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Project Title:
Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant with Integrated Carbon Capture

Base Contract:
Coal-Based Power Plants of the Future – Conceptual Design with Integrated CO_2 Capture

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1 Business Case

1.1 Market Scenario

The proposed coal power technology for this project is a Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant with post-combustion carbon capture at nominal 300 MWe gross size. This section describes the circumstances around the current coal power market place and how the proposed technology will be designed to counteract scenarios. Factors include:

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

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

- **Competition against other power sources –** In some regions, coal remains a low-cost generator, while in others, NG-based power is typically more economical due to the availability of low-cost NG (e.g., in the U.S., NG is about half the cost of elsewhere).
- **Drive towards low carbon –** 179 countries have signed the Paris Accord, whose goal is to reduce greenhouse gas (GHG) emissions (typically, countries have pledged to reduce CO_2 emissions on the order of 20–40% from 2012 levels). While the U.S. has not signed the accord, multiple states have enacted low-carbon initiatives including several that have committed to 80% reductions by 2040. Coal, as a fossil fuel, and one that produces double the CO_2 per MWh that NG does, is therefore a bigger target related towards reducing CO_2.
- **Energy security –** In some regions, coal is an abundant natural resource, representing energy security and reducing the need for reliance on fuels or energy from foreign countries. Finding ways to use it more effectively can be critical for these regions.
- **Environmental regulations –** Coal emission regulations – CO, NO_X, hazardous air pollutants, mercury, particulate matter, and SO_X – vary globally, but coal universally remains a tougher permitting challenge than NG.
- **Financing –** Financing is becoming more challenging for larger plants as the future power market has significant uncertainties, especially around carbon. Coal power plants are a particular challenge (30 banks have stopped financing coal). Smaller plants are thought to be lower risk since they require less capital, and hence have a better opportunity for financing.
- **Meeting a changing market –** The energy market is changing, largely due to the growth of variable renewable energy (VRE). Intermittency requires grid protection provided by dispatchable sources, which largely comes from fossil-based units. In the U.S., some coal power plants are providing such grid support, requiring them to operate more flexibly than they were designed for, which is deleterious to performance. Such operating behavior will likely also occur in other regions as renewables grow, reducing the need for base-load fossil power, while putting extra importance on their ability to provide grid resilience.

1.2 Domestic and International Market Applicability

1.2.1 United States

New coal power generation deployment has stagnated in the U.S., where coal is often not competitive with NG, or presents significant future environmental risk. There are few known coal power projects advancing in the U.S. and some utilities have pledged to eliminate coal power plants from their portfolio. Several things are likely needed for a significant resurgence in new coal:

- **Increase in the relative price of NG compared to coal –** While this has not been forecasted, it remains a possibility, especially as the demand for NG grows internationally.
- **Larger value for CO_2 either by regulation or for utilization –** If a significant market for CO_2 develops, this could help drive new coal power with carbon capture and storage (CCS). Enhanced oil recovery (EOR) remains the primary form of utilization and tapping into this market will likely be a necessity for any new coal plants with CCS in the short term. Governmental programs like 45Q provide a value for captured CO_2 as well, which aids in the overall project economics. In general, the worth of capturing CO_2 must be greater than the cost, which is not the case in most circumstances. Hence, the value must increase (perhaps by regulation) and/or the cost must decrease for coal CCS projects to be viable.
- **Regulatory certainty –** Uncertainty in future regulations increases risk, which makes coal power projects difficult to finance and generators more reticent to build them. Recent revisions to the Clean Air Act section 111(b) have been proposed to alter the definition of best system of emission reduction for new coal units to the most efficient demonstrated steam cycle in combination with best operating practices, instead of requiring partial CCS as was the case in the previous version. Getting this in place and adding certainty around the low-carbon future may be important for growth in coal power.

1.2.2 Outside the U.S.

Outside the U.S., different regions have different appetites for coal. A summary is given below.

- **China –** China is the largest coal producer and consumer in the world and coal accounts for 70% of its total energy consumption. Although China anticipates coal capacity growth of about 19% over the next five years, this comes at a time of slowing electricity demand. As a result, many coal plants have been operating at reduced capacity factors. Due to this, and growing environmental concerns, the Chinese government has announced it will postpone building some coal plants that have received approval and halt construction of others. However, there is still a need for new power, especially in the west, and a large supply of coal exists in China. Coal plants that are efficient (a key criterion) and smaller will likely be of appeal. CO_2 utilization for EOR and enhanced gas recovery are also growing possibilities.
- **Europe –** In Western Europe, following the Paris Accord, several countries announced plans to end coal-fired generation within their borders or set in place emissions reductions targets that would effectively require an end to coal without CCS: France by 2023, the United Kingdom and Austria by 2025, the Netherlands by 2030, and Germany by 2050. This makes new coal power difficult in the region. In Eastern Europe, there is more potential for new coal as brown coal resources are abundant and cheap. Efficiency and cleanliness will be keys in this

region. CCS may be a challenge, however, as underground storage is not popular, although Norway is developing a potential sink for CO_2 in the North Sea.

- **India –** India has large domestic coal reserves and recently had the largest growth in coal use of any country. India's draft National Electricity Plan indicates that the 50 GW of coal capacity in construction is sufficient to meet the country's needs for the next decade, but new coal remains a possibility. Most new coal plants proposed are supercritical units as India has imposed a carbon tax on coal, which is about $6.25/tonne-$CO_2$, making efficiency important in the region. Work has also been done to locate reservoirs for CCS.
- **Japan** – As of 2018, Japan had over 44 GW of coal plants in operation, with over 6 GW permitted or in construction. Japan's climate pledge is to reduce GHG emissions by 26% from 2013 levels by 2030, so improving efficiency and potentially performing CCS are important factors in Japan. Smaller-scale plants are also likely, in part because space is an issue. Japan is very interested in novel coal power cycles, including sCO_2 power cycles.
- **Korea** – Coal produces over 40% of Korea's power and the country still has plans for additional coal power, despite having a climate pledge with a 30% reduction in GHG emissions by 2030. Efficiency is also important in Korea, and they have strong interest in sCO_2 power cycles, having invested in the Department of Energy's (DOE) STEP program.
- **Others –** Coal is growing in some regions in Africa (e.g., Kenya and Zimbabwe) and Southeast Asia (e.g., Indonesia and Vietnam), which presents opportunities, although low-cost coal power will be critical in these areas. Smaller-scale plants will be a definite plus.

1.3 Market Advantage of the Proposed Concept

- The proposed concept consists of a pulverized coal power plant with superheat (SH) temperature/reheat (RH) temperature/SH outlet pressure of 1202°F/1238°F/4800 psia (650°C/670°C/330 bar) steam conditions with 41.3% (HHV) plant net efficiency, capable of flexible and low-load operation. The cycle has a gross generation capacity of 300 MW and optimizes the trade-off between maximum efficiency and minimum MW rating to achieve high efficiency while maintaining the high-pressure steam turbine inlet size within design and manufacturing limits as far as blade length and rotor diameter. This smaller size also reduces the financing hurdle and makes the system a better fit for niche locations that lack a low-cost NG supply, where power demands are typically lower.
- The steam cycle conditions selected for the proposed concept do not represent the upper range of AUSC conditions. By limiting the superheat steam temperatures in the proposed concept to 650°C, and reheat steam temperatures to 670°C, the amount of higher-cost, nickel-based alloy materials required is limited, thus helping to control capital costs. Further, the ability to use nickel-based alloys, such as Inconel 740H (IN740H), below their maximum operating range allows the designer to take advantage of their mechanical properties to support faster operational transitions, while minimizing fatigue damage and extending component life. Based upon market experience, GE sees the present cycle conditions for this concept as a sweet spot for small scale AUSC technology deployment in the future.
- The system provides enhanced cycling flexibility for an optimized operation regime for transient operation (i.e., faster start-up and load changes) and allows for flexible response to grid requirements, savings at start-up of initial power and thermal power consumption, and a more agile power plant that can provide more opportunities to bid in power markets. This plant incorporates stringent grid code compliance with dynamic cycles developed for optimal

primary, secondary, and tertiary frequency support, minimum-load operation on coal or coal and auxiliary fuel at lowest cost, ability to reduce start-up times, ramp-up times to maximize dispatch times, and automatic switchover between operating modes for better dispatch.

- With proper design and equipment specification, the pulverized coal combustion technology being used for this system can burn most types of coal, including variants with higher sulfur, moisture, and/or ash. The technology can also co-fire biomass, providing further fuel flexibility.
- The system includes an amine-based carbon capture system that has been proven in a 25 tonne CO_2 per day slip-stream. Thermal performance of <2.3 GJ/tonne CO_2 at 90% capture was consistently demonstrated. Mixed steam turbine extractions are utilized to optimize the carbon capture plant operation at variable loads. Net plant HHV efficiency with 90% carbon capture is expected to be 33.8%.

1.4 Estimated Cost of Electricity to Establish Competitiveness of Concept

An 84-MWth coal-fired combined-heat-and-power plant was recently built at the University of Alaska Fairbanks for $248M, which equates to ~$8000/kW. In this area, the relative annual fuel costs for the plant were about $5M for coal and $20M for NG. In such areas where NG supply is not available or is inconsistent, if coal can be delivered cheaply, smaller-scale coal power plants have an opportunity.

This example shows that dis-economies-of-scale increase the $/kW cost by nearly 80-100% for much smaller, 100 MW class coal plants. For the proposed 300 MW class coal plant, dis-economies of scale will be much less, with perhaps only a 30% increase in $/kW cost for conventional coal plants.

DOE's Low Rank Coal Baseline studies[1] show total plant costs (TPC), escalated to 2019 dollars of $2406/kW and $4243/kW, respectively, for a 550-MWe net supercritical coal power plant without (Case S12A) and with CCS (Case S12B). The resulting cost of electricity (COE) values are $74.3/MWh and $143/MWh, respectively, with a CO_2 captured cost of $52/tonne. DOE's atmospheric oxy-combustion baseline plant[2] (Case S12F) has a 2019 TPC of $4,084 with a COE of $133/MWh. Of relevance in the U.S., DOE's nominal 630-MWe net NG power plant[3] has 2019 COE values of $48/MWh and $83/MWh without and with CCS and CO_2 captured cost of $87/tonne. EPRI has analyzed these data from DOE and determined:

- The NG price to make the NG with CCS COE equal to PRB coal (at $1.15/MBtu) with CCS COE must go from $4.39/MBtu to $11.11/MBtu (approximately a 2.5 times increase)
- TPC for the proposed technology to equal the COE of supercritical coal with CCS is $4475/kW, and is $4000/kW to match the COE of an atmospheric oxy-combustion plant.

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[1] "*Cost and Performance Baseline for Fossil Energy Plants Vol 3b: Low Rank Coal Electricity: Combustion Cases",* DOE/NETL-2011/1463, March 2011

[2] "*Cost and Performance for Low-Rank Pulverized Coal Oxycombustion Energy Plants"*, NETL Report No. 401/093010

[3] "*Cost and Performance Baseline for Fossil Energy Plants, Volume 1a: Bituminous Coal and Natural Gas to Electricity, Revision 3*, DOE/NETL-2015/1723, July 2015

TPC for the proposed technology to get the cost of CO_2 captured to \$40/tonne is \$3275/kW. Based on this high-level review, for the proposed system to be competitive, beyond achieving the performance characteristics that have been set for this project, the table below provides cost targets for the technology in various regions and scenarios.

Region	Scenario	Competition	Cost Targets
U.S.	NG not available, coal and EOR / 45Q available	Small coal (300 MWe)	TPC < \$4500/kW
U.S.	NG < \$4.4/MBtu (coal \$1.2/MBtu) and no CO_2 value	NG with CCS	COE < \$80/MWh
U.S.	NG < \$4.4/MBtu (coal \$1.2/MBtu) and CO_2 value of \$50/tonne	NG with CCS	TPC < \$3300/kW; CO_2 cost < \$40/tonne
Africa, Asia, Europe	NG > \$13/MMBtu (coal \$1.2/MBtu)	Coal with CCS	COE< \$120/MWh; TPC < \$4000/kW
Anywhere	CO_2 value of \$50/tonne	Any CCS	CO_2 cost < \$40/tonne
Anywhere	Non-base load operation with CCS	Coal FIRST technologies	TPC < \$4000/kW; CO_2 cost < \$40/tonne;

The first 5 cases in the table assume a base-load unit with 85% capacity factor and ~3M tonnes of CO_2 captured annually. The \$50/tonne value for CO_2 is roughly a summation of EOR with 45Q credits (or 45Q credits for storage only). Option 2, with low NG price and no value for CO_2, is not a competitive option for this technology. So, the cost targets for the technology are TPC = \$4000/kW, COE = \$120/MWh, and CO_2 cost = \$50/tonne. Several additional comments:

- One of the short-term markets will be niche areas where NG supply is limited or unavailable without significant infrastructure investment, where coal can be supplied. In the U.S., this is largely in the west. Opportunities may also exist in Mexico. These applications will be small, perhaps smaller than 300 MWe net. In these cases, the capital costs must be lower than \$5000/kW. The other potential short-term market is in regions where there is an EOR play, e.g., Texas and Wyoming. As a result, this small-size, 300 MW AUSC is likely a better fit in oil & gas markets than larger plants.
- In regions where NG is more expensive (e.g., Africa, Asia, and Eastern Europe), or if NG prices should rise in North America, the technology will be competing directly with other post-combustion capture systems for coal. In these cases, the proposed technology must have efficiencies that are higher and capital costs that are comparable, and preferably superior (given that small-scale AUSC might be perceived to be higher risk).
- Another factor is if the value of CO_2 is increased (either by a CO_2 price or value) in comparison to the cost of CO_2 captured, then this proposed CCS technology will have more opportunities. Conversely, this system can be constructed or operated without the carbon capture system, if the region does not have a significant CO_2 policy or utilization opportunities (e.g., India or South Africa), or is not focused on low carbon but rather just cheaper power production (e.g., developing nations like Kenya).

2 Plant Concept Description and Important Traits

The concept for the "Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant" is a pulverized coal power plant with superheat (SH) temperature/reheat (RH) temperature/SH outlet pressure of 1202°F/1238°F/4800 psia (650°C/670°C/330 bar) steam conditions with 41.3% (HHV) plant net efficiency without carbon capture, and 33.8% (HHV) plant net efficiency with carbon capture, capable of flexible and low-load operation, consistent with the stated goals of the Department of Energy's (DOE's) Coal FIRST (Flexible, Innovative, Resilient, Small, Transformative) initiative. The cycle is for a gross generation capacity of 300 MW. . This small, flexible AUSC boiler concept was chosen because it is a reasonable compromise between the DOE goals of small plant MW capacity and high plant net efficiency. An AUSC turbine island smaller than 300 MW gross would require decreasing main steam temperature and pressure to maintain the minimum steam volumetric flow rate at the HP turbine inlet geometry required for minimum bucket lengths and nozzle carrier clearances.

The proposed concept has an expected net plant efficiency of 33.8% with carbon capture, roughly equal to the existing US coal fleet without carbon capture. It provides a step change in coal plant performance and will give US utilities the experience with large scale fabrication and operation of never commercially used advanced boiler materials needed for acceptance in the market.

The power plant concept being proposed provides enhanced cycling flexibility for an optimized operation regime for transient operation (i.e., faster start-up and load changes) and allows for flexible response to grid requirements, savings at start-up of initial power and thermal power consumption, and a more agile power plant that can provide more opportunities to bid in power markets. This plant incorporates stringent grid code compliance with dynamic cycles developed for optimal primary, secondary, and tertiary frequency support, minimum-load operation on coal or coal and auxiliary fuel at lowest cost, ability to reduce start-up times, ramp-up times to maximize dispatch times, and automatic switchover between operating modes for better dispatch.

The major components of the plant include a pulverized coal-fired boiler in a close-coupled configuration; air quality control system (AQCS) consisting of an ultra-low NO_x firing system, selective catalytic reduction (SCR) system for NO_x control, dry scrubber/fabric filter for particulate matter (PM)/SO_2/Hg/HCl control; an amine-based post combustion carbon capture system; and a synchronous steam turbine/generator. A block diagram of the overall plant is shown in Figure 2-1. Note that the block diagram shows only the steam extractions for the carbon capture system for simplicity and clarity of the diagram. The boiler/AQCS, steam turbine and carbon capture sub-systems are discussed in more detail in the following sections.

The estimated plant performance is shown in Table 2-1. The expected net plant efficiency is 41.3% without carbon capture and 33.8% with carbon capture. The plant concept is flexible through the use of high nickel-based alloys, such as Inconel 740H, in key components such as the thick walled SH header and steam separator, minimizing thermal stresses in these life-limiting components during fast load ramping operation. The plant concept meets the DOE goals for expected emissions rates and carbon capture performance. The plant emissions controls and carbon capture system are discussed more fully in subsequent sections.

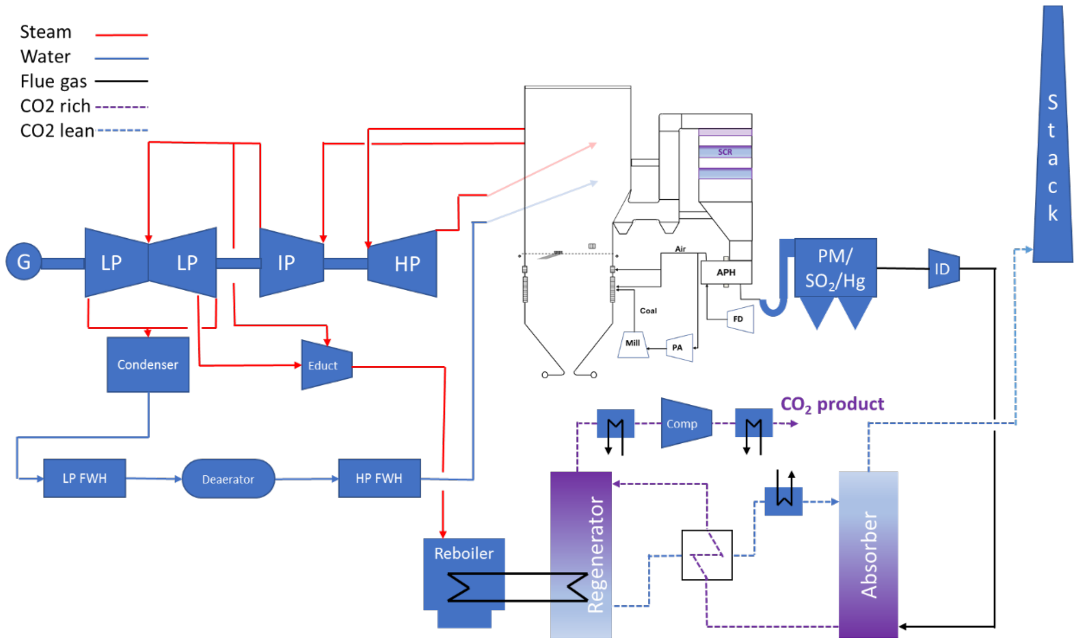

Figure 2-1 Small Flexible AUSC Coal-Fired Power Plant Block Diagram

Table 2-1 Estimated Plant Performance

Parameter	AUSC PC plant without CCS	AUSC PC plant with CCS
Size MW gross/net	300 / 276	300 / 209
Ramp rate up/down MW/min	15	15
Cold/Warm start time hours	4 / 2	4 / 2
	Firing PRB coal	Firing PRB coal
Full load net HR MMBtu/MWH	7.939	9.908
Full Load Plant net efficiency %	41.3	33.8
50% Load Plant net efficiency %	40.3	33.1
SO_2 lb/MWh-gross	1.00	1.00
NO_x lb/MWh-gross	0.70	0.70
PM (Filterable) lb/MWh-gross	0.09	0.09
Hg lb/MWh-gross	3x10-6	3x10-6
HCl lb/MWh-gross	0.010	0.010
CO_2 Capture Rate %	---	>90%

2.1 Boiler and Air Quality Control System

The proposed boiler concept is based on a reference advanced Ultra-Supercritical (USC) boiler with steam parameters of 650°C/670°C/330 bar, but downscaled to an output of 1,704,870lb/hr main steam flow with 300 MWe gross generating capacity. Potential material selections and temperature/pressure conditions for the boiler concept are shown in Figure 2-2. Final material choices, to be completed in the Pre-FEED, will balance the need for operating flexibility and material cost to meet flexibility goals at the lowest cost.

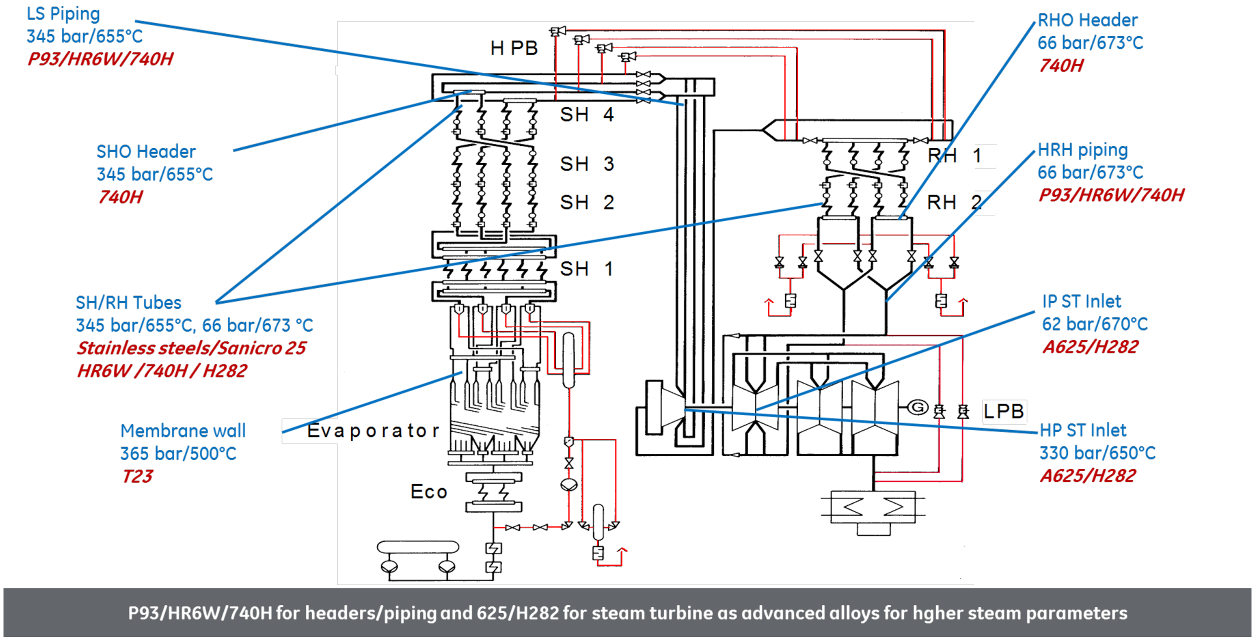

Figure 2-2 Small-Scale Flexible AUSC Coal-Fired Boiler Concept

The boiler expected performance with PRB coal is shown in Figure 2-3. The boiler concept is an innovative close-coupled arrangement. The horizontal high temperature convective surfaces have SH and RH header outlets at the front wall instead of the top of the boiler, yielding 25-30% shorter high energy piping runs than a typical arrangement. Elimination of the tunnel between the furnace exit vertical plane and low temperature convective pass results in a more compact boiler footprint.

The furnace front, rear and side walls along with the first pass front wall, first and second pass division wall and side walls are all up flow fluid cooled. Only the roof and second pass rear wall and the first circuits after the separator are steam cooled. This innovative arrangement essentially eliminates differential expansion between wall sections allowing faster start-up and higher load ramp rates.

The position of the shared wall between the high temperature and low temperature convective sections can be adjusted during design phase to achieve the convective section cross-sectional area required by design standards for convective pass flue gas velocity to be met independently of tube spacing and furnace plan area design standard requirements for coal type and slagging propensity. The design is highly customizable for different coals or biomass and can be optimized as required. Because this design minimizes plant foot print, it is a better arrangement from a cost perspective than a traditional 2-pass pulverized coal boiler design.

SH FINISH		
Fluid In	1133.5	°F
Fluid Out	1207.4	°F
Fluid Flow	1,705,000	lb/hr
Gas In	1705	°F
Gas Out	1547	°F
Gas Flow	2,080,000	lb/hr
SEF	1.00	
Surface Area	15500	sq. ft.
Inlet Gas Velocity	42.0	ft/sec

RH FINISH		
Fluid In	1114.8	°F
Fluid Out	1240.2	°F
Fluid Flow	1,317,000	lb/hr
Gas In	1904	°F
Gas Out	1730	°F
Gas Flow	2,080,000	lb/hr
SEF	0.98	
Surface Area	9704	sq. ft.
Inlet Gas Velocity	42.6	ft/sec

SH REAR		
Fluid In	1031.3	°F
Fluid Out	1148.5	°F
Fluid Flow	1,682,000	lb/hr
Gas In	2172	°F
Gas Out	1904	°F
Gas Flow	2,080,000	lb/hr
SEF	1.00	
Surface Area	10440	sq. ft.
Inlet Gas Velocity	44.9	ft/sec

SH FRONT		
Fluid In	951.6	°F
Fluid Out	1055.3	°F
Fluid Flow	1,637,000	lb/hr
Gas In	2,436	°F
Gas Out	2,172	°F
Gas Flow	2,080,000	lb/hr
SEF	1.00	
Surface Area	5772	sq. ft.
Inlet Gas Velocity	46.5	ft/sec

LTRH		
Fluid In	736.5	°F
Fluid Out	1114.8	°F
Fluid Flow	1,317,000	lb/hr
Gas In	1547	°F
Gas Out	966	°F
Gas Flow	2,080,000	lb/hr
SEF	0.98	
Surface Area	72068	sq. ft.
Inlet Gas Velocity	57.6	ft/sec

SPIRAL FINNED ECON		
Fluid In	626	°F
Fluid Out	687.7	°F
Fluid Flow	1,637,000	lb/hr
Gas In	966	°F
Gas Out	722	°F
Gas Flow	2,080,000	lb/hr
SEF	0.75	
Surface Area	116346	sq. ft.
Inlet Gas Velocity	41.1	ft/sec

General Performance Information		
SH Steam Flow	1,704,870	lb/hr
RH Steam Flow	1,316,530	lb/hr
SHO Temp	1207	°F
RHO Temp	1240	°F
SH Desup Spray	4	%
SH Desup Spray Flow	45,691	lb/hr
RH Desup Spray	0	
RH Desup Spray Flow	0	lb/hr
Feedwater Temp	626	°F
Tilt	-15	°
Excess Air	12	%
Boiler Efficiency	87.73	%
NHI/PA	1.64	Mbtu/hr-ft^2
Q FIRED	2191.3	Mbtu/hr
Fuel Fired	255,872	lb/hr

Air Heater Information		
Econ Exit Gas Temp	722	°F
AH Exit Gas Temp Uncorr	259	°F
AH Exit Gas Temp Corr	250	°F
Leaving Gas	2,235,974	lb/hr
Entering Pri Air	542,344	lb/hr
Entering Sec Air	1,324,629	lb/hr

Figure 2-3 Boiler Expected Performance

The boiler will use pressure part designs that are modularized, an example of which is shown in Figure 2-4. Fabrication of pressure part modules in the shop has several benefits. It reduces tube welds in on site, more difficult welds are performed more easily in the shop, and header girth welds can be done in the shop with automated machines while achieving a 0% rejection rate.

Ground modularization during construction of components that would be too large to ship effectively if they were shop modularized will be utilized, an example of which is shown in Figure 2-5. Ground modularization reduces the total number of pressure part lifts thus reducing schedule and allows more difficult welds to be performed more easily. Utilizing standard design modules for piping skids and instrument racks increases the flexibility schedule for design releases, fabrication releases, and erection sequencing. This allows for early turnover to electrical trades to complete and start the cold commissioning process.

The air preheater design will be optimized (for example, tri-sector vs quad-sector designs) to gain a maximum heat recovery that allows for an overall reduced heat rate. In general, this will reduce the flue gas temperature leaving the air preheater that will also have a system benefit of reducing the water consumption in the flue gas desulfurization (FGD) system. Air preheater materials that are suitable for a lower flue gas temperature, such as enamel coated heat transfer plates, will be incorporated and the potential impact of mercury oxidation additives on the air preheater will be considered. Corrosion of air preheater plates has been an issue when calcium bromide has been added to the coal in many US power plants using subbituminous coal, and improved designs for corrosion tolerance in this area will be considered.

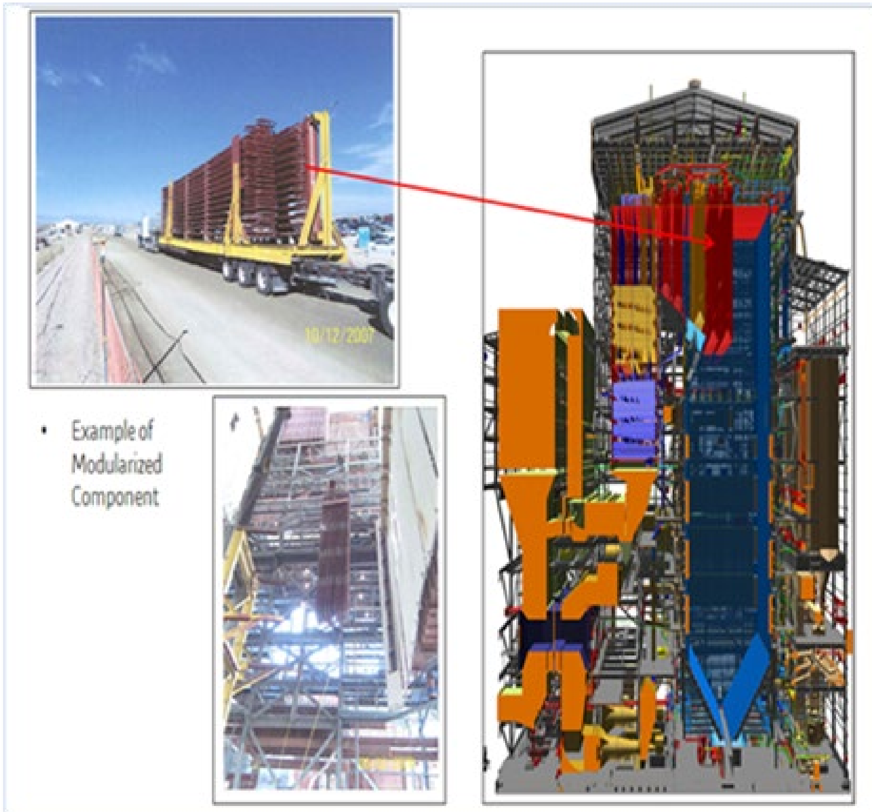

Figure 2-4 Example of Pressure Part Modules

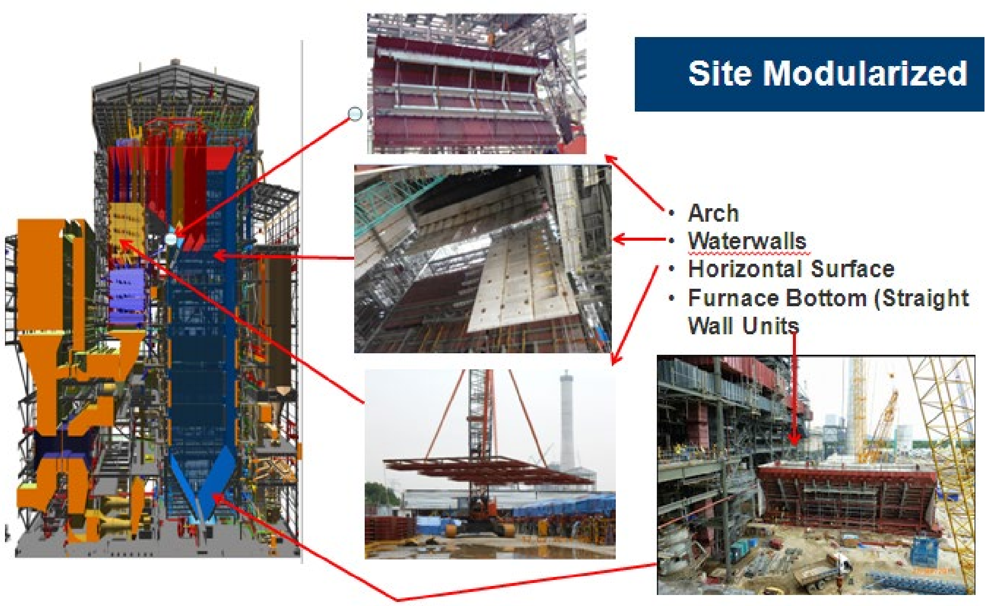

Figure 2-5 Examples of Ground Modularization

The particulate control and flue gas desulfurization (FGD) system design approach to be used will be GE's Novel Integrated Desulfurization (NID™) dry FGD/fabric filter system. This is a proven overall design that incorporates multiple modularized gas-solid entrained reaction sections followed by fabric filter modules. The NID™ system modular design fits well with the objectives of the Coal FIRST program, and the modular design allows for ease and speed of constructability. The entrained reactor section along with connected mechanical equipment can be pre-assembled in a workshop and transported to site. The fabric filter is built as modules on site and joined with the reactor section. The total NID™ module is lifted into place onto structural steel, then connected to flue gas inlet and outlet ductwork.

The NID™ system operates routinely with very low particulate and sulfuric acid emissions. Acid gas emissions can be controlled through the addition of lime reagent to reach high removal rates. Sulfur dioxide removal of greater than 98% is proven for long-term operation at a NID™ installation at a large Eastern US power plant. Additionally, SO_2 removal of 99% has been validated with pilot testing at GE's AQCS R&D center in Sweden. Additional design and controls concepts that require further full-scale implementation are anticipated to allow cost effective removal at greater than 99% on a continuous basis. Addition of hydrated lime to the ash recirculation duct allows use of higher sulfur content fuels. In addition to SO_2, the NID™ system has demonstrated long-term emission limits for HCl and Hg of <0.0001 lb/MMBtu and 0.4 lb/TBtu, respectively. This is a corresponding Hg removal rate of 96%. These very low emissions levels are important for consideration of downstream carbon capture technology where very low acid gas levels are generally preferred..

The NID™ dry FGD system helps minimize water consumption because it has no waste water stream. GE even has three installations using dry FGD technology to evaporate waste water from wet FGD systems and in one case cooling tower blowdown thus having advantage of eliminating or reducing another waste water stream from power plant. The extent to which water consumption is mimimized will be determined in the future Pre-FEED phase.

The NID™ modular design is also a key feature for the system turndown. For the Coal FIRST conceptual design, GE expects the system to include 3 or 4 operating NID™ modules at the full-capacity, and in turndown the controls can allow just one NID™ module to be in service. Additional controlled turndown of each entrained gas-solid reaction chamber for each NID™ module is a relatively new feature in the GE design. Further development of the mechanical and control aspects of this module turndown feature that maintains the fluidized reactor functionality would be addressed in the Coal FIRST Pre-FEED effort. Gas-solid CFD and/or flow modeling of the individual module turndown response is an area that is recommended as part of this further design improvement.

2.2 Carbon Capture System

The proposed carbon capture system (CCS) concept is based on a reference design for a post-combustion amine-based CCS but downscaled to process the flue gas from a 300 MWe net generating capacity plant. The simplistic version of the proposed carbon capture system Process Flow Diagram (PFD) is shown in Figure 2-6. A typical post combustion carbon capture system (CCS) consists of two main blocks, as follows:

- The CO_2 Absorber, in which the CO_2 from the power plant flue gas is absorbed into a solvent via fast chemical reaction, and

- A regenerator system where the CO_2 absorbed in the solvent is released, and then the sorbent is sent back to the absorber for further absorption.

A booster fan is used to drive the flue gas from the flue gas cooler through the CO_2 absorber, in which the CO_2 reacts with the lean solvent solution flowing from the middle of the column. The treated gas exits at the top of the tower. The rich solvent from the CO_2 absorber is sent to the regenerator after passing through multiple cross heat exchangers, where the rich solvent is heated to a higher temperature by the lean solvent solution returning from the regenerator. A reboiler heat exchanger vaporizes a portion of the water in the lean solvent solution to provide the stripping mechanism for removal of the CO_2 from the rich solvent solution. Steam from the plant is fed to the reboiler and condensate from the reboiler is returned to the plant. Gaseous CO_2 and water vapor exit the top of the regenerator. The lean solution exiting the regenerator at the bottom is pumped through cross heat exchanger network and followed by a cooler before it is sent to the CO_2 absorber for further CO_2 absorption. The process is broken down in the following subsystems (not all subsystems are shown on the diagram):

- Flue Gas Conditioning
- CO_2 Absorption
- CO_2 Regeneration
- Solvent Filtration and Reclamation

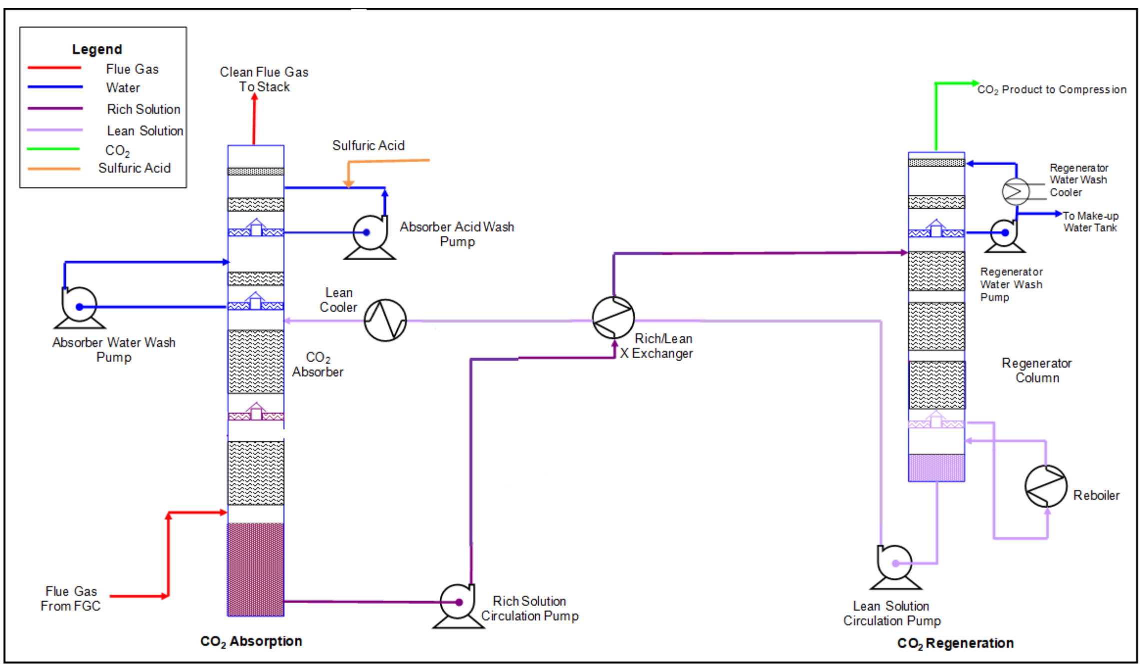

Figure 2-6 Process Flow Diagram of the proposed carbon capture technology

The technology has been demonstrated successfully in the field. In one of the validation plants (slipstream from a 580 MWe coal-fired boiler), the inlet flue gas flow rate of 5000 Nm^3/hr corresponded to a CO_2 production rate of 25 metric tonnes/day. CO_2 product purity greater than 99.5% after CO_2 compression and dehydration was demonstrated. The highly selective reaction with CO_2 is an important advantage and distinguishes this process from the results obtained from physical solvents, membranes, or adsorbents.

At one of the validation plants, the slipstream flue gas flowrate was stepped from 100% load down to 50% load, back up to 125%, then down to 75%, and finally back up to 100%. Each step lasted about an hour and the load tracking capability of the CCS unit was confirmed. The reboiler outlet temperature was adjusted to maintain 90% CO_2 capture rate. At 90% removal rate, the CO_2 capture control on the reboiler was set to automatic operation, with a 90% set-point. The inlet flue gas CO_2 concentration over the duration of the test was stable (the power plant was operating stable during this time and hence the CO_2 concentration was relatively constant). The flue gas flow rate changes were initiated based on a test plan, and the disturbance caused by these changes was recorded. At lower loads the steam flow to the reboiler fluctuated and it was more difficult to maintain stability, suggesting that the coupling between the steam cycle (steam extraction) and the CCS unit may be improved. The reboiler outlet temperature decreased to meet the same CO_2 removal requirement of around 90%. Therefore it is not expected that reduced and transient loads will result in increased solvent thermal degradation. The plant was a capture-and-release plant, so the impact of transient reduced loads on compressor performance and operability was not established.

In another set of transient tests, both the inlet flue gas flow and the regenerator inlet rich solution flow were varied to keep the same liquid-to-gas ratio as the design case. The reboiler outlet temperature was adjusted to obtain 90% CO_2 capture rate. At 90% removal rate, the CO_2 capture control on the reboiler was set to auto with a 90% set-point. The unit was kept stable for two hours, and then the flue gas flow was changed to the next setting step with the steam in automatic CO_2 capture control. The inlet flue gas CO_2 concentration over the duration of the test was stable. Tests at 80% and 60% load were completed. The energy efficiency (reboiler duty) improved at lower load. All of the runs showed a fast response to the change of loads. The stabilization took a little bit longer when going from a lower load to a higher load.

Improved absorber design, advanced regeneration concept, high efficiency heat exchanger network, and advanced solvent management processes make this technology unique and innovative. A thermal performance of <2.3 GJ/tonne CO_2 at 90% capture rate was consistently demonstrated. The solvent and emissions management strategies were also validated. The plant was designed and successfully operated for a multitude of operating conditions to cover a broad test campaign. These tests demonstrated flexible operating conditions and provided an understanding of the effects of load variations, start-ups and shutdowns. All test runs showed a fast response to change in load.

To increase net plant efficiency, heat sinks of the CCS system are integrated with optimal locations of the steam cycle to recover as much energy as possible. This can be accomplished by careful design and integration of the condensate and the cooling water from the CCS process into the water steam cycle as well as steam extractions for reboiler heating.

2.3 Steam Turbine

The proposed steam turbine concept is based on a reference advanced Ultra-Supercritical (USC) cycle with steam parameters of 650°C/670°C/330 bar, but downscaled to an output of 300 MWe gross generating capacity. This concept combines the existing capabilities of the GE USC modular steam turbine product platform with the use of high temperature materials, scaled to a plant size normally associated with much lower steam conditions.

The resulting provisional target level of performance, based on an optimization of the water steam cycle, is a gross efficiency of 53.38% at full load, net steam cycle efficiency without carbon capture of 51.2%, and net steam cycle efficiency with steam extractions for carbon capture of 45.9%.

The CO_2 control strategy is facilitated steam extractions from the IP and from the exhaust of the intermediate pressure turbine. Mixing these extractions with a steam educator allows the extraction rates from each location to be varied to give the correct extraction steam temperature and pressure throughout the operating load range.

A schematic of the water steam cycle without carbon capture is shown in Figure 2-7, with details provided in the full load turbine heat balance without carbon capture in shown in Figure 2-8 and with carbon capture in Figure 2-9.

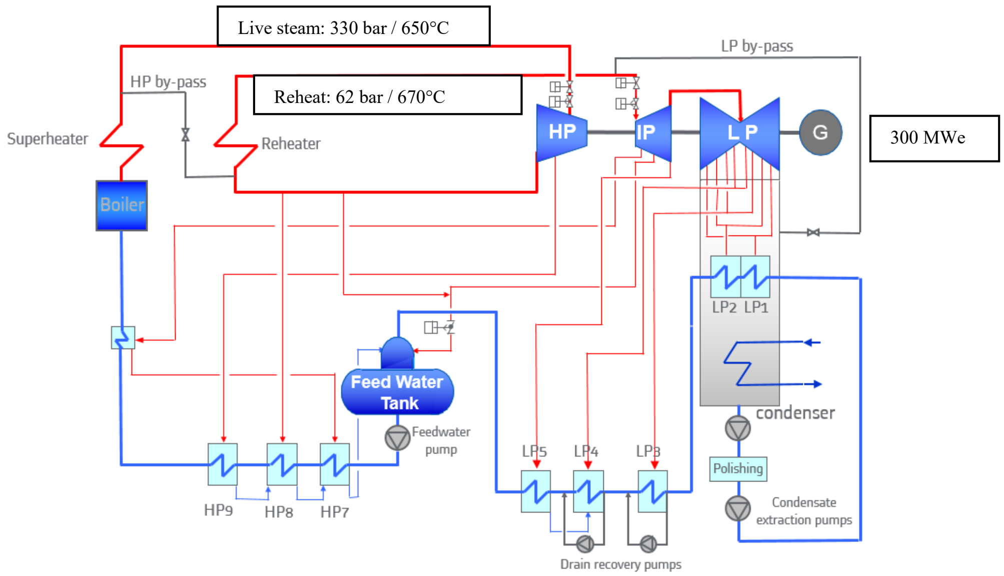

Figure 2-7 – Water Steam Cycle Schematic

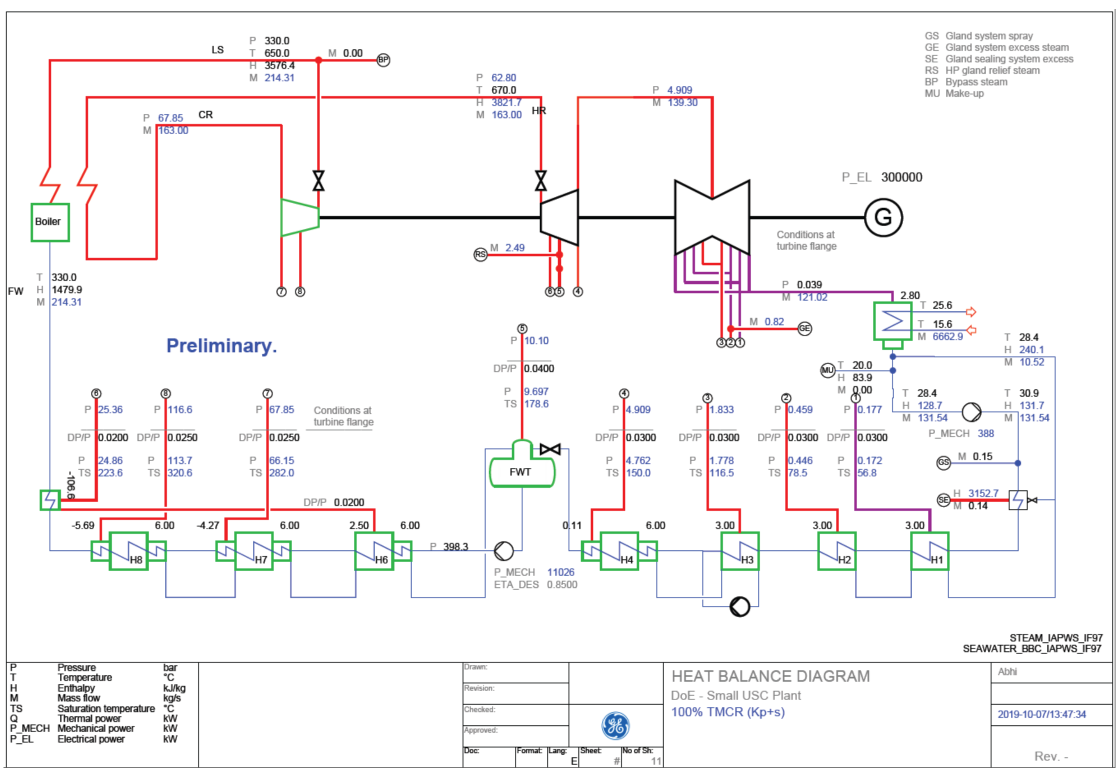

Figure 2-8 Preliminary Full Load Heat Balance without Carbon Capture

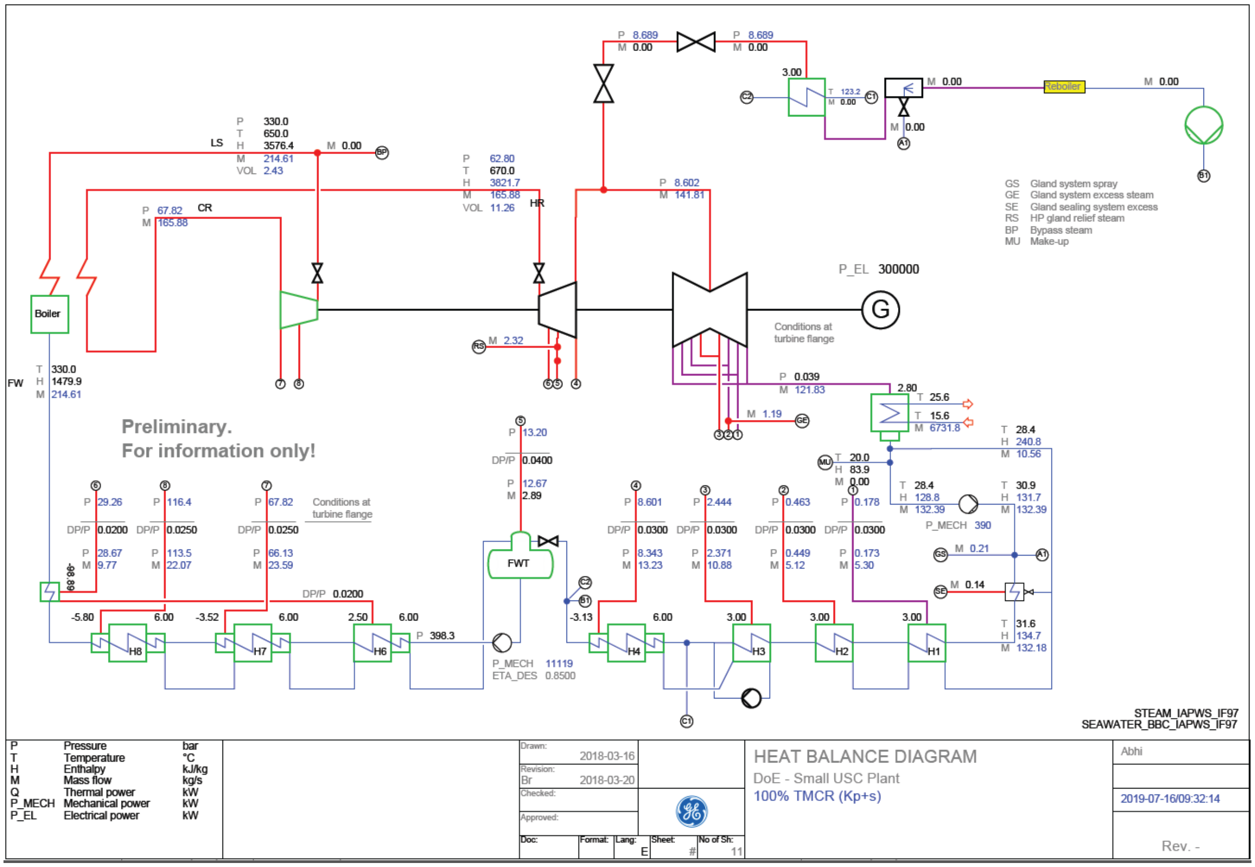

Figure 2-9 Preliminary Full Load Heat Balance with Carbon Capture

The proven modular steam turbine platform combines many design features supporting the evolution to more advanced and efficient steam cycles. Some of the features are unique to GE steam turbines and represent the best design practices developed over decades. These can be summarised as follows:

– Separated high pressure and intermediate pressure turbine modules using multiple shell casing design, with inner and outer casings cascading high temperature differences over several shells.

– Disk-type welded turbine rotors to apply new materials to the hottest and most exposed rotor sections. The optimised composition of materials in each rotor supports high operational flexibility combined with competitive product life time.

– Robust, multiple stage reaction type blading is used to moderate the pressure/ temperature drop per stage. Best suited steel alloys are available to off-set the stage specific stress levels.

– A consequent compact steam turbine and turbo-generator design in combination with the proven single bearing concept (single bearings between adjacent modules) minimises the overall shaft length.

– GE's pre-engineered and efficient low pressure steam turbine platform also offers sideways or downward exhausting steam designs to support optimised arrangement concepts and turbine hall layouts. (see Figure 2-10 and Figure 2-11)

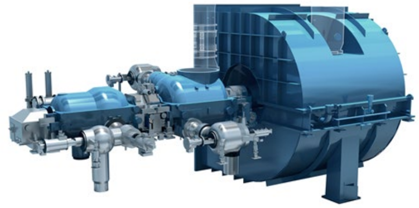

Figure 2-10 – Steam Turbine Train (side exhaust option)

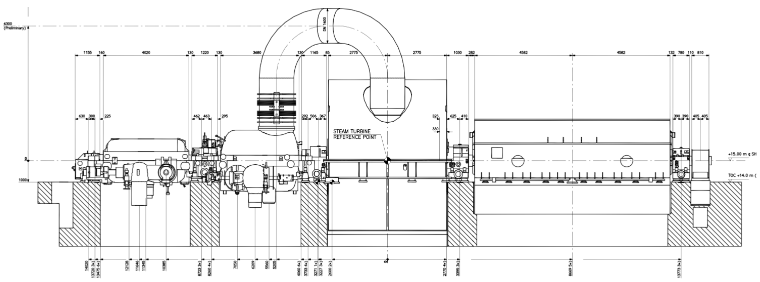

Figure 2-11 – Steam Turbine Train Including Generator (downwards exhaust option)

The stop valve is a quick-closing valve cutting-off the steam flow into the turbine if a turbine trip occurs. It is an open/close valve. The valve actuator is connected to the turbine protection system. In case of a turbine trip, the pressure in the hydraulic system drops and the stop valve closes. The closing time is <300 ms. The stop valve is located up-stream of the control valve. It is of the unloaded single seat type and integrated in a valve chest. For valve opening, an integrated pilot valve function equalises the steam pressure up and downstream of the valve. The valve head and the spindle are manufactured from a single forging. The surface sliding areas exposed to high stresses, such as the spindle and head, are hardened. Stellite type seal rings are used to prevent leakage along the valve stem. A circular steam strainer surrounding the valve assembly prevents solid particles from entering the blade path. At the open position, the valve head is fixed by the locking part to prevent vibrations and steam leakages. Boroscope openings allow inspections of the valve internals without disassembly.

The control-valve is designed to control the steam flow into the turbine. It is located downstream of the stop valve and is operated by a hydraulic actuator. The turbine controller sets the position of the valve to accommodate the steam flow to the load demand and operation mode. The control valve is of the unloaded single seat type. An integrated pilot valve function equalizes the steam pressure between locking piece and valve body, before lifting the valve head, to offset the required opening forces. Surface areas at the spindle exposed to higher stresses are nitrate treated. Stellite coated seal rings are used to avoid leakage along the valve spindle. In addition, the valve is connected to the sealing and extraction steam system. A circular flow straightener, located upstream of the valve, is used to harmonise the steam flow to the control valve. At the open position, the valve head is fixed by the locking part to prevent vibrations and steam leakages.

After passing the stop and control valves, the steam flows to the inlet scrolls of the inner casings. These scrolls are designed to harmonise the steam flow upstream of the first blading rows of the HP and IP flows. In addition, the first stationary radial blade-rows optimise the steam flow for the most efficient expansion. After expansion through the axial blading, the steam is exhausted via a nozzle at the top of the outer turbine casing upper half.

The turbine casings are of double shell design with an outer and an inner casing. The inner casing carries the stationary blading. The parting plane of both outer casings are horizontal, at the level of the rotor axis. The casing upper and lower halves are bolted together by means of hydraulically tightened expansion bolts or, in the case of the HP inner casing, via use of shrink rings. To extract steam outside the blade channel for feedwater heating, different sizes of extractions are distributed over the HP and IP module flows. The extraction connection between outer and inner casing is sealed with steam sealing rings, which accommodate differential thermal expansions. Provisions are made for proper alignment of all turbine internals. A system of wedges and supports ensures optimal adjustment and clearance between stationary and rotating parts during all operating conditions. Openings are provided to enable visual inspection of the blading, in-situ on-site rotor balancing and endoscope operations without disassembling the turbine casing. Gland seals are located where the rotor passes the outer casing. Labyrinth type sealings are used to minimize steam leakage. The seals are of the spring backed design. A system of steam tapping and sealing steam connected to the gland steam system prevents steam leakages. Representative small USC HP and IP turbine modules are shown in Figure 2-12 and Figure 2-13.

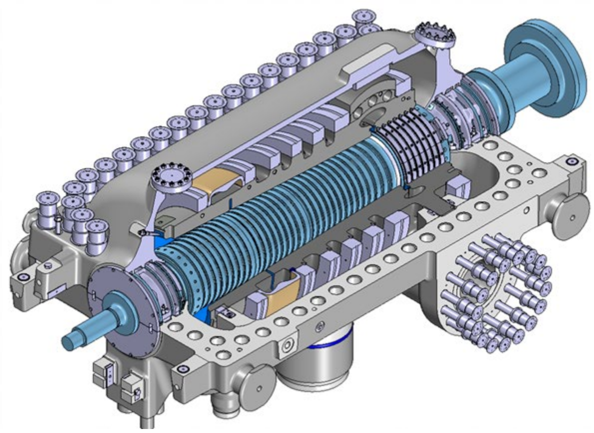

Figure 2-12 –Small USC HP Turbine Module

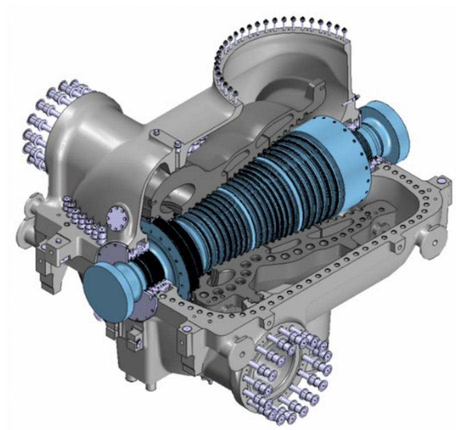

Figure 2-13 – Small USC IP Turbine Module

After passing through the cross-over pipe from the IP exhaust nozzle, the steam enters the LP turbine inlet section via an inlet scroll, which distributes the steam smoothly to both LP flows. After expansion, the steam is exhausted downwards to the condenser (sideways exhausting designs are an option). The LP casing is a double shell design. The welded outer casing consists of an upper and lower part. The upper part can be removed for inspection or maintenance without cutting the connection to the condenser neck. The lower part is supported straight on the foundation. Upper and lower casing halves are bolted at the parting plane and at the level of the rotor axis. The casing joints are sealed by a removable glass fiber sealing tape along with sealing compound. The inner casing is a cast design. If LP extraction is required, the extraction chambers are integrated into the inner casing. Hydraulically pre-stressed bolts are used on the casing, which is split at the level of the rotor. The LP inlet section is designed with a 360° inlet scroll ensuring efficient and harmonized steam flow to the blading. The first stationary blade row is radially arranged and distributes the steam evenly to both LP flows.

The inner casing is supported within the outer casing by brackets. Provisions are made for proper guidance of the turbine inner casing. A system of adjustable supports verifies optimized alignment and clearances between stationary and rotating parts at all operating conditions.

For proper cooling of the outer casing during low load operation, spray water nozzles are installed in the exhaust chamber of each LP flow. A rupture disc is located at the top of the outer casing. This disc protects the outer casing from deformation or damage due to excessive LP pressure. Inspection openings are provided for inspection of the blading without the need to open the turbine casings. A manhole is provided for access to the LP outer casing for manual inspection, re-balancing or maintenance work.

The rotor design depends on the specific project conditions. Either welded or mono-block type rotor design will be applied. If couplings are used, they will be integral with the rotor section. On-site rotor rebalancing is accomplished by utilizing small ports. This procedure is done without opening or dismantling the turbine casing.

Gland seals are located where the rotor passes the outer casing. Single radial type seals are used for tightening. The seals are of the spring-backed design. A system of tapping points and sealing steam connected to the gland steam system prevents steam leakages. A representative small USC LP turbine module is shown in Figure 2-14.

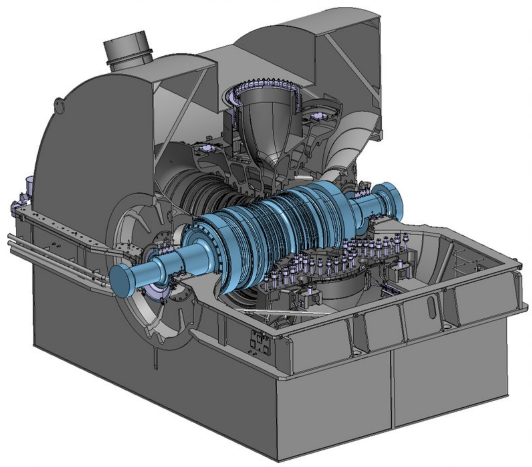

Figure 2-14 – Representative LP Turbine Module (downwards exhaust option)

The pedestals carry the axial and journal bearings to support the shaft line and to transfer the axial thrust to the pedestal. The train is comprised of a number of journal bearing pedestals, plus a single combined axial/radial bearing pedestal (located between HP & IP turbine). The radial portion bears the load generated by the rotor weight. The axial portion takes the residual axial thrust coming up from the reaction blading.

A compact single bearing design (one bearing between each turbine module) is used, with the rotor couplings located inside the pedestals. The outer casing(s) of the adjacent turbine cylinder(s) are safely supported on the pedestal. Vertical keys are used to ensure proper alignment of these turbine casing(s) and the pedestal. The rotor turning gear is located at the top of the combined axial/radial pedestal. It turns the shaft line during standstill and prior to start-up.

The cast bearing pedestal is split at the horizontal plane. By removing the upper casing half, the bearing can be inspected and replaced without touching the turbine casing(s) or separating the rotor coupling.

A base plate beneath the pedestal allows axial moving of the pedestal to follow the casing expansion. Strong anchor bolts are used to fix the base plate on the turbine foundation. Oil baffles at the points where the rotor passes through the pedestal wall prevent oil leakages. The bearing body is clamped between the pedestal halves. Fitting plates adjustable by shim sets ensure the right bearing position and are used to align the rotor train. Keys and wedges at the horizontal and vertical plane keep the casings in their position. A sight glass is provided in the oil return line on each pedestal to monitor the oil flow. Instrumentation is installed at the pedestal to monitor the bearing metal temperature, speed, phase angle, relative shaft vibration, relative shaft position and absolute expansion of pedestal. All instrumentation and probes are wired up to local terminal boxes.

The current GE offering already includes larger size steam turbines designed for steam conditions up to 330 bar / 650°C / 670°C. These rely on newly qualified materials including nickel-based alloys and, for cast parts up to 650°C, MarBN. Further development of materials technology is planned to enable a greater scope of MarBN usage including forgings to replace nickel options.

2.4 Important Traits of the Proposed Small-Scale Flexible AUSC Coal Power Plant

This section lists how the small-scale flexible AUSC coal power plant concept described in this conceptual design report meets the traits enumerated in RFP 89243319RFE000015.

- High overall plant efficiency (40%+ HHV or higher at full load, with minimal reductions in efficiency over the required generation range). The concept achieves 41.3% net plant efficiency as a CO_2 capture ready plant. Integration of carbon capture reduces this to 33.8% net plant efficiency, which is slightly higher than the average efficiency of the US coal fleet without CO_2 capture.

- Modular (unit sizes of approximately 50 to 350 MW), maximizing the benefits of high-quality, low-cost shop fabrication to minimize field construction costs and project cycle time. The concept is 300 MW gross capacity and incorporates shop modularization of selected boiler convective pass, AQCS and steam turbine components.

- Near-zero emissions, with options to consider plant designs that inherently emit no or low amounts of carbon dioxide (amounts that are equal to or lower than natural gas technologies) or could be retrofitted with carbon capture without significant plant modifications. The concept includes selective catalytic reduction for NO_x control and a NID™ dry scrubber/fabric filter for particulate matter, SO_2, mercury and acid gas control. The concept also includes post-combustion capture for CO_2 control.

- The overall plant must be capable of high ramp rates and achieve minimum loads commensurate with estimates of renewable market penetration by 2050. The conceptual boiler design includes use of nickel superalloys for selected thick walled components to minimize thermal stress during load cycling, and digital solutions for achievement of the target ramping rates. GE is developing digital technologies to assist existing units in achieving less minimum load of 20% or lower. One western US utility has achieved 15-18% minimum load with use of the digital product Digital Boiler + that is under active commercialization. Continuous operation of steam turbine at 20% load is possible, however exact operational requirements for such operation can only be finalized in the Pre-FEED stage. For the carbon capture process below about 90% load, steam extraction has to be moved from IP/LP crossover to IP turbine extraction in order to maintain the 5 bar minimum pressure for the carbon capture process. The additional extraction steam requirement is ~25% of LP inlet flow. This extraction amount is not considered an issue for operation of the LP turbine.

  Methods to reduce cold and warm unit startup times are the subject of present development activities within GE. Unit startup times presented herein are four (4) hours for cold start and two (2) hours for warm start. These startup times are projected based on previous development activities of units with similar steam conditions. Any further reduction of the cold start time would require deeper and further analysis, to be included as part of the optional Pre-FEED phase.

- Integration with thermal or other energy storage to ease intermittency inefficiencies and equipment damage. This is not directly addressed by this concept, and it is anticipated that the proposed concept has an appropriate size, and sufficient turn-down, to meet the needs of the future power markets, with intermittent renewable generation. However, this concept would generally be compatible with future advances in thermal or other energy storage.
- Minimized water consumption. This is addressed by use of GE's NID™ technology for flue gas desulfurization.
- Reduced design, construction, and commissioning schedules from conventional norms by leveraging techniques including but not limited to advanced process engineering and parametric design methods. This is addressed by modular shop fabrications concepts for selected boiler convective pass assemblies, the NID™ system, and steam turbine modules.
- Enhanced maintenance features including technology advances with monitoring and diagnostics to reduce maintenance and minimize forced outages. This is addressed by including GE's digital tools for condition monitoring and asset management.
- Integration with coal upgrading, or other plant value streams (e.g., co-production). This is not addressed by this concept. Further evaluation in this area is planned, as part of the Pre-FEED effort, which will determine the options for coal upgrading, and corresponding overall system performance improvement.
- Capable of natural gas co-firing. This concept includes side horn gas ignitors for up to 10% natural gas cofiring on a heat input basis. The use of plasma ignitors to improve start up rates on coal will be further evaluated, as part of the optional Pre-FEED effort.

3 Technology Development Pathway Description

3.1 Current State of the Art

Current state-of-the-art coal-fired pulverized coal (PC) power plants operate at ultra-supercritical (USC) steam conditions, which have traditionally been defined by EPRI as temperatures more than 1100°F (593°C). Due to material mechanical property limitations, the maximum steam temperature typically used with the currently available ferritic steels is 1130°F (610°C) for the main steam and 1150°F (621°C) for the reheat steam. AUSC steam conditions are at temperatures above those of USC plants. USC steam power plants can be constructed of materials with a documented track record in commercial operations. Going to higher steam temperatures (and pressures) can achieve higher steam plant efficiencies, improving the performance of the plant and reducing emissions, including CO_2. Materials of construction are the limiting factor to achieve higher temperatures. The ferritic materials that are suitable for the high-temperature portions of USC power plants will not be adequate for steam temperatures higher than the current state-of-the-art.[4]

While the current fleet of USC plants represents a significant advance, compared to earlier subcritical and supercritical plant designs, the state-of-the-art USC plants, they still have some key shortcomings, limitations, and challenges. The overall plant efficiency of USC plants is limited by the conventional (ferritic) materials of construction, which support steam temperatures up to 1150ºF (621ºC). Emissions of current state-of-the art USC plants are still greater than those of natural gas technologies. Most current USC plants have been designed to be base loaded, and have limited capability to achieve high ramp rates, and low minimum loads. Typical USC plants also have relatively high water consumption. These plants also have long construction schedules, and rely on extensive field-erection and assembly.

3.2 How Proposed Plant Concept Will Overcome Shortcomings

The primary benefit of employing AUSC steam conditions is a significant increase in net plant efficiency associated with the higher steam temperatures and the attendant reduction in fuel use and associated CO2 production (per unit net MWh output). In addition to increased efficiency, the proposed concept addresses shortcomings of other coal-fired plants, including the following:

- Size: Large (800+ MWe) scale base-load coal fired power plants are not an ideal fit for the modern electrical grid. The small (300 MWe gross) size of the proposed concept would integrate better in a scenario that includes electricity generated from intermittent renewable sources.
- Flexible Operation: The majority of existing coal fired power plants was originally designed for optimal operation under base load conditions, which limits the options for cycling and low load operation for these types of plants. Coal-fired power plants are increasingly called upon to operate in load-following and cycling operation to support intermittent renewable capacity, and to provide critical ancillary services to the grid. The power plant concept provides enhanced cycling flexibility for an optimized operation regime for transient operation (i.e., fast start-up, load changes, dynamic cycling, etc.) to

[4] *Novel Cycles Database Report: 2018*. EPRI, Palo Alto, CA: 2018. 3002014390.

allow for flexible response to grid requirements, savings at start-up of initial power and thermal power consumption, and a more agile power plant that can provide more opportunities to bid in power markets. The conceptual design includes use of nickel-based alloys for selected thick walled components to minimize thermal stress during load cycling, an innovative furnace arrangement to ensure uniform heat absorption, uniform outlet temperature distribution, and uniform thermal expansion that will allow fast startups and rapid load swings, and digital solutions for achievement of the target ramping rates. The GE NID™ dry FGD system will help to support flexible operation of the conceptual design. The FGD system will include multiple operating modules at the maximum full-load capacity, and in turn-down the controls can allow just one module to be in service.

- Emissions: The goal of new coal fired power plants is to achieve near-zero emissions, with low amounts of carbon dioxide (amounts that are equal to or lower than natural gas technologies). The concept includes selective catalytic reduction for NO_x control and a NID™ dry scrubber/fabric filter for particulate matter, SO_2, mercury and acid gas control. The concept also includes integrated post-combustion capture for CO_2 control.
- Water Use: Water consumption in the proposed concept is addressed by use of GE's NID™ technology for flue gas desulfurization.
- Modular: The proposed concept incorporates shop modularization of selected boiler convective pass, AQCS, and steam turbine components.
- Cost: While the increased efficiency of the AUSC concept comes with a capital cost premium, compared to a traditional USC plant, the proposed concept includes several features that are aimed at reducing AUSC plant costs. The proposed concept does not push steam temperatures to the upper range of AUSC conditions. By limiting the superheat steam temperatures in the proposed concept to 650°C, and reheat steam temperatures to 670°C, the amount of higher-cost, nickel-based alloy materials required is limited, thus helping to control capital costs. While limiting the steam temperature, to below the maximum allowed by the nickel-based alloy materials, will necessarily have an impact upon the thermal efficiency, it also provides an economic advantage, due to the lower cost of materials. Further, the ability to use nickel-based alloys, such as Inconel 740H (IN740H), below their maximum operating range allows the designer to take advantage of their mechanical properties to support faster operational transitions, while minimizing fatigue damage and extending component life. Based upon market experience, GE sees the present cycle conditions for this concept as a sweet spot for small scale AUSC technology deployment in the future. Additionally, the boiler convective pass has been designed to using a close-coupled arrangement, in which the horizontal high temperature convective surfaces have SH and RH header outlets at the front wall instead of the top of the boiler, yielding 25-30% shorter high energy piping runs than a typical arrangement. Elimination of the tunnel between the furnace exit vertical plane and low temperature convective pass results in a more compact boiler footprint, results in lower cost, compared to a traditional 2-pass pulverized coal boiler design. The operating amd maintenance costs are expected to be slightly higher, compared to other pulverized coal plants of similar size, and will be calculated in the Pre-FEED phase of this project.
- Schedule: The proposed AUSC concept will reduce design, construction, and commissioning schedules, compared to traditional USC plants, through the use of modular

shop fabrications concepts for selected boiler convective pass assemblies, the NID™ FGD system, and steam turbine modules.

3.3 Key Technical Risks of Proposed Concept

There are several key technical risks associated with the proposed concept, as follows:

- Materials of Construction: Based on the conceptual design, the most likely candidate materials suitable for long service at steam temperatures approaching 650°C main steam temperature would include Sanicro 25, HR6W, P93, MarBN, and IN740H. The IN740H is critical for the highest metal temperature application including tubing, headers, and piping. Many of these alloys are nonstandard materials in current boiler applications, and only some have full American Society of Mechanical Engineers (ASME) code approval. There is limited in-service experience for some of these materials, especially at the AUSC conditions, and there is a risk that the long-term behavior of these alloys may differ from the expectations.
- Supply Chain for Advanced Materials: The construction of the AUSC concept plant would require the supply chain to deliver several large components, made of nickel-based alloys. Such components have never been fabricated, at the required scale, using the alloys needed to support AUSC steam conditions. There are risks associated with first-of-a-kind fabrication of pipe extrusions, castings, and forgings, as well as the associated machining, welding, inspection and repair operations.
- Design Codes for Advanced Materials: The pressure parts of proposed concept AUSC power plant would generally need to be designed to ASME Boiler and Pressure Vessel Code. Since the nickel-based alloy materials are relatively new, some of the required materials, components, fabrication processes, and inspection criteria have not yet been incorporated within the ASME Code. There is a risk that OEMs may not be able to design, and customers will not be able to accept, AUSC power plants, if the ASME Code does not include sufficient coverage for the new advanced nickel-based alloys.
- AUSC Boiler Design: The innovative AUSC boiler design presents challenges. The fluid cooled boiler enclosure will incorporate an advanced over-fired air (OFA) system and must account for its effects on heat absorption in the furnace. The boiler design will use a spiral/vertical water wall arrangement that will utilize a portion of the vertical waterwalls to form the side walls of the extended backpass to ensure uniform heat absorption, uniform outlet temperature distribution, and uniform thermal expansion to allow fast startups and rapid load swings. Similarly, work is needed on header, terminal tube and interconnecting link design and arrangement. Increasing the number of links between heat exchanger sections reduces the OD and thickness of the links and headers making them more flexible during rapid changes in firing rate. The ultrahigh temperature finishing steam sections are arranged in a horizontal configuration and will need hanger tubes with corrosion resistance.
- AUSC Steam Turbine Design: While the proposed concept is based on a foundation of established technologies within GE, the application of these technologies in the proposed configuration, for the AUSC steam parameters and at the anticipated scale, represents an innovative step forward in steam turbine design. There is technical risk associated with the

use of a first-of-a-kind AUSC steam turbine. Within the turbine train there is uncertainty about the location of steam extractions (especially for carbon capture requirements), optimized cycle for final steam paths, rotor dynamics, thermal expansion and location of axial bearings. The HP and IP valves would need to be redesigned at a smaller size, with advanced materials. The HP and IP turbines would need a revised blade path layout for the AUSC steam conditions. There is also a need for advanced sealing, to improve efficiency and lower steam excitation forces. Long Lead Items (rotor and castings) can be released for purchase in 2022-23 based on the AUSC ComTest component fabrication demonstration results. For the steam turbine costs provided herein, this time frame is feasible. Internally, testing for MarBN as a cost out option is ongoing. Readiness for 2022-23 can't be guaranteed.

Carbon Capture System: The proposed concept design utilizes a proven amine-based solvent for coal flue gas applications. The performance data reported in this document are specific to that chemistry. However, the proposed process design has inherent flexibility and can accommodate diverse amine-based solvents. At the time this report is being written, the CCS technology proposed has not achieved the criterion of transformational technology (<\$40/tonne CO_2). GE invented a new amine that is able to absorb CO2 without needing water as a carrier (aminosilicone). Eliminating the need for water aims to reduce the cost penalty of carbon capture almost in half, relative to aqueous amine solutions. This technology was developed under partial DOE funding and was carried all the way through to a pilot-scale test facility at the National Carbon Capture Center in Alabama under DOE Awards DE-FE0013687 and DE-FE0013755. Aminosilicone technology readiness is still low but it is considered as potentially transformational. As part of the Pre-FEED effort, the team will revisit the opportunity to adapt the concept design to the aminosilicone carrier and determine if it is a preferred technology to the established, demonstrated one.

3.4 Assessed Technology Gaps and R&D Needed for Commercialization by 2030

The proposed concept is expected to be at an appropriate level of readiness to enable a high-quality pilot plant (or potentially full-scale demonstration plant) FEED study in the 2022 timeframe. The remaining technology gaps would be addressed via a combination of:

1. Work being performed under this Coal FIRST Conceptual Design, and optional Pre-FEED effort (DOE Contract 89243319CFE000023),
2. The A-USC ComTest Phase II effort (DOE DE-FE0025064),
3. Separate boiler design R&D effort, as outlined in Section 4.2,
4. Separate steam turbine design R&D effort, as outlined in Section 4.2, and
5. Novel carbon capture (aminosilicone) R&D effort, as outlined in Section 4.2.

The work under the present Coal FIRST contract (including both conceptual design and optional Pre-FEED efforts) is expected to be completed in 2020. The ComTest project is scheduled to be completed in September 2021. The R&D efforts associated with the steam turbine, and the carbon capture may be reasonably completed by the end of 2021, assuming that adequate funding is available. Consequently, assuming successful execution of these efforts, the schedules and work scopes of these identified projects are compatible with the initiation of a coal-based pilot plant

FEED study in the 2022 timeframe. This timeframe also supports the commercialization of the proposed concept by 2030.

3.5 Development Pathway Description

Due to a decade and a half of DOE-sponsored R&D, with technical leadership and management provided by EPRI, materials are now available for use in coal-fired steam cycles that will support designs with steam temperatures up to 760°C. Previous DOE-funded work, which included steam-loop testing in an operating coal-fired boiler setting, validated that there are nickel-based alloys available that are suitable for use in these AUSC steam conditions.[5]

This earlier work has been followed by a subsequent DOE-funded component testing (ComTest) project, aimed at constructing full-scale nickel-based alloy components designed for AUSC service, validating the US domestic supply chain for these components, and closing the technical gaps to support the readiness to construct a commercial scale (300 MWe) AUSC pilot demonstration plant. Specific AUSC component areas that are being addressed in the current DOE-funded ComTest Phase II project include:

1. Pressure Relief Valve (PRV) – Qualification testing of PRVs to qualify valve designs for AUSC conditions.
2. Boiler Pressure Parts – Fabrication and assembly of commercial-size superheater and reheater (SH/RH) pressure parts, including nickel-based alloys, with simulated field erection and field repair:
    a. Inlet and outlet headers
    b. SH/RH tubing
    c. Tube membrane panel with weld overlay
    d. Weldments incorporating advanced materials
3. Pipe – Extrusion, bending, and welding of large diameter, thick wall, nickel-based alloy pipe.
4. Wye Forging – Fabrication of forged "wye" fittings to transfer steam from the reheater line to the turbine inlet.
5. Steam Turbine – Fabrication and validation of key full-scale steam turbine components:
    a. Nozzle carrier casting: 9500 kg casting of nickel-based alloy
    b. Rotor forging: Manufacture 76 cm diameter triple-melt ingot made using a Vacuum Induction Melting-Electroslag Remelting-Vacuum Arc Remelting process, to be forged into a 305 cm long step rotor forging.

Additionally, as part of the ComTest Phase II project, the project team will address the need for ASME Code Cases, which would be needed to allow designers to use certain nickel-based alloy components in future power plant applications, including commercial scale pilot demonstration. There are four ASME Code Case actions covered within ComTest Phase II:

1. Provide for alternative overpressure protection, as an alternative to a spring-operated PRV.
2. Expand ASME B16.34 to allow bolted-flange design at high temperatures.
3. Revise ASME Code Case 2902 for IN740H, to permit the use of shielded metal arc welding as a permissible welding process.
4. Permit the use of wrought forms of Haynes 282 in A-USC power plants.

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[5] Purgert, R., et al. (2015a). Boiler Materials for Ultrasupercritical Coal Power Plants, Final Report, DEFG26-01NT41175, Energy Industries of Ohio (Independence, OH, USA).

GE has identified a set of steam turbine components, and associated R&D development activities, as summarized in Section 4.2, which would serve to address the remaining technology gaps. The component areas identified include the following:

1. Turbine Train (optimization, rotor dynamics, thermal expansion, and axial bearings)
2. HP& IP Valves (small valve design, internals redesign)
3. HP & IP Turbines (blade path layout, redesign for small size with advanced materials)
4. Advanced Sealing (improved sealing efficiency and lower steam excitation forces)
5. Materials (Extension of MarBN to forged applications)

Future R&D work on GE's novel carbon capture system is intended to include the following topic areas, as described in Section 4.2:

1. Modular designs of the mass transfer equipment (absorber, regenerator)
2. Improved design of the cross heat exchangers and reboilers for reduced temperature approaches
3. Real-time solvent analyzer for optimized performance and solvent management
4. "Virtual sensors"/digital twin for absorber (temperature bulge location), cross heat exchanger (temperature approach pinch point) and reboiler (heating elements skin temperature) operation
5. Improved/new material selection of reduced CAPEX

4 Technology Original Equipment Manufacturers

4.1 Commercial Equipment

The major equipment for the boiler/AQCS island includes:

- Boiler furnace
- SH lead platen, intermediate platen and finishing sections
- RH low temperature horizontal, intermediate and finishing sections
- Spiral finned economizer with future provision for design for different fuels
- Separator
- Selective catalytic reduction system (2 catalyst layers + space for future layer)
- Regenerative air preheater
- Bowl mills (quantity 5)
- Novel Integrated Desulfurization (NID™) dry FGD/fabric filter system
- FD, ID and PA fans
- Boiler feed pump

The major equipment for the steam turbine island includes:

- HP turbine module
- IP turbine module
- LP turbine modules
- Main steam stop & control valve
- Reheat steam stop & control valves (quantity 2)
- Bearing pedestals (quantity 5 – front, thrust, intermediate, driven end, non-driven end)
- Generator
- Condenser and condensate pump
- Low pressure (LP) and high pressure (HP) feedwater heaters
- Deaerator

The major equipment for any post-combustion amine-based carbon capture system includes:

- CO_2 absorber column
- Absorber water wash cooler
- Lean solvent solution cooler
- CO_2 compressor
- CO_2 dryer skid
- Solvent regenerator column
- Regenerator water wash cooler
- Rich/Lean solvent solution heat exchangers
- Solvent regenerator reboiler
- Flue gas cooler
- Flue gas cooler heat exchanger
- Axial booster fan
- Solvent solution filter system
- Solvent reclaimer unit
- Solvent, chemical, solvent drain, make-up water and auxiliary storage tanks

4.2 Equipment Requiring R&D

GE is a leader in the design of pulverized coal fired boilers ranging in capacity from 100,000 lbs/hr at 250 psig to over 7,000,000 lbs/hr and pressures exceeding 5000 psig. Final outlet steam temperatures of up to 1200°F have been attempted in the past. This experience has demonstrated the need for improved materials and the development of an improved boiler design that is robust and flexible.

The plant concept proposed is based on a foundation of established technologies within GE for both boilers and steam turbines. Nevertheless, the application of these technologies in the proposed configuration, for the foreseen steam parameters and at the anticipated scale, represents an innovative step forward for which the following boiler and steam turbine development work is required.

This innovative, small flexible AUSC boiler design presents many challenges. Development work will be needed on the fluid cooled boiler enclosure to incorporate the advanced OFA system and its effects on the heat absorption in the furnace. The boiler design will use a spiral/vertical water wall arrangement that will utilize a portion of the vertical waterwalls to form the side walls of the extended backpass to ensure uniform heat absorption, uniform outlet temperature distribution, and uniform thermal expansion that will allow fast startups and rapid load swings. Additional work would be needed to incorporate high-grade materials into the water wall fin welded membranes to address the pressures and temperatures of the AUSC boiler.

Similarly, work is needed on header, terminal tube and interconnecting link design and arrangement. For example, increasing the number of links between heat exchanger sections reduces the OD and thickness of the links and headers making them more flexible during rapid changes in firing rate. The ultra, high temperature finishing steam sections will need to be studied to determine the best means of support for flexibility and any possible "corrosion resistant" arrangements.

Table 4-1 Steam Turbine Components Requiring R&D

Component	Development
Turbine Train	– Water steam cycle optimization, including requirement and location of extractions, also covering carbon capture requirements. – Overall performance determination for optimized cycle using finalized steam paths. – Rotor dynamics feasibility for optimized reaction technology blade paths – Thermal expansion determination at elevated temperatures; confirmation of axial bearing location
HP & IP valves	– New valve design at small size with advanced materials, based on standard USC designs. – Redesign of internals with advanced materials. – Lifetime verification.
HP & IP turbines	– Blade path layout for defined steam conditions – Module redesign for small size with advanced materials, including lifetime verification.
Advanced Sealing	– For better sealing efficiency and lower steam excitation forces
Materials	– Extension of MarBN to forged applications

GE is a leader in the development of both cleaner coal technologies and Air Quality Control Systems, and is at the forefront of the development of carbon capture technology advancements. GE has designed and constructed 13 CO_2 Capture and Storage Solutions (CCS) demonstration projects around the world. These technologies are ready for large-scale implementation.

GE is fully aware of the fast technological development occurring in the CCS domain, and is ready to further develop or partner with the right entities to further commercialize CCS technologies that could meet the DOE target of transformational technologies (<$40/tonne CO_2). In particular, GE invented a new amine that is able to absorb CO_2 without needing water as a carrier (aminosilicone). Eliminating the water aims to reduce the cost penalty of carbon capture almost in half, relative to aqueous amine solutions. This technology was developed under partial DOE funding and was carried all the way through to a pilot-scale test facility at the National Carbon Capture Center in Alabama. The pilot met all its technical goals. Continued development of this post-combustion capture technology under the Coal FIRST initiative is under consideration. Carbon capture system equipment-related R&D topics include:

- Modular designs of the mass transfer equipment (absorber, regenerator)
- Improved design of the cross heat exchangers and reboilers for reduced temperature approaches
- Real-time solvent analyzer for optimized performance and solvent management
- "Virtual sensors"/digital twin for absorber (temperature bulge location), cross heat exchanger (temperature approach pinch point) and reboiler (heating elements skin temperature) operation
- Improved/new material selection of reduced CAPEX

4.3 A&E Prior Work and Access to Information

EPRI has selected AECOM as the Architecture & Engineering (A&E) firm for the present Coal FIRST contract. AECOM is a leading, fully integrated, engineering firm that provides planning, consulting, architectural, engineering, procurement, construction, and design/build services to commercial and government clients worldwide. With approximately 87,000 employees, AECOM is number 164 on the 2018 Fortune 500 list with annual revenue of $20.2B+ (FY18). Their team of professionals has the experience and capabilities to successfully execute the full life cycle of a project. AECOM has experience in commercial pulverized coal fired power plants, and in executing Pre-FEED and FEED studies for AUSC plant designs.

EPRI, GE, and AECOM all have experience working together on projects to advance AUSC technology under multiple DOE-funded projects, including the ongoing AUSC ComTest (DE-FE0025064) and Evaluation of Steam Cycle Upgrades to Improve the Competitiveness of U.S. Coal Power Plants (DE-FE0031535) projects.

Under the ComTest Phase I project, AECOM was responsible for managing Pre-FEED, FEED, and detailed design activities of a pilot-scale AUSC unit balance-of-plant (BOP) design and equipment selection, as part of the ComTest Phase I project. Phase I included plans to design and construct an AUSC pilot plant at a host site located in Alabama. The AECOM work scope included design and selection of BOP equipment to support testing and operational demonstration of a 760°C AUSC steam turbine (GE design), steam superheater (GE design), and associated 760°C nickel alloy piping. AECOM's engineering scope of work included overall process, BOP equipment, piping connections, host site infrastructure upgrades, utility tie-ins, and interface with significant collaboration of host site personnel and all subcontractors. Additional responsibilities included overall site management, project execution plan, risk assessment, process hazards analysis, environmental assessment, cost estimates, schedules, procurement, and construction. Under the present Phase II, AECOM has responsibility for maintaining the master schedule, and as part of this responsibility is interacting with GE, as well as nickel-based alloy suppliers, and component fabricators.

As part of the Evaluation of Steam Cycle Upgrades to Improve the Competitiveness of U.S. Coal Power Plants project, AECOM has responsibility to prepare project cost estimates and construction schedules for the upgrades to existing coal-fired power plants, including AUSC material technology options.

This history of prior work makes AECOM ideally qualified to work with the OEM (GE) on this project, and demonstrates that AECOM has excellent access to the information on a broad spectrum of AUSC equipment.