PEFORMANCE RESULTS REPORT

Coal-Based Power Plants of the Future – Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture (HGCC)

Rev. 1 – Final

Prepared by: Barr Engineering Co.

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Acronyms

ASU	Air Separation Unit
AQCS	Air Quality Control System
BDL	Blowdown Losses
BFW	Boiler Feedwater
BMCR	Boiler Maximum Continuous Rating
BOP	Balance of Plant
CCSEM	computer-controlled scanning electron microscopy
CCS	Carbon Capture System
CFD	Computational Flow Dynamics
CL	Closed loop
CWP	Circulating water pumps
CQMS	Coal Quality Management System
CND	Condenser
CSPI	Combustion System Operational Performance Indices
CW or C.W	Cooling Water
CWS	Cooling Water System
DCC	Direct Contact Cooler
DEA	Deaerator
DEMIN	Demineralizer
DHI	Doosan Heavy Industries
ELG	Effluent Limitation Guideline
EME	Electrostatic Mist Eliminator
ESP	Electrostatic Precipitator
ESS	Energy Storage System
FD	Forced Draft
FEGT	Furnace Exit Gas Temperature
FGD	Flue Gas Desulfurization
FSEA	Full Stream Elemental Coal Analysis
GAH	Gas Air Heater
GEN	Power Generator
GGC	Gas to Gas Cooler
GGH	Gas to Gas Heater
GE	General Electric
GT	Gas Turbine
HHV	Higher Heating Value
HGCC	Hybrid Coal and Gas Boiler and Turbine Concept with Post Combustion Carbon Capture
HX	Heat exchangers

KO	Knockout
ID	Induced Draft
LHV	Low Heating Value
LNB	Low NOx Burner
LP	Low Pressure
ME	Mist Eliminator
OFA	Overfire air
PA	Primary Air
PAC	Powdered Activated Carbon
PC	Pulverized Coal
PCC or PCCC	Post Combustion Carbon Capture
RFP	Request for Proposal
RO	Reverse Osmosis
SCR	Selective Catalytic Reduction
SFC	Submerged Scraper/Flight Conveyor
TMCR	Turbine Maximum Continuous Rating
VFDs	Variable Frequency Drives
ZLD	Zero Liquid Discharge

1.0 Plant Performance Targets

1.1 General Plant Requirements

The proposed concept meets specific design criteria in the RFP as follows:

- Overall plant efficiency of 43% with ESS, 37% without ESS (RFP value 40% without carbon capture).
- Using a modular approach as much as possible.
- Near-zero emissions using a combination of advanced air quality control systems (electrostatic precipitator (ESP), wet flue gas desulfurization system (FGD), selective catalytic reduction (SCR) for NO_x control) that make the flue gas ready for traditional post-combustion carbon-capture technology.
- Capable of high ramp rates (expected 6% versus RFP 4%) and minimum loads (expected better than 5:1 target).
- Integrated energy storage system (ESS) with 50 MW Lithium Ion / Vanadium Redox Hybrid System.
- Minimized water consumption by the use of a cooling tower versus once-through cooling, and internal recycling of water where possible.
- Design and commissioning schedules shortened by using state-of-the-art design technology, such as digital twin, 3D modeling, and dynamic simulation.
- Enhanced maintenance features to improve monitoring and diagnostics such as coal-quality impact modeling and 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 is an integral part of the design with the gas turbine responsible for nearly a quarter of direct power output. The gas turbine exhaust is used to assist with heating the coal-fired steam boiler.

Table 1-1 General Plant Requirements

Total Plant Output and Turndown with Full Environmental Compliance (From Addendum 1 RFP)		Proposed Plant Target
Target	>5:1	>5:1
Total Plant Ramp Rates (From Addendum 1 RFP)		Proposed Plant Target
Target	>4% max load/minute	>6% max load/minute
Time to Max Load	<2 hours	ESS 50 MW immediate, combustion turbine 86 MW in 30 min, full load from cold 6-9 hours Warm start 3-4 hours to full load.
Co-Firing Ability (From Addendum 1 RFP)		Proposed Plant Target
Target	<30% Natural Gas Heat Input	<30% Natural Gas Average Heat Input

1.2 Water Requirements

Table 1-2 Water Requirements

Target Plant Water Daily Average Suggested Target		Proposed Plant Target
Raw Water Withdrawal	<14 (gpm)/MWnet	<9 (gpm)/MWnet <13 (gpm)/MWnet (w/o ESS)
Raw Water Consumption	<10 (gpm)/MWnet	<8 (gpm)/MWnet <10 (gpm)/MWnet (w/o ESS)

1.3 System Size Basis

Table 1-3 System Size Requirements

Plant Size Basis (From Addendum 1 RFP)		Proposed Plant Target
Key Component Modularized	As much as possible	As much as possible (includes factory and field modularization, skid-mounted and prefab piping/wiring as much as possible)
Maximum Power	50MWe–350 MWe	350 MWe Net
Maximum Plant Efficiency (w/o CCS parasitic load)	>40%	>40% w/o CCS parasitic load >35% with CCS parasitic load

1.4 Environmental Targets

Table 1-4 Environmental Targets

Air Pollutant	PC (lb/MWh-gross) (From Addendum 1 RFP)	Proposed Plant Target (lb/MWh-gross)
SO_2	1.00	1.00
NO_x	0.70	0.70
PM (Filterable)	0.09	0.09
Hg	$3x10^{-6}$	$3x10^{-6}$
HCl	0.010	0.010
CO_2	90% Capture	116 lb/MWh-gross (90% Capture)

The output-based emissions limits shown above are specified in the Coal FIRST RFP. While these are reasonable emission limits, case-specific air-quality compliance requirements could drive limit adjustments. Ambient air-quality attainment designations vary across the country; therefore, the ultimate siting of the project will determine the increment of negative air quality impact that is available for new emissions. The carbon capture aspect of the project implies a process that exhausts a cooler residual gas stream to the atmosphere from a stack that is likely lower than a conventional coal plant stack. These stack parameters will be used as inputs to air dispersion modeling, which would be expected to show a dispersion profile different than experienced with a conventional coal-fired stack. Until siting and exhaust stream characteristics are established, it is possible that compliance with air quality standards could drive project design adjustments.

Table 1-5 Solid Waste Requirements

Solid Wastes (Less than Case B12B Equivalent (scaled to 350 MW)		Proposed Plant Target
Bottom Ash Discharge	Saleable, 40 tons/day	Saleable, 40 tons/day
Fly Ash Discharge	Saleable, 170 tons/day	Saleable, 151 tons/day
FGD Gypsum Waste	Saleable, 274 tons/day	Saleable, 230 tons/day
Wastewater Solid Waste	Minimized	20 tons/day
ZLD Crystallized Waste	Minimized	40 tons/day
CO_2 Capture Amine Waste	Saleable, 43 tons/day	1 ton/day

Table 1-6 Liquid Discharge Requirements

<table>
<tr><th colspan="2">Liquid Waste (From Addendum 1 RFP)</th><th>Proposed Plant Target</th></tr>
<tr><td>Wastewater</td><td>None, Zero Liquid Discharge</td><td>None, Zero Liquid Discharge</td></tr>
<tr><td>SCR Catalyst</td><td>None, Zero Liquid Discharge</td><td>None, Zero Liquid Discharge</td></tr>
<tr><td>PCC</td><td>None, Zero Liquid Discharge</td><td>170 tpd (30 gpm) sent to Wastewater Treatment / ZLD
<table>
<tr><td></td><td>PCC Effluent
lb/hr</td></tr>
<tr><td>H_2O</td><td>15,800</td></tr>
<tr><td>$(NH4)_2SO_4$</td><td>1100</td></tr>
<tr><td>Na_2SO_4</td><td>179</td></tr>
</table>
</td></tr>
</table>

1.5 Plant Capacity Factor

Table 1-7 Plant Capacity Factor

Projected Plant Capacity Factor (Used to compare with Case B12B)	
Capacity Factor—based on cost for MWh basis to compare with B12B	85%

2.0 Performance Results Summary

2.1 Plant Performance Summary

Table 2-1 Overall Plant Performance Summary

	Overall Performance Summary				
Fuel Type	**Bituminous 100% (Base)**	**Bituminous 50%**	**Bituminous 30%**	**Sub-Bituminous**	**Lignite**
Total Gross Power Output, MWe	407.6	135.3	81.1	408.2	354.2
CO_2 Capture/Removal auxiliaries, kWe	5,128	2,763	1,696	5,420	4,979
CO_2 Compression, kWe	17,622	11,339	6,960	19.067	17,123
ZLD System, kWe	1,850	997	612	1,955	1,796
Balance of Plant, kWe	32,974	15,609	9,070	35,109	30,347
Total Auxiliaries, MWe	57.6	30.7	18.3	61.6	54.2
Net Power, MWe	350.0	104.6	62.8	346.6	300.0
HHV Net Plant Efficiency, % with ESS	43.2	29.7	29.1	41.8	40.1
HHV Net Plant Heat Rate with ESS, kJ/kWh (BTU/kWh)	8,342 (7,907)	12,109 (11,477)	12,385 (11,739)	8,620 (8,170)	8,983 (8,515)
LHV Net Plant Efficiency, %	45.7	30.8	30.1	44.3	42.6
LHV Net Plant Heat Rate, kJ/kWh (BTU/kWh)	7,877 (7,466)	11,680 (11,070)	11,945 (11,322)	8,125 (7,701)	8,452 (8,011)
HHV Net Plant Efficiency without ESS, %	37.0	29.7	29.1	35.7	34.6
HHV Net Plant Heat Rate without ESS, kJ/kWh (Btu/kWh)	9,739 (9,231)	12,109 (11,477)	12,385 (11,739)	10,080 (9,554)	10,404 (9,861)
HHV Net Plant Efficiency, % w/o CO_2 capture, w/o ESS	43.6%				
HHV Net Plant Heat Rate w/o CO2 capture & w/o ESS kJ/kWh (BTU/kWh)	8,267 (7,835)				
HHV Boiler Efficiency, %	89.7	88.4	91.7	87.6	85.6
LHV Boiler Efficiency, %	92.3	91.6	95.0	90.4	88.1
Steam Turbine Cycle Efficiency, %	56.5	52.2	49.0	56.8	56.4
Steam Turbine Heat Rate, kJ/kWh (BTU/kWh)	6,366 (6,034)	6,892 (6,532)	7,350 (6,967)	6,335 (6,004)	6,382 (6,049)
Condenser Duty (Except PCC), GJ/hr (MMBTU/hr)	896 (849)	439 (416)	295 (280)	902 (855)	762 (722)
As-Received Coal Feed, kg/hr (lb/hr)	72,504 (159,844)	46,732 (103,025)	28,685 (63,239)	102,096 (225,083)	113,119 (249,385)
NG fuel Feed, kg/hr (lb/hr)	18,144 (40,001)	0	0	18,144 (40,001)	18,144 (40,001)
Limestone Sorbent Feed, kg/hr (lb/hr)	7,300 (16,094)				
HHV Thermal Input, kWt (MMBTU/hr)	811,064 (2767)	351,954 (1201)	216,036 (737)	829,939 (2832)	748,624 (2554)

	Overall Performance Summary				
Fuel Type	**Bituminous 100% (Base)**	**Bituminous 50%**	**Bituminous 30%**	**Sub-Bituminous**	**Lignite**
LHV Thermal Input, kWt (MMBTU/hr)	765,849 (2614)	339,466 (1158)	208,371 (711)	782,262 (2669)	704,339 (2403)

Table 2-2 Plant Power Summary

Power Summary					
Coal Type	**Bituminous 100% (Base)**	**Bituminous 50%**	**Bituminous 30%**	**Sub-Bituminous 100%**	**Lignite 100%**
Steam Turbine Power, MWe	270.6	135.3	81.1	271.2	226.5
Gas Turbine Power, MWe	86.8	-	-	86.8	86.8
Battery, MWe	50.2	-	-	50.2	40.9
Total Gross Power, MWe	407.6	135.3	81.1	408.2	354.2
Total Gross Power w/o battery, MWe	357.4			358	313.3
Auxiliary Load Summary					
Ash Handling	700	451	277	986	1,092
Boiler Feed Water Pump	9,168	2,810	1,088	9,169	7,195
Circulating Water Pumps	3,110	1,848	1,242	3,126	2,642
CO2 Capture/Removal Auxiliaries	5,128	2,763	1,696	5,420	4,979
CO2 Capture and Compression	17,622	11,339	6,960	19,067	17,123
Coal Handling and Conveying	201	129	79	283	313
Condensate Pumps	436	137	57	439	359
Cooling Tower Fans	1,788	875	588	1,797	1,519
Dry ESP	3,000	1,617	992	3,171	2,913
Flue Gas Desulfurization/Ox Air Reagent Prep. Gypsum	4700	4703	4704	4705	4706
Forced Draft Fans	567	306	188	574	551
Ground and Service Water Pumps	228	123	75	241	221
GT Auxiliary	420	-	-	420	420
Induced Draft Fans	3,949	2,128	1,306	4,600	3,834
Miscellaneous Balance of Plant[A]	804	471	303	847	776
Primary Air Fans	1,044	563	345	1,488	1,014
Pulverizers	1,411	909	558	1,519	1,635
Reboiler Condensate Pump	184	61	24	193	183
SCR	200	108	66	211	194
Steam Turbine Auxiliaries	233	126	77	246	226
Transformer Losses	830	415	249	832	695
Wastewater Pre-Treatment/ZLD System	1,850	997	612	1,955	1,796
Total Auxiliaries, MWe	57.6	30.7	18.3	61.6	54.2
Net Power, MWe	350.0	104.6	62.8	346.6	300.0
Net Power w/o battery, MWe	300.0			296.4	259.1

A Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.0 Performance Results Details

3.1 Performance Model/Material and Energy Balance

The mass and energy balances around the power block of the system for the steam, flue gas emissions (including boiler and gas turbine), and feedwater systems were modeled in an integrated plant performance calculation tool—UniPlant from Doosan Heavy Industries. The results from the model are included in Appendix A. The full-load carbon capture system mass and energy balance was modeled in Doosan Babcock process simulation software. Doosan Heavy Industries has modeled low-load operation of the power block and steam and flue gas emissions, and the University of North Dakota/Envergex has performed low-load operation modeling of the carbon capture system. Additional documents from Doosan Heavy Industries and Doosan Babcock and the modeling results performed by the University of North Dakota/Envergex are provided in Appendix B.

Barr evaluated water, carbon, and other balance-of-plant systems by doing an overall mass balance in Excel, based on vendor-provided information. The environmental systems were specified based on the power block simulations, and vendor information was gathered and integrated into the overall mass balance.

The Hybrid Gas/Coal Concept (HGCC) power plant has a high predicted plant efficiency of 37.0% with PCC. This efficiency can be increased up to 43.2% during peak time by using ESS power charged with surplus power during low demand time and near area renewable power.

The HGCC power plant 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. In case of the High-Sodium lignite coal firing, a larger boiler is required for the same power output with bituminous. But, the same HGCC boiler can be used if the steam power output is reduced from 270MW to 227MW. The slagging and fouling can be controlled with the reduced heat release rate by this reduced power output and proper selection of boiler tube transverse pitch. The burner system can operate without significant issues using the High-Sodium Lignite coal moisture up to 40% moisture. Plant efficiency using the High-Sodium lignite coals is expected to be approximately 3.1% lower than a bituminous firing. The lignite coal power plant efficiency can be increased if the steam turbine is modified for 227MW power output. Additional coal drying system with waste heat can also increase efficiency.

The HGCC power plant can be applied and have optimum efficiency to all kinds of U.S. coals with small modification of steam turbine and an addition of coal drying system for the High-Sodium lignite coal. Standardization of power output with the same hardware design is a realization of the “Transformative” concept of Coal FIRST which is fundamentally redesigned to change how coal technologies are manufactured. For the power plant construction, it can be more focused on the performance optimization and selection of optimum power output combination selection of modular product. DHI has been putting a great effort on the hardware design for each power plant construction in the past. HGCC power plants with various power generation units of gas turbine and ESS are appropriate to cover the whole U.S. power plant owner needs. The HGCC power plant efficiency can be increased by increasing the main and reheat steam temperature more than 600°C. But, the steam temperature of 600°C would be very appropriate for the wide application of the HGCC in the U.S. because some coals may cause issues such as coal ash corrosion at higher steam temperatures.

3.2 Water Balance

A water balance was developed as part of the HGCC performance evaluation. Clean water is reused in the system as much as possible. Recycling considerations include:

- A portion of the cooling tower blowdown is used for the limestone slurry makeup that goes to the flue gas desulphurization scrubber and other FGD makeup water.
- The filtrate from dewatering is recirculated back into the scrubber as makeup.
- The carbon capture system produces a clean effluent at the cooler. This effluent is used as makeup to the PCC system, but about 50 gpm can be recirculated back into the overall plant makeup.
- About 24 gpm of condensate from the CO_2 compressors is recirculated back into the overall plant makeup.
- The distillate from the wastewater and ZLD system is recirculated back to the overall plant makeup.

The cooling tower makeup is considered greater than 95% of the overall plant makeup. The cooling tower evaporative losses are the most significant losses of water. The blowdown, which considers eight (8) cycles when using pretreatment addition for cooling tower make-up, is the largest stream that goes to wastewater. Because of the back-pressure requirements of the HGCC system, air-cooled condensers have not been considered as a viable cooling option.

Because the scrubber outlet temperature is expected to range from 50-55°C, the evaporative losses at the FGD system are not significant, and the makeup water requirement is enough for the reclaim recycle and limestone slurry feed. If the outlet temperature of the scrubber unit is higher, more cooling tower blowdown can be fed into the scrubber system as makeup water, while the remaining cooling tower blowdown is sent to the wastewater and ZLD system.

Separate systems for potable water (1 gpm), oil-water separator (3 gpm), and sanitary treatment were considered. These systems were not included in the system water balance and would operate independently of the plant. The stormwater system (estimated at 110 gpm rate) is also considered, but not included in the system water balance.

Table 3-1 Water Balance

System	In (GPM)		Out (GPM)		
	Makeup	Recycle from other systems	Emission / Waste	Discharge to Wastewater	Recycle to other Systems
Combustion	400-From Combustion	0	0	0	400 - FGD water vapor
Water System - Cooling Tower, Service Water, Boiler Feedwater	2310	70 (From PCC)	2000 - cooling tower evaporative and drift losses	10 - cooling tower blowdown, & 100 water treatment backwash, pile runoff, drainage	270 - cooling tower blowdown to FGD
FGD Scrubber	0	670	20 - gypsum moisture and bonded water	70-FGD purge	580 - to PCC water vapor
PCC System	0	580	480- stack water vapor, PCC effluent	30 (Liquid Effluent)	70 - to HGCC makeup water
Total Before WW	**2710-400=2310**	**1320**	**2500**	**210**	**1320**
Wastewater Treatment / ZLD	0	210	42		168 - to HGCC makeup water
Overall Plant Water	**2142**	**168**	**2542**		

3.3 Steady State Emissions Data

The environmental targets for emissions of Hg, NO_x, SO_2, and PM were presented in Section 1.4. A summary of plant air emissions is presented in Table 3-2.

Table 3-2 Air Emissions (Bituminous TMCR at 85% Capacity Factor)

Pollutant	Bituminous TMCR at 85% Capacity Factor Kg/GJ (lb/MMBTU) (gross output)	Bituminous TMCR at 85% Capacity Factor Tonne/year (ton/year at 85% capacity factor)	Bituminous TMCR at 85% Capacity Factor Kg/MWh (lb/MWh) (gross output-unless specified other)	Subbituminous TMCR at 85% Capacity Factor Kg/MWh (lb/MWh) (gross output-unless specified other)	Lignite TMCR at 85% Capacity Factor Kg/MWh (lb/MWh) (gross output-unless specified other)	Bituminous TMCR at 85% Capacity Factor PPMDV (6% O_2)
SO_2	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0	0	0
NO_x	0.007 (0.015)	148.6 (163.8)	0.056 (0.123)	0.059 (0.129)	0.062 (0.137)	10
SO_3	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0	0	0
HCl	0.000 (0.000)	0.000 (0.000)	0.000 (0.000)	0	0	0
Particulate	0.0003 (0.0007)	6 (6.6)	0.002 (0.005)	0	0	0
Hg		0.0034 (0.0037)	$9.2\text{x}10^{-7}$ ($2.0\text{x}10^{-6}$)	0	0	0
CO_2 (gross output)	7(16)	167,616 (184,765)	63 (139)	67 (149)	69 (153)	13,970
CO_2 (net output)	-	-	75 (166)			13,970
Pollutant	**mg/Nm^3**					
Particulate Concentration	<2 (after FGD at 32°F and 14.696 psia)					

NO_x emissions from the boiler are anticipated to be below 150 ppm for bituminous coal firing using low NO_x burners and overfire air (OFA). It is further reduced to less than 10 ppm with the SCR system.

The temperature of the flue gas leading up to the gas-gas cooler (GGC) will be maintained higher than the acid dew point (~130-140°C), maintaining SO_3 in the gas phase. We, therefore, do not expect corrosion or fouling issues in the air-preheater or the feed-water heater HX.

Within the GGC, the flue gas is cooled to ~95°C, condensing a significant portion of the SO_3. Considering the bituminous coal composition, there is sufficient fly ash loading in the flue gas, where most of condensed SO_3 will be deposited. The SO_3 will adhere to the ash particles predominantly, and not on the tube surface, because of the much higher surface area of the fly ash. Some of the ash (with the condensed SO_3) will find its way to the heat exchange surfaces of the GGC. The GGC is also equipped with aggressive soot-blowing functionality and complete soot-blowing coverage, to periodically clean the heat exchange surfaces in an effective fashion, allowing the HX to perform per design.

The GGC is installed ahead of the low temperature dry ESP, which is also designed with ash collection and discharge that can handle the SO_3-coated ash. While earlier design guidelines may have been conservative with respect to acid dew points and heat exchanger operation, recent experiences in both Korea and China, provide sufficient data and details for the GGC design in the context of a low-temperature ESP (< 100oC),[i] [ii]and provide the confidence that the GGC component can be operated reliably and meet performance targets (i.e., achieve low exit flue gas temperatures of ~90-100°C). Such operation is necessary to achieve the ultra-low emissions of particulate (<5 mg/Nm3) and acid gases. Additionally, materials of construction of the GGC (NL GGH Cooler) include sulfuric acid resistant material and a phenolic coating to combat any corrosion issues.

SO_2 and Hg will be reduced to near zero by the wet FGD and new two-stage electrostatic mist eliminator (EME) technology. At the exit of the FGD, SO_2 concentration will be less than 15 ppm. The EME technology targets high-efficiency removal of pollutants via two steps: first, via the application of a micro spraying system that provides a very large number of reactive droplets and, consequently, a high surface area (10x versus the standard) to counteract the challenge of low SO_2 concentrations at the exit of the FGD; and second, by incorporating a two-stage wet ESP (EME) for collection of the fine droplets with very high efficiency.

The EME is also very effective for particulate matter (PM), SO_3, and Hg reduction. It has >99% removal efficiency for PM bigger than 0.7 μm and >70% for 0.3 μm or less. Therefore, EME has the same performance characteristics as a baghouse for PM10 removal.

In our AQCS system, a non-leakage gas-gas heat exchanger (GGH) is located before the dry ESP. Thus, this system includes a cold ESP, which has better removal efficiency of mercury. In addition, the majority of mercury in bituminous-fired boilers exists as Hg^{2+}, which is soluble. Most Hg^{2+} that is not removed in the ESP is captured by the wet FGD and additionally by the EME, which uses wet ESP technology to remove Hg^{2+} and Hg-PM. In the case of a sub-bituminous coal firing, Hg^0 exists in gaseous form. The SCR catalyst will oxidize a portion of the Hg^0 to Hg^{2+}. This can be further supplemented with a trace bromide/iodide addition to the coal-fired boiler, as necessary, to completely oxidize the mercury. The EME will also remove condensable PM such as SO_3 and HCl to a very high efficiency.

This AQCS system eliminates the need for activated carbon injection and additional sulfur oxide removal additives, which reduce CAPEX investment and OPEX cost.

Table 3-3 Carbon Balance

Carbon In		Carbon Out	
	Kg/hr (lb/hr)		**Kg/hr (lb/hr)**
Coal	46,200 (101,900)	Stack Gas	6,000 (13,300)
Air (CO_2)	50 (110)	FGD Product	50 (110)
PAC	0 (0)	Fly Ash	120 (270)
FGD Reagent	800 (1,800)	Bottom Ash	20 (50)
Natural Gas	12,500 (27,500)	CO_2 Product	53,300 (117,500)
		CO_2 Dryer Vent	5 (11)
		CO_2 Knockout	28 (62)
Total	59,500 (131,000)	Total	59,500 (131,000)

Table 3-4 Sulfur Balance

	Sulfur In Kg/hr (lb/hr)		Sulfur Out Kg/hr (lb/hr)
Coal	1,800 (4,000)	FGD Product	1540 (3,400)
		Ash / WWT/ZLD	250 (550)
		Stack Gas (SO_2)	5 (10)
Total	1,800 (4,000)	**Total**	1,800 (4,000)

Table 3-5 Solid Waste

Solid Waste	
Bottom Ash Discharge	Saleable, 40 tons/day
Fly Ash Discharge	Saleable, 151 tons/day
FGD Gypsum Waste	Saleable, 230 tons/day
Wastewater Solid Waste	20 tons/day (Sludge)
ZLD Crystallized Waste	40 tons/day
CO_2 Capture Amine Waste	1 ton/day (Reclaimer Waste and Spent Activated Carbon)

Table 3-6 Removal Performance

Pollutant	Technology	Removal Performance
SO_2	Wet Limestone Forced Oxidation Scrubber	99%, 15 ppmv
	Electrostatic Mist Eliminator (EME)	4 ppmv outlet target
	Amine Base CC	<4 ppmv outlet
NO_x	LNBs and OFA	0.09 kg/GJ (0.19 lb/MMBTU)
	SCR	93.3% 0.007 kg/GJ (0.015 lb/MMBTU)
Particulate	Dry ESP	99.9%
HCl	Wet FGD, EME, Amine Base Carbon Capture	99.9%
Hg	SCR, Wet FGD, EME	97%
CO_2	Amine Base Carbon Capture	90%

4.0 Equipment Summary

Description	Type	Design Condition	Operating Qty.	Spares
PFD-010 COAL DELIVERY, STOCKPILE, AND CRUSHING				
Rail Car Delivery/Rail Dump Pocket	Rail car dump	3000 tph	1	0
Feeders (rail dump pocket)	Vibrating	750 tph each	4	0
Conveyors	Belt	3000 tph each	2	0
Surge Bin with Stacker Boom	Cone bottom	3000 tph	1	0
Feeder (stockpile)	Apron	250 tph	1	0
Conveyor	Belt	250 tph	1	
Surge Bin (crusher feed)	Cone bottom		1	0
Feeder (crusher)	Belt	250 tph	1	0
Crusher	Roll	250 tph	1	0
Feeder (crusher)	Apron	250 tph	1	0
Conveyor w/tramp metal magnet and sampler	Belt	250 tph	1	0
Surge Bin (Full Spectrum Elemental Analyzer feed)	Cone bottom		1	0
Feeder (Full Spectrum Elemental Analyzer feed)	Apron	250 tph	1	0
Conveyor with Full Spectrum Elemental Analyzer	Belt	250 tph	1	0
PFD-011 COAL STORAGE AND PULVERIZATION				
Tripper Conveyor	Belt	250 tph	1	0
Storage Silos	Cone bottom	800 tons total, 40,000 cubic feet total	5	0
Feeders	Vibrating	25 tph each	5	0
Conveyor	Belt	125 tph	1	0
Conveyor with Full Spectrum Elemental Analyzer	Belt	125 tph	1	0
Tripper Conveyor	Belt	125 tph	1	0
Storage for CO_2			1	0
Indirect Firing System				
Coal Bunkers	Cone bottom	400 ton each	2	1
Coal Feeder (bunker discharge)			2	1
Pulverizers	Vertical spindle mill		2	1
Cyclones			2	1
Dust collectors	Baghouse		2	1
Drag Chain Feeder (Pulverized Coal)		90 tph	1	0
Primary air fans	Centrifugal		2	1
Airlock (PCB Inlet)	Rotary		1	1
Feeder (pulverized coal)	Screw	25 tph each	3	1
Airlocks (PCB Outlet)	Rotary	25 tph each	3	5

Description	Type	Design Condition	Operating Qty.	Spares
Pulverized Coal Bin	Cone bottom	200 ton each	1	1
Airlocks	Rotary		3	5
Pulverized Coal Pipe (feed to burners)	Pipe		2	1
Hot Gas Generator			2	1
Fresh Air Fan	Centrifugal		2	1
Combustion Air Fan	Centrifugal		2	1
Seal Air Fan	Centrifugal		2	1
Pulverizer Air Re-Circulation Duct			2	1
Pulverizer Air By-Pass Duct(Vent Line)			2	1
Pulverized Coal Duct			2	1
Multi-gamma Analyzer			3	1
Pyrite reject system (dewatering tank and pump)	Sluice system	10 TPH capacity; includes pyrites hoppers, water supply pumps, JETPULSION pumps, and conveyor piping	1	0
PFD-012 COMBUSTION				
Boiler including SCR System	Opposed wall-fired, USC, Two-pass radiant-type	210 kg/s superheated steam flow, 251bar/603°C/603°C NO_x reduction at SCR from 150 ppm to 10ppm; 1ppm NH3 slip allowance; Inlet Gas Conditions: 2,197,600 m3/hr gas volume flow, 387 °C temperature, and 750 mmHg pressure	1	0
Forced draft fan	Axial	7,690Am3/min, 5.3kPa	2	0
ID fans (Combined)	Axial	13,700 Am3/min, 11.0kPa (inlet Temp : 90°C)	2	0
Primary Air Fan	Centrifugal	1,800 Am3/min, 14.5kPa	2	0
PC Transport Fan	Centrifugal	1,150 Am3/min, 13.0kPa	3	1
Gas Air Heater	Regenerative	Air flow 120 kg/s, gas flow 130 kg/s(Coal only)	2	0

Description	Type	Design Condition	Operating Qty.	Spares
Bottom Ash Scraper Conveyor (ash handling)	UCC Model 1019 MAX® SFC	Up to 8 hours storage capacity at 1.6 TPH ash generation rate	1	0
Ammonia Storage Injection System	Horizontal tank	220 lb/hr injection rate	1	0
Gas Turbine with bypass stack	GE 6F03 Model	87 MW, natural gas fired, 620°F exhaust temp	1	0
Gas Air Heater			1	0
PFD-013 STEAM TURBINE AND FEEDWATER HEATING				
Steam Turbine	USC, Tandem compound	270 MWe, 242 bar/600ºC/600ºC	1	0
Steam Turbine Generator	Hydrogen cooled, static type excitation	320 MVA, 0.9PF, 18kV, 60Hz, 3-Phase	1	0
Boiler Feed Pump - Electric Driven	Centrifugal	230 kg/s flow; 11.71 Bar(a) pressure; 187 °C temperature; max turndown to 20% of flow (42 kg/s)	2-50% (2 operating at 50% of full load)	0
Condensate Pumps	Centrifugal	1870 gpm flow rate; 380 psi pressure; 94°F condensate max temp	2-50%	
Condenser	Steam driven; bottom steam turbine exhaust interface; two pass; divided waterbox; self-cleaning	830 MbTU/hr heat duty; 83,000 gpm cooling water volume; 888,900 lb/hr steam flow rate; 60°F inlet temp, 80°F outlet temp; 1.5" Hg back pressure	1	0
Condenser Auxiliaries	Stainless Steel Expansion Joint; Basket Tips; Sacrificial Anodes; Tube Installation/Removal Kit (Less Driver); Slide Plates; Startup/Commissioning Spares		1	0
Deaerator w/Storage Tank		4 kg/s, 360°C, 11.5 Bar(a) IPT steam to 210 kg/s, 180°C,10.91 Bar(a) H_2O	1	0
Slipstream Feedwater Heaters - Flue gas		Heater 1: 65 kg/s, 305 bar(a), 190 °C; Heater 2: 111.47kg/s, 26.4 bar(a), 114°C	2	0
Gland Steam Condenser		120 kg/s	1	0
High Pressure Feedwater Heater	Shell and Tube	210 kg/s, 320 bar	4	0

Description	Type	Design Condition	Operating Qty.	Spares
Low Pressure Feedwater Heater	Shell and Tube	160 kg/s, 26 bar	4	0
Energy Storage System	Lithium Ion / Vanadium Redox Hybrid System	50 MWe, 50 MWh	1	0
PFD-014 WATER SYSTEM				
Ground Water Pumps	Centrifugal	220 gpm, 75 ft tdh	2x50%	1x50%
Raw Water Pump	Centrifugal	220 gpm, 75 ft tdh	2x50%	1x50%
Makeup Water Tank			1x100%	NA
Makeup Water Transfer Pump	Centrifugal	917 gpm, 35 ft tdh	2x50%	1x100%
Circulating Water Pump	Vertical Turbine Pump	45,000 gpm, 100 ft tdh	6x33%	3x33%
Circulating Water Booster Pump	Centrifugal	25,000gpm, 100 ft tdh	4x50%	2x50%
Closed Cycle Water (CCW) Cooling Heat Exchangers	Shell and Tube	5000 gpm Circulating Water, 80F Inlet 60F Outlet	4x100%	4x100%
Closed Cycle Cooling Water Pumps	Centrifugal	5,000 gpm, 105 ft tdh	4x100%	4x100%
Cooling Tower	Counter Flow Mechanical Draft			
Cooling Tower Blowdown Pumps		215 gpm, 35 ft tdh	10x10%	1x10
Sodium Hypochlorite Feed Skid			1x100%	NA
Coagulant Feed Skid			1x100%	NA
Mixed Media Filters		80 GPM, 35 tdh	1x100%	1x100%
Fire/Service Water Tank			1x100%	NA
Service Water Pump	Centrifugal	80 gpm, 35 tdh	2x50%	1x50%
Activated carbon filtration		30 gpm	1x100%	1x100%
Cartridge filters		30 gpm	1x100%	1x100%
Anti-Scalant Feed Skid			1x100%	NA
Acid Feed Skid			1x100%	NA
Caustic Feed Skid			1x100%	NA
Reverse Osmosis	1st & 2nd Pass	30 gpm	1x100%	1x100%
Fractional Electro-de-ionization (FEDI)		30 gpm	1x100%	1x100%
PFD-015 AIR QUALITY CONTROL SYSTEMS				
Gas-to-Gas Cooler		330 kg/s, 1200 tph	1-100%	0
Dry Electro Static Precipitator (Dry ESP for fly ash handling)		330 kg/s, 1200 tph	2-50%	0

Description	Type	Design Condition	Operating Qty.	Spares
Fly Ash System	UCC Vacuum System with (2) Model 65-W-72 Filter/Separators, (2) mechanical exhausters, bin vent filter, field-welded 20ft diameter fly ash storage silo, Model 1535 Paddle Mixer/Unloader, and telescopic spout dry unloader	Conveying capacity: 13 TPH up to 500ft		
ID Booster Fan	Axial	330 kg/s, 1200 tph	1-50%	1-50%
Wet FGD System				
Non-leakage type GGH		330 kg/s, 1200 tph	1-100%	0
Limestone feed system (rail dump, bin, day silo)		20 tph	1-100%	0
Limestone Feeders	Weigh Belt-Gravimetric	18,000 lb/hr	1-100%	1-100%
Ball mill with mill classifier	Horizontal Ball Mill with Lube Oil System	18,000 lb/hr	1-100%	1-100%
Mill product tank with agitator	Field-Erected or Pre-Fabricated	55% Slurry, 2,500 GAL	1-100%	1-100%
Slurry tank with agitator	Field-Erected	30% Slurry, 24,000 GAL	1-100%	0
Limestone slurry pumps	Horizontal, Centrifugal	150 GPM	1-100%	1-100%
FGD w/EME	Counter Current, Spray Tower, Trays, EME	330 kg/s, 1188tph	1-100%	0
Absorber Recycle Pumps	Horizontal, Centrifugal	27,000 GPM	3-33%	1-33%
Absorber Bleed Pumps	Horizontal, Centrifugal	300 GPM	1-100%	1-100%
Absorber Agitators	Side Entry		3	0
Oxidation Air Compressors and Lances	Centrifugal or Roots	7,300 cfm, normal, dry	1-100%	1-100%
Primary hydroclone (gypsum) / Launder Box		250 GPM	1 Unit - 6 cyclones	2 cyclones
Secondary hydroclone (gypsum) / Launder Box		80 GPM	1 Unit - 4 cyclones	2 cyclones
Vacuum filter with filtrate receiver and vacuum pump	Horizontal Belt	12 tph	1-100%	1-100%
Filtrate pump	Horizontal, Centrifugal	70 GPM	1-100%	1-100%
Gypsum conveyor	Belt	20 tph	1-100%	1-100%
Purge Tank and Agitator	Field-Erected	13,000 GAL	1-100%	0
Purge Pumps	Horizontal, Centrifugal	70 gpm	1-100%	1-100%
Reclaim water tank and agitator	Field-Erected	48,000 GAL	1-100%	0
Reclaim Water Pumps	Horizontal, Centrifugal	200 GPM	1-100%	1-100%
Makeup Water tank	Field-Erected	56,000 GAL	1-100%	0

Description	Type	Design Condition	Operating Qty.	Spares
Makeup Water Pumps	Horizontal, Centrifugal	250 GPM	1-100%	1-100%
PFD-016 ZERO LIQUID DISCHARGE				
WW Pre-Treatment Lime silo	Equipped with Dust Collector, Vibrating Bin Bottoms		1x100%	NA
WW Pre-Treatment Lime Conveyor	Screw Conveyor		1x100%	NA
WW Pre-Treatment Lime Sluicing Tank			1x100%	NA
WW Pre-Treatment Lime Sluicing Tank Agitator			1x100%	NA
WW Pre-Treatment Lime Sluicing Tank Heater			1x100%	NA
WW Pre-Treatment Lime Slurry Pump		60 gpm	1x100%	1x100%
WW Pre-Treatment Clarifier			1x100%	NA
WW Pre-Treatment Caustic Feed Skid			1x100%	NA
WW Pre-Treatment Sulfuric Feed Acid Skid			1x100%	NA
WW Pre-Treatment Polymer Feed Skid			1x100%	NA
WW Pre-Treatment Clarifier		11 ft Diameter	1x100%	NA
WW Pre-Treatment Filter Press		.75 tph	1x100%	NA
WW Pre-Treatment Feed Pumps		100 gpm Feed	1x100%	1x100%
ZLD Seeded Brine concentrator	Electric Driven Mechanical Vapor Recompression	90 gpm Feed	1x100%	NA
ZLD Forced Circulation Crystallizer	Steam Driven	13 gpm Feed	1x100%	NA
Centrifuge and waste handling		1.4 tph	1x100%	NA
PFD-017 CARBON CAPTURE				
CO_2 Amine System				
Booster Fan	Centrifugal with VFD and Inlet Guide Vane	650 tph	1-50%	1-50%
Flue Gas Cooler / Heat Exchanger	Direct Contact Packed-Bed Column with Counter-current Cooling Water Circuit	1300 tph	1-100%	0
DCC Recirc Cooler			1-100%	0
DCC Cooling water pump	Centrifugal	1300 tph	1-100%	1-100%
Absorber	Doosan Solvent, Metal packing, Counter-current column	1260 tph	1-100%	0

Description	Type	Design Condition	Operating Qty.	Spares
Rich Solvent Pump	Centrifugal	2780 tph	1-100%	1-100%
Lean Solvent Pump	Centrifugal	2480 tph	1-100%	1-100%
Lean Solvent Heat Exchanger	Water Cooled	Hot: 2250 tph	20	0
Rich Amine Heat Exchanger	Water Cooled	Cold: 2520 tph		0
Reclaimer		4.6 tph Steam	1-100%	0
Stripper	Packed-bed	2480 tph	1-100%	0
Reboiler	A plate and frame type thermosyphon reboiler/ LP steam	3890 tph	1-100%	0
Wash Pumps (1st stage)	Centrifugal	2470 tph	1-100%	1-100%
Wash Pumps (2nd stage)	Centrifugal	1190 tph	1-100%	1-100%
Wash Water Cooler	Water Cooled		1-100%	0
Precoat Waste Solids and Handling		40 tph	1-100%	1-100%
Gas-to-Gas Heater	Water Transport	1050 tph	1-100%	0
Stack		1050 tph	1-100%	0
CO_2 Product Reflux Vessel		290 tph	1-100%	0
CO_2 Compressor (from 1st stage to 5th stage, each)		110 tph	2-50%	1-50%
CO_2 DEHY System (from 1st stage to 2nd stage, each)	No triethylene glycol	110 tph	2-50%	1-50%
CO_2 Interstage Coolers	Cooling water, 7 stages	110 tph	1-100%	1-100%
CO_2 Compressor Condensate Pump	Centrifugal	70 tph		
CO_2 Purge System	Low pressure "Cardox" System	4 hr CO_2 storage; 150 tons pulverized coal storage; 20 kg/s coal feed rate to burner; 1000-ft storage silo to source		

5.0 Technology Assessment

5.1 Technology Summary

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

- USC pulverized coal boiler
- USC steam turbine
- AQCS consisting of SCR, ESP, Wet FGD, and EME
- PCC system and CO_2 compression
- Process controls
- ESS with storing capability from HGCC and nearby renewable source
- Advanced coal property monitoring and management system

The major engineering challenge will be integrating the following six systems into commercially-available hardware.

- *Indirect Coal Firing System.* This system effectively decouples coal mill operation from boiler operation. The advantage of this system is that the boiler turndown and ramp rate are dramatically improved when compared to a traditional pulverized coal boiler. This system mills the coal and stores it in bins, employing a CO_2 gas inerting system to prevent auto-ignition. Similar CO_2 gas inerting systems are deployed in the cement/lime industry and for lignite-fired boilers in Germany. From the bins, the coal is fed into the boiler as load changes. Kidde Fire Systems is currently developing the preliminary CO_2 gas inerting system design for the HGCC concept. DHI will supply the burners with design considerations identified during the FEED study.

  In markets with increasing requirements for the flexible operation of the hard coal and lignite power plants, modifying an existing boiler and installing an indirect firing system in parallel with the conventional direct firing system will allow a reduction of the boiler's minimum load lower than 30%. In this way, a kind of "idle" operation can be achieved, where the plant stays on the grid at a very low load, providing primary and secondary control services with the ability to ramp up again whenever required by the system operator.

  For fuels with high moisture contents, such as a lignite, the indirect firing concept requires heat energy for coal drying during pulverization and handling of the off-gas (vapors) from the dryer/pulverizer system. The process scheme of the steam-heated fluidized-bed drying and its integration in a hybrid firing system is shown in Figure 5-1. The vapor resulting from coal water evaporation is cleaned and partially used for fluidization and heat recovery in the low-pressure preheaters of the power plant. A system similar to that shown has operated for more than 10 years in the Niederaußem K power station (Germany), including a prototype fluidized-bed dryer.

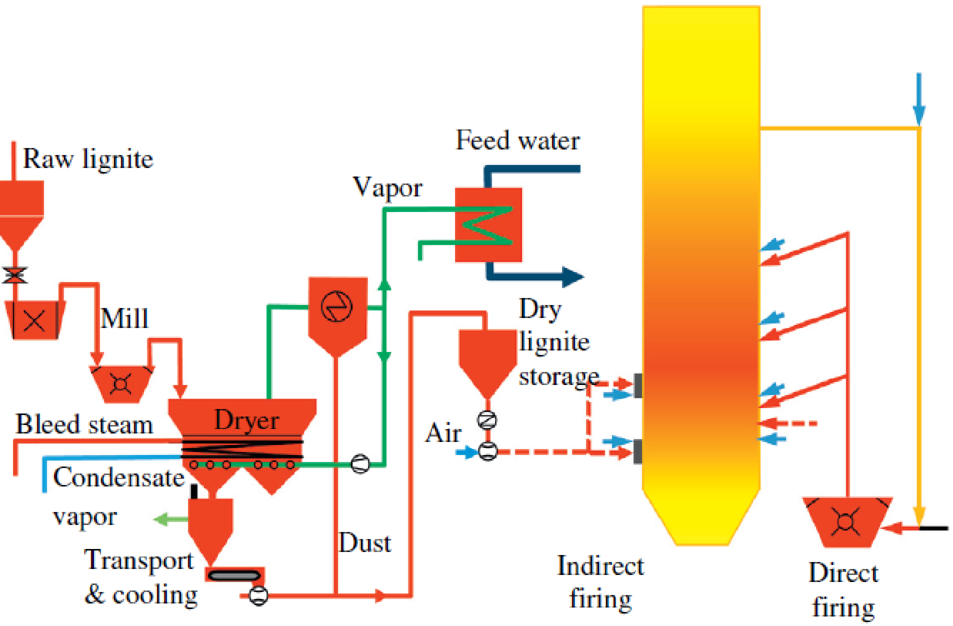

Figure 5-1 External Pre-drying System based on Fluidized Bed Drying Technology for Lignite Firing

- *Gas Turbine (GT) Integration*. The exhaust from the GT will be introduced into the boiler via the windbox and the overfire air system. The lower O_2 content and higher temperature of the flue gas requires that CFD modeling be performed to optimize the performance of the burner/OFA system for NO_x emission, combustion completion, and heat transfer rates for the various sections of the boiler (waterwalls, superheater, reheater, etc.).

- *Flue Gas/Air Heater Heat Recovery*. The high flowrate and temperature of the gas turbine flue gas (which, in part, is used to supply oxygen for combustion) minimizes boiler air preheating requirements. To accomplish the required heat recovery from the combustor flue gas, two additional heat exchangers are included to preheat the condensate and the feedwater system. The equipment used to achieve this integration is standard commercial systems; however, its integration with the boiler/feedwater cycle is novel.

- *ESS (batteries)*. The ESS (Lithium Ion / Vanadium Redox Hybrid System) is undergoing commercial deployment. Discussions are ongoing with ESS suppliers to integrate their systems with this concept.

- *Advanced coal property monitoring and management system.* This component is designed to minimize impact on performance and reliability. Variability of coal properties is managed using on-line analyzers, fireside performance indices, and condition-based monitoring.

- *Cooling water circuit.* Due to the carbon capture system demands, we anticipate that the cooling tower cell footprint, power usage, and water usage will be significant compared to the rest of the plant. While we plan to further investigate how to optimize pretreatment to consider more cycles, reducing the amount of blowdown required for wastewater treatment, the evaporative losses and the makeup water necessary to recover those losses is great. In an effort to reduce the water consumption and wastewater, air-cooling was considered but disregarded due to backpressure requirements. We had also considered a modularized cooling system of cells, but due to their size, the modules would still require a significant amount of labor for installation. Further evaluation of how to reduce evaporative losses and water usage, the cooling tower footprint, and increased cooling efficiency could be beneficial.

5.2 Technical Challenges & Critical Components

5.2.1 Technical Gaps

The HGCC key technical gaps and risks as well as the proposed approaches to address them are discussed in the following subsections.

Boiler Combustion Gaps

<u>Boiler Size:</u> The USC technologies are well proven—up to 1,000 MW—and have demonstrated 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 270 MW-class USC coal power plant, featuring rapid start and low-load operation, will require a thorough design study and analysis.

<u>Coupled Indirect System Design and Optimization</u>: Pulverized coal combustion systems are divided according to how they are connected to the boiler. In the preFEED phase, indirect coal firing system was applied to improve plant flexibility. To optimize the efficiency of the plant, it was upgraded to a system that combines boiler and pulverizer air. In the FEED study, coupled indirect system will be further developed through detailed design and system risk assessment.

	Advantages
Direct Firing System	• Considerably smaller investment costs • Lower operating and maintenance costs • Less complex safety devices required • Minimize loss of boiler efficiency
In Direct Firing System	• High flexibility of the firing system (Ramp Rate) • Minimum load reduction and Start-up time • Separation of fuel preparation and combustion

Use of the turbine exhaust gas in the OFA ports is beneficial because the lower oxygen concentration and higher gas flow provides higher momentum for mixing with the main boiler flue gas (always a challenge for OFA injection). It also provides reduced O_2 levels throughout the furnace volume, reducing the formation of NO_x along with improved burnout.

Mixing the GT flue gas with the combustion air does not significantly affect flame stability. However, the draft loss of the burner air register increases when the oxygen partial pressure decreases, delaying combustion. This could result in increased unburned carbon content. This risk is mitigated by multiple strategies in our design.

Through the HGCC preFEED study, it is analyzed in terms of both the qualitative effects and the quantitative effects applying actual boiler design in both the GT exhaust gas and pure-air modes by combustion CFD. Investigated parameters include gas temperature, flow distribution, species concentration, and char burnout. CFD results show that NO_x concentration at the furnace outlet is 99 ppm (at 6% O2) in GT exhaust mode and 113 ppm in pure-air mode, which are less than the NO_x emission target of 150 ppm. Carbon in ash at the outlet of the furnace is 4.5% in the GT exhaust-gas mode and 2.7% in the pure air mode. These results indicate no serious problems in terms of combustion. These combustion performances will be verified in further by a pilot-scale test in the FEED study. However, the OFA system should be considered further to enhance flow penetration, such as by introducing two-stage OFA. In addition, it is assumed that GT exhaust gas and air are completely mixed, so suitable a mixer and duct should be designed to match this assumption.

Boiler Heat Transfer Surfaces: USC heat transfer surfaces operate at higher temperatures than subcritical boilers. The proposed concept has a lower adiabatic flame temperature than pure air combustion. The addition of the GT exhaust gas in the OFA could result in changing the furnace exit gas temperature, which would shift the heat absorption duty from the furnace body to the convective section. All of these could result in boiler heat absorption changes. Such changes require an optimization study of the configuration and design parameters of the boiler to maximize the benefits (heat extraction) and minimize the risks (fouling and slagging in convective section) for boiler design and the RFP requirements.

5.2.2 Risks

The key technical risk associated with the HGCC is the integration of the combustion turbine into the boiler. Introduction of turbine exhaust into the boiler requires that the following areas be redesigned compared to a traditional pulverized coal boiler (refer to Section 5.1):

- Coal preparations, handling, storage, and fire suppression systems
- Furnace windbox and burners
- Overfired air system
- Flue gas/air heater and external heat exchangers

The design issues are anticipated to cover:

- CO_2 inerting system
- Heat transfer for the various boiler sections
- Expected tube metal temperatures and their variation as load changes
- NO_x emissions reductions from the overfire air system
- Flue gas temperature entering the SCR system at all boiler loads
- Efficiency at risk during high ramp rates
- Minimum load considerations

5.3 Development Pathway

5.3.1 Research & Development

To address the gaps identified above, we recommend:

- Burner evaluation to identify the optimal operating parameters for hotter transport air
- Demonstration testing at the MW_{th} scale to verify and confirm the CFD model and burner evaluation
- Burner performance test
- Optimizing OFA design

Analysis of the boiler furnaces using GT exhaust gas as an oxidant showed no serious problems in terms of combustion. This analysis result is performed under the premise that the GT exhaust gas supplied to the burner is well mixed with pure air and the mixed oxygen concentration is constant. Therefore, there is room for change, depending on actual GT and boiler operation. It is considered necessary to review this in the future and further study is needed.

It is proposed to carry out a combustion performance test by applying a pilot scale model (3MW) of actual burner. The burner combustion test facility owned by Doosan Heavy Industries & Construction is designed to recycle exhaust gas and supply pure air to the burner. It also has an indirect type pulverizer, which can be used to check the burner's combustion performance against the actual combustion conditions, which can be operated in the boiler by controlling the concentration of oxygen supplied to the burner by load. It is possible to obtain flame characteristic data according to the burner outlet speed which is different between the pure air operation mode and the GT exhaust gas operation mode.

Optimizing OFA Design

As confirmed by the analysis results, the penetration depth was different because the flow rate difference between the GT exhaust gas and the pure-air operation mode is very large. In order to optimize the performance, it is necessary to review the design that satisfies both modes of operation, such as adopting a two-stage OFA.

Mixer and Mixing Duct Design and Optimization

In the preFEED phase, the GT exhaust gas and the air were assumed to be completely mixed in the GT exhaust gas operation mode. However, this kind of mixing requires a suitable mixer and duct design for it.

Coupled Indirect System Design and Optimization

Pulverized coal combustion systems are divided according to how they are connected to the boiler. In the preFEED stage, indirect coal firing system was applied to improve plant flexibility. To optimize the efficiency of the plant, it was upgraded to a system that combines boiler and pulverizer air and injects it. This will further be developed in the FEED study.

The proposed development is essential to identifying the optimal method of adding GT flue gas into the boiler system without adversely affecting boiler design. A two-year timeline is proposed for the evaluations with a completion date of 2022. A FEED study can be performed concurrently with the evaluations. Subsequently, a demonstration of the concept to reduce investment and risk can be implemented in the 2024-2027 timeframe and the FEED updated to include results from the demonstration.

Table 5-1 illustrates items to be addressed during the FEED stages of the project

Table 5-1 Technical Pathway

Technical pathway	Technical agendas	Key activities	Target
Research & Development	Optimize heat absorption profile	CFD modeling of boiler; burner tuning for GT flue gas; pilot demonstration to validate CFD modeling and identify fouling/slagging issues.	Identify optimal integration of GT flue injection to boiler
FEED	Demonstration and new build project feasibility	Basic design and critical component detail design for the targeted plant demonstration and new build power plant.	Confirm the technical and economic feasibility of demonstration 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	Full Scale Commercial Greenfield Construction	Commercial demonstration by applying the FEED study result and plant demonstration experience developed technology. The project will be conducted by commercial contract except for developed components.	350MW Scale commercial

A project schedule has been developed as part of the project execution plan provided in Appendix C. Items in the technology gap review will be addressed during the FEED study.

5.4 Technology Original Equipment Manufacturers

5.4.1 Commercial Equipment

The equipment required to execute the HGCC project is available on the market. Examples of the major components are listed in Table 5-2. To the greatest extent practicable, all equipment and products purchased will be made in The United States of America, shop assembled and shipped. This will be further defined in our FEED proposal.

Table 5-2 Commercially Available Equipment

Equipment Item	Manufacturer
Gas turbine	GE
Steam turbine	DHI, GE, Siemens
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

Equipment Requiring Research & Development

The main R&D challenge for the HGCC is the new and emerging hardware in the ESS Battery storage system. The concept envisions a 50-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 involve integrating the indirect firing system and the combustion turbine into the USC boiler design.

The R&D items listed in Table 5-3 will be developed during the preFEED stage and conducted and completed in the FEED stage.

Table 5-3 Equipment Not Commercially Available

Equipment features / Concept	R&D Entity/Manufacturer
Construction and operation of integration of the GT exhaust gas with coal combustion burner	DHI
Fast startup USC boiler model control system	DHI
Low-load operation USC steam turbine model with PCC control system	DHI/Doosan Babcock/PCC Manufacturer
ESS battery (limited commercial installations)	DHI/ESS Vendor
USC boiler indirect firing system – Integration with boiler/combustion turbine	DHI
Battery storage/USC boiler/combustion turbine control system	DHI/ESS Vendor

Appendix A Power Plant of the Future Process Flow Diagrams

PERFORMANCE SUMMARY

TOTAL PLANT LOAD				MCR
COAL POWER PLANT LOAD				MCR
COAL TYPE	BITUMINOUS	SUB-BITUMINOUS	LIGNITE	
AMBIENT DRY BULB TEMPERATURE	15.0	15.0	15.0	°F
AMBIENT RELATIVE HUMIDITY	60.0	60.0	60.0	%
BAROMETRIC PRESSURE	1.0	1.0	1.0	bara
GAS TURBINE LOAD	100	100	100	%
GAS TURBINE POWER OUTPUT	86.8	86.8	86.8	MW
STEAM TURBINE POWER OUTPUT	270.6	271.2	226.5	MW
ENERGY STORAGE SYSTEM POWER OUTPUT	50.2	50.2	40.9	MW
PLANT GROSS POWER OUTPUT	407.6	408.2	354.2	MW
AUXILIARY POWER CONSUMPTION	57.6	61.6	54.2	MW
PLANT NET POWER OUTPUT	350.0	346.0	300.0	MW
NATURAL GAS HEAT INPUT	265.0	265.0	265.0	MW
COAL HEAT INPUT	546.1	564.9	483.6	MW
PLANT GROSS EFFICIENCY (HHV)	50.3	49.2	47.3	%
PLANT NET EFFICIENCY (HHV)	43.2	41.8	40.1	%
PLANT NET EFFICIENCY WITHOUT ENERGY STORAGE SYSTEM (HHV)	37.0	35.7	34.6	%

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
G	CAH	CAH	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
F	CAH	CAH	-	3/15/2020	ISSUED FOR REVIEW
E	CAH	CAH	-	2/15/2020	ISSUED FOR REVIEW
D	CAH	CAH	-	1/24/2020	ISSUED FOR REVIEW
C	CAH	CAH	-	1/6/2020	ISSUED FOR REVIEW - PERFORMANCE REPORT
B	KDS	-	-	11/22/19	ISSUED FOR CLIENT REVIEW

RELEASED TO/FOR	A	B	C	D	E	F	G
CLIENT	6/19/19	11/22/19	1/6/2020	1/24/2020	2/15/2020	3/15/2020	3/27/2020
BID	—	—	—	—	—	—	—
CONSTRUCTION	—	—	—	—	—	—	—

DATE RELEASED

BARR
Corporate Headquarters:
Minneapolis, Minnesota
Ph: 1-800-632-2277

Project Office:
BARR ENGINEERING CO.
4300 MARKETPOINTE DRIVE
Suite 200
MINNEAPOLIS, MN 55435
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www.barr.com

Scale	NO SCALE
Date	6/12/19
Drawn	DAK
Checked	CAH
Designed	CAH
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

HGCC FUEL PREP, COMBUSTION, WATER SYSTEM
OVERALL PROCESS FLOW DIAGRAM

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. PFD-001
REV. No. G

ISSUED FOR FINAL
PRE-FEED STUDY
NOT FOR CONSTRUCTION

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
F	CAH	CAH	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
E	CAH	CAH	-	3/15/2020	ISSUED FOR REVIEW
D	CAH	CAH	-	1/24/2020	ISSUED FOR REVIEW
C	CAH	CAH	-	1/6/2020	ISSUED FOR REVIEW - PERFORMANCE REPORT
B	KDS	-	-	11/22/19	ISSUED FOR CLIENT REVIEW

RELEASED TO/FOR	A	B	C	D	E	F	0
CLIENT	6/19/19	11/22/19	1/6/2020	1/24/2020	3/15/2020	3/27/2020	
BID							
CONSTRUCTION							

DATE RELEASED

BARR
Corporate Headquarters: Minneapolis, Minnesota Ph: 1-800-632-2277
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Scale	NO SCALE
Date	6/12/19
Drawn	DAK
Checked	CAH
Designed	CAH
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

HGCC AIR QUALITY CONTROL SYSTEM AND WASTEWATER
OVERALL PROCESS FLOW DIAGRAM

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. PFD-002
REV. No. F

ISSUED FOR FINAL
PRE-FEED STUDY
NOT FOR CONSTRUCTION

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
D	KAS2	KAS2	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
C	KAS2	KAS2	-	3/15/2020	ISSUED FOR REVIEW
B	KAS2	KAS2	-	1/24/2020	ISSUED FOR REVIEW
A	KAS2	KAS2	-	1/6/2020	ISSUED FOR REVIEW - PERFORMANCE REPORT

RELEASED TO/FOR	A	B	C	D	0	1	2
CLIENT	1/6/2020	1/24/2020	3/15/2020	3/27/2020			
BID							
CONSTRUCTION							

DATE RELEASED

BARR
Corporate Headquarters: Minneapolis, Minnesota
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Project Office:
BARR ENGINEERING CO.
4300 MARKETPOINTE DRIVE
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Scale	NO SCALE
Date	11/25/19
Drawn	DAK
Checked	KAS2
Designed	KAS2
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

STEAM TURBINE AND FEEDWATER HEATING PROCESS FLOW DIAGRAM

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. PFD-013
REV. No. D

Appendix B Power Plant of the Future Overall and Feedwater Stream Mass & Energy Balances

	Combustion Air	Coal Feed + Pulverizer Air	Natural Gas Feed to Combustion Turbine	Natural Gas Turbine Combustion Air	Heated Natural Gas Turbine Exhaust to Boiler	CO2 Inerting Gas	Ammonia Injection to SCR	Boiler Feedwater	Flue Gas from Boiler	HPT Steam to Boiler	HPT Steam from Boiler to IPT	Boiler Steam to HPT	Bottom Ash Discharge	Flue Gas from Gas Air Heater with SlipStream
	1	6A	8	9	11A	12	14	15	16	17A	17B	18	20	22
V-L Mass Fraction														
Ar	0.013	0.013	0.000	0.013	0.013	0.000	0.000	0.000	0.012	0.000	0.000	0.000	0.000	0.012
CO_2	0.001	0.001	0.025	0.001	0.044	0.973	0.000	0.000	0.186	0.000	0.000	0.000	0.000	0.183
H_2O	0.006	0.006	0.000	0.006	0.041	0.027	0.810	1.000	0.070	1.000	1.000	1.000	1.000	0.069
N_2	0.750	0.750	0.026	0.750	0.738	0.000	0.000	0.000	0.698	0.000	0.000	0.000	0.000	0.699
NOX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O_2	0.230	0.230	0.000	0.230	0.164	0.000	0.000	0.000	0.030	0.000	0.000	0.000	0.000	0.034
SO_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.003
CH4	0.000	0.000	0.862	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Organics	0.000	0.000	0.087	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000	0.000	0.190	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
V-L Flowrate (kg/hr)	337518.2	146439.6	18144.0	769644.0	1092996.0	1815.0	101.0	521644.7	1165205.0	647969.9	647969.9	756006.9	145.0	1188396.0
Solids Flowrate (kg/hr)	0.0	72504.0	0.0	0.0	0.0	0.0	0.0	0.0	5800.3	0.0	0.0	0.0	1450.1	5800.3
Temperature (°C)	15.00	77.00	27.00	29.00	530.13	45.00	29.00	304.54	387.26	366.99	600.00	600.00	65.00	133.58
Pressure (MPa, abs)	0.10	0.11	3.04	0.10	0.11	0.15	0.20	31.77	0.10	5.46	5.15	24.23	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]					549.69	0.00		1351.00	398.93	3103.51	3665.65	3500.76		114.79
V-L Flowrate (lb/hr)	744092.7	322840.7	40000.3	1696757.2	2409640.8	4001.3	222.7	1150018.0	2568810.9	1428514.4	1428514.4	1666692.7	319.7	2619937.8
Solids Flowrate (lb/hr)	0.0	159842.3	0.0	0.0	0.0	0.0	0.0	0.0	12787.4	0.0	0.0	0.0	3196.8	12787.4
Temperature (°F)	59.00	170.60	80.60	84.20	986.23	113.00	84.20	580.17	729.07	692.58	1112.00	1112.00	149.00	272.44
Pressure (psia)	14.65	15.23	435.00	14.50	15.23	22.19	29.01	4607.86	14.07	791.62	746.37	3514.71	14.50	14.07
Steam Table Enthalpy (Btu/lb)[A]					236.32	0.00		580.83	171.51	1334.27	1575.95	1505.06		49.35

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	Service Water to Boiler Treatment	Treated Boiler Water	Steam to PCC and ZLD	LPT Steam to Condenser	Circulating Water Pump to Condenser	Condenser to Closed Loop Circulating Water	Feedwater Heater to Condenser	Low Pressure Steam Crossover Reboiler Condensate	Gland Steam Condensate to Condenser	Condenser to Gland Steam / Feedwater System	Cooling Tower to Circulating Water Pump	Cooling Tower Blowdown to FGD Makeup	Cooling Tower Evaporative + Drift Losses	Cooling Tower Water Makeup	Total Service Water
	23	**24**	**25D**	**26**	**27**	**28**	**29**	**29I**	**30**	**31**	**32**	**33**	**34**	**35**	**37**
V-L Mass Fraction															
Ar	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CO_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
H_2O	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
N_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NOX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SO_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CH4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Organics	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
V-L Flowrate (kg/hr)	7496.1	7496.1	213499.1	401943.6	18850459.0	18850459.0	13608.1	204517.9	2124.0	422679.8	18850459.0	64892.7	454249.0	519141.7	18352.8
Solids Flowrate (kg/hr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temperature (°C)	25.00	25.00	268.40	33.16	15.55	26.67	101.40	169.43	69.97	33.16	15.55	26.67	26.67	26.67	25.00
Pressure (MPa, abs)	0.20	0.20	0.50	0.01	0.45	0.45	0.18	2.64	0.03	0.01	0.45	0.10	0.10	0.10	0.20
Steam Table Enthalpy (kJ/kg)[A]			2999.25	2326.30			425.08	717.74	292.91	138.94					
V-L Flowrate (lb/hr)	16526.0	16526.0	470680.1	886125.0	41557721.9	41557721.9	30000.5	450880.1	4682.6	931840.0	41557721.9	143062.5	1001437.3	1144499.8	40460.6
Solids Flowrate (lb/hr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Temperature (°F)	77.00	77.00	515.12	91.69	59.99	80.00	214.52	336.97	157.95	91.69	59.99	80.00	80.00	80.00	77.00
Pressure (psia)	29.01	29.01	72.66	0.73	65.00	65.00	25.96	382.90	4.50	0.73	65.84	30.00	14.50	14.50	29.01
Steam Table Enthalpy (Btu/lb)[A]			1289.45	1000.13			182.75	308.57	125.93	59.73					

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	Total Makeup Water	Flue Gas from GGC	ESP Flyash Unloading	Flue Gas from Dry ESP	Flue Gas from ID Fan	Limestone Slurry to FGD	Gypsum Product Discharge from FGD	FGD Purge Stream + Surplus Water to Water Treatment	Flue Gas from FGD	Water Treatment Product to ZLD	Wastewater Sludge Loadout	ZLD Crystallized Solids Waste	ZLD Treated Distillate to Makeup	Flue Gas from Cooler to Amine Scrubber
	38	39	40	41	42	43	44	45	46	47	48	49	50	51
V-L Mass Fraction														
Ar	0.000	0.012	0.000	0.012	0.012	0.000	0.000	0.000	0.011	0.000	0.000	0.000	0.000	0.012
CO_2	0.000	0.183	0.000	0.183	0.183	0.000	0.000	0.000	0.182	0.000	0.000	0.000	0.000	0.196
H_2O	1.000	0.069	1.000	0.069	0.069	1.000	1.000	1.000	0.102	1.000	1.000	0.000	1.000	0.033
N_2	0.000	0.699	0.000	0.699	0.699	0.000	0.000	0.000	0.673	0.000	0.000	0.000	0.000	0.725
NOX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
O_2	0.000	0.034	0.000	0.034	0.034	0.000	0.000	0.000	0.031	0.000	0.000	0.000	0.000	0.034
SO_2	0.000	0.003	0.000	0.003	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CH4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Organics	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000
V-L Flowrate (kg/hr)	574142.4	1188496.8	574.2	1188496.8	1188496.8	26490.1	1551.3	15968.0	1234538.3	32368.4	143.7	0.0	25894.7	1146587.3
Solids Flowrate (kg/hr)	0.0	5800.3	5742.3	58.0	58.0	6622.5	8790.7	958.1	0.0	958.1	958.1	1270.1	0.0	0.0
Temperature (°C)	25.00	90.02	90.02	90.02	95.02	25.00	25.00	45.02	45.02	25.00	25.00	25.00	25.00	35.00
Pressure (MPa, abs)	0.20	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.11
Steam Table Enthalpy (kJ/kg)[A]		68.23	90.02	68.23	50.02				20.85					
V-L Flowrate (lb/hr)	1265754.3	2620160.0	1266.0	2620160.0	2620160.0	58400.0	3420.0	35203.1	2721663.1	71359.4	316.8	0.0	57087.5	2527766.4
Solids Flowrate (lb/hr)	0.0	12787.4	12659.5	127.9	127.9	14600.0	19380.0	2112.2	0.0	2112.2	2112.2	2800.0	0.0	0.0
Temperature (°F)	77.00	194.04	194.04	194.04	203.04	77.00	77.00	113.04	113.04	77.00	77.00	77.00	77.00	95.00
Pressure (psia)	29.01	14.07	14.07	14.07	14.79	14.79	14.79	14.50	14.79	14.79	14.79	14.79	14.79	15.23
Steam Table Enthalpy (Btu/lb)[A]		29.33		29.33	21.50				8.96					0.00

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	CO2 Spent Carbon and Reclaimer Waste to Loadout	Captured CO2 to Compressors	Flue Gas from GGH to Stack	Pure CO2 for Storage or Utilization	CO2 Compressor Condensate
	53	54	56	57	58
V-L Mass Fraction					
Ar	0.000	0.000	0.015	0.000	0.000
CO_2	0.000	0.973	0.023	1.000	0.000
H_2O	0.000	0.027	0.060	0.000	1.000
N_2	0.000	0.000	0.862	0.000	0.000
NOX	0.000	0.000	0.000	0.000	0.000
O_2	0.000	0.000	0.040	0.000	0.000
SO_2	0.000	0.000	0.000	0.000	0.000
CH4	0.000	0.000	0.000	0.000	0.000
Other Organics	1.000	0.000	0.000	0.000	0.000
NH3	0.000	0.000	0.000	0.000	0.000
Total	1.000	1.000	1.000	1.000	1.000
V-L Flowrate (kg/hr)	0.0	208174.0	965322.0	199114.0	5573.0
Solids Flowrate (kg/hr)	40064.3	0.0	0.0	0.0	0.0
Temperature (°C)	25.00	45.00	99.37	40.00	40.0
Pressure (MPa, abs)	0.10	0.15	0.10	15.70	0.2
Steam Table Enthalpy (kJ/kg)[A]			78.17	293.23	
V-L Flowrate (lb/hr)	0.0	458940.4	2128148.9	438966.7	12286.2
Solids Flowrate (lb/hr)	88325.8	0.0	0.0	0.0	0.0
Temperature (°F)	77.00	113.00	210.87	104.00	104.00
Pressure (psia)	14.79	22.19	14.79	2277.10	21.76
Steam Table Enthalpy (Btu/lb)[A]			33.61	126.07	

Notes:

[1] Stream table data from the "HBD_BLR" & "HBD_TBN" tab of Doosan's conceptual heat and mass balance spreadsheet: DOE_HGCC_Pre-FEED_Final_TMCR_Release_rev0.2.xlsx

[2] Stream data design based off Exhibit 3-54 Case B12B stream table, supercritical unit with capture on page 139 of the NETL report: \\barr.com\projects\Mpls\48 WV\31\48311001 Coal FIRST_01 Coal and NG Concept\Deliverables\20190731 CoalFIRST CombustionConcept 17_FINAL.docx

[3] The following Streams are no flow streams for the full load base case and would only have flow during certain situations such as startup or shutdown: 3A, 21A

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	Boiler Feedwater (excludes slipstream)	CR Steam to Boiler	HR Steam from Boiler to IPT	Boiler Steam to HPT	Main Steam to FWH	HPT Steam to FWH	Steam to LPT	IPT Steam to LPT and Auxiliaries	Steam to PCC and ZLD	IPT Steam to FWH	IPT Steam to Deaerator	IPT Steam to FWH	LPT Steam to Condenser	LPT Steam to Gland Steam Condenser	LPT Steam to FWH
	15	17A	17B	18	18B	18C	25	25A	25D	25F	25G	25H	26	26B	26C
V-L Mass Fraction															
Ar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2O	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
N_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Organics	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
V-L Flowrate (kg_{mole}/hr)															
V-L Flowrate (kg/hr)	521,645	647,970	647,970	756,007	40,752	50,112	419,584	624,102	213,499	0	13,680	24,516	401,944	2,124	13,608
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	304.54	366.99	600.00	600.00	450.91	364.67	268.40	268.40	268.40	-	360.92	472.80	33.16	186.07	166.34
Pressure (MPa, abs)	31.77	5.46	5.15	24.23	8.57	5.19	0.50	0.50	0.50	0.00	1.09	2.23	0.01	0.03	0.18
Steam Table Enthalpy (kJ/kg)[A]	1351.00	3103.51	3665.65	3500.76	3266.92	3103.51	2999.25	2999.25	2999.25	-	3179.61	3405.39	2326.30	2851.50	2803.96
Density (kg/m^3)															
V-L Molecular Weight															
V-L Flowrate (lb_{mole}/hr)															
V-L Flowrate (lb/hr)	1150017.977	1428514.394	1428514.394	1666692.72	89842.67424	110477.9174	925014.5	1375894.524	470,680	0	30159.2016	54048.46	886124.9628	4682.61288	30000.47
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	580.17	692.58	1112.00	1112.00	843.64	688.41	515.12	515.12	515.12	0.00	681.66	883.04	91.69	366.93	331.41
Pressure (psia)	4607.86	791.62	746.37	3514.71	1243.27	752.60	72.66	72.66	72.66	0.00	158.24	323.29	0.73	4.50	25.96
Steam Table Enthalpy (Btu/lb)[A]	580.8254514	1334.269132	1575.94583	1505.05589	1404.522786	1334.269132	1289.445	1289.4454	1289.445	0	1366.986242	1464.054	1000.128977	1225.924334	1205.486
Density (lb/ft^3)															

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	LPT Steam to FWH	LPT Steam to FWH	Circulating Water Pump to Condenser	Condenser to Closed Loop Circulating Water	FWH to FWH	FWH to FWH	CO2 Compressor to FWH	FWH to FWH	Low Pressure Steam Crossover Reboiler Condensate	FWH to Deaerator	Deaerator to Boiler Feed Pump	FWH to Deaerator	Boiler Feed Pump to Slipstream FWH	FWH to FWH	FWH to FWH
	26D	**26E**	**27**	**28**	**29B**	**29C**	**29D**	**29H**	**29I**	**29K**	**29L**	**29M**	**29P**	**29S**	**29U**
V-L Mass Fraction			0												
Ar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2O	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
N_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SO_2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CH4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Organics	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
V-L Flowrate (kg_{mole}/hr)															
V-L Flowrate (kg/hr)	0	0	18,850,459	18,850,459	29,556	422,428	392,872	21,132	204,518	626,946	756,007	115,381	521,645	521,645	521,645
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	-	-	15.55	26.67	36.49	95.80	95.80	113.98	169.43	169.43	183.72	195.33	189.73	218.84	268.07
Pressure (MPa, abs)	0.00	0.00	0.45	0.45	2.64	2.64	2.64	2.64	2.64	2.64	1.09	2.23	31.77	31.77	31.77
Steam Table Enthalpy (kJ/kg)[A]	-	-			155.23	403.35	403.35	480.00	717.74	717.74	779.66	831.74	821.51	948.55	1172.57
Density (kg/m^3)															
V-L Molecular Weight															
V-L Flowrate (lb_{mole}/hr)															
V-L Flowrate (lb/hr)	0	0	41557721.91	41557721.91	65159.75	931284.4	866124.6502	46588.03	450880.0639	1382164.463	1666692.72	254369.0556	1150017.977	1150018	1150018
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	0.00	0.00	59.99	80.00	97.68	204.44	204.44	237.16	336.97	336.97	362.70	383.59	373.51	425.91	514.53
Pressure (psia)	0.00	0.00	65.84	65.84	382.90	382.90	382.90	382.90	382.90	382.90	158.24	323.29	4607.86	4607.86	4607.86
Steam Table Enthalpy (Btu/lb)[A]	0	0	0	0	66.73689	173.4093	173.4092863	206.3629	308.5726569	308.5726569	335.1934652	357.5838349	353.1857266	407.8031	504.1144
Density (lb/ft^3)															

[A] Steam table reference conditions are 32.02°F and 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

	FWH to FWH	Slipstream FWH to Boiler FW	Condenser to Condensate Pump	Gland Steam Condenser to CO2 Compressor Heat Exchanger	Gland Steam Condenser to FWH
	29V	29W	31	31C	31D
V-L Mass Fraction					
Ar	0	0	0	0	0
CO_2	0	0	0	0	0
H_2	0	0	0	0	0
H_2O	1	1	1	1	1
N_2	0	0	0	0	0
O_2	0	0	0	0	0
SO_2	0	0	0	0	0
CH4	0	0	0	0	0
Other Organics	0	0	0	0	0
Total	1	1	1	1	1
V-L Flowrate (kg_{mole}/hr)					
V-L Flowrate (kg/hr)	521,645	234,362	422,680	392,872	29,556
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	301.17	305.92	33.16	36.49	36.49
Pressure (MPa, abs)	31.77	30.50	0.01	2.64	2.64
Steam Table Enthalpy (kJ/kg)^A	1333.88	1358.73	138.94	155.23	155.23
Density (kg/m^3)					
V-L Molecular Weight					
V-L Flowrate (lb_{mole}/hr)					
V-L Flowrate (lb/hr)	1150018	516674.743	931839.9631	866124.6502	65159.74872
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	574.11	582.66	91.69	97.68	97.68
Pressure (psia)	4607.86	4423.51	0.73	382.90	382.90
Steam Table Enthalpy (Btu/lb)^A	573.4652	584.148753	59.73344798	66.73688736	66.73688736
Density (lb/ft^3)					

Notes:

[1] Stream table data from the "HBD_BLR" & "HBD_TBN" tab of Doosan's conceptual heat and mass balance spreadsheet: DOE_HGCC_Pre-FEED_Final_TMCR_Release_rev0.2.xlsx

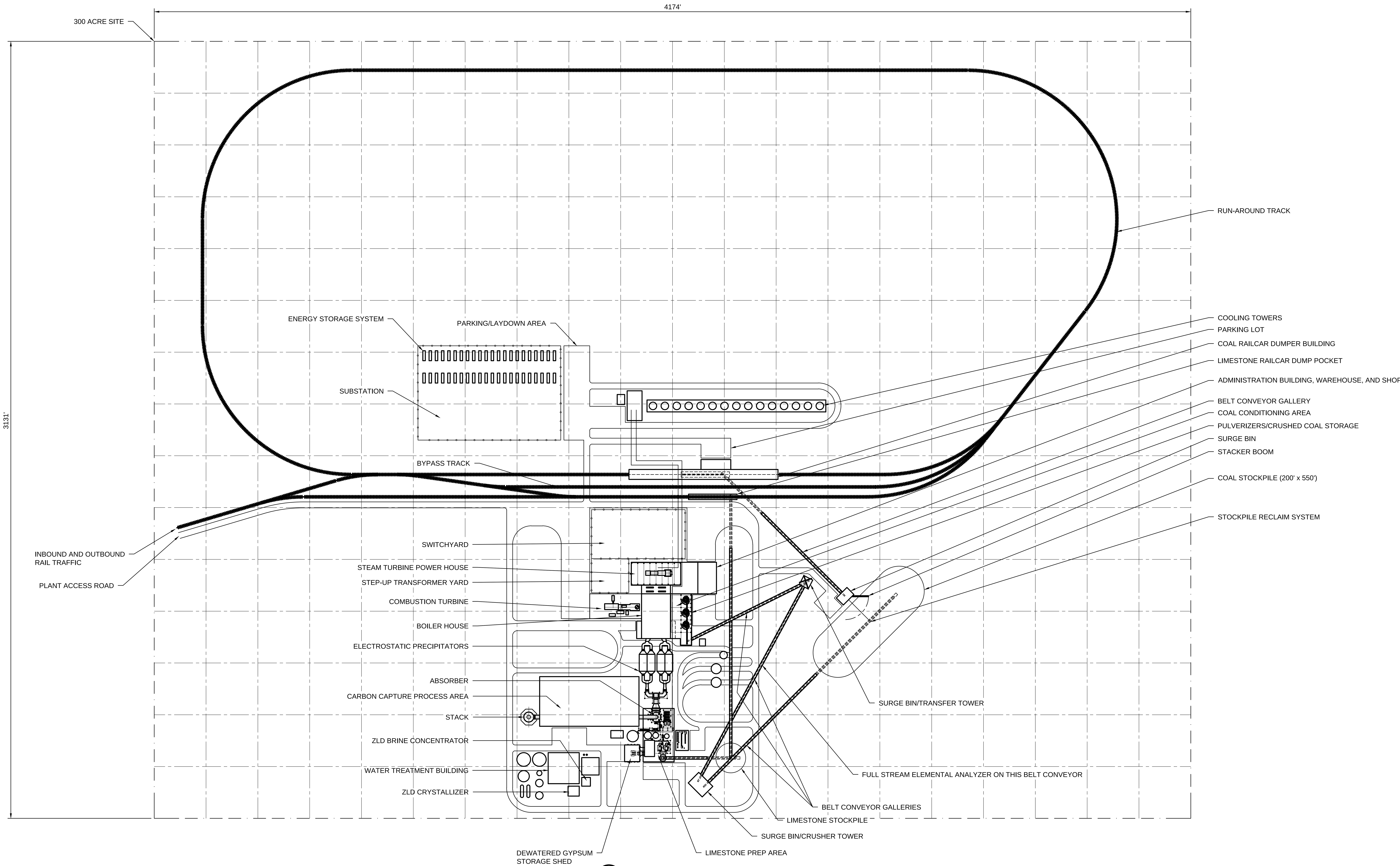
[2] Stream data design based off Exhibit 3-54 Case B12B stream table, supercritical unit with capture on page 139 of the NETL report: \\barr.com\projects\Mpls\48 WV\31\48311001 Coal FIRST_01 Coal and NG Concept\Deliverables\20190731 CoalFIRST CombustionConcept 17_FINAL.docx

[3] The following Streams are no flow streams for the full load base case and would only have flow during certain situations such as startup or shutdown: 3A, 21A

^{A} Steam table reference conditions are 32.02°F and 0.089 psia

^{B} Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Appendix C Power Plant of the Future Site Layout



1 PLAN: OVERALL SITE
1"=200'

0 200 400
SCALE IN FEET

ISSUED FOR FINAL
PRE-FEED STUDY
NOT FOR CONSTRUCTION

NO.	BY	CHK.	APP.	DATE	REVISION DESCRIPTION
C	NLN	NLN	-	3/27/2020	ISSUED FINAL FOR PRE-FEED STUDY
B	DAK	NLN	-	3/15/2020	ISSUED FOR REVIEW
A	DAK	NLN	-	1/6/2020	ISSUED FOR REVIEW

RELEASED TO/FOR	A	B	C	0	1	2	3
CLIENT	1/6/2020	3/15/2020	3/27/2020				
BID							
CONSTRUCTION							

DATE RELEASED

BARR
Corporate Headquarters: Minneapolis, Minnesota
Ph: 1-800-632-2277

Project Office:
BARR ENGINEERING CO.
3128 14TH AVENUE EAST
HIBBING, MN 55746
Ph: 1-800-225-1966
Fax: (218) 262-3460
www.barr.com

Scale	AS SHOWN
Date	12/4/19
Drawn	DAK
Checked	
Designed	CAH/DAK
Approved	

NETL/DOE COAL FIRST - HGCC
PRE-FEED STUDY

HGCC

GENERAL ARRANGEMENT
OVERALL SITE PLAN

BARR PROJECT No. 48/31-1001.01
CLIENT PROJECT No.
DWG. No. GA-001
REV. No. C

CADD USER: Hibpwuser FILE: \\HIB-PWHIB_PW_IN\6F4089CC-EE24-48C7-B9CB-2CF121BCF236\B2422135-87FE-438E-8D20-7EC8DBB8A6A4\4831100101_GA-001 PUBLIC.DWG PLOT SCALE: 1:1 PLOT DATE: 3/31/2020 7:39 AM
BAR M:\AutoCAD 2011\AutoCAD 2011 Support\enu\Template\Barr_2011_Template.dwt Plot at 1 10/05/2010 14:03:50

Appendix D Power Plant of the Future Performance Report List of Assumptions

Appendix D Assumption List

I. Site Characteristics and Ambient Conditions (Based on Design Basis Report)

II. Water Balance

1. Condenser backpressure is 1.5” Hg
2. The hot circulating water temperature is 80oF, and is cooled down to 60oF
3. The cooling tower will be run at at least eight (8) cycles of concentration to meet the cooling tower circulating water quality limits
4. Boiler feedwater is 33.4gpm
5. 15.4gpm of the treatment water backwash is sent to the wastewater treatment to maintain water balance.
6. Scrubber Evaporative Losses are based on 55oC.
7. 12.3 m3/hr of chloride is purged from the FGD
8. Gypsum moisture is 0.15%
9. The Gypsum bonded water is 21% of the total Gypsum capacity.
10. FGD Makeup water / Limestone Slurry Feed can be taken from the cooling tower blowdown
11. Limestone slurry feed is based on an 80/20 Water/Limestone mixture.
12. 10,000 kg/hr of Flue Gas PCC condensate can be used in the remainder of the plant.
13. PCC Effluent is based on Doosan’s PCC Performance Results Rev F03.
14. Wastewater Distillate can be reused in the plant makeup water system.
15. Wastewater sludge is based on Doosan’s PCC Performance Results Rev F03.
16. Wastewater Effluent losses are 20%
17. Flows are representative of average daily flows for annual average conditions
18. Equipment shall not be designed to handle peak flows.
19. Sanitary wastewater will be discharged to the POTW
20. Coal pile area is 5 acres
21. Paved area is 20 acres
22. Non-Contact Stormwater will be discharged from the facility as direct discharge without treatment
23. Oily wastewater will be treated to remove oil/grease and the effluent routed to the local POTW. The effluent stream will contain less than 10 mg/L of oil/grease.
24. Potable water demand is 20 gallons per day per person
25. Average daily precipitation is assumed 0.5 inches
26. Steam/Condensate/Feedwater cycle makeup is 1% of main steam flow

III. Carbon-Sulfur Balance

1. 90% of FGD Limestone Slurry is $CaCO_3$.
2. FGD Gypsum flowrate is based on 90% Gypsum.

IV. Civil Assumptions

No.	Assumption	Reference Doc.
1	Civil Quantities provided to truth check percentage multiplier	
2	"The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads."	Cost and Performance Baseline For Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity: NETL-PUB-22638, 2019-09-24
3	Installation at a greenfield site	Cost and Performance Baseline For Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity: NETL-PUB-22638, 2019-09-24
4	No Wetlands/soft soils	
5	Granular Fill for concrete slabs is available on site and covered under excavation and placement	
6	Topsoil covered under excavation and placement	
7	Groundwater not encountered during civil construction	
8	Capital costs for roads/access stops at edge of GA (incurred by municipalities beyond what is shown)	
9	Capital costs for rail stops at edge of GA (incurred by railroad)	
10	Concrete Pavement assumed to be 8" concrete thickness over 6" aggregate subbase	

V. Structural Assumptions

No.	Assumption
1	5 FT FROST DEPTH
2	• The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.

VI. Mechanical Assumptions

No.	Assumption	Reference Doc.
1	Density and ACFM calculated using air properties at actual temperature and pressure.	
2	Duct design velocities of 4000 fpm.	
3	Insulation thicknesses estimated assuming 120F skin temperature of lagging required (JM 1230 MinWool - 1200 flexible batt).	
4	Low carbon steel (ASTM A635/ ASTM A35) ductwork for 650F or less before boilers.	SMACNA
5	Low alloy steel (ASTM A387-22) ductwork for temperatures from 650F-1000F.	2004 ASME Boiler and Pressure Vessel Code, Part II, pg. 30.
6	Additional 20% of steel weight added to account for flanges, stiffeners, etc.	
7	HA/CA flowrates to pulverizers based on providing 30ft^3 of air per pound of coal at 150F mill outlet temperature and 450F mill inlet temperature.	B and W Steam Book, pg. 13-7, Figure 11, 41st Ed.
8	All ductwork has a square cross section.	
9	Corten steel (ASTM A606-4) ductwork downstream of airheaters to carbon capture area.	
10	Makeup water tank was scaled from Mesquite Power LLC 1200 MW (Combined cycle plant). Makeup water tank is similar in function to Mesquite's 1M Gallon raw water tank. Scaling by net energy production results in 225,000 gallon makeup water tank. See Drawing 065162-CWSB-M2662.	
11	Fire water/service water tank was scaled from Mesquite Power LLC 1200 MW (combined cycle plant) fire water storage tank (300,000 gallons) resulting in 70,000 gallon tank.	
12	Demineralized water storage tank was scaled from Mesquite Power LLC 1200 MW (combined cycle plant) fire water storage tank (155,000 gallons) resulting in 35,000 gallon tank.	
13	HGCC Closed circuit cooling water pumps flowrate were scaled from case B12B net power (650 MW). PCCC System closed cooling derived from Doosan Babcock Performance information.	

VII. EI&C Assumptions

No.	Assumption	Comment
1	**Controls Estimate includes:**	provided by (BARR)
	Processor rack w/ 2 processors for load sharing (non-redundant)	
	10 Remote I/O panels (20 I/O racks) with 20%+ spare based on I/O count	
	Stratus redundant server. Virtualized system.	
	Historian SE server	
	HMI server	
	Engineering workstation	
	Domain Controller (may not be needed)	
	10 HMI client licenses	
	PLC Programming (Barr)	
	HMI Programming (Barr)	
	Redundant processors	
	Redundant network	
	HMI client PC hardware	
	Estimate does not include:	
	Start-up/Commissioning	
	Project Management	
	Redundant I/O	
	I/O devices	
	Budget for Drawings	
	Etc.	

[i] Zhang, Yang, et al. "Field test of SO3 removal in ultra-low emission coal-fired power plants." Environmental Science and Pollution Research 27.5 (2020): 4746-4755.

[ii] Chen, Heng, et al. "Fouling of the flue gas cooler in a large-scale coal-fired power plant." Applied Thermal Engineering 117 (2017): 698-707.