvement-Startup time	Advanced boiler model design with drainable superheater and advanced control system/logic	2 hours full load for warm start
Potential 2030 Status	Plant Retrofit demonstration	Verify the technology benefit by demonstration for a retrofit project - Adding gas turbine on the existing power plant with some modification	Technical proof and component reliability verification
	Full Scale Commercial demonstration	Commercial demonstration by applying the FEED study result and Plant Retrofit demonstration experience developed technology. The project will be conducted by commercial contract except for developed components.	350MW Scale commercial demonstration

3.4 Anticipated Commercial Scale Schedule

Figure 3.1 below provides an anticipated project schedule. The schedule has what would be considered typical project durations. The major schedule unknowns would be related to the durations for the permitting and construction. The HGCC uses a modular approach, which could lead to reduced construction and commissioning periods.

Figure 3.1 Anticipated Commercial Scale Schedule

ID	Task Name	Duration	Start
1			
2	Notice to Proceed	1 day?	Thu 7/25/19
3			
4	Site Selection	120 days	Fri 7/26/19
5			
6	Preliminary Engineering	120 days?	Fri 7/26/19
7			
8	Permitt Preparation	120 days?	Fri 7/26/19
9			
10	Submit Permit	1 day?	Fri 1/10/20
11			
12	Permittint Process	360 days?	Mon 1/13/20
13			
14	Receive Permit	1 day?	Mon 5/31/21
15			
16	Feed Study	360 days?	Fri 1/10/20
17			
18	Develop EPC Contract	360 days?	Fri 1/10/20
19			
20	Finalize EPC Contract	1 day?	Fri 5/28/21
21			
22	Develop Financing Optior	360 days	Fri 1/10/20
23			
24	Financial Close	1 day?	Tue 6/1/21
25			
26	Construction	720 days?	Wed 6/2/21
27			
28	Commissioning	180 days	Wed 9/20/23
29			
30	Commercial Operatioin	1 day?	Wed 5/29/24



Project: Combustion Schedule.mpp
Date: Thu 7/25/19

Task	Inactive Task	Manual Summary
Split	Inactive Milestone	Start-only
Milestone	Inactive Milestone	Finish-only
Summary	Inactive Summary	External Tasks
Project Summary	Manual Task	External Milestone
External Tasks	Duration-only	Progress
External Milestone	Manual Summary Rollup	Deadline

Page 1

4 Technology Original Equipment Manufactures

4.1 Commercial Equipment

The equipment required to execute the HGCC is currently available on the market today. Examples of the major component are listed in Table 4.1.

Table 4.1 Commercial Equipment

Equipment Item	Manufacturer
Gas turbine	GE
Steam turbine	DHI, GE, Siemens, Skoda
USC steam boiler	DHI
Gas air heater	DHI
Heat exchangers	Yuba,
Boilers	DHI, Alstom, B&W
Boiler Fans	Barron,
SCR	DHI
Dry ESP	DHI
Wet FGD with EME	DHI
Non leakage gas heater and cooler	DHI
PCC	Doosan Babcock
Condenser	DHI
Cooling tower	Marley, SPX

4.2 Research & Development

The main R&D challenge for the HGCC is for new/emerging hardware in the ESS Battery storage system. The concept envisions a 51 MW storage system integrated into the basic USC pulverized coal steam cycle. Items of concern are the capital cost, O&M cost, efficiency, and longevity.

The remainder of the concerns relate to the integrating the redesigned coal firing system and the combustion turbine into the USC boiler design.

The R&D items listed in Table 4.2 will be developed during the preFEED stage and conducted and completed in the FEED stage.

Table 4.2 Conceptual Research and Development

Equipment Item	preFEED Preliminary Development for FEED Study Completion
GT gas combustion Coal burner	Coal burner development for NOx 150ppm and Maximum O_2 level of 3.5% at boiler exit with 30% gas turbine exhaust combustion co-firing
Fast startup USC boiler model	Advanced boiler model to minimize full load start up time after weekly shutdown. Drainable superheater with advanced control system/logic would be required

Equipment Item	preFEED Preliminary Development for FEED Study Completion
Low load operation USC Steam turbine model with PCC	Steam turbine can run down to 20% and provide steam for PCC
Low energy and low cost PCC	Amine base PCC with reboiler heat duty level of 2.0 MJ/kg CO_2 and 30% cost down by modulization
ESS Battery	Reductions in capital cost and O&M costs. Improvements to efficiency, improvements to longevity
USC Boiler Firing System	Integrating the Redesigned Firing System into a new burner system
USC Boiler/Combustion Turbine	Integrating the combustion turbine exhaust into the boiler proper and overfired air system
Flue Gas Heat Recovery	Integrating two additional heat exchangers to recover heat from the flue gas for use in the condensate/feedwater heater cycle

4.3 Prior Work Experience & Available Information

Barr has worked on projects for more than 300 power companies, ranging from small municipal utilities to large regional power producers and nonregulated energy developers. Barr brings together engineering and environmental expertise to provide innovative solutions in the face of changing regulations, markets, and political climates. Barr offers a wide range of services for power clients who seek to add a new generation facility or powerline, make improvements to a current facility, meet environmental requirements, or diversify their fuel portfolio, Barr can take a project from the first feasibility studies and regulatory negotiations through construction, startup, and closure.

Barr has worked with many Original Equipment Manufacturers including GE and B&W powerblock components to perform technoeconomic evaluations and concept studies, detailed design plant betterment, and environmental related services that directly or indirectly involve large industry power generation equipment. Barr has also worked with fuel cell and Organic Rankine Cycle concept studies where OEM vendors were solicited for cost evaluation and feasibility studies.

A description of the projects are described below:

Option study and design for air jig system dewatering rejects handling and storage: A 1200 MW facility in the Midwest used existing jigs designed to discharge pyrite rejects (in dry form) from the fluidized bed dryers into a holding tank where jet style pumps were employed to sluice the resulting slurry (mixture of water and pyrites) to the existing ponds. To reduce water contamination caused by creating the slurry and eliminate the storage of pyrites in the ponds, a dry transport system was proposed for the pyrites and a new truck load-out station to enable the disposal in an existing landfill. Barr investigated and developed three options for conveying the pyrites from the existing storage bin to the new, truck load-out facility and, once the best option was selected, completed the mechanical, electrical/instrumentation and control, and civil/structural engineering for installation and construction. Barr worked with Jenike and Johanson to customize a silo transition piece, liner, and hopper based on friction, abrasiveness, and flow properties of the dry coal rejects. Barr also specified explosion panels and cooperated with Fike to procure explosion panels for the rejects silo. Barr performed a risk evaluation and identified and specified instrumentation, suppression system, and alarms around the silo for monitoring and control.

Detailed cost estimate and preliminary design of power generation system: Barr worked closely with Engine Manufacturers such as GE and Wartsila and Steam Boiler Manufactures such as Cleaver Brooks to obtain emissions criteria, sizing, operating parameters and philosophy and cost around different options for a new power and steam generation fleet at an existing power facility.

Electric energy resource options study: Based on current industry practices, technologies status, equipment conditions, vendor input, and environmental conditions, Barr prepared a discussion of the strengths, weakness, opportunities and threats (SWOT) associated with over 15 different options which included fuel cells, turbines, natural gas conversion, biomass retrofit, etc.

Power grid integration: Barr worked with OEMs such as Caterpillar, Deutz, Cummins, Jennbacher engine generators to be used as prime power distributed generation as well as auxiliary power and provided design details for interconnects to the power grid. The services included the specification and design of the power plant auxiliaries including generator step up transformers including Delta Star, Virginia Transformer, ABB and GE. Additional equipment that was specified included Siemens, ABB, GE, Southern States, Cooper Power for substation circuit breaker, metering and protection systems and components on substations thru 138 kV.

Barr has not worked directly with Doosan on a project, but Doosan and Barr have worked with the same clients in the past such as:

- Ameren
- Dairyland Power
- Lansing Board of Water and Light

Most of the major pieces of hardware will be supplied by Doosan. For the Concept Study the technical performance and cost data has been provided by Doosan directly or a subsidiary company. Doosan subsidiary companies have provided technical and cost data for the PCC System and the ESS Batteries. The team has not needed to rely on any outside OEMs for the basic power block equipment to support the concept study.

The Team will rely heavily on Doosan and its subsidiary companies as in the Concept Study to complete the work envisioned in the preFEED study. Additional OEMs will be contacted to provide technical and cost information for the major components as required to confirm technical and cost information.

4.4 Information Accessibility from OEMs

Barr is working directly with Doosan Heavy Industries (DHI) and has developed a strong relationship throughout the proposal phase and this study. DHI and Barr were able to meet in person on three different occasions throughout the course of this study. Doosan and Barr meet weekly to discuss project status and needs. Doosan is a critical team member for this project and has direct contact with the following entities to determine pricing, operational parameters and limitations, and future technological roadmaps:

- Doosan Heavy Industries & Construction
- Doosan Mecatec
- Doosan Lentjes
- Doosan GridTech
- Doosan Babcock - PCC
- Doosan Skoda Power

Barr has solicited the vendor for the ZLD (Aquatech).

Barr has used publicly accessible information for the GE F6.03 combustion turbine.

4.5 Implementation Team for initial plant and commercialization

The expected team will include four main categories for implementation:

- Future Utility/IPP Developer – power plant user
- Barr Engineering, Envergex, Microbeam, UND – engineering, research and development
- Doosan – technology vendor
- EPC Contractor – detailed engineering, procurement, and construction

Future utility/IPP Developer will be part of future discussions and further discussions with an EPC contractor will be conducted during the preFEED study.

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[xii] Control of mercury emissions from coal-fired electric utility boilers, Air pollution prevention and control division, US EPA

Attachment A

Tables, Graphs and Figures

Table A1.1 Cycling Attributes

System	Cold Start (hrs)	Warm Start (hrs)	Ramp Rate (MW/min)	Min Load (MW)
ESS	Immediate	Immediate	N/A	0
Combustion Turbine	0.5	0.5	7	35.7 (can be 0 if shut down)
USC Boiler/Steam Turbine	6-9	Approximately 3 hours and 40 minutes	15.8	52.6

Table A1.2: Services Comparison

Generation Type	Load Following	VAR/Voltage Support	Turndown Ratio	Spinning Reserve
HGCC	X	X	7.6/1	x
USC Coal	X	X	3/1	x
NGCC	X	X	2/1	x
Wind	None	Marginal	None	None
Solar	None	Marginal	None	None

Figure A2.1: Hybrid Gas/Coal Power Plant's preliminary operation scenario

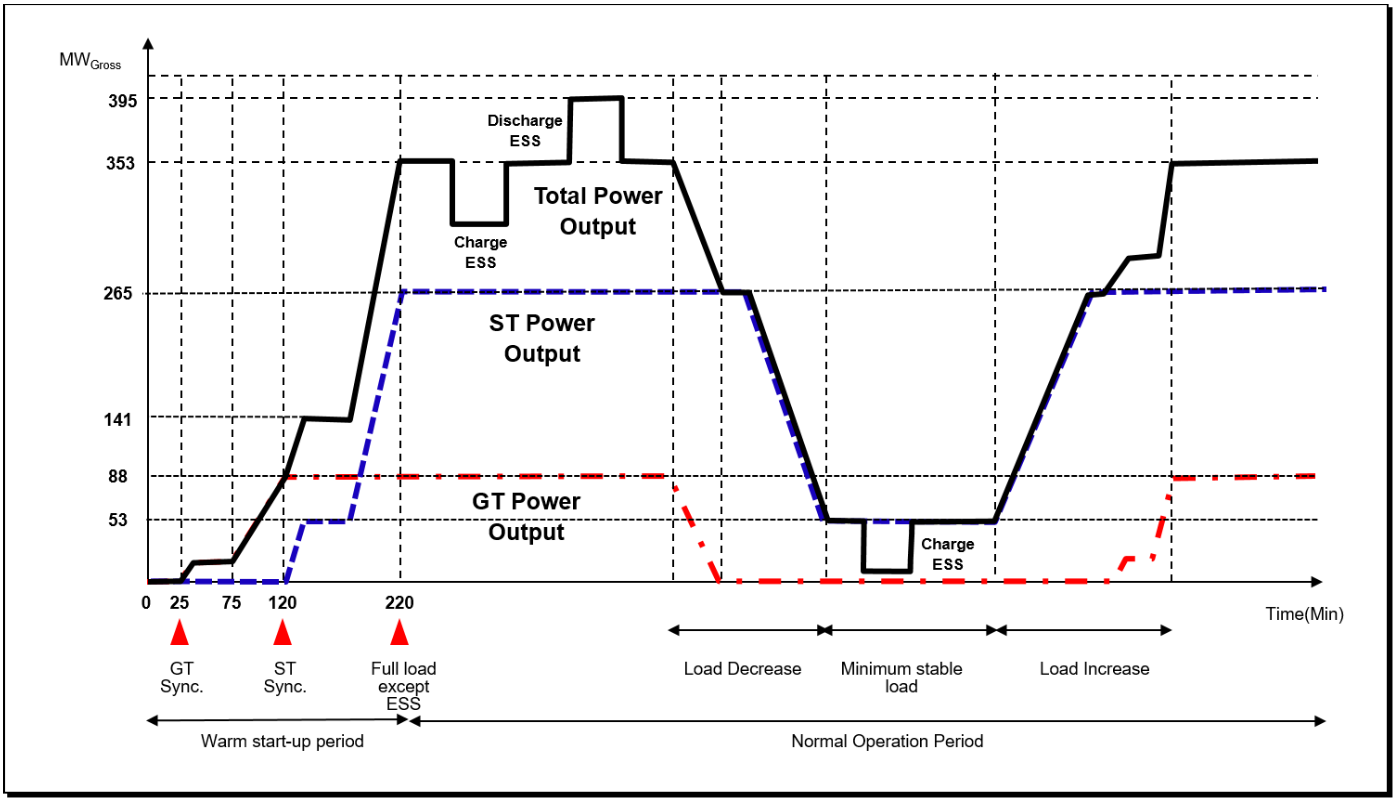


Figure A2.2: Advanced Coal Property and Plant Performance Optimization Control System

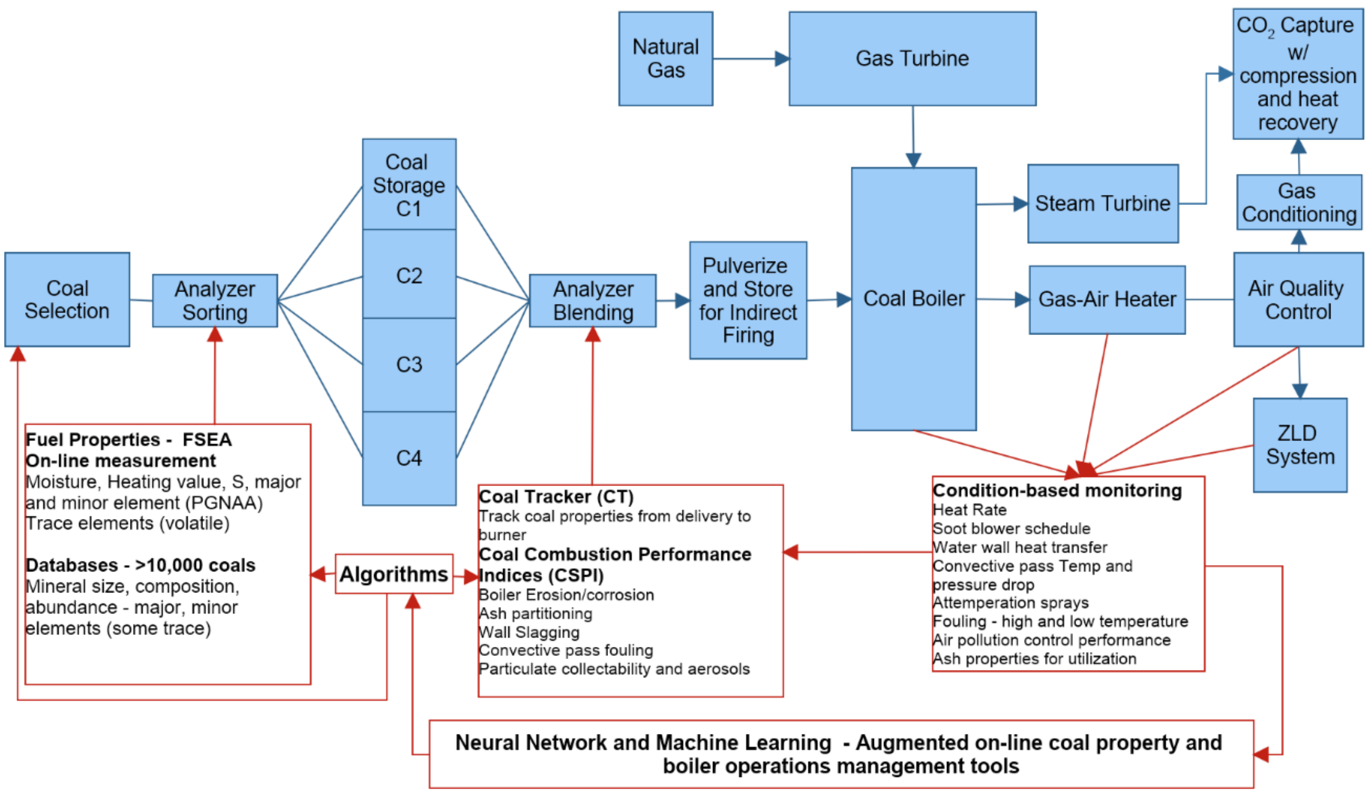


Figure A3.1: Flame shape and temperature comparison between air and GT gas + air

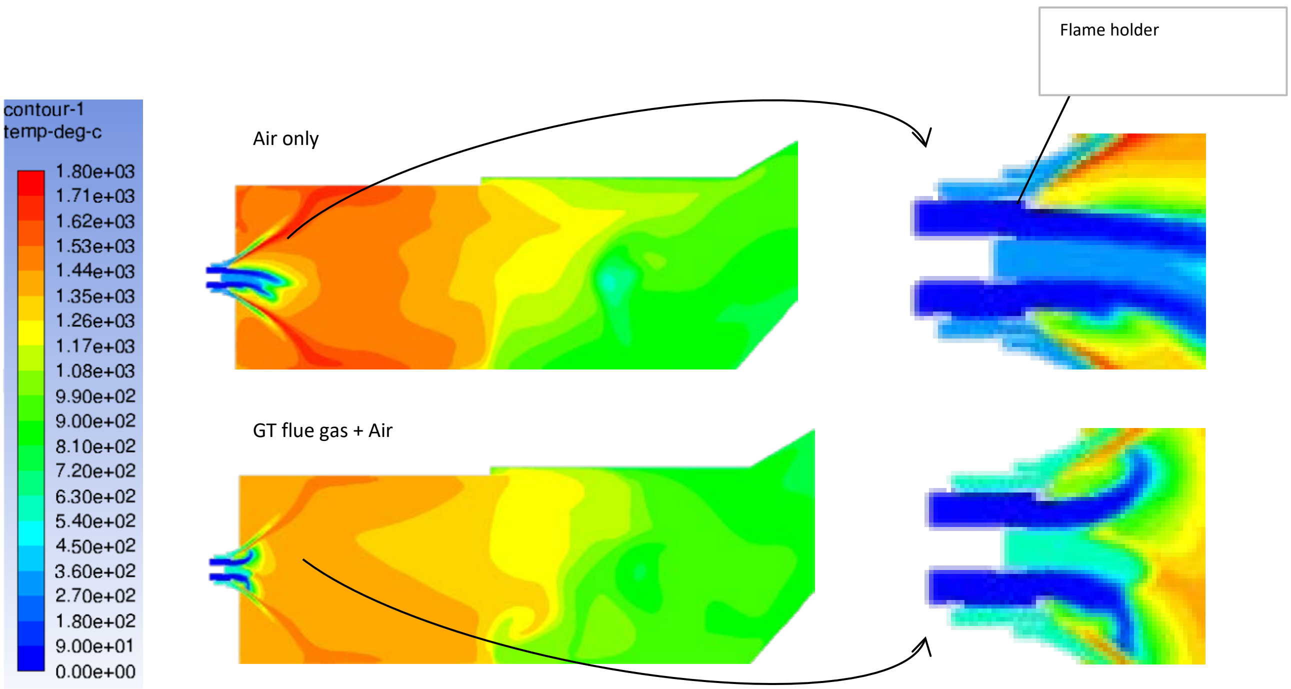
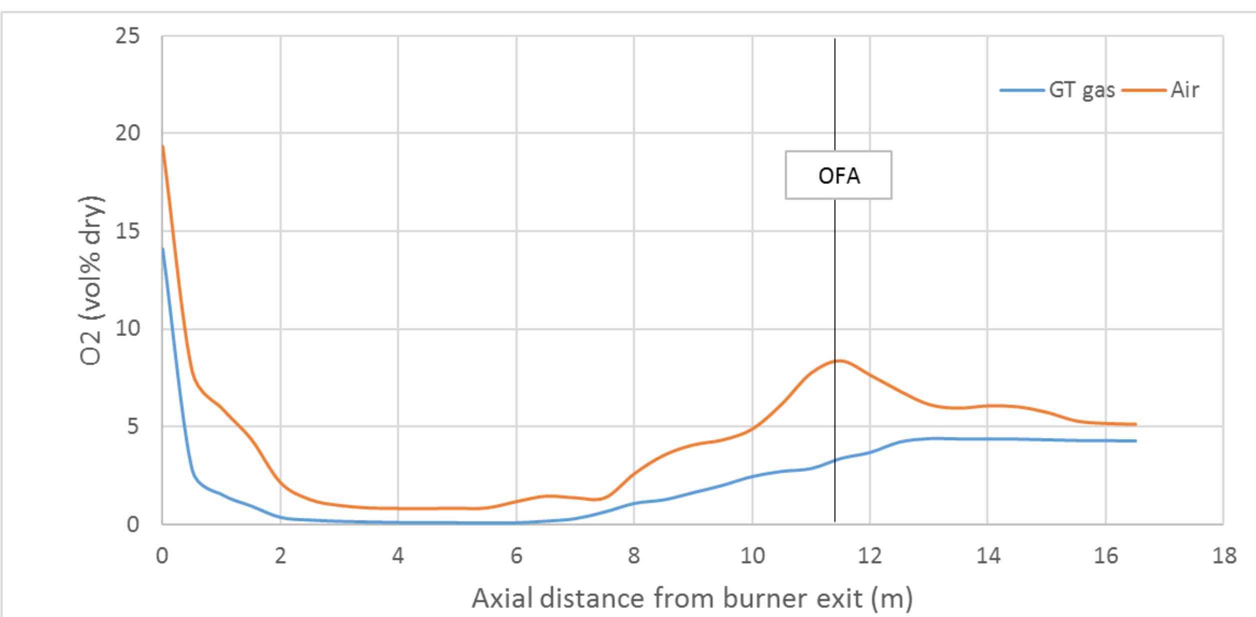


Figure A3.2: Oxygen concentration comparison between air and GT gas + air



Attachment B

List of Assumptions and Clarifications

E.1 Site Characteristics and Conditions

The following site characteristics and ambient conditions are assumed based on the RFP.

Parameter	Value
Site Conditions	
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (Pulverized Coal), acres	300
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water
Elevation, (ft)	0
Ambient Conditions	
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[A]	15.6 (60)
Air composition based on published psychrometric data, mass %	
N_2	72.429
O_2	25.352
Ar	1.761
H_2O	0.382
CO_2	0.076
Total	100.00

E.2 Fuel Type and Composition

The following provide assumptions made about the different fuel types and their compositions.

Rank	Bituminous (Base Case)	
Seam	Illinois No. 6 (Herrin)	
Source	Old Ben Mine	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen[B]	6.88	7.75
Total	100.00	100.00

Rank	Sub-Bituminous	
Seam	Montana Rosebud	
Source	Montana	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	25.77	0.00
Ash	8.19	11.04
Volatile Matter	30.34	40.87
Fixed Carbon	35.70	48.09
Total	100.00	100.00
Sulfur	0.73	0.98
HHV, kJ/kg (Btu/lb)	19,920 (8,564)	26,787 (11,516)
LHV, kJ/kg (Btu/lb)	19,195 (8,252)	25,810 (11,096)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	25.77	0.00
Carbon	50.07	67.45
Hydrogen	3.38	4.56
Nitrogen	0.71	0.96
Chlorine	0.01	0.01
Sulfur	0.73	0.98
Ash	8.19	10.91
Oxygen[B]	11.14	15.01
Total	100.00	100.00

Rank	Low-Sodium Lignite	
Seam	**Wilcox Group**	
Source	**Texas**	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	32.00	0.00
Ash	15.00	22.06
Volatile Matter	28.00	41.18
Fixed Carbon	25.00	36.76
Total	100.00	100.00
Sulfur	0.90	1.32
HHV, kJ/kg (Btu/lb)	15,243 (6,554)	22,417 (9,638)
LHV, kJ/kg (Btu/lb)	14,601 (6,277)	21,472 (9,231)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	32.00	0.00
Carbon	37.70	55.44
Hydrogen	3.00	4.41
Nitrogen	0.70	1.03
Chlorine	0.02	0.03
Sulfur	0.90	1.32
Ash	15.00	22.06
Oxygen[B]	10.68	15.71
Total	100.00	100.00

Rank	High-Sodium Lignite	
Seam	**Beulah-Zap**	
Source	**Freedom, ND**	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	36.08	0.00
Ash	9.86	15.43
Volatile Matter	26.52	41.48
Fixed Carbon	27.54	43.09
Total	100.00	100.00
Sulfur	0.63	0.98
HHV, kJ/kg (Btu/lb)	15,391 (6,617)	24,254 (10,427)
LHV, kJ/kg (Btu/lb)	14,804 (6,634)	23,335 (10,032)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	36.08	0.00
Carbon	39.55	61.88
Hydrogen	2.74	4.29
Nitrogen	0.63	0.98
Chlorine	0.00	0.00
Sulfur	0.63	0.98
Ash	9.86	15.43
Oxygen[B]	10.51	16.44
Total	100.00	100.00

Natural Gas Composition		
Component		**Volume Percentage**
Methane	CH_4	93.1
Ethane	C_2H_6	3.2
Propane	C_3H_8	0.7
n-Butane	C_4H_{10}	0.4
Carbon Dioxide	CO_2	1.0
Nitrogen	N_2	1.6
Methanethiol[A]	CH_4S	5.75×10^{-6}
	Total	100.00
	LHV	**HHV**
kJ/kg (Btu/lb)	47,454 (20,410)	52,581 (22,600)
MJ/scm (Btu/scf)	34.71 (932)	38.46 (1,032)

E.3 Cost Estimation

Operating and Maintenance Cost

Operating Labor		
Operating Labor Rate (Base):	39.70	$/hour
Operating Labor Burden:	30	% of Base
Labor O-H Charge Rate:	25	% of Labor

Operating Labor Requirements per Shift		
Skilled Operator:	2	hours
Operator:	11.3	hours
Foreman:	1	hours
Lab Tech(s), etc.:	2	hours
Total:	16.3	hours

Fixed Operating Cost Includes:

- Annual Operating Labor:
- Maintenance Labor:
- Administrative & Support Labor:
- Property Taxes and Insurance:

Variable Operating Cost Includes:

- Maintenance Material
- Consumables
  - Water
  - Chemicals:
    - Lime
    - MDEA (m^3)
- Waste Disposal
  - Fly Ash
  - Slag
  - ZLD Solid Waste

Fuel Cost Includes:

- Coal
- Natural Gas

Total Overnight Cost (TOC) Includes:

Site Condition Factors:

- Costs associated with structures was based on the site being located in the Midwest

Fuel Type and Composition Factors:

- Bituminous coal used in modelling, cost estimation, and base case evaluation
- Fuel Costs are derived from various studies conducted and reports provided by the U.S. Energy Information Administration (EIA), as footnoted through report

Cost and Performance Factors:

- The Current Dollar (2019) was used in all cost estimations
- The Gross Domestic Product (GPD) Implicit Price Deflator (IPD) provides a valid means of converting costs to and from the current dollar value
- Vendor quotations provide adequate information for major equipment costs
- Capital costs can be estimated through factor analysis (6 tenths rule) of other cost estimations conducted in previous years for similar systems
- Operation and Maintenance (O&M) costs can be estimated through factor analysis (direct linear comparison) of other cost estimations conducted in previous years for similar systems
- O&M costs can be scaled on a comparison equipment count
- Capital Costs and O&M cost structures and values are derived by case studies found in "Cost and Performance Baseline for Fossil Energy Plants - Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity (Revision)" by DOE/NETL (published July 6, 2015)
- Base case capital charge was assumed to be 0.124 – Baseload Case
- Cost was conducted using a sparing philosophy

Operation Factors:

- Assumed capacity factor is 0.85 (Baseload Case)
- Plant production was modeled using typical computer software with typical levels of computation variances

Attachment C

Responses to DOE Feedback on DRAFT Report

ATTACHMENT F RESPONSES TO DOE FEEDBACK FROM DRAFT REPORT

Barr HYBRID Conceptual Design Report Review – File 1

Topic Area	Specific Consideration to Address	Comments	Barr Response
		Concept Report	
Ability to Meet Projected Future Plant Characteristics; Comments are limited to those characteristics associated with the proposed concept; Strikethrough those characteristics not intended to be part of the concept	Coal Feed (are concepts required to consider all four coals?)	Lignite, bituminous, and subbituminous were evaluated from a heat-efficiency perspective, but other design considerations, such as the air quality control system (AQCS), were not evaluated.	Bituminous is the base case for this study. The AQCS is applicable to each coal type. Details of all the parameters for each coal have not been evaluated for this phase and will be addressed in the preFEED study. DHI conducted an evaluation on Boiler NOx emission and put a SCR inlet conditions on the Table 2.2. Refer to Section 2.9
	High overall efficiency (40%+ HHV w/o carbon capture)	41-43.5% efficient with energy storage system (ESS), but 35.1- 37.1% without ESS (no action required).	
	Modular (unit size 50 - 350 MW)	300-400 MW targeted size (no action required).	
	Near-zero emissions (includes zero liquid discharge)	Zero liquid discharge (ZLD) and AQCS equipment (no action required).	
	Solids disposal - limited landfill; dry bottom and fly ash discharge)	Some landfill for bottom ash, but WFGD so sales of gypsum (no action required).	
	90% CO2 capture	90+% CO2 capture (no action required).	
	High ramp rates (> or equal to 4%; can use up to 30% natural gas)	High ramp rates, but question safety of decoupling coal feed from pulverizers, has this been considered?	A detailed process hazard analysis will be conducted during detailed design. The technologies to mitigate hazards with the dust is well known and will be included as part of the design and code review. PHA will be part of the preFEED study. Refer to Section 2.10
	Low minimum load - 5:1 turndown	7:6:1 turndown with different components turning off (no action required).	

	Cold / Warm start - less than 2 hours	CT can be at full load within 30 mins and so can ESS. Coal plant is ultracritical so can start quicker, but will still require near 9 hours to start (starting cold coal plant within 2 hours is not practical).	
	Integration with energy storage	Battery ESS	
	Minimize water consumption	Water treatment to reuse water.	
	Reduced design, construction, and commissioning schedules	Not addressed	Addressed in Section 2.4
	Reduce maintenance and forced outages	Pulverizers are taken out, so no maintenance on those.	
	Integration with coal upgrading or other plant value streams (e.g. co-production)	NA	
	Capable of natural gas co-firing	Standalone NG CT.	
Cost analysis	Methodology	Section 4.3	
	Capital cost estimate	100-200 million plant retrofit; 1,800 million full scale project demonstrations (no action required).	
	O&M cost estimate (including range of operating conditions)	Not provided, this should be addressed.	Addressed in Section 1.3. The details of the O&M breakdown are provided in Attachment C.
	Sensitivity analyses	Section 1.3 (no action required)	
State-of-Technology	Assessment of state of technology for key system components (includes list of commercial equipment)	Section 4.1 (no action required)	

Technology gap analysis	Technology gaps identified	1) USC plants are normally over 400 MW for economics, so study/analysis required. 2) USC higher temps lead to ash sticking on heat transfer surfaces. 3) "Furnace heat absorption change due to the large volume of hot gas injection should also be investigated." (no action required)	
	Project risk associated with the technology gap	Integration of the CT flue gas into the boiler - heat transfer affects, tube metal temps as load changes, NOx emissions, temperatures entering SCR, minimum load considerations. (no action required)	
	R&D needs for commercialization by 2030 (includes list of equipment)	Provided (no action required)	
	Plan and state of addressing gap (e.g. development timeline, critical test results)	Look to evaluate technology gaps in 2019 with retrofit demonstration by 2030 (no action required).	
Identify role of OEM(s) associated with key system components		Provided	
Business case	Market scenario (includes coal types, natural gas price, renewable penetration, carbon constraints, …)	Section 1.3	
	Domestic and international market	Section 1.4	
	Market advantage of the concept; noteworthy beneficial aspects of the proposed systems and technologies	Section 1.1	

	Estimated COE that establishes competitiveness of the concept	not provided, should be addressed	Competitiveness is predicated on real prices for turn down and ramp rates that are not monetized in today's market.
Project Execution Plan	Project timeline to result in detailed plant design (e.g. include financing, site selection, permitting, design)	not provided, should be addressed	Created schedule for full implementation for a commercialized facility. Gantt chart for implementation is included in Section 3.4
	Implementation team for initial plant and commercialization	not provided, should be addressed	Organization chart provided for Future Utility/IPP Developer, Barr Engineering, Envergex, Microbeam, UND, and Technology Vendor Doosan in Section 4.5. Further discussion with EPC contractor will be conducted during preFEED study
Assessment and Specific Concerns	Areas where study does not adhere to the specified design basis	NA	
	Improper or unjustified assumptions	NA	
	Omissions of significant data	NA	
	Inadequately addressed technical risks/uncertainties	NA	
	Important risk issues	An optimization study of the configuration and design parameters of coal and gas would be required. See Section 3.2 and its subsections.	
	Technologies that are not commercially available requiring additional R&D	NA	
	System integration challenges	Several systems have not been integrated in a commercial application. The major engineering challenge will be to integrate the four systems (Indirect Coal Firing System, Combustion Turbine Integration, Flue Gas/Air Heater Heat Recovery, & ESS	

		(batteries)) into the already commercially available hardware.	
	Potential shortfalls with respect to the project target metrics	NA	
Identify issues that need to be addressed (label issues numerically)			
Issue resolution (use the numerical labeled issue to comment on how the issue was or is being resolved)			
Other topics or relevant comments on work status	1) Indirect firing is stated as a feature of this process, but storing pulverized coal in silos is a potentially dangerous design. Please provide details on what protection measures are included to prevent fires and explosions. 2) There is a gas-gas heat exchanger before the DESP that would lower the temperature. Depending on the ash, this can be detrimental to DESP collection efficiency, and coal fly ash has been known to be better at higher temperatures. Please explain reasoning for GGH. 3) Where is hydrated lime injected for SO3 control? SO3 is known to help lower fly ash resistivity. 4) Table 2.2 shows the FGD's PM reduction at 90%. Please confirm as this is much higher than industry experience. 5) Is the ZLD integrated with the plant's WWT system for FGD bleed streams, and if so, then are there concerns with how the sulfates will affect the RO system?		1) Discussion about the PHA, CO monitors, explosion suppression canister systems, and fast acting dampers/explosion panels is included in Section 2. 2) Recent research show the DESP has a best efficiency at 90~100deg C range. Therefore, the NL GGH cooler was placed before the DESP. 3) Lime injection was eliminated and additional equipment will be installed in FGD to meet SOx reduction target. 4) Refer to Section 2.3.5.1 EME has a function of wet ESP and has an excellent PM reduction capability. Therefore, the FGD with EME can achieve more than 90% reduction efficiency. 5) Wastewater from the flue gas cleanup and cooling tower blowdown are collected and sent to a zero liquid discharge system or ZLD. The RO system will include pretreatment for hardness removal eliminating scaling concerns due to high sulfates. Refer to Section 2.3.5.7

Barr HYBRID Conceptual Design Report Review – File 2

1) Page 1-2 – CT Bypass

How many hours of CT exhaust will be bypassed? Does the CT have CO and NOx control technologies to meet permit limits?

The combustion turbine can operate independently from the USC Boiler as needed during the startup process. From a cold start, the full exhaust of the combustion turbine will be directed to a bypass stack. As the USC Boiler is warmed, routing of exhaust gas from the combustion turbine will be gradually transitioned to the boiler until all the exhaust is routed to the USC Boiler and the bypass to the stack is closed. It is anticipated that the bypass will be utilized for approximately two hours during a warm start until the steam turbine is synchronized to the grid. The bypass stack will be used during cold start times for up 6-8 hours until the steam turbine in synchronized to the grid. It should be noted that it is not necessary to start the combustion turbine in advance of firing the boiler. If output from the combustion turbine is not needed the USC boiler can start independently. Refer to Section 1.1.

Provisions will be included in the air permit, which will allow the combustion turbine to operate using the bypass stack for a specified period of time before the exhaust is routed into the USC boiler. The combustion turbine comes standard with burners that minimize CO and NOx emissions. Refer to Section 1.1.

2) Page 1-4 – $/MWh

Please provide financial parameters used to estimate Cost of Electricity.

Detailed Spreadsheets are provided in Attachment C.

3) Page 1-6 – Pulverized coal storage

How many hours of pulverized coal will be stored? What is the long-term experience regarding silo plugging?

The coal bunker that feeds into the mill can hold enough coal for 12 hours of firing. The coal storage used for indirect firing can hold enough for up to two hours of storage capacity provide fast start up and load change achievement. Silo plugging can be prevented by installing equipment to vibrate pulverized coal in the coal bunker. Refer to Section 2.1.

4) Page 1-6 – ESS

51 MW ESS – How many hours of storage capacity? How long does it take to charge the batteries? How many cycles of operation is the ESS system is designed for?

The 51 MW ESS will have 51 MWh capacity with a 1-hour discharge and charge time. It will effectively cover the initial startup and load following when renewable power is lost and before gas turbine ramp up is complete - a 30-minute duration. The ESS is expected to have a 20-year life and the operation capability is expected to be 8,000 cycles. Refer to Section 2.3.4.

5) Page 2-11– Wet FGD

Why wasn't the FGD system designed for 10 ppm SO2 outlet? For a new power plant, most wet FGD OEMs are willing to design for 10 ppm exhaust to avoid polishing step.

The NOx and SO2 flue gas concentrations are 10 ppm and 4 ppm, respectively. Additional DeSOx control with a one stage sieve tray and one stage vortexTM tray, newly developed by Doosan Lenjtes, will be added to meet the 4 ppm SO2 target. Refer to Section 2.3.5.1.

6) Page 2-8 – Steam for Carbon Capture process

It appears that the process steam for the PCC is taken from the Steam Turbine. At full load, 125.7 lb/s process steam is required. How is the turbine imbalance handled when the boiler is at 30% load? The amount of steam required for such a case may be higher than boiler can produce.

The required reboiler steam flow at 30% load is 62.9 lb/s with an inlet temperature of 501.7oF, which is about 50% of design flow and 100% of design temperature. This unbalanced load steam requirement can be met in the current proposed boiler and turbine concept design. However, more detailed analysis will be conducted at preFEED stage, especially for turbine stability. Refer to Section 2.3.5.3.

7) Page 2-15 – Table 3

Please provide the breakdown of aux. power. Is the CO2 compressor power/booster fan power included?

The auxiliary power breakdown was added to Table 2.4. The auxiliary power of CO_2 compressor power/booster fan is included.

8) Page 2-18 – Figure 2-5

Are you leaving out potential heat rate improvements for this plant? How would the cost savings implied in this Figure be applied to a newly designed high efficiency plant?

The impacts of ash deposition increase heat rate in the new plant in the same way as an existing system. The preFEED phase would intend to incorporate Performance Indices-Coal Tracker programs to manage fuel properties. Refer to Section 2.6.1

9) Page 2-19 – Table 2-4

Why is the aux power the same for bituminous and sub-bituminous coals and lower for lignite?

The auxiliary power of Sub-bituminous case has been corrected in Table 2.5. Normally, the Lignite auxiliary power would be higher than the Sub-bituminous auxiliary power. However, in the conceptual study, the same boiler size was used so the power output for Lignite was reduced. Refer to Section 2.7.

10) Page 3-2 – Approach for Advancement

What is the size of the small scale combustion testing envisioned? Is this already planned by Barr or Doosan?

The necessity of a small-scale test will be determined in the preFEED stage. If it is required, the test will be conducted in the FEED stage. If the test is conducted, it is expected that a 3MWth DHI test facility will be used. Refer to Section 3.2.1.

11) Page 4-1 – Table 4-2

Which one of these R&D activities will be completed at the end of pre-feed? Will the final design significantly be impacted if these activities are not carried out and the identified issues are not resolved?

The R&D items listed in Table 4.2 will be developed during the preFEED stage and conducted and completed in the FEED stage.