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Proposal: RFP 89243319RFE000015

Project Title:

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

Pre-FEED Contract:

Coal-Based Power Plants of the Future – Final Report

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1 Concept Background

1.1 Coal-fired Power Plant Scope Description

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, 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 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 NOx firing system, selective catalytic reduction (SCR) system for NOx control, dry scrubber/fabric filter for particulate matter (PM)/SO2/Hg/HCl control; an amine-based post combustion carbon capture system; and a synchronous steam turbine/generator. A block diagram of the overall plant (Concept 1) is shown in Figure 1-1. 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.

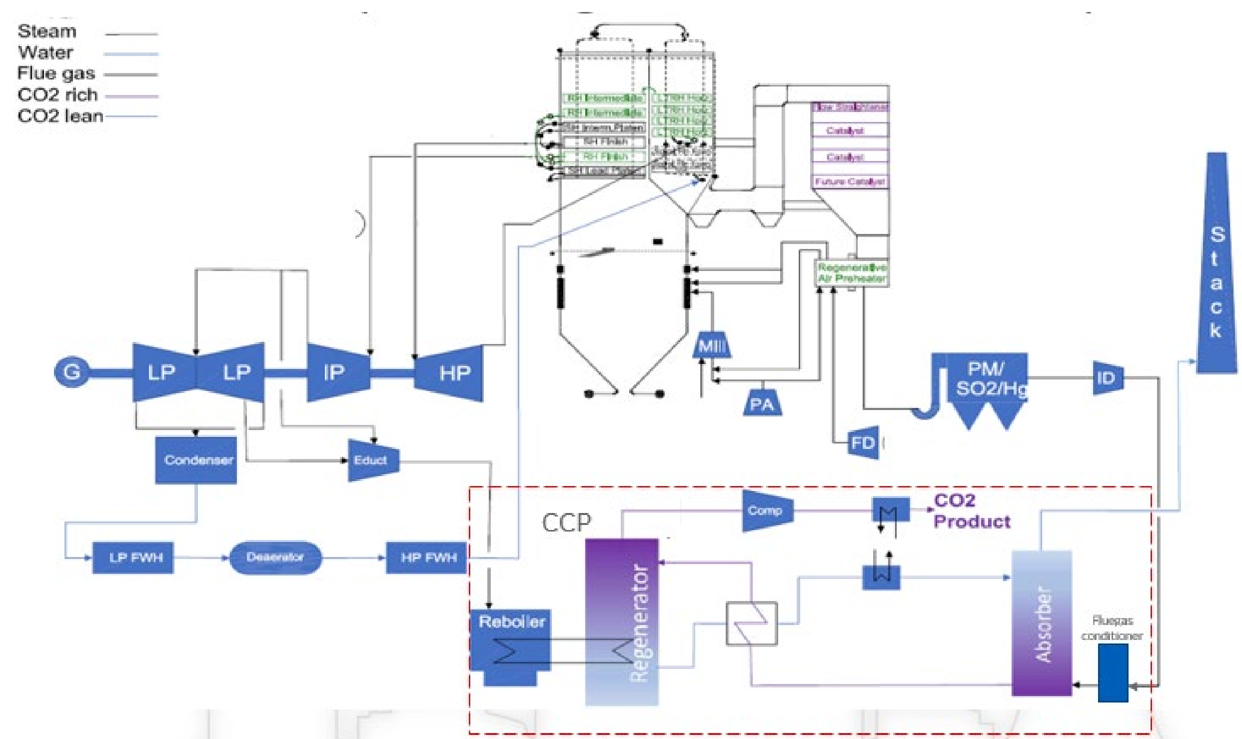


Figure 1-1 Small, Flexible AUSC Coal Power Plant Block Diagram (Concept 1)

A second plant concept (Concept 2 - provided in a separate report) incorporates the addition of a gas turbine heat recovery boiler to supply process steam to separate carbon capture systems for removal of carbon dioxide (CO_2) from the flue gas of the AUSC coal power plant and from the flue gas of the gas turbine/heat recovery boiler. This allows the AUSC coal plant steam turbine to operate at its highest efficiency by eliminating steam extractions for process steam. A block diagram of the overall plant is shown in Figure 1-2.

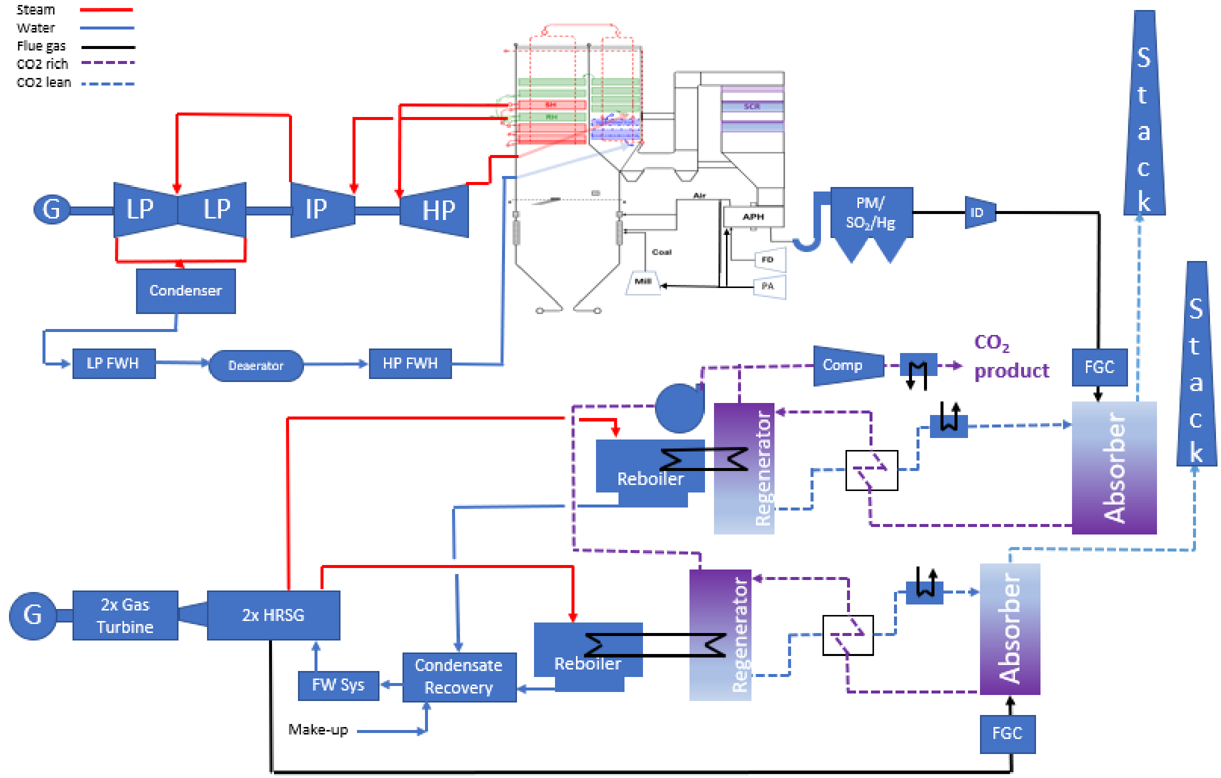


Figure 1-2 AUSC Coal plus Gas Turbine/Heat Recovery Boiler Power Plant Block Diagram (Concept 2)

1.2 Plant Capacity

The AUSC coal plant steam cycle has a gross generation capacity of 300 MW at TMCR (309MW at VWO) in Concept 1 without the process stream extraction to the CCP.. Because of the auxiliary load requirements and process steam extractions, the AUSC coal plant has a gross/net generation capacity of 278MW/227MW at VWO load.

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. A smaller AUSC turbine island 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.

Overall generation capacities of the integrated Concept 1 power plants are 278 MW gross / 227 MW net.

1.3 Plant Location

The plant location is a 300 acre greenfield site in the Midwestern U.S. with level topography. Coal is supplied by rail or truck delivery, and natural gas is supplied by pipeline. Fly ash and bottom ash disposal is off-site. Plant water needs are assumed to be 50% from municipal water supply and 50% from ground water.

2 Process Description

2.1 Proposed Plant Concept

Concept 1 for the "Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant" is a pulverized coal power plant with SH temperature/RH temperature/SH outlet pressure of 1202°F/1238°F/4800 psia (650°C/670°C/330 bar) steam conditions, with appropriate turbine steam extractions for carbon capture system process steam demand.

A block diagram of the overall plant (Concept 1) is shown in Figure 1-1. 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.

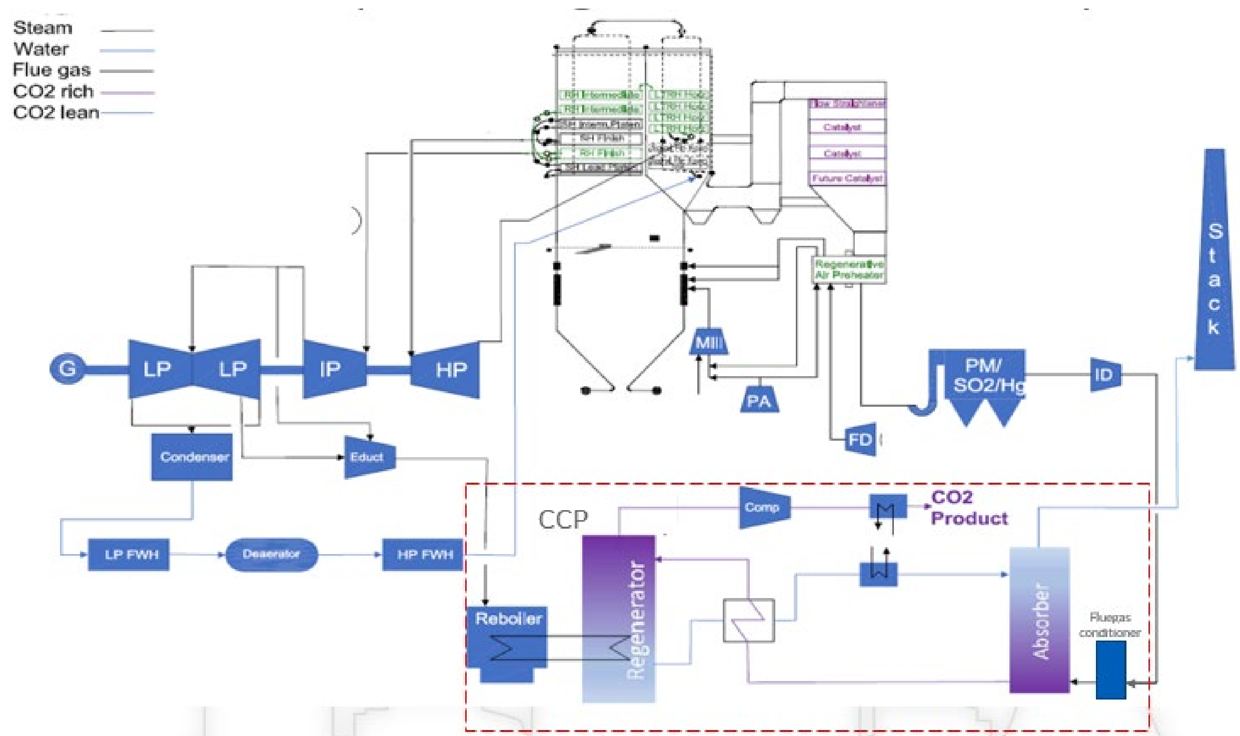


Figure 1-1 Small, Flexible AUSC Coal Power Plant Block Diagram (Concept 1)

The power plant concepts being proposed provide enhanced cycling flexibility for an optimized operation regime for transient operation (i.e., faster start-up and load changes) and 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 competitive power markets. These plant concepts incorporate 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.

This section lists how the small-scale flexible AUSC coal power plant concept described in this Design Basis 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). Concept 1 achieves 34.5% net plant efficiency at VWO load with integration of carbon capture, which is slightly higher than the average efficiency of the US coal fleet without CO_2 capture. The AUSC coal boiler net plant efficiency is 43.2% at VWO load (284 MW net without process steam extraction to CPP).
- 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, with 90% carbon capture rate.
- 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 for both Concept 1 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% (60 MW gross for Concept 1) or lower. One western US utility has achieved 15-18% minimum load with use of a digital product Digital Boiler + that is under active development. Continuous operation of steam turbine at 20% load is confirmed possible.

  While the carbon capture process operates below approximately 90% load, steam extraction in Concept 1 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.

  Unit startup times for Concept 1 presented herein are four (4) hours for cold start and two (2) hours for warm start for Concept 1 from first fire to turbine sync. These startup times are projected based on previous development activities of units with similar steam conditions.
- Integration with thermal or other energy storage to ease intermittency inefficiencies and equipment damage. This is not directly addressed, and it is anticipated that the proposed concepts have an appropriate size, and sufficient turn-down, to meet the needs of the future power markets, with intermittent renewable generation. However, these concepts 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, steam turbine modules, the gas turbines, and the waste heat boiler.
- 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 these concepts.
- Capable of natural gas co-firing. This concept includes side horn gas ignitors for up to 10% natural gas cofiring of the AUSC coal boiler on a heat input basis.

2.2 Target Level of Performance

Table 2-1 below shows the expected plant efficiency range at full and part load and a summary of the emissions control, including CO_2 emissions control.

Table 2-1 Expected Overall Integrate Concept 1 Plant Performance and Emissions

Parameter	Concept 1
VWO Size MW gross/net	278 / 227
Ramp rate up/down MW/min	15
Cold/Warm start time hours[note 1]	4 / 2
	Firing PRB coal
VWO (103%) load net HR MMBtu/MWH	9896
VWO (103%) Load Plant net efficiency %	34.5
50% Load Plant net efficiency %	33.1
SO_2 lb/MWh-gross	1.00
NO_x lb/MWh-gross	0.70
PM (Filterable) lb/MWh-gross	0.09
Hg lb/MWh-gross	$3x10^{-6}$
HCl lb/MWh-gross	0.010
CO_2 Capture Rate %	>90%

note 1: from first fire to turbine sync
note 2: emissions noted are as required per RFP. Significantly lower emissions are expected.

The boiler concept includes 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 are 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. The minimize plant foot print provided by this concept is a better arrangement from a cost perspective than a traditional 2-pass pulverized coal boiler design.

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 799 T/hr main steam flow with 278 MWe gross generating capacity at VWO. Potential material selections and temperature/pressure conditions for the boiler concept are shown in Figure 2-1.

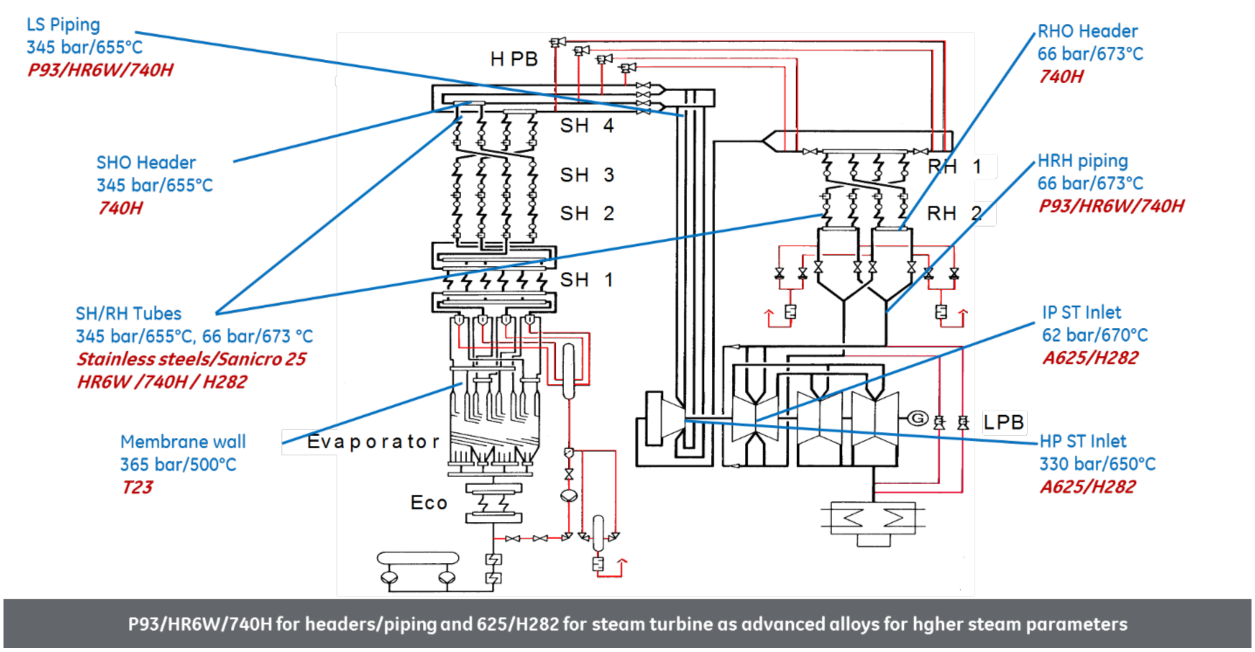


Figure 2-2 Small-Scale Flexible AUSC Coal-Fired Boiler Concept

The air preheater design will be optimized (for example, tri-sector versus 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.

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 process flow diagram is shown in Figure 2-2.

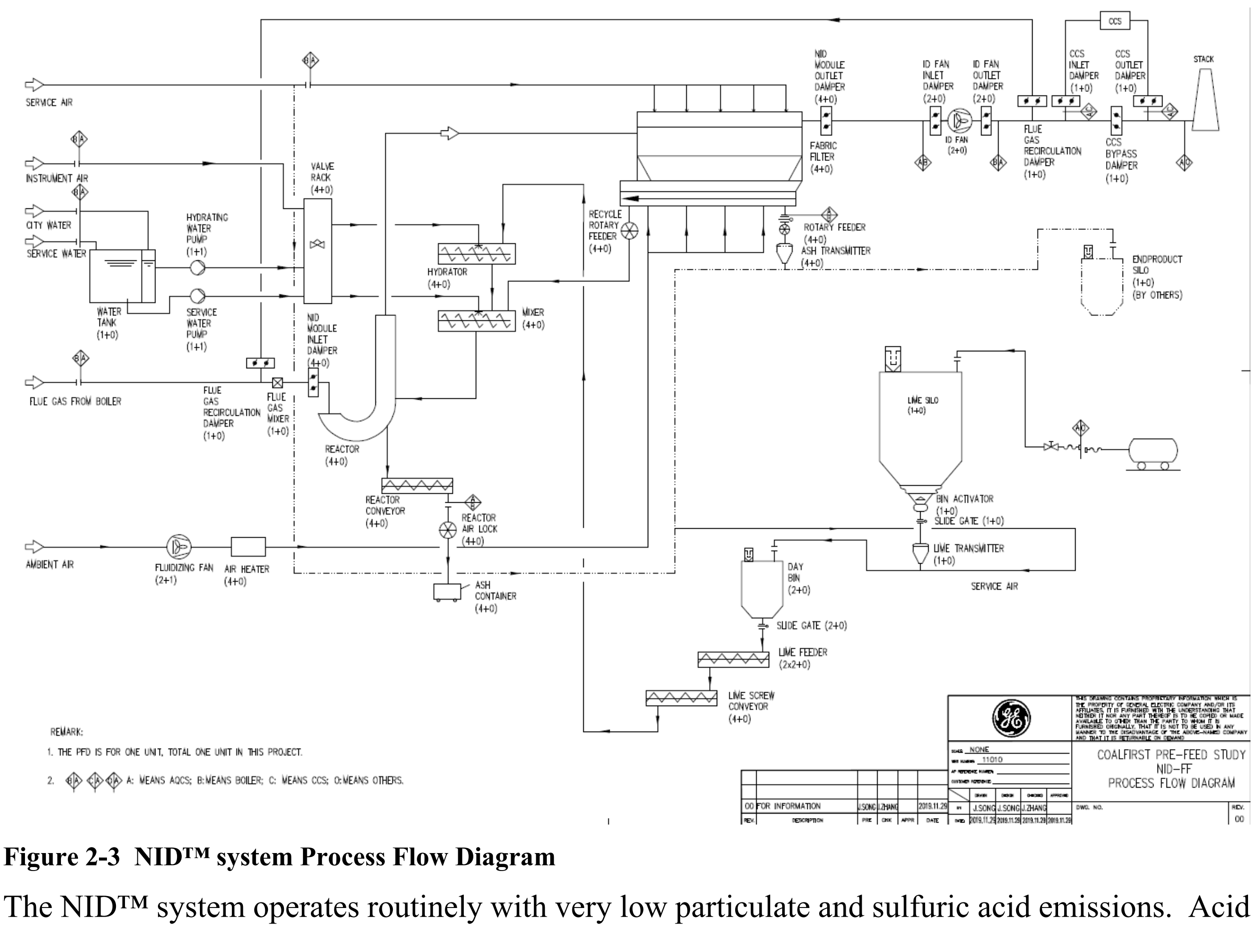


Figure 2-3 NID™ system Process Flow Diagram

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 AUSC Coal FIRST conceptual design, GE expects the system to include 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. 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.

The simplistic version of the proposed carbon capture system Process Flow Diagram (PFD) is shown in Figure 2-3. 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.

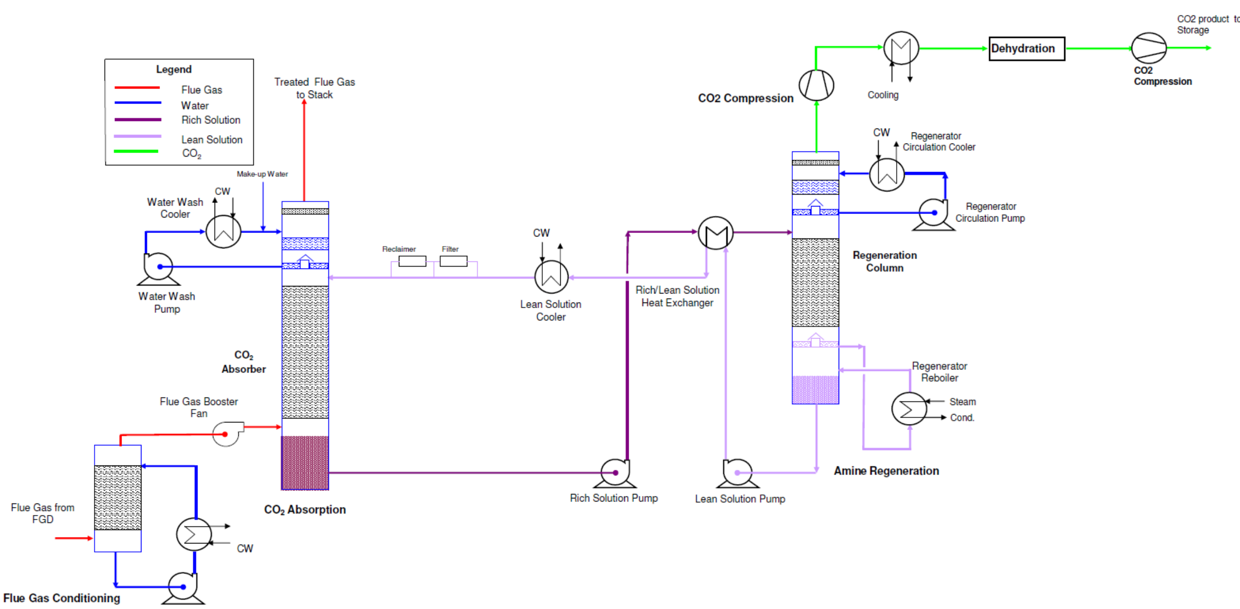


Figure 2-3 Process Flow Diagram of the proposed carbon capture technology

The carbon capture plant (CCP) is part of the planned air quality control system (AQCS) with the specific target to reduce the CO_2 emissions of the host power plant. The proposed CCP concept utilizes a proven Advanced Amine Process (AAP), comprising a proprietary amine-based solvent in a proprietary flow scheme for flue gas applications. The AAP technology applied is based on a reference design for large scale post-combustion capture plants, but downscaled to process the flue gas from target host plant capacity (equivalent of 300 MWe).

The main CCP plant performance target is 90% CO_2 capture from the pretreated flue gas of up-stream AQCS components, while producing a CO_2 product with specified quality in terms of composition and battery limit conditions – pressure and temperature – for further utilization.

These targets are accomplished with the objectives to achieve minimized utility consumptions, primarily steam and electrical power, but also cooling water and chemical consumptions, primarily amine make-up. Additional CCP plant integration options with the host power plant water/steam cycle could further improve the overall operations expenditures (OPEX) on cost of additional capital expenditures (CAPEX). Generally, amines-based processes are proven technologies for decades in the Oil & Gas industry. In this application, the process has been optimized to combustion flue gas under atmospheric pressure and power plant operations.

The main emission target for the CCP is a 90% reduction of CO_2 emissions for the AUSC coal plant. A validated solvent and emission management is utilized to keep the emissions generated from the CCP below tolerable limits, typically defined for amines and ammonia.

The individual CCP equipment design is considering a well-balanced techno-economical solution (CAPEX/OPEX-ratio) to achieve the performance targets, like CO_2 capture, CO_2 product quality and emissions, while keeping the OPEX on a low level. This comprises the following components:

- Flue gas conditioning system for an optimized CO_2 absorption performance
- Improved absorber design maximizing the CO_2 loading in the rich solvent
- Advanced regeneration concept minimizing steam consumption and CO_2 product compression power demand
- High efficiency heat exchanger network maximizing heat recovery from the hot lean solvent from the regenerator
- Advanced solvent management
- Efficient CO_2 product compression & dehydration system to accommodate CO_2 pipeline conditions

All equipment of the CCP is designed to meet these targets. The interplay of its different components is harmonized for operation within the required operating range. Figure 2-4 shows the specific advantages and features of the AAP technology outlined in the bullets above.

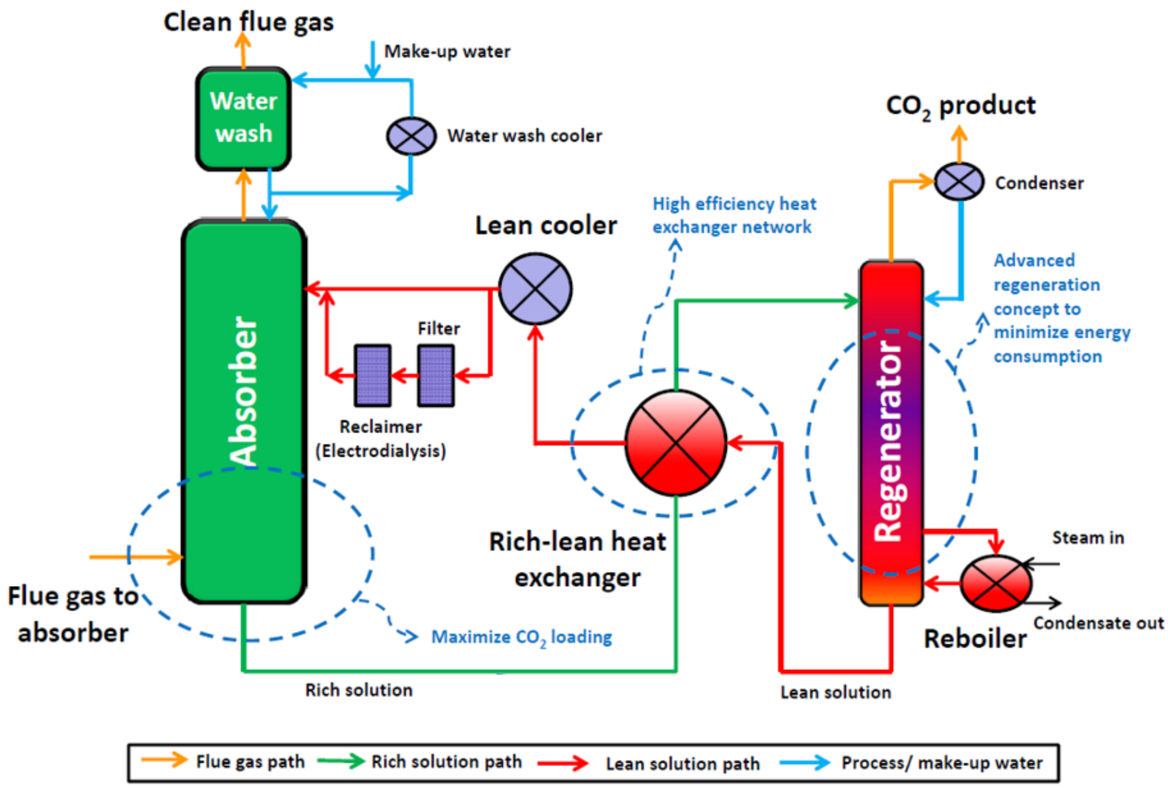


Figure 2-44 Features and Advantages of the Advanced Amine Process

The selection of a suitable solvent is crucial in terms of resistance to thermal and chemical degradation, material selection (corrosion resistance) and stable operation in term of foaming and fouling. The amine-based solvent ideally should be non-hazardous and not degrade into hazardous byproducts that could have an environmental impact.

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 to 2.4 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 from the CCS process into the water steam cycle as well as steam extractions for reboiler heating.

The carbon capture plant (CCP) will have flexibility in terms of flue gas flow capacity (operating range) and with regards to different fuels for the AUSC coal power plant, as long as the flue gas CO_2 concentration to the CCP is close to the design case. The typical standard operating range for the CCP is approximately 50-60% of design capacity, while the best operating performance is typically at 100% capacity (at highest efficiency). Therefore, turndown is often combined with operation below the best efficiency point. Lower turndown operation (< 50%) may require additional design features, such as:

- Specific recycle arrangements for compressor and pump systems
- Multiple parallel equipment arrangement (for one service), so that partial stream flow capacity can be turned off, while the remaining equipment remain in operation
- Disproportional turndown strategy for the core absorption/regeneration cycle (this means turndown of solvent circulation lower than capacity reduction of the flue gas feed to the CCP).

Thus, the required turndown for the host power plant with its full environmental compliance of 5:1, means an operational range for the CCP of 20% to design capacity is expected to be achievable.

The required start-up time for the host power plant from cold conditions is 4 hours and from warm conditions is 2 hours, respectively. The CCP design allows for transient operating flue gas flow changes, e.g. during start-up or shut-down of host power plant. Previous test runs at pilot-scale showed a fast response of the CCP design as proposed to change in load.

For the CCP a bypass for the flue gas feed to the stack is recommended, which allows to ramp up/down the host power plant at a different ramp rate or with different cold/warm start duration than the CCP. Also, the reduction of steam flow from the power plant to the CCP Regenerator Reboiler is an option to generate more electrical power during transient operations, with resulting reduced CO2 capture rate.

The proposed steam turbine 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.

A schematic of the water steam cycle for the AUSC steam turbine with no steam extractions is shown in Figure 2-5.

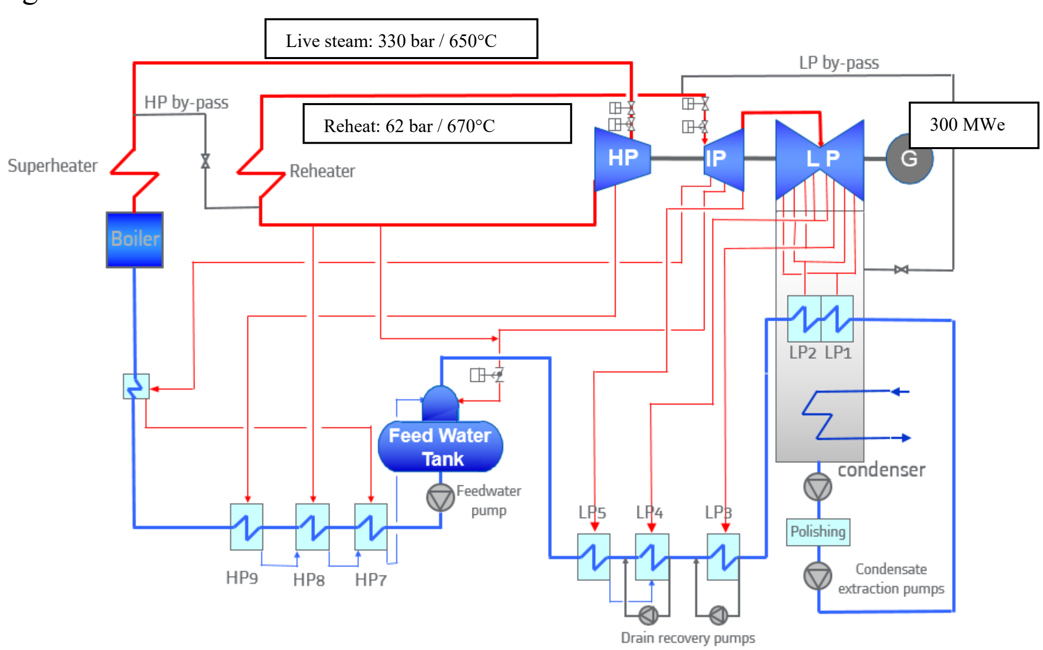
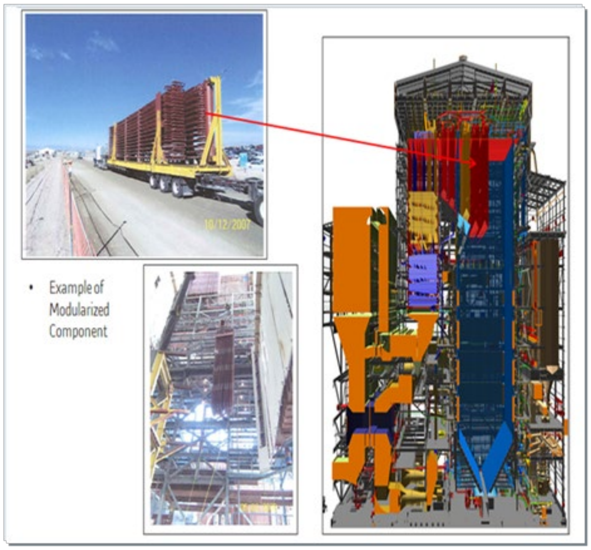


Figure 2-55 Water Steam Cycle Schematic



The boiler will use pressure part designs that are modularized, an example of which is shown in Figure 2-6. 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.

Figure 2-66 Example of Pressure Part Modularization

Ground modularization on site 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 2-7. 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.

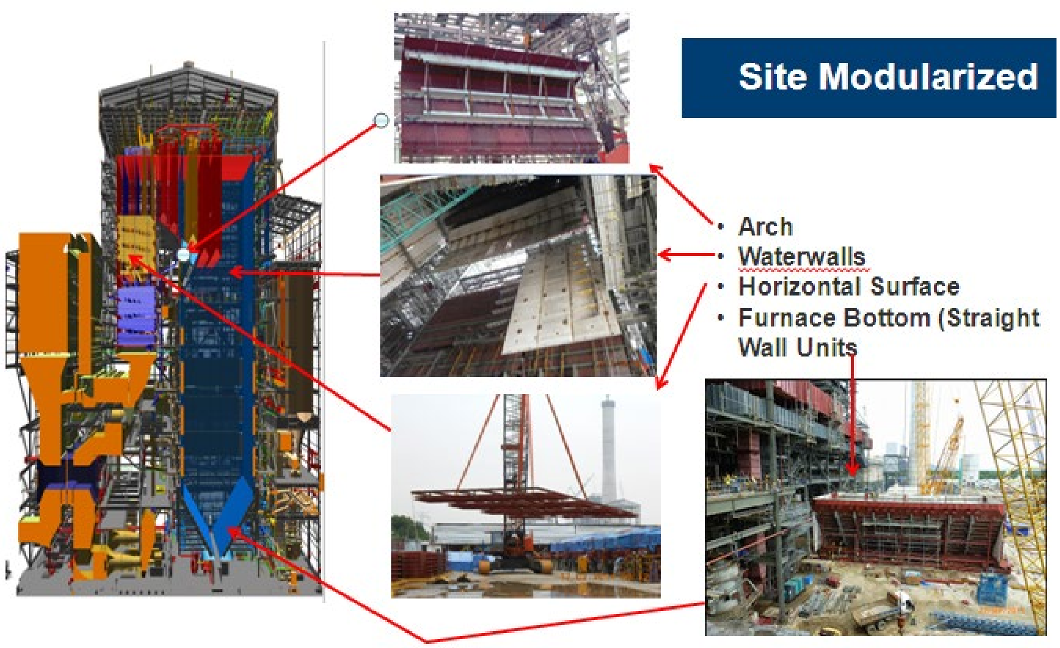


Figure 2-77 Examples of Ground Modularization

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 2-8 and Figure 2-9)

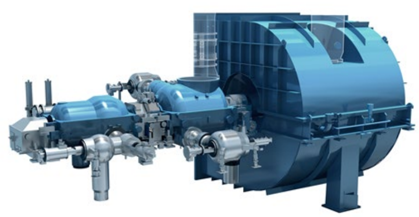


Figure 2-88 Steam Turbine Train (side exhaust option)

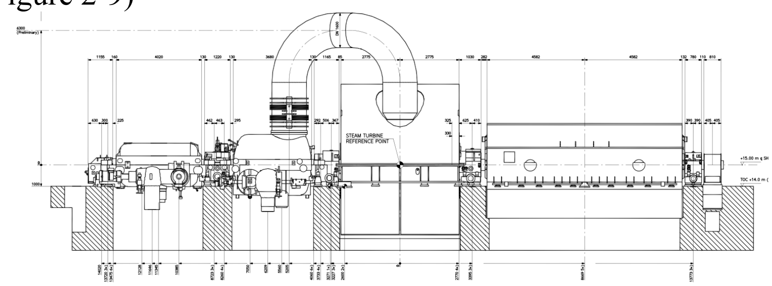


Figure 2-9 Steam Turbine Train Including Generator (downwards exhaust option)

Representative small USC HP and IP turbine modules are shown in Figure 2-10 and Figure 2-11. These modules are shop assembled and transported to site as modular units.

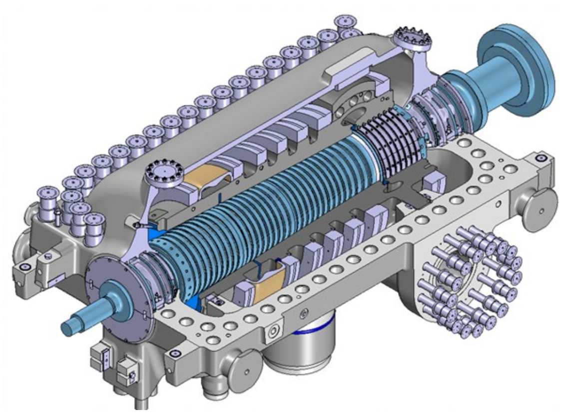


Figure 2-10 Small USC HP Turbine Module

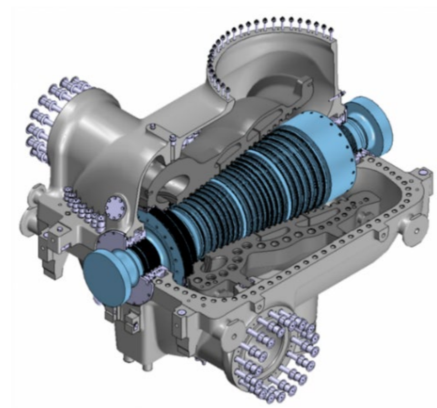


Figure 2-11 Small USC IP Turbine Module

A representative small USC LP turbine module is shown in Figure 2-12. These modules are shop assembled and transported to site as modular units.

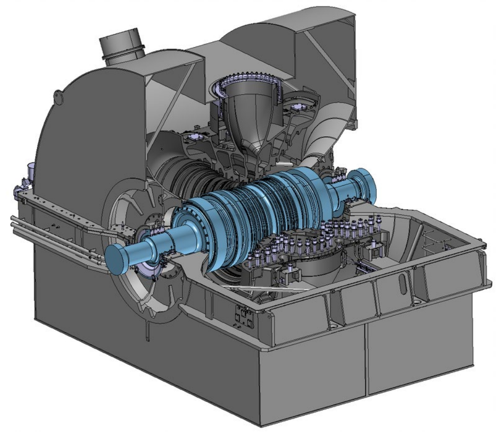


Figure 2-12 Representative LP Turbine Module (downwards exhaust option)

3 Design Basis

1. **General Information**

	Parameter	**Value**
1.1	**Plant**	AUSC Coal Plant
1.2	**Location**	Greenfield, Midwestern
1.3	Plant owner	not applicable
1.4	**Power Plant power production, MWe gross (w/o CCS) per Power Unit**	300
1.5	**Power Plant power production, MWe net (w/o CCS) per Power Unit**	
1.6	**Number of Power Units to be equipped with Carbon Capture Unit(s)**	1 (concept 1);
1.7	**Number of Carbon Capture units per Power Unit**	1 (concept 1); 1 for AUSC
1.8	**Total number of Carbon Capture units for all Power Units together**	1 (concept 1) 1 for AUSC
1.9	Type of fuel (coal, natural gas, etc.)	coal (concept 1);
1.10	SCR installed (Yes/No)	Yes • SCR, which reduces NOx, upstream of air preheater • NID, which reduces SO2, SO3 and particulates (dust)
1.11	Particulate collection installed (ESP, fabric filter, etc.)	
1.12	SO3 control installed (lime injection, WESP, etc.)	
1.13	SO2 control installed (WFGD, etc.)	
1.14	**CO_2 capture efficiency**	90 %
1.15	**Average full load operating hours per year (for yearly consumptions/productions calculations)**	5000
1.16	Plant availability in hours per year	8000
1.17	Specific local design requirements e.g. piling, EHS, seismicity, etc.?	n.a.
1.18	Potential plant integration e.g. DCS, control room, switch room, etc. or standalone plant	no separate DCS, control room, switch room, etc. for CCS plant

2.0 Units of Measure

	Parameter	Units
	Temperature	°C
	Pressure	bara
	Vacuum pressure	mbara
	Weight (mass)	kg
	Volume, liquids	m^3
	Volume, gases,	actual m^3
	Volume, gases, norm	Nm^3 [at 0 °C and 1013 mbara]
	Flow, liquids	m^3/h, kg/h
	Flow, gases	m^3/h, kg/h
	Flow, solids	kg/h
	Flow, steam	kg/h
	Heat	kJ
	Power	MW, kW

3.0 Flue Gas to Carbon Capture Plant (CCP) - per Power Plant unit

<u>For Coal FIRST:</u>

- Note: Data provided at interface point/battery limit (BL) to Carbon Capture Plant (CCP).

	Parameter	Units	Design Value
3.1a	**Description of interface point (BL connection point) proposed by Customer**	- downstream of AQCS for power plant and Flue Gas Blower - 103 % of guarantee rate, VWO – design case	
3.2a	**Gas flow rate to Carbon Capture Plant**	kg/h wet	1,075,084
3.3a	**Gas flow rate to Carbon Capture Plant**	Nm^3/h wet	836,724
3.4a	**Temperature at interface point**	°C	80
3.5a	**Pressure at interface point**	barg	0
3.6a	Composition		
	O_2	vol %, wet	3.5
	N_2	vol %, wet	69
	Argon	vol %, wet	---
	H_2O	vol %, wet	14.4
	CO_2	vol %, wet	13.1

	SO_2	ppmv wet	14
	SO_3	ppmv wet	0.3
	NO	ppmv wet	50
	NO_2	ppmv wet	<2
	NH_3	ppmv wet	<2
	HCl	ppmv wet	<1
	HF	ppmv wet	<1
	Total Particulate Matter	mg/Nm3 wet	10

4.0 Treated Flue Gas from Carbon Capture plant (per Power plant Unit)

	Parameter	**Units**	**Design Value**
4.1	**Description of interface point (BH connection point) proposed by Customer**	- downstream of CCP emission control system for power plant (concept 1	
4.2	**Pressure at interface point**	bara	1.000
4.3	Composition/emissions (in case max. allowed limits are defined)		
	Amines	mg/Nm³ dry	no special requirements
	NH3	mg/Nm³ dry	no special requirements
	Amine degradation products	mg/Nm³ dry	no special requirements
	Other?	mg/Nm³ dry	

5.0 CO_2 Product Specification

	Parameter	**Units**	**Design Value**
5.1	**Use of CO_2 product (saline aquifer, EOR, utilization, other?)**	Enhanced Oil Recovery (EOR)	
5.2	**Description of interface point (BH connection point) proposed by Customer**	downstream of CO2 compression and aftercooling (concept 1 and 2)	
5.3	**Temperature at interface point**	°C	40
5.4	**Pressure at interface point**	bara	120
5.5	Requested composition		
	CO_2	vol %, dry	min. 99.0
	N_2	ppm-mol, wet	

	Argon	ppm-mol, wet	N2 and Ar together < 10,000
	H_2O	ppm-mol, wet	max. 50
	O_2	ppm-mol, wet	max. 100
	NH_3	ppm-mol, wet	n.a.
	Amines	ppm-mol, wet	n.a.
	Glycol	ppm-mol, wet	n.a.
	Other?	ppm-mol, wet	n.a.

6.0 Flue Gas Condensate from Carbon Capture plant (per Power Plant)

	Parameter	Units	Min. Value	Max. Value	Design Value
6.1	Description of interface point (BH connection point) proposed by Customer	downstream of condensate pump flow control valve; condensate tank ISBL of power plant			
6.2	Temperature at interface point	°C			< 50
6.3	Pressure at interface point	bara			5.0
6.4	Any composition restrictions?				

7.0 Reserved

8.0 Steam Supply

	Parameter	Units	Min. Value	Max. Value	Design Value
8.1	**Description of interface point (BH connection points) proposed by Customer**	downstream of de-superheating station			
8.2	**Temperature at interface point**	°C	147	160	approx. 5 °C superheated, i.e. T = Tsat (@ 3.8 bara) 142 °C + 5 °C = 147 °C
8.3	**Pressure at interface point**	bara	3.8	4.5	3.8 bara @ BL CCP (assuming FCV; FI on CCP part)

9.0 Steam Condensate

For Coal FIRST:

	Parameter	**Units**	**Min. Value**	**Max. Value**	**Design Value**
9.1	Description of interface point (BH connection points) proposed by Customer for condensate	downstream of steam condensate pump flow control valve			
9.2	Temperature at interface point	°C			137
9.3	**Pressure at interface point**	bara			7.0

10.0 Cooling Water

	Parameter	**Units**	**Min. Value**	**Max. Value**	**Design Value**
10.1	Description of interface point (BL connection point) proposed by Customer	at battery limit of CCP site			
10.2	**Type (sea water, river water, cooling tower, closed loop CW, etc.)**	cooling water			
10.3	**Temperature - supply at interface point**	°C		n.a.	15.6
10.4	**Temperature - return (if return temp has a constraint) at interface point**	°C			25.6
10.5	**Max. allowed overall CW temperature difference between supply and return (if limited)**	°C			10
10.6	**Supply pressure at interface point**	bara			5.0
10.7	**Allowable pressure drop between supply and return**	bar			1.5
10.8	**Available flow rate- if restricted**	t/h			n.a.

11.0 Electric Power

	Parameter	**Units**	**Design Value**
11.1	Description of interface point (BH connection point) proposed by Customer	at battery limit of CCP site	
11.2	Voltage	V	
11.3	Amperage	A	

12.0 Site/Climate conditions

	Parameter	Units	Min. Value	Max. Value	Design Value
12.1	Barometric pressure	bara			1.01
12.2	**Ambient temperature**	°C		n.a.	15
12.3	Relative humidity	%			60

13.0 Storage requirements

	Parameter	Design Value
13.1	Storage requirements in days for chemicals?	30

14.0 Plot space

	Parameter	Units	Min. Value	Max. Value	Design Value
14.1	Plot space will be estimated for AAP plant, inside battery limits including all required process equipment as well as storage tanks and loading/unloading facilities (subject to confirmation by detailed process design); Scope (ISBL facilities)/Terminal points according to definition in Carbon Capture Ready study. The space requirement is estimated under the assumption, that the available plot space area is located close to the tie-ins into the flue gas duct downstream the FGD and suitably shaped to allow a reasonable arrangement of the CCP equipment as typical for chemical plants; e.g. adjacent rectangular shaped area(s) of reasonable widths and lengths	m^2			no limitation - greenfield

The following Exhibits 1-5 were taken from the original RFP for this Coal FIRST project.

Exhibit 1: Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (Pulverized Coal), acres	300
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

Exhibit 2: Site ambient conditions

Parameter	Value
Elevation, (ft)	0
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[A]	15.6 (60)
Air composition based on published psychrometric data, mass %	
N_2	72.429
O_2	25.352
Ar	1.761
H_2O	0.382
CO_2	0.076
Total	100.00

[A]The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 8.5°F above ambient wet bulb conditions in ISO cases.

Exhibit 3: Design coal – Sub-Bituminous

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

Exhibit 4: Natural gas characteristics

Natural Gas Composition			
Component		**Volume Percentage**	
Methane	CH_4	93.1	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1.0	
Nitrogen	N_2	1.6	
Methanethiol[A]	CH_4S	$5.75x10^{-6}$	
	Total	100.00	
	LHV	**HHV**	
kJ/kg (Btu/lb)	47,454 (20,410)	52,581 (22,600)	
MJ/scm (Btu/scf)	34.71 (932)	38.46 (1,032)	

[A]The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH_4S) with trace levels of H_2S. Note: Fuel composition is normalized and heating values are calculated.

Exhibit 5: MATS and NSPS emission limits for PM, HCl, SO_2, NOx, and Hg

Pollutant[A]	PC limits (lb/MWh-gross)
SO_2	1.00
NOx	0.70
PM (Filterable)	0.09
Hg	$3x10^{-6}$
HCl	0.010

4 Performance Results

4.1 AUSC Carbon Capture Plant Process Flow Description

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, 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 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 NOx firing system, selective catalytic reduction (SCR) system for NOx control, dry scrubber/fabric filter for particulate matter (PM)/SO2/Hg/HCl control; an amine-based post combustion carbon capture system; and a synchronous steam turbine/generator.

A Process Flow Diagram of the overall plant (Concept 1) is shown in Figure 4-1. Note that the Process Flow Diagram shows only the steam extractions for the carbon capture system for simplicity and clarity of the diagram. The steam turbine, boiler/AQCS and carbon capture sub-systems are described in more detail in the following sections.

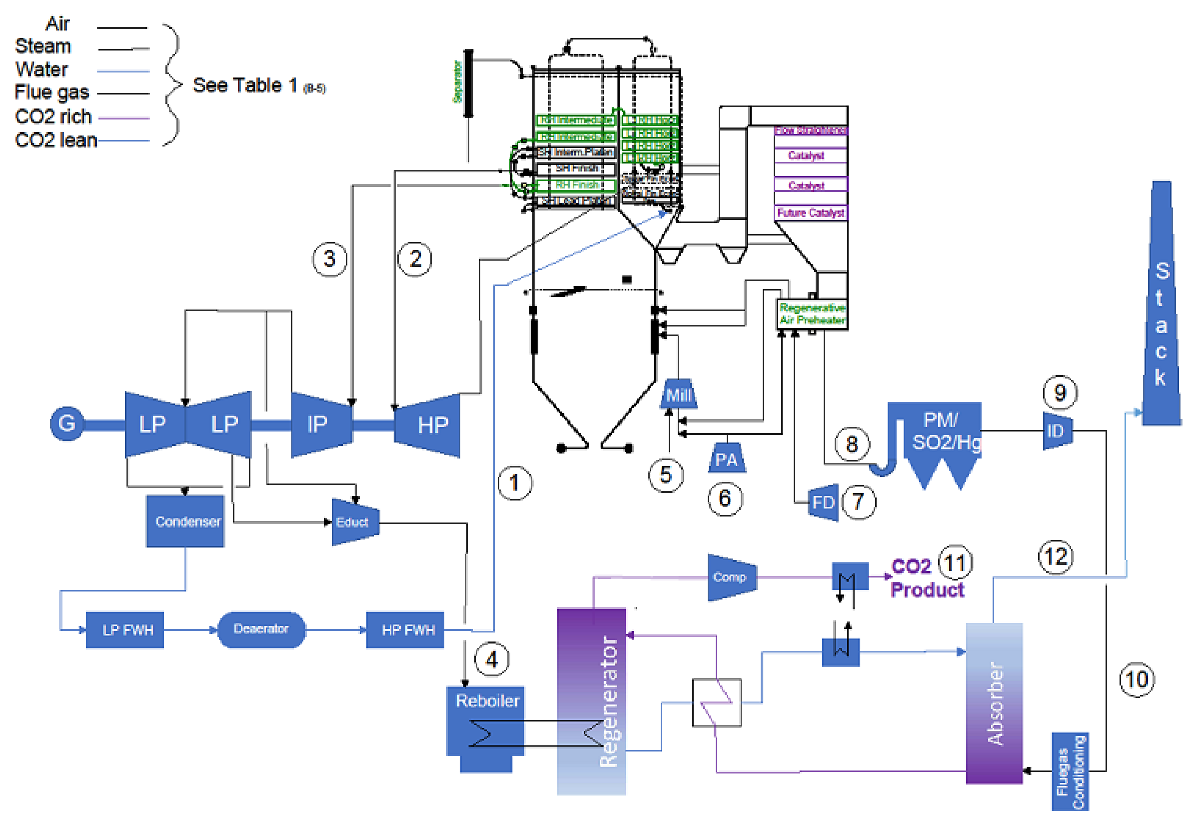


Figure 4-1 Small, Flexible AUSC Coal Power Plant Process Flow Diagram (Concept 1)

4.2 Performance Summary

Table 4-1 below shows the expected plant efficiency range at full load and a summary of the emissions control, including CO_2 emissions control.

Performance Summary for AUSC coal plant:

AUSC carbon capture efficiency of 90% → 193.5 metric tons/hr CO_2 captured
Net plant efficiency of the integrated AUSC coal plant → 34.5% with carbon capture

Table 4-1 Expected Plant Performance and Emissions

Parameter	Concept 1 w/out CCP (no steam extraction to CCP)	Concept 1 w/out CCP but with steam extraction to CCP	Concept 1 w/CCP integration
Size MW gross/net at VWO	309 / 284	278 / 254	278 / 227
Ramp rate up/down MW/min	15	15	15
Cold/Warm start time hours[note 1]	4 / 2	4 / 2	4 / 2
Turn down capability	20%	20%	20%
	Firing PRB coal	Firing PRB coal	Firing PRB coal
VWO Unit net HR Btu/MWH	7908	8862	9896
VWO Load Plant net efficiency %	43.2	38.5	34.5
50% Load Plant net efficiency %	40.3	33.7	28.2
SO_2 lb/MWh-gross[note2]	1.00	1.00	1.00
NO_x lb/MWh-gross	0.70	0.70	0.70
PM (Filterable) lb/MWh-gross	0.09	0.09	0.09
Hg lb/MWh-gross	$3x10^{-6}$	$3x10^{-6}$	$3x10^{-6}$
HCl lb/MWh-gross[note 2]	0.010	0.010	0.010
CO_2 Capture Rate %	NA	NA	>90%

note 1: from first fire to turbine sync
note 2: emissions noted are as required per RFP. Significantly lower emissions are expected.

4.3 Coal-fired Power Plant Heat Balance Diagram (Concept 1)

The AUSC Boiler is designed to generate steam defined by the Turbine Heat Balance shown in Figure 4-2. Note that the CO2 control strategy is facilitated by steam extractions for use by the Carbon Capture Plant's reboiler:

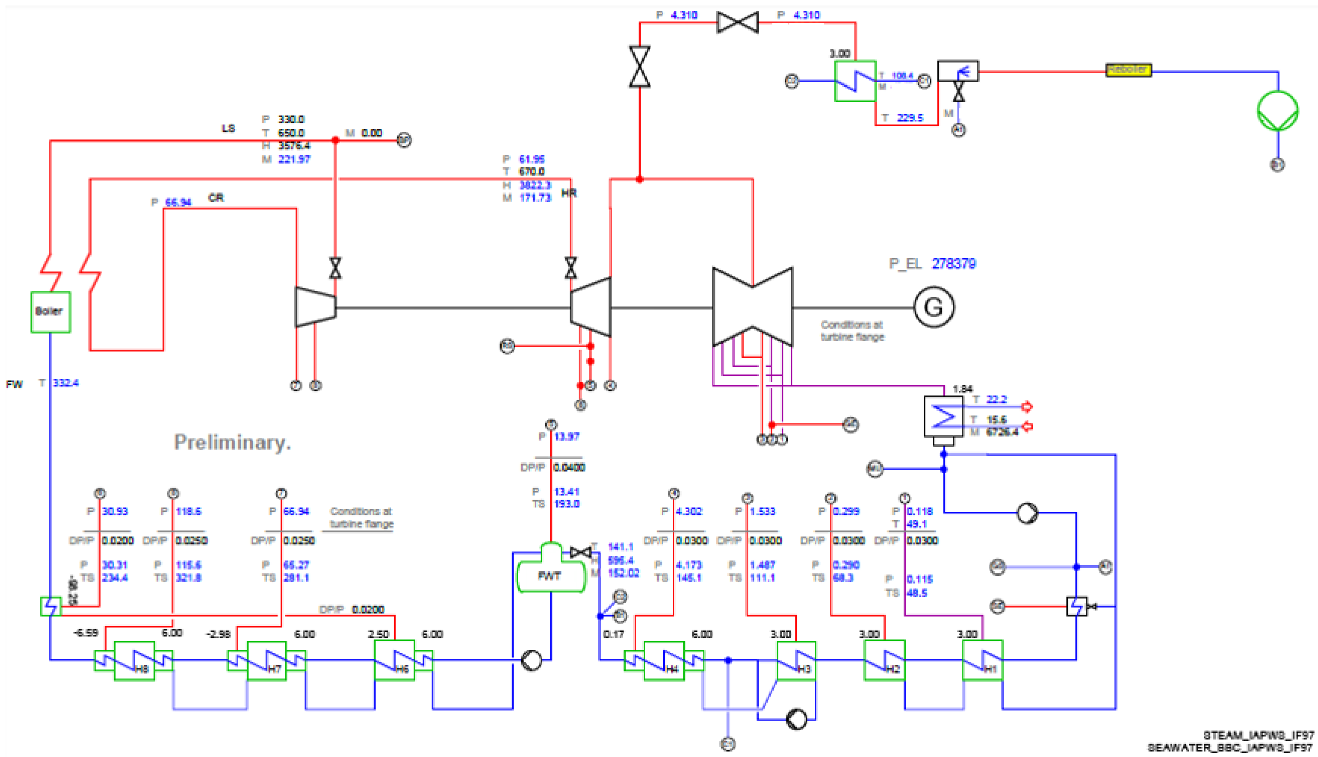


Figure 4-2 Small, Flexible AUSC Coal Power Plant Heat Balance Diagram (Concept 1) at VWO load

4.4 AUSC Boiler and AQCS systems Performance

The AUSC Boiler Expected Performance is shown in Figure 4-3. The predicted Boiler efficiency on HHV basis is 87.5%.

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 shorter high energy piping runs than a typical arrangement. Elimination of the tunnel between the furnace exit vertical plane and low temperature convective pas 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 addresses differential expansion between wall sections allowing faster start-up and higher load ramp rates.

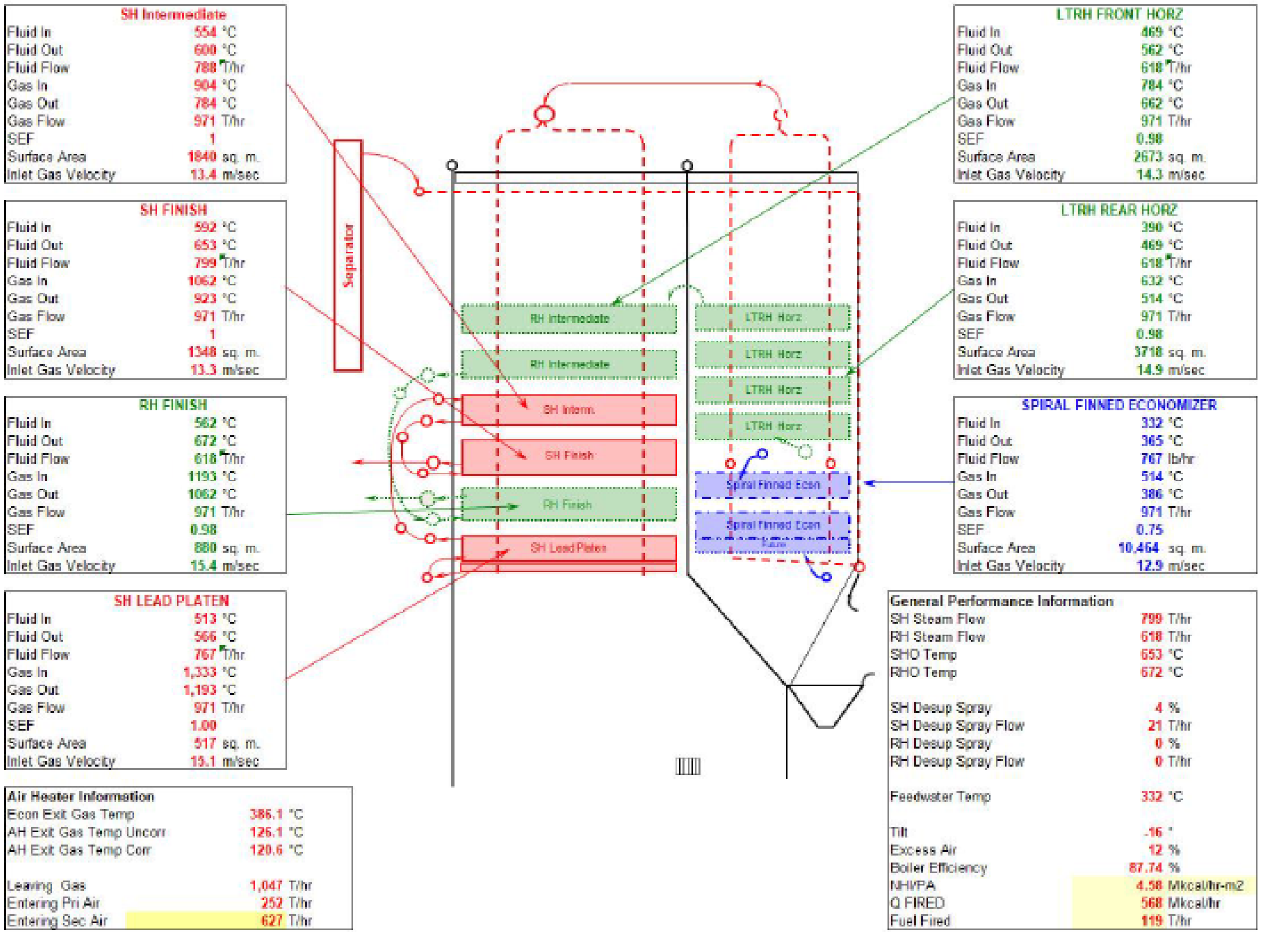


Figure 4-3 AUSC Boiler Expected Performance at VWO (103%) Load

GE Power Inc.'s most recent development is the TFS XP™ Ultra Low NO_X Firing System. This system represents over 45 years of progressively developed global and local staging techniques designed to minimize O_2 availability during the critical early phases of combustion when the volatile (fuel) nitrogen species are formed. A key feature of this firing system is the tri-level OFA design consisting of "close coupled" overfire air (CCOFA) and two(2) levels of separated overfire air (SOFA). Moving the upper most SOFA windboxes from the traditional "corner" location to the furnace walls in a "counter" fireball orientation completed the design by providing superior mixing, minimum gas-side energy imbalance (GSEI) and control of CO emissions while operating at minimum NO_X emissions levels.

The TFS XP™ firing system has some additional important features including;

- Dynamic classifiers for improved mill performance (fineness and capacity)
- Concentric firing to maintain "oxidizing" conditions along the furnace walls in the firing zone, and
- Enhanced ignition coal nozzle tips for more rapid release of fuel nitrogen, improved coal combustion (lower UBC HL) and low load flame stability

The Boiler Auxiliary Equipment include Coal Mills, PA, FD and ID fans, SSC (submerged scraper conveyer), and APH (air preheater).
The air preheater design will be optimized to gain the maximum heat recovery that allows for an overall reduced heat rate.

The generated flue gas is cleaned by the Air Quality Control Systems (AQCS) by removing particulate and SO2, NOx and other acidic gases, prior to discharge to the downstream Carbon Capture System (CCS) or to the atmosphere when the CCS is bypassed.

The conditions in Coal First Pre-Feed Study Project with request for high performance, low water consumption, zero liquid discharge, modular design and wide turn down ratio are ideal for the SCR and NID-FF technologies.

The SCR system is a well proved post combustion technology for converting by-product NO_x to atmospheric N_2 at reduction efficiencies of +90%. The process involves injecting ammonia (anhydrous, aqueous or as urea) into the flue gas stream of an appropriate temperature and then passing the flue gas through a reactor vessel containing catalyst. An economizer gas bypass system will be used to control SCR inlet gas temperature. The reactor box is a standard multi-layer design with inlet turning vanes, flow straighteners, ash moving devices and integrated catalyst module removal system.

The NID-FF system (whose Process Flow Diagram is shown in Figure 4-4) uses compact reactors combined with Fabric Filters (FF) as dust collector. The reagent handling is possible to be located flexibly in the vicinity of the NID-FF unit and the same for ash handling system.

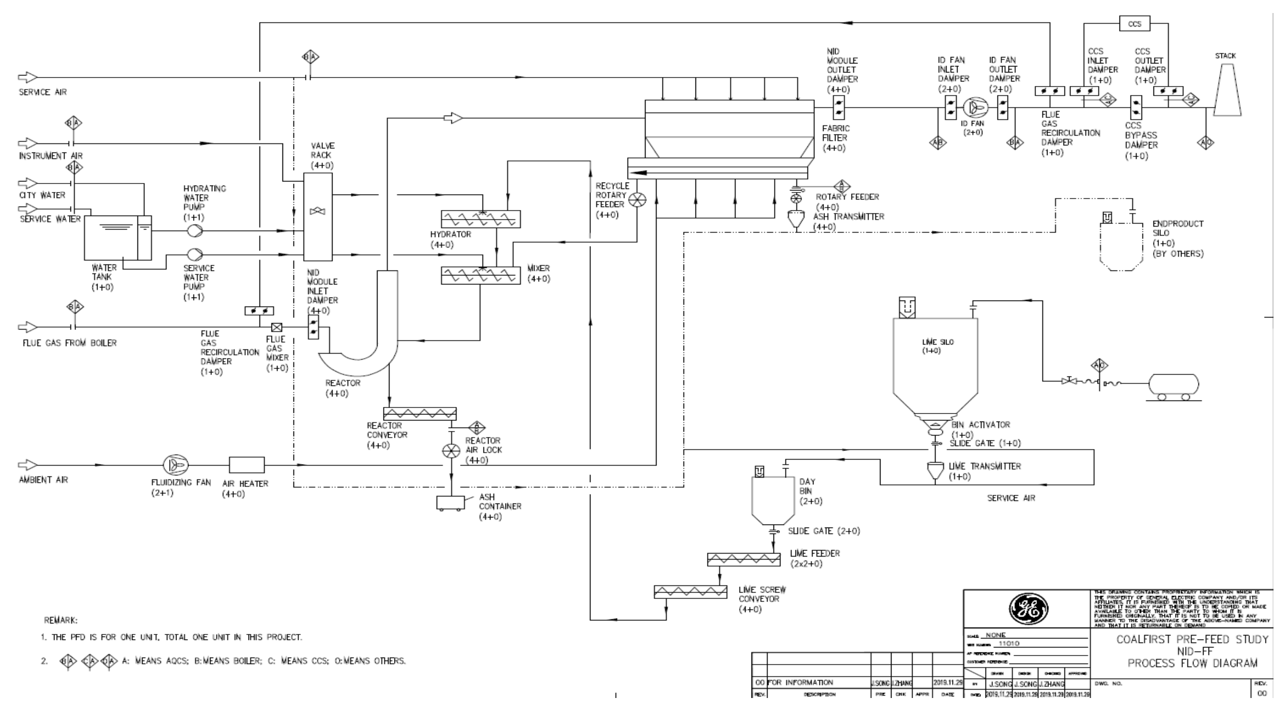


Figure 4-4 NID™ System Process Flow Diagram

4.4.1 Performance Summary Data for the AQCS NIDS

	Unit of measure (UOM)	
	Coal	Rosebud
Boiler load	% MCR	VWO
Flue gas flowrate	kg/h	1,032,417
Flue gas flowrate	Nm3/h	789,924
Flue gas flowrate	m3/h	1,159,967
Gas temperature	ºC	120
Design barometric pressure	Pa	100,801
Static pressure	Pa(g)	-3,483
Total Pressure	Pa	97,319
Gas composition:		
CO2	ppmv, Wet	138,686
N2	ppmv, Wet	714,362
H2O	ppmv, Wet	113,586
O2	ppmv, Wet	32,629
SO2	ppmv, Wet	735
SO3	ppmv, Wet	0.79
Density	kg/Nm3	1.307
	kg/m3	0.890
Dust load (volumetric)	mg/Nm3, 6% O2 dry	9756.4
Dust load (mass)	kg/h	7,888

4.4.2 Flue gas emission for NID-FF design

Pollutant	mg/Nm3, dry, 6%O2	Remarks
SO_2	41	≥ 98% removal efficiency
PM (Filterable)	10	
Hg	$5x10^{-4}$	
HCl	0.35	

TURN-DOWN RATIO
5:1 turndown ratio with full environmental compliance.

LOAD CHANGE RATE
Greater than or equal to 4% ramp rate (up to 30% Heat Input from natural gas can be used).

LIME QUALITY
The quick lime provided as a reagent to the process shall have the following minimum quality characteristics:

- ⩾90 active CaO as per ASTM C 25.
- Particle size: 100% < 3mm, 80% < 0.8mm.
- Chemical activity such that the contact with water leads to a temperature increase > 40°C in 3 minutes as per ASTM C 110
- Density when stored in silo:

Min	900 kg/m^3
Typical	1 000 kg/m^3
Max	1 300 kg/m^3

PROCESS WATER QUALITY
The Process Water provided to the process shall follow water quality characteristics below at the terminal point:

Description	**Unit**	**Mixer Water**	**Hydrator Water**
Total dissolved solids	g/l	< 20	< 1
Total suspended solids	g/l	< 10	< 10
Sulphate, SO_4^{2-}	mg/l	< 500	< 200
Chloride, Cl^-	mg/l	< 1000	< 100
Carbonate $HCO_3^- + CO_3^{2-}$	mg/l	< 1000	< 500
pH		>6.5	>6.5
Particle size	mm	< 0.3	< 0.3
Temperature	°C	15 – 35	15 – 35
Pressure	bar (g)	⩾2	⩾2

CLOSED COOLING WATER QUALITY

The Closed Cooling Water provided to the process shall follow water quality characteristics below at the terminal point:

Description	Unit	Value
Water source		Demineralized water
pH at 25°C		8 – 9
Conductivity at 25°C	µs/cm	< 10
Temperature	°C	< 35
Pressure	barg	5-7

EMERGENCY SHOWER WATER

Emergency water system with showers is to be installed with appropriate water quality based on local safety requirements, to be chosen by the customer as suitable for showers (presumably drinking water).

Water pressure required at terminal point, minimum 2 bar(g)

COMPRESSED AIR QUALITY

The Compressed Air provided to the process shall have the following quality characteristics at the terminal point:

Instrument Air

Pressure		kPa(e)	700
Particulate	ISO8573.1 Class 1	µm	⩽ 0.5
Dew point	ISO8573.1 Class 2	°C	⩽ -40
Oil content	ISO8573.1 Class 2	mg/m³	⩽ 0.1

Process Air

Pressure		kPa(e)	700
Particle	ISO8573.1 Class 2	µm	⩽ 5
Dew point	ISO8573.1 Class 4	°C	⩽ 3 or min. ambient temperature
Oil content	ISO8573.1 Class 3	mg/m³	⩽ 1

ELECTRICAL POWER SUPPLY

Electric power at the terminal point shall have the following specification.

Low voltage power supply	Voltage – Frequency – Phase	480 V – 60 Hz – 3 phase
	Fluctuation of voltage	Within ±10%
Medium voltage power supply	Voltage – Frequency – Phase	6.0 kV – 60 Hz – 3 phase
	Fluctuation of voltage	Within ±10%
For Instruments	240V, 60Hz 3 Phase or 24V DC	
For PLC	240V, 60Hz 3 Phase or 24V DC	

ELECTRICAL EQUIPMENT PROTECTION SPECIFICATION

Electrical equipment and instrument in electric and electronic rooms IP31

Electrical equipment and instrument in process area IP54

Electrical equipment and instrument outdoors IP55

GAS PRESSURE FOR MECHANICAL DESIGN

The following gas pressure was chosen as the design basis for the NID-FF installation.

Description	Unit	Normal	Excursion
Under pressure in flue gas path, for mechanical design	Pa	– 6,500	– 8,700

4.4.3 Consumption Data

Following consumption numbers are expected for one boiler unit:

Boiler load		VWO	TMCR	70% TMCR	50% TMCR	35% TMCR	20% MCR
Quick lime	kg/h	3503	3409	2412	1710	1222	675
Powdered Activated Carbon (PAC)	kg/h	50	48	36	30	23	22
Mixer water	m^3/h	24.7	24.0	15.9	12.4	10.8	9.0
Hydrating water	m^3/h	2.2	2.1	1.5	1.1	0.8	0.4
Closed cooling water	m^3/h		10			5	
End product from NID	t/h	14.9	14.4	10.3	7.5	5.4	3.2

Service air (Max.)	Nm^3/h	2,074	2,074	1,556	1,037	1,037	1,037
Service air (Normal operation)	Nm^3/h	1,018	941	598	720	378	295
Instrument air	Nm^3/h	60					

4.4.4 Pressure Drop Data

Following pressure drop numbers are expected for design conditions:

Boiler load	Unit	VWO	TMCR	70% TMCR	50% TMCR	35% TMCR	20% MCR
Pressure drop across NID-FF (flange-to-flange)	Pa	3000	2900	2800	3400	2700	2500

4.4.5 Power Consumption Data

Following auxiliary power consumption numbers are expected for design conditions

Boiler load	Unit	VWO					
Power Consumption of NID-FF system	kW	350					
Power Consumption of PA, FD, ID fans, misc. fans, HP mills, feeders, vaporizer, SSC and APH	kW	7,056					

4.5 AUSC Carbon Capture Plant

The simplified version of the proposed carbon capture system Process Flow Diagram (PFD) is shown in Figure 4-5. 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.

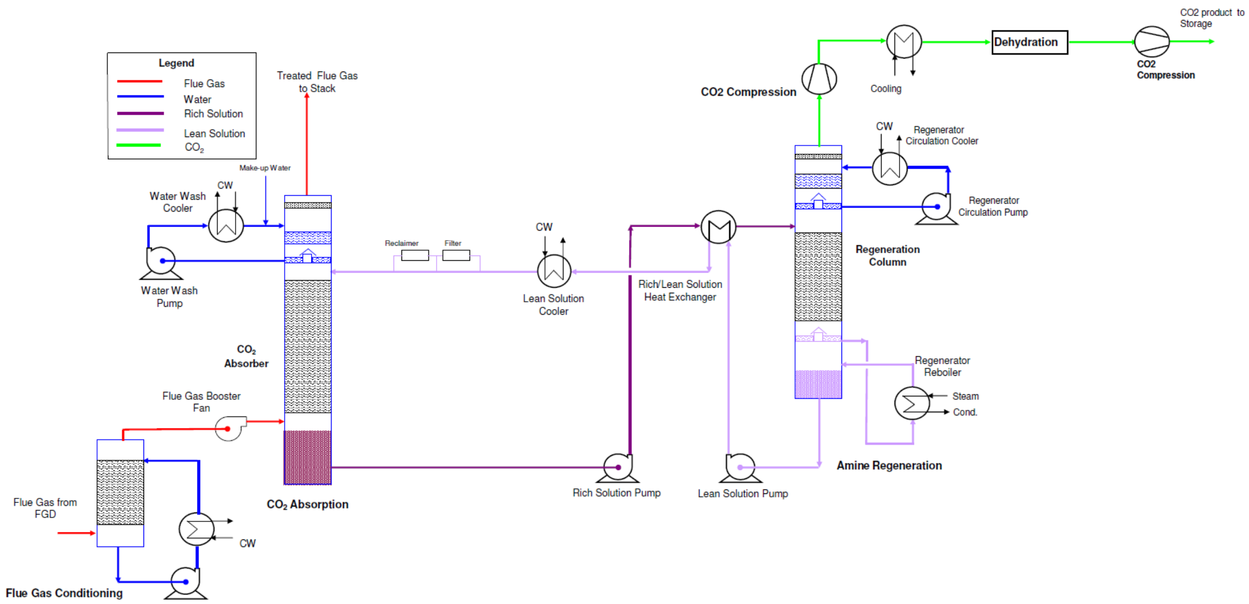


Figure 4-5 Process Flow Diagram of the proposed carbon capture technology

The CCP is located downstream of the traditional AQCS plant section with the specific target to reduce the CO2 emissions of the host power plant. The proposed CCP concept utilizes a proven Advanced Amine Process (AAP), comprising a proprietary amine-based solvent in a proprietary flow scheme for flue gas applications. The AAP technology applied is based on smaller scale AAP pilot plant experience as well as a reference design for large scale post-CCPs, but downscaled to process the flue gas from target host plant capacity.

The main CCP plant performance target is 90 % CO2 capture from the pre-treated flue gas of up-stream AQCS components, while producing a CO2 product with specified quality in terms of composition and battery limit conditions - pressure and temperature - for further utilization.

These targets are accomplished with the objectives to achieve minimized energy and utility consumptions, primarily steam and electrical power, but also cooling water and chemical consumptions, primarily amine make-up. Additional CCP plant integration options with the host power plant water/steam cycle could further improve the overall operations expenditures (OPEX) on cost of additional capital expenditures (CAPEX). Generally, amines-based processes are proven technologies for decades in the oil and gas industry. In this application, the process has been optimized to combustion flue gas under atmospheric pressure and power plant operations.

The main emission target for the CCP is a 90% reduction of CO_2 emissions for the AUSC coal plant in Concept 1. A validated solvent and emission management is utilized to keep the emissions generated from the CCP below tolerable limits, typically defined for amines and ammonia.

The individual CCP equipment design is considering a well-balanced techno-economical solution (CAPEX/OPEX-ratio) to achieve the performance targets, like CO_2 capture, CO_2 product quality and emissions, while keeping the OPEX on a low level. This comprises the following components:

- Flue gas conditioning system for an optimized CO_2 absorption performance
- Improved absorber design maximizing the CO_2 loading in the rich solvent
- Advanced regeneration concept minimizing steam consumption and CO_2 product compression power demand

- High efficiency heat exchanger network maximizing heat recovery from the hot lean solvent from the regenerator
- Advanced solvent management
- Efficient CO_2 product compression & dehydration system to accommodate CO_2 pipeline conditions

All equipment of the CCP is designed to meet these targets. The interplay of its different components is harmonized for operation within the required operating range. Figure 4-6 shows the specific advantages and features of the AAP technology outlined in the bullets above.

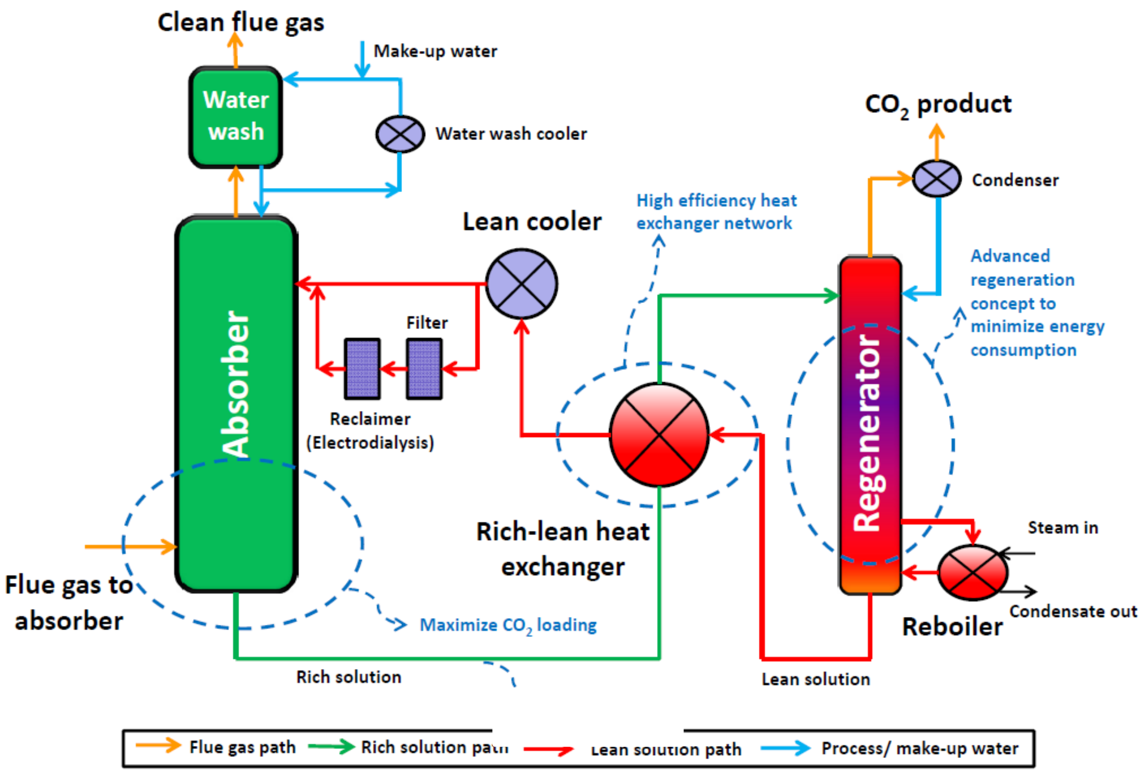


Figure 4-6 Features and Advantages of the Advanced Amine Process

4.5.1 Performance Summary

The scope of this Performance Summary Report is to summarize:

- CO2 capture efficiency
- CO2 product flow and quality
- energy and utility consumption figures
- chemical consumption figures
- expected emissions
- expected effluents
- solid wastes

of the CCP for the governing design case (BMCR/VWO case of the host AUSC coal plant) of **Concept 1**, defining the CCP design plant capacity.

Out of scope of this Performance Summary Report are:

- performance figures for any turndown operation of the CCP
- plant integration optimizations for the host power plant and CCP, offering potential for reduced energy and utility consumption figures.

4.5.2 CO2 Capture Efficiency

The CCP is designed to capture at least 90 % of the CO2 contained in the specified flue gas outlet stream from the AQCS. For the design case (BMCR/VWO case) of **Concept 1**, the total flue gas outlet stream from the AQCS plant section will be routed to the CCP. The relevant design flue gas stream from AQCS plant section is a wet flue gas flow of 1.075 t/h, respectively 836.7 kNm^3/h. This stream contains a CO2 concentration of 13.09 vol-%, wet, which results in a CO2 flow of 215.0 t/h in the total flue gas to the CCP unit.

90 % of this CO2 contained in the total flue gas stream will be captured in the CCP unit and compressed to the required pressure of 120 bar(abs) for Enhanced Oil Recovery (EOR) utilisation. Thus, the maximum CO2 capture plant capacity for subject power plant is 193.5 t/h, respectively 4,644 t/day of CO2 product, which is captured from 100 % of flue gas flow.

4.5.3 CO2 Product Flow and Quality

Typically, the CO2 product stream will be delivered to the CCP boundary at a pressure between 100 and 150 bar(abs), depending on site specific conditions like distance to storage site. For the CO2 capture study, the CO2 product pressure of 120 bar(abs) is assumed for the purpose of this study as specified. The battery limit for the CCP pertaining to the CO2 Product route is assumed at CO2 compressor outlet flange, respectively its aftercooler.

The expected CO2 product stream characteristics are provided in Table 4-2.

Table 4-2: CO2 product characteristics of the CCP

Description	**Units**	
CO2 product mass flow at CCP design plant capacity	t/h	193.5
CO2 product temperature (at CCP battery limit)	°C	40
CO2 product pressure	bar(abs)	120
Composition		
CO2	vol-%, wet	> 99.5
N2 (including Ar)	ppm-mol, wet	balance (< 5,000)
H2O	ppm-mol, wet	< 50
O2	ppm-mol, wet	< 100
Amine, degradation products, TEG	ppm-mol, wet	traces

4.5.4 Low Pressure Steam

Energy in the form of steam is needed within the AAP technology regeneration system to:

- release the CO2 in the Amine Regenerator and produce the desired CO2 product stream
- regenerate the CO2-"rich" amine solution from the CO2 Absorber in order to produce a reagent for reuse.

LP Steam has been foreseen to provide this thermal energy to the Amine Regenerator Reboiler.

The estimated value for steam consumption is shown in table below and is based on the shown assumed steam pressure and temperature. For the CO2 capture study, a saturated steam temperature at the CCP battery limit of 147 °C was assumed.

Estimated steam demand for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	**Units**	
Steam pressure at battery limit to CCP *1)	bar(abs)	min. 3.8
Steam temperature at battery limit to CCP *1)	°C	147

<u>Note 1:</u>

Steam conditioning/de-superheating is assumed to be outside of CCP scope.

The condensate from the regeneration reboiler is returned to the host power plant's steam/water cycle to generate steam again. The required condensate pressure of 7.0 bar(abs) at the CCP battery limit is assumed.

4.5.5 Electrical Power

The CCP's electrical demand may be provided by a single medium voltage electrical feed to the CCP's electrical power distribution. The electrical distribution strategy to provide the most economical electrical power to the individual CCP components will be developed in a later stage. The electrical power distribution equipment may include, but is not limited to switchgear, substations, power transformers, Motor Control Centers (MCCs), power distribution transformers, power distribution panels.

The CO2 compressor outlet pressure, respectively the required pressure of the CO2 product at CCP battery limit influences significantly the electrical power consumption of the CCP. This pressure is assumed for the purpose of this study and needs to be defined by site-specific condition of distance to storage site and will need a more detailed calculation in a later stage.

Estimated electrical power consumption for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
Average demand at CCP design plant capacity	MW	26.5
CCP electrical power per year (at 5,000 full load operating hours per year)	MWh	132,500

All small and large size machinery, e.g. CO2 Compressor, are assumed electrical motor driven. No steam turbine is considered as driver of any machine.

4.5.6 Cooling Water

For the CO2 capture study, the availability of cooling water is assumed. The cooling water is assumed to be provided from host power plant. The CO2 capture study in hand and its performance/consumptions calculations have been done for the specified Cooling Water (CW) supply temperature of 15.6 °C.

Note, the CCP performance is depending on available cooling water supply temperature.

The cooling water conditions are assumed as following:

Parameter	Unit	Total
CW supply temperature	°C	15.6
CW return temperature	°C	25.6
CW supply pressure	bar(abs)	5.0
CW return pressure	bar(abs)	3.5

The cooling water utilization for the AAP CCP is mainly for cooling of the following process heat loads:

- flue gas conditioning
- CO2 Absorber system
- Water Wash at CO2 Absorber
- Water Wash at Amine Regenerator
- CO2 Compression system.

The estimated cooling water amount required for the AAP CCP plant considering an assumed 10 °C temperature increase is shown in the following tabulation.

Estimated cooling water demand for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
Average demand at CCP design plant capacity	m^3/s	5.3
	m^3/h	19,200

Cooling water supply temperature (design)	°C	15.6
Overall cooling water temperature increase in CCP	°C	10
Cooling water supply pressure (design)	bar(abs)	5.0
Cooling water allowable pressure drop over the CCP	bar	1.5

4.5.7 Demineralized Water

The CCP, with the inclusion of the Water Wash System at the top of the CO2 Absorber, is designed to be nearly water neutral, e.g. any water make-up requirements or waste water treatment requirements have been minimized. During periods of ambient conditions with higher temperature and start-up periods, a small amount of demineralized water may be additionally required. In addition, the ED Reclamation unit and the Water Wash System of the CO2 Absorber require some demineralized water feed. Further, process water for gearbox cooling and equipment seals is anticipated but is not included in the estimate demineralized water consumption figure below.

There is considerable flexibility with regard to the demineralized water flow rate and quality that can be accepted by the AAP of the CCP. The optimization for a minimum demineralized water consumption will be evaluated in a later stage.

For the CO2 capture study, the demineralized water as specified in following tabulation is considered as make-up for the CCP.

Parameter	Value
Chlorides - limits chloride corrosion-related problems	< 2 ppmw
Total dissolved solids - limits ash build-up and foaming problems	< 50 ppmw
Total hardness - limits calcium and magnesium scale problems	< 2 ppmw
Sodium/potassium - limits heat stable salts	< 10 ppmw
Iron - limits iron scale and build-up and fouling	< 1 ppmw

Demineralized water is mainly consumed in following services:

- CO2 Absorber
- Amine Reclamation unit.

Estimated demineralized water demand for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
Average demand at CCP design plant capacity	t/h	3.0
CCP demand per year (at 5,000 full load operating hours per year)	t/year	15,000
Amount for first fill	m^3	1.500

4.5.8 Nitrogen

Nitrogen is consumed in following services:

- storage tanks, for blanketing
- drain drums, for blanketing.

Estimated demand of nitrogen for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
Average demand at CCP design plant capacity	Nm^3/h	3.0
CCP demand per year (at 5,000 full load operating hours per year)	$kNm^3/year$	15.1

4.5.9 Instrument Air

Instrument air is consumed in following services:

- CO2 Compression and Amine Reclaimer Unit
- other instruments and control valves.

Estimated demand of instrument air for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
Average demand at CCP design plant capacity	Nm^3/h	430
CCP demand per year (at 5,000 full load operating hours per year)	$kNm^3/year$	2,150

4.5.10 Amine Solution

GE Power's AAP technology uses UCARSOL™ FGC-3000 as the solvent, a proprietary advanced amine solvent supplied by DOW, the largest supplier of specialty chemicals in the world.

Amine solution is lost from the process mainly in two ways:

- in the flue gas leaving the CO2 Absorber
- in the waste water stream from the Amine Reclaimer.

The advanced amine solvent will be transported to site by tank truck and fed to the Amine Tank in concentrated form with low water content. It will be fed into the unit in its concentrated form, in case the amine concentration in the loop is decreasing. There will be a separate water make-up stream to the amine circulation loop, in case the amine concentration becomes too high.

Concentration of the amine solvent solution that will be stored in the CCP

Two solvent supply tanks, one for the advanced amine solvent and one for additive make-up are considered for the proposed CCP design. The concentration intended to be supplied will be concentrates of higher concentration than used amine concentration (> 60 wt-% amine, balance water).

Estimated amine solvent demand (pure, 100 % concentration) for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
Amount of solvent (100 %) for initial fill	m^3	1,500

4.5.11 Sodium Hydroxide

Sodium hydroxide (NaOH) is used for two services in the AAP CCP:

- for amine reclamation process to neutralize the amine solution
- for SO2 removal in the Flue Gas Conditioning section to adjust the SO2/NO2 content contained in the incoming flue gas to the optimum level for the AAP optimum operation.

NaOH will be delivered to site by tank truck already in the correct dilution and fed to the Caustic Storage Tank in the storage tank area.

Estimated demand of NaOH (based on NaOH concentration of 30 wt-%) for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
Average demand at CCP design plant capacity	t/h	0.28
CCP demand per year (at 5,000 full load operating hours per year)	t/year	1,400

Demands to be confirmed with Reclaimer package unit vendor. Consumption can be reduced, if the AQCS plant section can be modified for a higher SOX removal.

4.5.12 Antifoam

In order to effectively control potential occurrence of foaming in the amine solution cycles, the AAP is designed with provisions for antifoam injection in various areas of the system. The AAP technology uses a specific recommended antifoam chemical. The antifoam agent is supplied to site in liquid form already in the right concentration in special storage totes that will be situated in the storage tank area. Spare totes can be stored indoors in a suitable warehouse storage area and delivered to the storage tank area as required.

Estimated demand of antifoam for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
CCP demand per year (at 5,000 full load operating hours per year)	t/year	7.0

Note, the demand per full load operating hour is normally no flow, only discontinuous supply in case of potential occurrence of foaming in the amine solution cycles. The maximum peak demand is trace amounts to the system.

4.5.13 Activated Carbon

In order to keep the solution loops free from particles and traces of organic chemicals and degradation products, the AAP is equipped with an effective filtering system, consisting of an activated carbon filter followed by a mechanical filter. The activated carbon inventory of the filter is expected to be exchanged against fresh activated carbon once per 1.5 years. The activated carbon is supplied to site in storage totes or big bags and filled into the activated carbon filter.

Estimated demand of activated carbon for the CCP of the CO2 capture study:

(subject to confirmation by detailed process design)

Description	Units	
CCP demand per year (at 5,000 full load operating hours per year)	m^3/year	100

Note, the demand per full load operating hour is none. However, the active carbon bed is to be changed on a regular schedule, depending on the flue gas impurity concentrations. The estimate is based on expected exchange against fresh activated carbon once per year.

4.5.14 Tri-Ethylene Glycol

Tri-Ethylene Glycol (TEG) is consumed in following service:

- CO2 Dehydration unit.

Estimated demand of TEG for the CCP of the CO2 capture study:

(preliminary, subject to confirmation by detailed process design)

Description	Units	
Average demand at CCP design plant capacity	kg/h	2.9
CCP demand per year (at 5,000 full load operating hours per year)	t/year	14.5

4.5.15 AAP Outlet Flue Gas Emissions

The CCP is designed to treat the flue gas outlet stream from the AQCS plant section of the host power plant for the design case (BMCR/VWO case) of **case 1**, and to remove at least 90 % of the entering CO2. The amine content in the flue gas after the capture plant is expected to be less than 1 ppmv. The flue gas discharge temperature leaving the AAP is approximately 40 °C. The treated flue gas from the AAP plants are assumed to be returned to a tie-in in the duct from the AQCS plant section to the common stack.

The expected treated flue gas characteristics are given in following table. Since the function of the CCP is to capture CO2, the treated flue gas may also contain trace components which have entered the CCP with the inlet flue gas such as SOx, NOx, HCl, HF, NH3, PM. Some are dependent on the trace inorganic constituents of the coal which were not provided to EPRI for use in this study.

Description	**Units**	
AAP outlet flue gas volumetric flow (wet, norm) at CCP design plant capacity	kNm^3/h	663,890
AAP outlet flue gas mass flow (wet) at CCP design plant capacity	t/h	822.1
AAP outlet CO2 mass flow	t/h	21.5
Flue gas temperature	°C	~ 40
Flue gas pressure	bar(g)	atmospheric
Composition (wet)		
H2O	vol-%, wet	6.96
CO2	vol-%, wet	1.65
N2 (including Ar)	vol-%, wet	86.98
O2	vol-%, wet	4.41
Amine	ppmv, wet	< 1
Amine Degradation products	ppmv, wet	traces

4.5.16 Flue Gas Condensate

The Flue Gas Conditioning section of the CCP will generate two product streams:

- a flue gas condensate stream
- a spent caustic stream.

The flue gas condensate stream is the flue gas condensate stream due to flue gas moisture condensation when the temperature of the flue gas is cooled down in the top section of the flue gas conditioning column. The accumulated condensate contains predominantly water with a trace amount of dissolved gases (like N2, O2, CO2) which are part of the incoming flue gas and get dissolved in the condensate. This Flue gas condensate is sent to the CCP battery limit for further handling and reuse in the host power plant.

The expected flue gas condensate stream characteristics are provided as follows:

Description	Units	
Flue gas condensate mass flow at CCP design plant capacity	t/h	62.0
Temperature	°C	< 50
Pressure	bar(abs)	5.0

4.5.17 Spent Caustic

The Flue Gas Conditioning section of the CCP will generate two product streams:

- a flue gas condensate stream
- a spent caustic stream.

The spent caustic stream is an aqueous spent caustic stream from caustic scrubbing of the flue gas in the bottom section of the flue gas conditioning column. This stream contains predominantly water with a trace amount of dissolved gases (like N2, O2, CO2) as well as some dissolved sodium salts which are formed during caustic wash of the acid gases (mostly SO2, NO2) from the incoming flue gas. This spent caustic is sent to the CCP battery limit for further handling and reuse in the host plant.

The expected spent caustic stream characteristics are provided as follows:

Description	Units	
Spent caustic mass flow at CCP design plant capacity	t/h	~ 0.19
Temperature	°C	< 50
Pressure	bar(abs)	5.0

4.5.18 Other Liquid Effluents

Other liquid waste water streams of the CCP are:

- CO2 Dehydration unit effluent
- ED Reclaimer effluent (ED Reclaimer brine)
- backwash water from Amine Pre-Filter
- blow down water from Amine Regenerator Water Wash section
- amine purge.

Some of these waste waters are expected not to be a continuous effluent over the complete operating time, but are provisional streams foreseen for maintaining plant operability/ performance and/or for solvent management as needed, e.g. expected to be required under certain operating conditions only. The continuous and discontinuous waste water streams are estimated to be approximately between 1.5 m^3/h (continuous) and 5.5 m^3/h (discontinuous) for the CCP. The waste water streams can be sent to a Waste Water Treatment unit of the host power plant and which is not in the scope of the CCP for further handling and reuse in the host power plant. Those streams containing major amounts of solvent related components may be sent to a first treatment step for separation of the waste water into a treated water and a more concentrated waste stream containing most of the solvent related components, e.g. concentrate from Reclaimer brine or amine purge. This concentrated waste stream can then be collected and sent to chemical disposal or may potentially be co-combusted in a boiler. The treated water stream may be recycled back to the CCP plant and thereby replace make-up process water.

Further typical plant waste waters like rain sewage, sanitary sewage and fire-fighting sewage are expected.

4.5.19 Solid Wastes

Two main solid waste streams are generated in the CCP, both resulting from amine filtration. The insoluble contaminants can usually be removed by mechanical filtration. Soluble contaminants that are surface-active can be removed to a certain extent by activated carbon filtration. This results in following waste streams:

- spent (loaded) Activated Carbon Bed.
- potentially filter cake from the Pre-Filter if further

4.6 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.

Other areas that are still being developed are part of ongoing efforts with the DOE Fossil Energy Group as well as GE R&D efforts for both the Boiler and Turbine. As of today this timeframe also supports the commercialization of the proposed concept by 2030.

5 Cost Results

5.1 Concept Background

5.1.1 Coal-fired Power Plant Scope Description

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, 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 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 NOx firing system, selective catalytic reduction (SCR) system for NOx control, dry scrubber/fabric filter for particulate matter (PM)/SO2/Hg/HCl control; an amine-based post combustion carbon capture system; and a synchronous steam turbine/generator. A block diagram of the overall plant (Concept 1) is shown in Figure 5-1-1. 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.

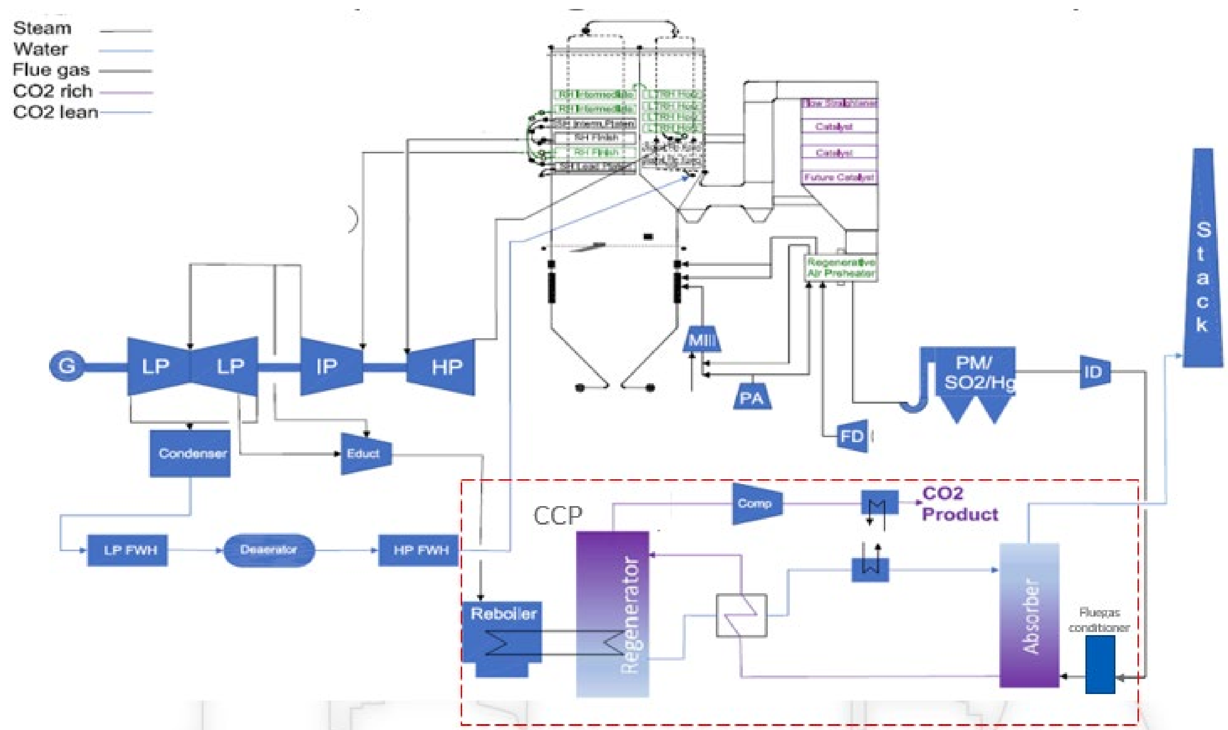


Figure 5-1-1 Concept 1 Block Diagram

5.1.2 Plant Capacity

The AUSC coal plant steam cycle has a gross generation capacity of 300 MW at TMCR (309MW at VWO) in Concept 1 without the process stream extraction to the CCP. Because of the auxiliary load requirements and process steam extractions, the AUSC coal plant has a gross/net generation capacity of 278MW/227MW at VWO load.

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. A smaller AUSC turbine island 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.

Overall generation capacities of the integrated Concept 1 power plants are 278 MW gross / 227 MW net.

5.1.3 Plant Location

The plant location is a 300 acre greenfield site in the Midwestern U.S. with level topography. Coal is supplied by rail or truck delivery, and natural gas is supplied by pipeline. Fly ash and bottom ash disposal is off-site. Plant water needs are assumed to be 50% from municipal water supply and 50% from ground water.

5.1.3.1 Estimated Cost of Electricity of Concept 1

The cost of electricity for Concept 1 was estimated using the methodology outlined in the DOE/NETL report titled "Quality Guidelines for Energy System Studies - Cost Estimation Methodology for NETL Assessments of Power Plant Performance, September 2019". The cost of electricity for Concept 1 was compared to earlier DOE/NETL Low Rank Baseline cases both without and with CO_2 capture. These cases included supercritical PC with post-combustion CO_2 capture (Case S12B) and atmospheric oxy-combustion (Case S12F). The costs for these Low Rank Baseline cases were escalated to bring them up to 2020 dollars. The cost of \$2.23/MMBtu for PRB coal delivered to the mid-west plant site was taken from the DOE/NETL report titled "Quality Guidelines for Energy System Studies - Fuel Prices for Selected Feedstocks in NETL Studies, January 2019". Table 5-1 summarized the costs of electricity for all cases.

Table 5-1 Cost of Electricity Comparisons

Case	S12A SCPC	S12B SCPC w/CCS	S12F Atm Oxy	B12A SCPC	B12B SCPC w/CCS	AUSC PC	Concept 1
Capital	32.2	56.7	54.4	28.3	51.0	34.4	66.0
FOM	11.3	18.6	17.7	9.5	16.1	12.9	23.6
VOM	7.0	12.8	10.6	7.7	14.0	7.9	14.8
Fuel	19.7	28.2	24.6	18.9	24.2	17.6	22.1
CO_2 Transport & Storage		11.1	9.6		8.9		8.7
Cost of Electricity, \$/MWh	70.2	127.3	116.9	64.4	114.1	72.8	135.2

It is important to note that the plant sizes for the DOE/NETL Low Rank Coal Baseline cases are 550 MW net, while the net power outputs of the AUSC PC and Concept 1 are 284 and 227 MW net, respectively

Figure 5-1-2 compares the components of the cost of electricity for the above cases.

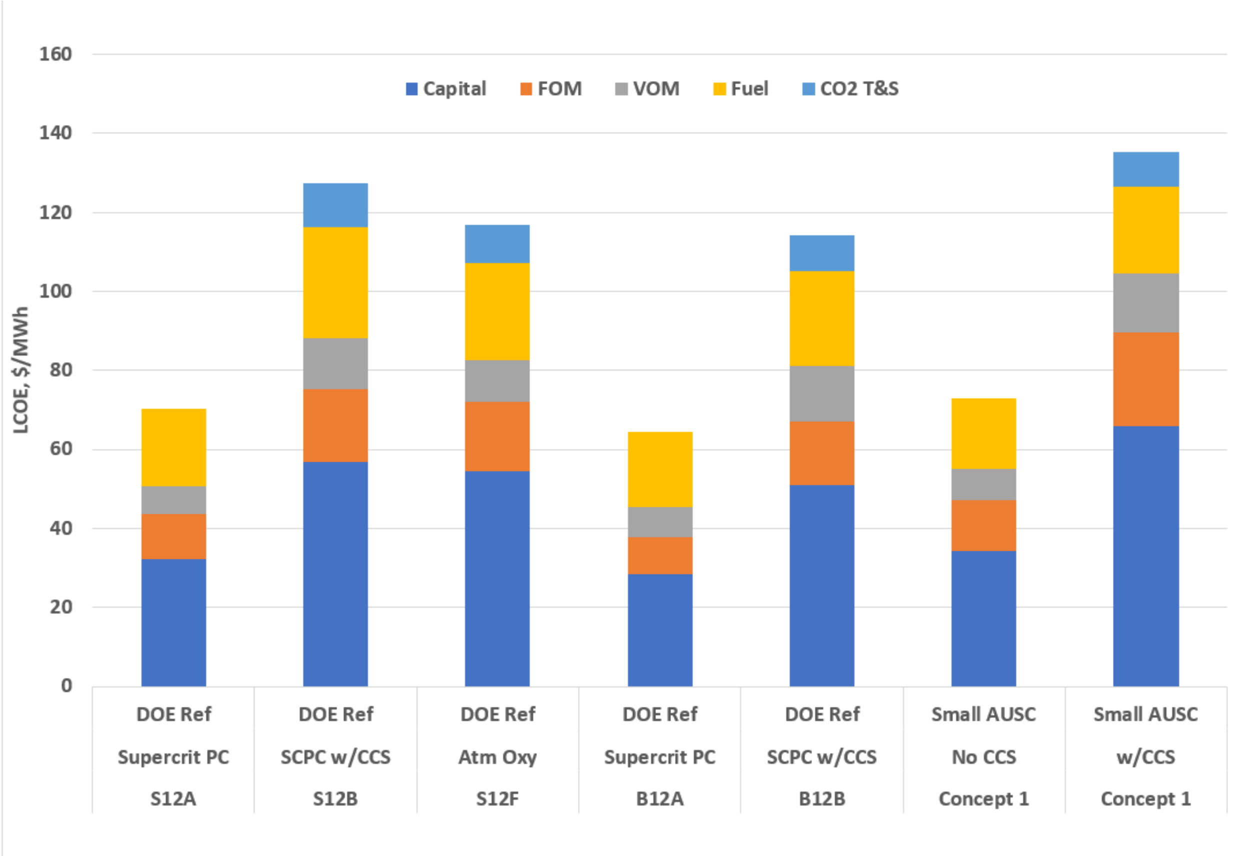


Figure 5-1-2 Cost of Electricity Comparisons

The capital costs used in the cost of electricity comparison were calculated based upon DOE-NETL methods, as summarized in Table 5-2.

Table 5-2 Capital Calculation for Cost of Electricity

	Small AUSC Concept 1 No CCS	Small AUSC Concept 1 w/CCS	Comments
Total Plant Cost (TPC) , $/kW	2,551	4,896	
TOC/TPC Ratio	1.23	1.23	Average TOC/TPC ratio from cases B12A and B12B from Reference 1
Total Overnight Cost (TOC) , $/kW	3,138	6,022	Equals TPC x TOC/TPC Ratio
TASC/TOC Ratio	1.154	1.154	From Exhibit 3-7 in Reference 2
Total As Spent Capital Cost (TASC), $/kW	3,621	6,949	Equals TOC x TASC/TOC ratio
Fixed Charge Rate (FCR) (applied to TASC)	0.0707	0.0707	From Exhibit 3-5 in Reference 2
Capacity Factor (CF)	85%	85%	Same as Baseline Cases in Reference 1
Capital Component of COE, $/MWh	**34.4**	**66.0**	Equals (TASC x FCR) / (8760 hr/yr x CF) x 1000kW/MW

Reference 1. *Cost and performance baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity*, Sept 24, 2019, NETL-PUB-22638

Reference 2. *Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance*, Sept 6, 2019

The sensitivity of cost of electricity based upon carbon credit is shown in Table 5-3. The $35/ton CO_2 is based on the 45Q tax credit for EOR, while the $50/ton CO_2 is based on the 45Q credit for sequestration. Note that the amount of credit is less for Concept 2, which includes firing natural gas in the gas combustion turbines. This results in a lower amount of CO_2 being captured per net MWh.

Table 5-3 Sensitivity of Cost of Electricity Based Upon Carbon Credit

CO2 Credit, $/ton CO2	**-**	**35.00**	**50.00**	**-**	**35.00**	**50.00**
	Small AUSC Concept 1 No CCS	Small AUSC Concept 1 w/CCS	Small AUSC Concept 1 w/CCS	Small AUSC Concept 2 No CCS	Small AUSC Concept 2 w/CCS	Small AUSC Concept 2 w/CCS
Capital, $/MWh	34.4	66.0	66.0	35.4	63.8	63.8
FOM, $/MWh	12.9	23.6	23.6	13.3	22.8	22.8
VOM, $/MWh	7.9	14.8	14.8	8.1	13.2	13.2
Fuel Cost, $/MWh	17.6	22.1	22.1	17.7	31.4	31.4
CO2 T&S Cost, $/MWh	0.0	0.0	8.7	0.0	0.0	7.8
CO2 Credit,$/MWh	0.0	-33.5	-47.8	0.0	-30.2	-43.1
Cost of Electricity, $/MWh	**72.8**	**93.1**	**87.4**	**74.4**	**101.0**	**95.9**

5.2 Plant Description

5.2.1 Proposed Plant Concept for the Cost Study

Concept 1 for the "Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant" is a pulverized coal power plant with SH temperature/RH temperature/SH outlet pressure of 1202°F/1238°F/4800 psia (650°C/670°C/330 bar) steam conditions, with appropriate turbine steam extractions for carbon capture system process steam demand.

The power plant concepts being proposed provide enhanced cycling flexibility for an optimized operation regime for transient operation (i.e., faster start-up and load changes) and 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 competitive power markets. These plant concepts incorporate 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.

This section lists how the small-scale flexible AUSC coal power plant concept described in this Design Basis 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 1 achieves 33.8% net plant efficiency with integration of carbon capture, 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, with 90% carbon capture rate for both the AUSC coal boiler and the gas turbine/heat recovery boiler.

  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 for Concept 1 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% (60 MW gross for Concept 1) or lower. One western US utility has achieved 15-18% minimum load with use of a digital product Digital Boiler + that is under active development. similar steam conditions.
- 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, 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 these concepts.
- Capable of natural gas co-firing. This concept includes side horn gas ignitors for up to 10% natural gas cofiring of the AUSC coal boiler on a heat input basis.

The carbon capture plant (CCP) will have flexibility in terms of flue gas flow capacity (operating range) and with regards to different fuels for the AUSC coal power plant, as long as the flue gas CO_2 concentration to the CCP is close to the design case. The typical standard operating range for the CCP is approximately 50-60% of design capacity, while the best operating performance is typically at 100% capacity (at highest efficiency). Therefore, turndown is often combined with operation below the best efficiency point. Lower turndown operation (< 50 %) may require additional design features, such as:

- Specific recycle arrangements for compressor and pump systems
- Multiple parallel equipment arrangement (for one service), so that partial stream flow capacity can be turned off, while the remaining equipment remain in operation
- Disproportional turndown strategy for the core absorption/regeneration cycle (this means turndown of solvent circulation lower than capacity reduction of the flue gas feed to the CCP).

Thus, the required turndown for the host power plant with its full environmental compliance of 5:1, means an operational range for the CCP of 20% to design capacity is expected to be achievable.

The required start-up time for the host power plant from cold conditions is 4 hours and from warm conditions is 2 hours, respectively. The CCP design allows for transient operating flue gas flow changes, e.g. during start-up or shut-down of host power plant. Previous test runs at pilot-scale showed a fast response of the CCP design as proposed to change in load.

For the CCP a bypass for the flue gas feed to the stack is recommended, which allows to ramp up/down the host power plant at a different ramp rate or with different cold/warm start duration than the CCP. Also, the reduction of steam flow from the power plant to the CCP Regenerator Reboiler is an option to generate more electrical power during transient operations, with resulting reduced CO2 capture rate.

The proposed steam turbine 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.

A schematic of the water steam cycle for the AUSC steam turbine with no steam extractions is shown in Figure 5-2.

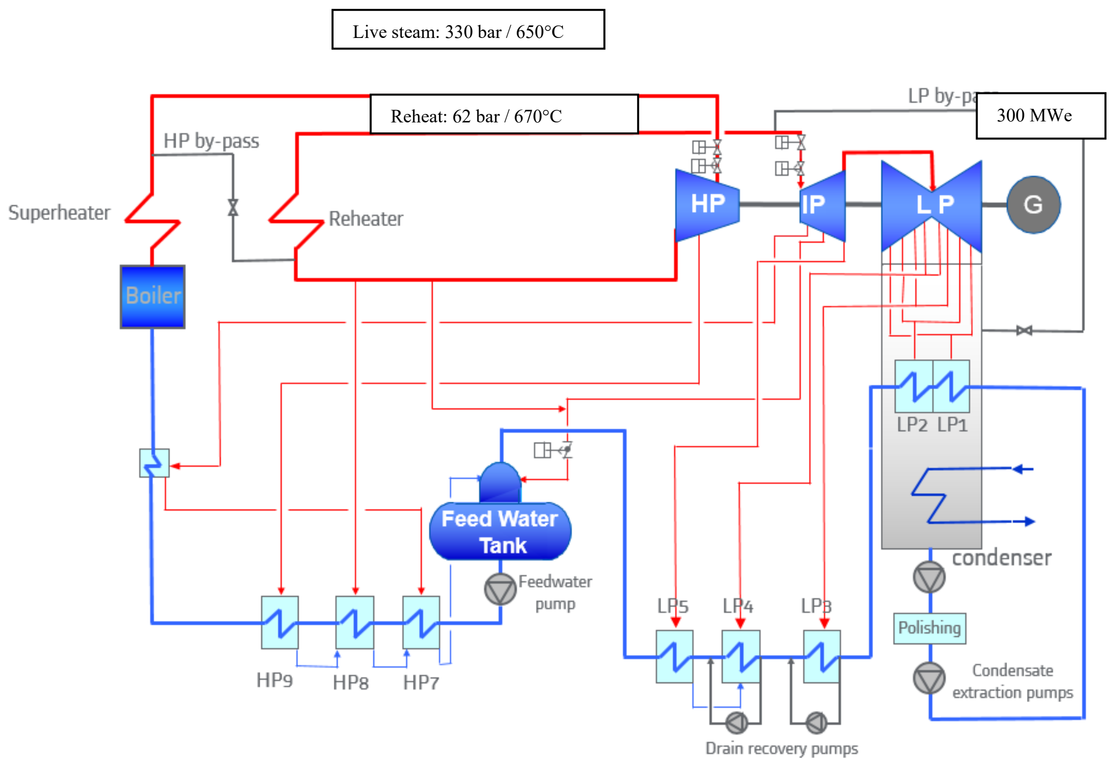
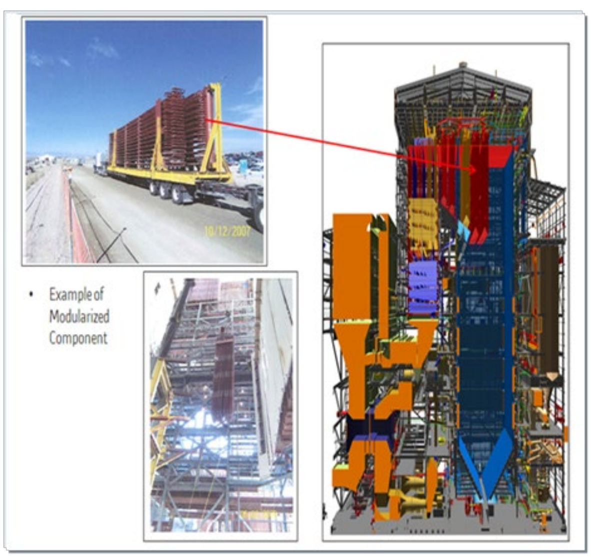


Figure 5-2 Water Steam Cycle Schematic



The boiler will use pressure part designs that are modularized, an example of which is shown in Figure 5-3. 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.

Figure 5-3 Example of Pressure Part Modularization

Ground modularization on site 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 5-3. 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.

Figure 5-4 Examples of Ground Modularization

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 5-5 and Figure 5-6)

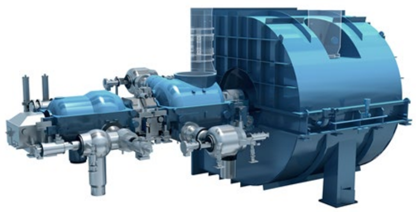


Figure 5-5 Steam Turbine Train (side exhaust option)

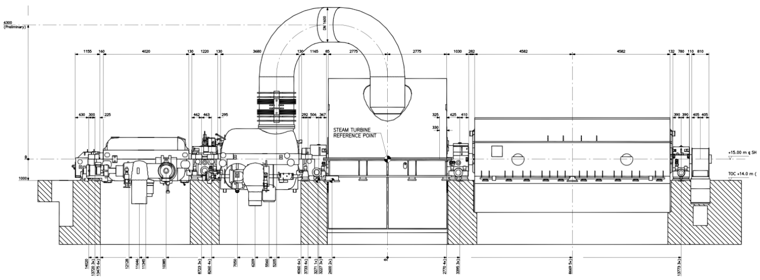


Figure 5-6 Steam Turbine Train Including Generator (downwards exhaust option)

Representative small USC HP and IP turbine modules are shown in Figure 5-7 and figure 5-8. These modules are shop assembled and transported to site as modular units.

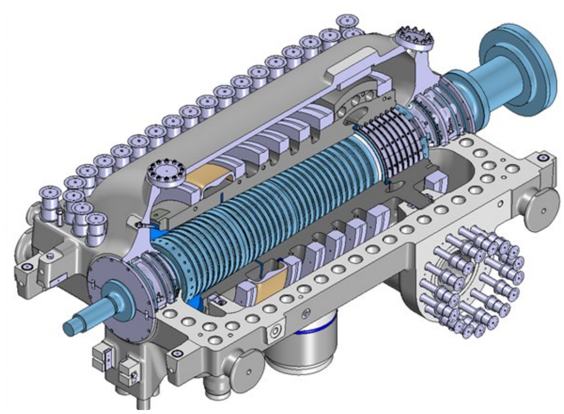


Figure 5-7 Small USC HP Turbine Module

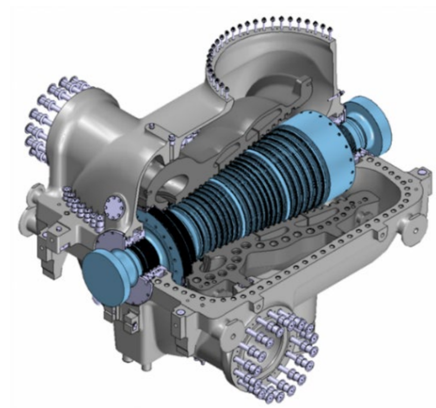


Figure 5-8 Small USC IP Turbine Module

A representative small USC LP turbine module is shown in Figure 5-9. These modules are shop assembled and transported to site as modular units.

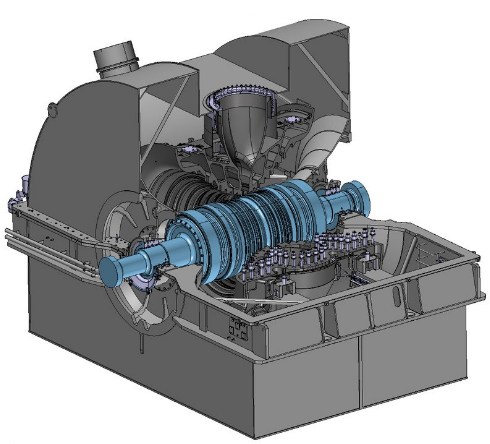
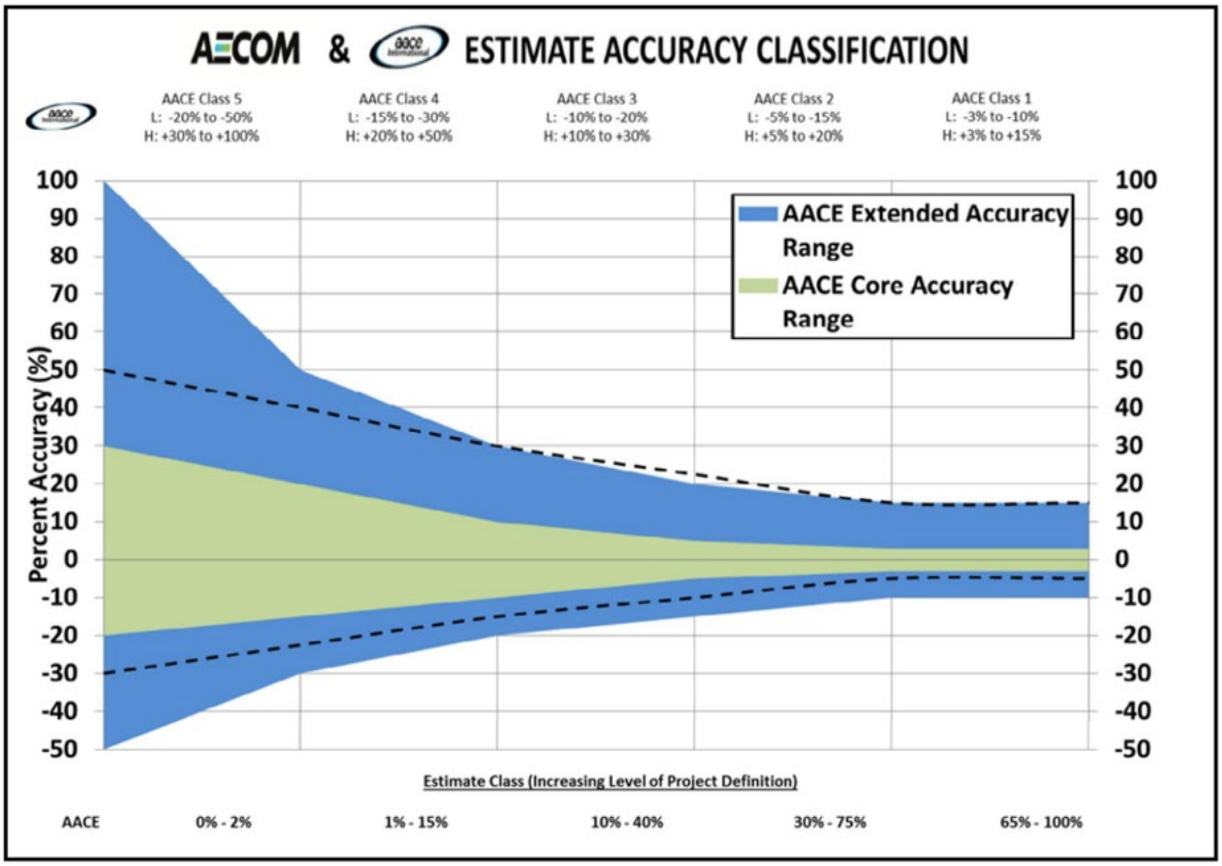


Figure 5-98 Representative LP Turbine Module (downwards exhaust option)

5.3 AECOM Cost Estimate for the EPC

5.3.1 Purpose

Electric Power Research Institute (EPRI) has requested AECOM to prepare Engineering, Procurement and Construction (EPC) cost estimates for concept power plants. One estimate would be for a 309 MW Advanced Ultra-Supercritical Coal-Fired (AUSC) Power Plant and the other estimate would be for a 278 MW AUSC power plant with Carbon Capture and Sequestration (CCS). The estimates will be developed as Class 4 estimates as defined by the Association for the Advancement of Cost Engineering (AACE) with an accuracy range of -15% to +30%, see AACE estimate accuracy graph below.



5.3.2 Basis

The Class 4 estimates includes Engineering, Procurement, Construction (EPC) plus scope and costs by others to represent an EPC Total Installed Cost (TIC) estimate through start-up and commissioning. The estimates are based on preliminary engineering deliverables.

The cost estimates have been prepared for the following cases:

1. Estimate for a 309 MW gross / 284 MW net Advanced Ultra-supercritical Coal-Fired (AUSC) Power Plant located midwestern United States.
2. Estimate for a 278 MW gross / 227 MW net Advanced Ultra-supercritical Coal-Fired (AUSC) Power Plant with Carbon Capture and Sequestration (CCS) located in midwestern United States.

The main sources used to develop the Class 4 estimates include the following:

1. Major equipment cost information provided by General Electric (GE),
2. Cost estimates for essential components required to support OEM equipment operation and other BOP equipment, based on AECOM power experience and relevant past projects,
3. Recently published data from the National Energy Technology Laboratory (NETL) and U.S. Energy Information Administration (EIA) were used for comparison purposes.
4. Recommended Practices from AACE organization,

AECOM similar power projects were used as the basis for the estimates.

The 309 and 278 MW gross plants estimated were from previous projects that were factored accordingly. In addition, the EIA published information was also used as a comparison to validate the numbers.

Capacity Factored estimating method was used as following the recommendations of the AACE International Recommended Practices. Pricing was then reviewed an adjusted to reflect data from previous AECOM power plant work. The summary estimates include pricing for equipment, material and labor.

The equipment and material differences used in the AUSC plant design were accounted for n the estimates. These included a Novel Integrated Desulfurization NID system for flue gas desulfurization and using higher grade piping materials required for the AUSC boilers.

The Summary Estimates included the information provided by GE for the Owner Furnished Equipment (OFE) costs.

The following information was provided by GE for the plant equipment cost.

1	Boiler and AQCS	$225,000,000
2	Turbine	$15,000,000
3	CCS	$254,000,000

Labor to install the GE equipment was included in the Class 4 estimates. GE's AQCS equipment included a Novel Integrated Desulfurization (NID) System (dry scrubber). Dry scrubbing eliminates the need for labor, equipment and materials for the following equipment; sorbent receiving, sorbent unloading, sorbent preparation, WFGD absorber vessel, gypsum dewatering and spray dryer evaporator.

5.3.3 Estimate Detail

An estimate breakout for direct construction labor, plant equipment, material, construction equipment, indirect construction labor, expenses, construction management, engineering, startup, insurance, G&A and Fee was developed based on AECOM previous similar power projects.

Total Project Cost

The total project cost includes the following

1. Total Installed Cost
    a. Direct Field Cost
    b. Indirect Field Cost
    c. Home Office Cost
2. Insurance
3. G&A
4. Fee

Each item is detailed below.

Direct Field Cost

The direct field cost portion of the estimate includes following cost breakdown for labor and materials.

1. Site Development
2. Concrete
3. Structures
4. BOP Equipment & OFE Equipment Labor
5. Piping
6. Electrical
7. Instrumentation and Controls
8. Buildings

Indirect Field Cost & Home Office

The indirect field cost portion of the estimate includes the following.

1. Field Indirect Labor and Materials (including Facilities)
2. Construction Equipment

Home Office Cost

The home office cost includes the following,

1. Construction Management Staff & Services
2. Engineering
3. Startup and Commissioning

Insurance

Insurance is primarily the AECOM domestic package for field work and home office work. AECOM construction labor rates include workers compensation rates.

G&A

A percentage of 5% was set as the G&A rate.

Fee

A percentage of 8% was set as the Fee rate.

Reference Documents and Resources:

The following documents and resources were used to develop the estimate summary and estimate detail.

1. U.S. Department of Energy, National Energy Technology Laboratory, “Cost and Performance for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity”, September 24, 2019
2. U.S. Department of Energy, National Energy Technology Laboratory, “Quality Guidelines for Energy System Studies, Capital Cost Scaling Methodology: Revision 4 Report”, October 2019
3. U.S. Department of Energy, National Energy Technology Laboratory, “Quality Guidelines for Energy Systems Studies Cost Estimation Methodology for NETL Assessments of Power Plant Performance”, September 6, 2019
4. U.S. Energy Information Administration, “Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies”, February 2020
5. AACE International, “Recommended Practice 58R-10, Escalation Estimating Principles and Methods Using Indices”, May 25, 2011
6. AACE International, “Recommended Practice 59R-10, Development of Factored Cost Estimates – As Applied in Engineering, Procurement, and Construction for the Process Industries”, June 18, 2011
7. U.S. Department of Labor, “Bureau of Labor Statistics, Consumer Price Index”, January 2020

Please note that the cost estimates provided herein are dependent upon the various underlying assumptions, inclusions, and exclusions utilized in developing them. Actual project costs will differ, and can be significantly affected by factors such as changes in the external environment, the manner in which the project is implemented, and other factors which impact the estimate basis or otherwise affect the project. Estimate accuracy ranges are only projections based upon cost estimating methods and are not a guarantee of actual project costs.

Estimate Detail

A further breakout for direct construction labor, material, construction equipment,

Expenses and Subcontracts was developed using the AACE International

Recommended Practices for Estimating. Each power plant type (AUSC and AUSC with CCS) was estimated separately which added two additional estimates to the Summary estimate which included both plants.

5.3.4 Civil / Structural / Architectural (C/S/A)

The C/S/A portion of the estimate was broken down using the AACE International Recommend Practices and AECOM's power industry experience. The cost of labor and materials for each of the following was developed.

1. Site Development
2. Concrete
3. Structures
4. Buildings
5. Painting

5.3.5 Mechanical

The Mechanical portion of the estimate was broken down using the information supplied by GE for OFE, AACE International Recommend Practices and AECOM's power industry experience. The cost of labor and materials for each of the following was developed.

1. Owner Furnished Equipment
   a. GE Boiler & AQCS equipment
   b. Turbine
   c. CCS
2. Balance of Plant (BOP) Mechanical
   a. BOP Equipment
   b. Piping
   c. Insulation

5.3.6 Electrical / Instrumentation & Controls (I&C)

The Electrical / I&C portion of the estimate was broken down using the AACE International Recommend Practices and AECOM's power industry experience. The cost of labor and materials for each of the following was developed.

1. Main Power System
2. Auxiliary Power System
3. BOP Electrical
4. Instrumentation
5. Substation & Switchyard

5.4 Project Indirect Cost

The Indirect Project Cost portion of the estimate was broken down using the AACE International Recommend Practices and AECOM's power industry experience. The breakout included the cost of labor, materials, construction equipment and expense. In this case the AECOM scope used a contingency of 15%. The GE Equipment used a contingency of 20%.

The project indirect costs include the following:

1. Craft Support Labor, Materials and Facilities
2. Construction Equipment
3. Consumables
4. Construction Management (Field Staff)
5. Home Office Engineering
6. Home Office Start-up Support and Training
7. Start-up Craft Labor Support
8. Miscellaneous Expenses (i.e. Insurance, Warranty, Taxes, etc.)

CLIENT:	Electric Power Resource Institute (EPRI)	DATE:	15-Apr-20
PROJECT:	AUSC - 309 MW gross / 284 MW net	PREPARED BY:	CY
LOCATION:	Midwestern United States	FIELD L FAC:	
JOB NO.:		FIELD L RATE:	
REV NO.:	15		

TOTAL PROJECT

ACCT	DESCRIPTION	KEY QUANTITIES (AECOM)	FIELD WORKHOURS (AECOM)	FIELD LABOR (AECOM)	MATERIAL (AECOM)	SUBCONTRACTS SUB HOURS	SUBCONTRACTS SUB COST	TOTAL BASE BID
03	SITE DEVELOPMENT		-	$ 10,785,183	$ 3,710,548	-	$ -	$ 14,495,731
04	CONCRETE	-	-	$ 2,086,668	$ 1,521,140	-	$ -	$ 3,607,808
05	STRUCTURES	-	-	$ 13,216,686	$ 13,273,283	-	$ -	$ 26,489,969
06	EQUIPMENT & BOP PIPING (OFE EQUIP BY GE BELOW)		-	$ 113,319,508	$ 62,680,295	-	$ -	$ 175,999,803
11	STEAM PIPING			$ 7,530,111	$ 18,577,751		$ -	$ 26,107,862
12	ELECTRICAL		-	$ 7,209,440	$ 14,735,745	-	$ -	$ 21,945,186
13	INSTRUMENTATION		-	$ 3,657,511	$ 8,471,931	-	$ -	$ 12,129,442
14	PAINTING (INCLUDED WITH BOP)		-	$ -	$ -	-	$ -	$ -
15	INSULATION (INCLUDED WITH BOP)		-	$ -	$ -	-	$ -	$ -
16	BUILDINGS		-	$ 1,524,399	$ 1,603,175	-	$ -	$ 3,127,573
	DIRECT FIELD COST		-	**$ 159,329,505**	**$ 124,573,867**	-	**$ -**	**$ 283,903,372**
31	SUPPORT STAFF AND SERVICES		-	$ -	$ -	-	$ -	$ -
32	CONST SUPPLIES / CONSUMABLES		-	$ -	$ -	-	$ -	$ -
33	TEMPORARY FACILITIES		-	$ -	$ -	-	$ -	$ -
33	FIELD OFFICE EXPENSES		-	$ -	$ -	-	$ -	$ -
	FIELD INDIRECT LABOR & EXPENSES (INCL FACILITES)		-	$ 28,390,337	$ -	-	$ -	$ 28,390,337
41	CONSTRUCTION EQUIPMENT (INCLUDES FUEL)		-	$ -	$ 11,356,135	-	$ -	$ 11,356,135
22	HEAVY HAUL/LIFT		-	$ -	$ -	-	$ -	$ -
42	SMALL TOOLS AND COMSUMABLES		-	$ -	$ -	-	$ -	$ -
	CASUAL OVERTIME		-	$ -	$ -	-	$ -	$ -
50	VENDOR STARTUP ASSISTANCE (Include w/ Equip Supply)		-	$ -	$ -	-	$ -	$ -
51	CRAFT SUPPORT - COMMISSIONING		-	$ -	$ -	-	$ -	$ -
21	COMMISSIONING SPARES		-	$ -	$ -	-	$ -	$ -
21	FIRST FILLS AND CHEMICALS		-	$ -	$ -	-	$ -	$ -
	INDIRECT FIELD COST		-	**$ 28,390,337**	**$ 11,356,135**	-	**$ -**	**$ 39,746,472**
	TOTAL FIELD COST		-	**$ 187,719,842**	**$ 135,930,002**	-	**$ -**	**$ 323,649,844**
31A	CONST. MANAGEMENT STAFF & SERVICES			$ 19,873,236				$ 19,873,236
61	HOME OFFICE SERVICES			$ 22,712,270				$ 22,712,270
	START UP AND COMMISSIONING SERVICES			$ 4,258,551				$ 4,258,551
	TOTAL FIELD AND HOME OFFICE	-	-	**$ 234,563,898**	**$ 135,930,002**	-	**$ -**	**$ 370,493,900**
71	BONDING/BAR (INCLUDED BELOW)							$ -
71	AUTO INSURANCE, TAXES, BONDS, WARRANTY				$ -			$ -
	Total Other Cost			**$ -**	**$ -**	-	**$ -**	**$ -**
94	ESCALATION			$ -				$ -
	Total Escalated Cost			**$ 234,563,898**	**$ 135,930,002**	-	**$ -**	**$ 370,493,900**
92	CONTINGENCY			$ 35,184,585	$ 20,389,500		$ -	**$ 55,574,085**
	TOTAL INSTALLED COST		-	**$ 269,748,483**	**$ 156,319,503**	-	**$ -**	**$ 426,067,985**
99	G&A	5.00%		$ 13,487,424	$ 7,815,975		$ -	$ 18,524,695
	SUBTOTAL			**$ 283,235,907**	**$ 164,135,478**	-	**$ -**	**$ 447,371,385**
	FEE	8.00%		$ 22,658,873	$ 13,130,838		$ -	$ 35,789,711
	SUBTOTAL			**$ 305,894,779**	**$ 177,266,316**	-	**$ -**	**$ 483,161,095**
71	INSURANCE						$ 1,196,943	$ 1,196,943
	GRAND TOTAL			**$ 305,894,779**	**$ 177,266,316**		**$ 1,196,943**	**$ 484,358,038**
	GE BOILER & AQCS SUPPLY				$ 225,000,000			$ 225,000,000
	GE TURBINE SUPPLY				$ 15,000,000			$ 15,000,000
	TOTAL PROJECT COST		-	**$ 305,894,779**	**$ 417,266,316**	-	**$ 1,196,943**	**$ 724,358,000**

CLIENT:	Electric Power Resource Institute (EPRI)	DATE:	15-Apr-20
PROJECT:	AUSC with CCS - 278 MW gross / 227 MW net	PREPARED BY:	CY
LOCATION:	Midwestern United States	FIELD L FAC:	
JOB NO.:		FIELD L RATE:	
REV NO.:	15		

AECOM

TOTAL PROJECT

ACCT	DESCRIPTION	KEY QUANTITIES	FIELD WORKHOURS	FIELD LABOR (AECOM)	MATERIAL (AECOM)	SUBCONTRACTS SUB HOURS	SUBCONTRACTS SUB COST	TOTAL BASE BID
03	SITE DEVELOPMENT		-	$ 11,164,529	$ 3,842,036	-	$ -	$ 15,006,565
04	CONCRETE	-	-	$ 1,869,930	$ 1,424,388	-	$ -	$ 3,294,318
05	STRUCTURES	-	-	$ 11,005,477	$ 10,851,732	-	$ -	$ 21,857,210
06	EQUIPMENT & BOP PIPING (OFE EQUIP BY GE BELOW)		-	$ 194,979,491	$ 66,768,958	-	$ -	$ 261,748,448
11	STEAM PIPING			$ 7,452,050	$ 18,386,752		$ -	$ 25,838,802
12	ELECTRICAL		-	$ 9,638,168	$ 18,670,587	-	$ -	$ 28,308,756
13	INSTRUMENTATION		-	$ 3,956,833	$ 9,160,145	-	$ -	$ 13,116,978
15	INSULATION		-	$ -	$ -	-	$ -	$ -
16	BUILDINGS		-	$ 1,403,361	$ 1,467,546	-	$ -	$ 2,870,906
	DIRECT FIELD COST		-	**$ 241,469,839**	**$ 130,572,144**	-	**$ -**	**$ 372,041,983**
31	SUPPORT STAFF AND SERVICES		-	$ -	$ -	-	$ -	$ -
32	CONST SUPPLIES / CONSUMABLES		-	$ -	$ -	-	$ -	$ -
33	TEMPORARY FACILITIES		-	$ -	$ -	-	$ -	$ -
33	FIELD OFFICE EXPENSES		-	$ -	$ -	-	$ -	$ -
	FIELD INDIRECT LABOR & EXPENSES (INCL FACILITES)		-	$ 29,391,317	$ -	-	$ -	$ 29,391,317
41	CONSTRUCTION EQUIPMENT (INCLUDES FUEL)		-	$ -	$ 11,719,322	-	$ -	$ 11,719,322
22	HEAVY HAUL/LIFT		-	$ -	$ -	-	$ -	$ -
42	SMALL TOOLS AND COMSUMABLES		-	$ -	$ -	-	$ -	$ -
	CASUAL OVERTIME		-	$ -	$ -	-	$ -	$ -
50	VENDOR STARTUP ASSISTANCE (Include w/ Equip Supply)		-	$ -	$ -	-	$ -	$ -
51	CRAFT SUPPORT - COMMISSIONING		-	$ -	$ -	-	$ -	$ -
21	COMMISSIONING SPARES		-	$ -	$ -	-	$ -	$ -
21	FIRST FILLS AND CHEMICALS		-	$ -	$ -	-	$ -	$ -
	INDIRECT FIELD COST		-	**$ 29,391,317**	**$ 11,719,322**	-	**$ -**	**$ 41,110,639**
	TOTAL FIELD COST		-	**$ 270,861,156**	**$ 142,291,467**	-	**$ -**	**$ 413,152,622**
31A	CONST. MANAGEMENT STAFF & SERVICES			$ 20,648,330				$ 20,648,330
61	HOME OFFICE SERVICES			$ 24,182,729				$ 24,182,729
	START UP AND COMMISSIONING SERVICES			$ 4,464,504				$ 4,464,504
	TOTAL FIELD AND HOME OFFICE	-	-	**$ 320,156,718**	**$ 142,291,467**	-	**$ -**	**$ 462,448,185**
71	BONDING/BAR (INCLUDED BELOW)							$ -
71	AUTO INSURANCE, TAXES, BONDS, WARRANTY				$ -			$ -
	Total Other Cost			**$ -**	**$ -**	-	**$ -**	**$ -**
94	ESCALATION			$ -				$ -
	Total Escalated Cost			**$ 320,156,718**	**$ 142,291,467**	-	**$ -**	**$ 462,448,185**
92	CONTINGENCY			$ 55,803,316	$ 24,801,403		$ -	**$ 80,604,719**
	TOTAL INSTALLED COST		-	**$ 375,960,034**	**$ 167,092,869**	-	**$ -**	**$ 543,052,904**
99	G&A	5.00%		$ 18,798,002	$ 8,354,643		$ -	$ 27,152,645
	SUBTOTAL			**$ 394,758,036**	**$ 175,447,513**	-	**$ -**	**$ 570,205,549**
	FEE	8.00%		$ 31,580,643	$ 14,035,801		$ -	$ 45,616,444
	SUBTOTAL			**$ 426,338,679**	**$ 189,483,314**	-	**$ -**	**$ 615,821,993**
71	INSURANCE						$ 1,485,921	$ 1,485,921
	GRAND TOTAL			**$ 426,338,679**	**$ 189,483,314**		**$ 1,485,921**	**$ 617,307,914**
	GE BOILER & AQCS SUPPLY				$ 225,000,000			$ 225,000,000
	GE TURBINE SUPPLY				$ 15,000,000			$ 15,000,000
	GE CCS				$ 254,000,000			$ 254,000,000
	TOTAL PROJECT COST		-	**$ 426,338,679**	**$ 683,483,314**	-	**$ 1,485,921**	**$ 1,111,308,000**

5.4.1 O&M Costs description : AECOM

The O&M cost estimates have been prepared for the following cases:

1. Estimate for a 309 MW gross / 284 MW net Advanced Ultra-supercritical Coal-Fired (AUSC) Power Plant located midwestern United States.
2. Estimate for a 278 MW gross / 227 MW net Advanced Ultra-supercritical Coal-Fired (AUSC) Power Plant with Carbon Capture and Sequestration (CCS) located in midwestern United States.

The O&M cost estimates used the NETL O&M cost estimating methodology as a template. Each O&M cost estimate is made up of Fixed Operating Cost and Variable Operating Cost.

The Fixed Costs include:

1. Annual Operating Labor
2. Maintenance Labor
3. Administration & Support Labor
4. Property Taxes & Insurance

The annual operating labor costs for the AUSC and AUSC with CCS O&M estimates were just slightly less than those of the concept plants. The smaller size power plant still need about the same amount of operations personnel to operate the plant. The annual operating labor rate used was the base rate ($/hour) plus a 30% burden.

The maintenance labor costs for the AUSC and AUSC with CCS O&M estimates were based on the maintenance material costs which were assumed to be 1% of the cost of the plant. The maintenance labor then would be calculated as a 40/60 split for labor/materials.

The administrative and support labor was calculated as 25% of the operating labor cost.

The property taxes and insurance was assumed to be 2% of the cost of the plant.

The Variable Cost include:

1. Maintenance Materials
2. Consumables
3. Waste Disposal Cost

The Variable Operating Cost Consumables include a breakdown for the following:

1. Water
2. Makeup and Waste Water Treatment
3. Brominated Activated Carbon

4. Enhanced Hydrated Lime
5. Ammonia
6. SCR Catalyst
7. CO_2 Capture System Chemicals (CCS only)
8. Triethylene Glycol (CCS only)

The Variable Operating Cost Waste Disposal includes a breakdown for the following;

1. Fly Ash
2. Bottom Ash
3. SCR Catalyst
4. Triethylene Glycol (CCS only)
5. Thermal Reclaimer Unit Waste (CCS only)
6. Prescrubber Blowdown Waste (CCS only)

The variable cost consumables and waste disposal costs were calculated based on usage as dictated by the size of the plant in MW. The water, makeup water and water treatment efficiencies of an AUSC plant were taken into account.

5.5 Class 4 Estimates Documents O&M Estimate

AECOM

EPRI Coal FIRST Project Class 4 Estimate

Operations and Maintenance Case 1 Cost Estimate

Rev: 9
Date: 4/15/2020
Est: CY

Description	EPRI Class 4 - AUSC PC wo CCS 309/284 MW (2020$)		EPRI Class 4 - AUSC PC w CCS 278/227 MW (2020$)	
	Total	($/kW-net)	Total	($/kW-net)
Fixed Operating Cost				
Annual Operating Labor	$ 5,402,258	$ 19.022	$ 6,752,822	$ 29.748
Maintenance Labor	$ 4,829,054	$ 17.004	$ 7,408,757	$ 32.638
Administrative & Support Labor	$ 2,557,828	$ 9.006	$ 3,540,395	$ 15.596
Property Taxes and Insurance	$ 14,487,160	$ 51.011	$ 22,226,160	$ 97.913
Total Fixed Operating Cost	**$ 27,276,299**	**$ 96.043**	**$ 39,928,134**	**$ 175.895**
	Total $	($/MWh-net)	Total $	($/MWh-net)
Varialble Operating Cost				
Maintenance Materials	$ 7,243,580	$ 3.42540	$ 11,113,080	$ 6.57485
Consumables				
Water	$ 1,161,344	$ 0.54919	$ 1,442,059	$ 0.85317
Makeup and Waste Water Treatment Chemicals	$ 1,002,597	$ 0.47412	$ 1,245,997	$ 0.73717
Brominated Activated Carbon	$ 280,508	$ 0.13265	$ 280,508	$ 0.16596
Enhanced Hydrated Lime	$ 1,076,047	$ 0.50885	$ 1,076,047	$ 0.63662
Ammonia	$ 2,237,454	$ 1.05807	$ 2,237,454	$ 1.32375
SCR Catalyst	$ 267,287	$ 0.12640	$ 267,287	$ 0.15814
CO_2 Capture System Chemicals	$ -	$ -	$ 3,304,995	$ 1.95534
Triethylene Gycol	$ -	$ -	$ 422,171	$ 0.24977
Waste Disposal				
Fly Ash	$ 2,807,024	$ 1.32741	$ 2,807,024	$ 1.66072
Bottom Ash	$ 623,542	$ 0.29487	$ 623,542	$ 0.36891
SCR Catalyst	$ 4,471	$ 0.00211	$ 4,471	$ 0.00264
Triethylene Gycol	$ -	$ -	$ 21,729	$ 0.01286
Thermal Reclaimer Unit Waste	$ -	$ -	$ 15,222	$ 0.00901
Prescrubber Blowdown Waste	$ -	$ -	$ 225,945	$ 0.13368
Total Variable Operating Cost	**$ 16,703,855**	**$ 7.89906**	**$ 25,087,532**	**$ 14.84257**
Fuel Cost				
Coal Illinois No. 6 @ $53.35/ton	$ 39,899,177	$ 18.87	$ 38,967,703	$ 23.05
Total Var O&M incl fuel	$ 56,603,032	$ 26.77	$ 38,967,703	$ 37.90

AECOM
AUSC without CCS
Initial & Annual Operating and Maintenance Costs

Rev 9
Date: 4/15/2020
Est: C.Yost

Advanced Ultra-Supercritical Pulverized Coal-Fired Power Plant without Carbon Capture & Sequestration (AUSC PC wo CCS)

MW net	284	MW
MW gross	309	MW
Capacity Factor (%)	85%	
Plant Cost	$724,358,000	

Operating & Maintenance Cost

Operating Labor	**2020 $**			**Operating Labor Reqm't per Shift**
Operating Labor Rate	39.53	$/hour	Skilled Operator	2.0
Operating Labor Burden	30.00	% of base	Operator	7.0
Labor O-H Charge Rate	25.00	% of labor	Foreman	1.0
			Lab Techs, etc.	2.0
			Total	**12.0**

Fixed Operating Cost

Annual Operating Cost

			Annual Cost $	($/kW-net)
Annual Operating Labor			$ 5,402,258	$ 19.022
Maintenance Labor	% of Maint	40.00%	$ 4,829,054	$ 17.004
Administration & Support Labor	% of Op Labor	25.00%	$ 2,557,828	$ 9.006
Property Taxes and Insurance (2% of total Plant Cost)			$ 14,487,160	$ 51.011
			$ 27,276,299	**$ 96.043**

Variable Operating Costs

Maintenance Material			**Annual Cost $**	**$/MWh-net**
Maintenance Material (1% of Plant Cost)	% of Maint	60.00%	$ 7,243,580	$ 3.42540
Subtotal			**$ 7,243,580**	**$ 3.42540**

Consumables	**UOM**	**Initial Fill**	**Per Day**	**1/2020 $ Unit Cost**	**Initial Fill**	**Annual Cost**	**$/MWh-net**
Water	1000 gals	-	1,918.71	$ 1.95	$ -	$ 1,161,344	$ 0.54919
Makeup and Waste Water Treatment Cl	lbs	-	5.72	$ 564.74	$ -	$ 1,002,597	$ 0.47412
Brominated Activated Carbon	ton	-	0.55	$ 1,642.88	$ -	$ 280,508	$ 0.13265
Enhanced Hydrated Lime	ton	-	14.07	$ 246.43	$ -	$ 1,076,047	$ 0.50885
Ammonia	ton	-	23.41	$ 308.04	$ -	$ 2,237,454	$ 1.05807
SCR Catalyst	ft^3	6,926	5.59	$ 154.02	$ 1,066,776	$ 267,287	$ 0.12640
Subtotal					**$ 1,066,776**	**$ 6,025,239**	**$ 2.84927**
Waste Disposal							
Fly Ash	ton	-	231.88	$ 39.02	$ -	$ 2,807,024	$ 1.32741
Bottom Ash	ton	-	51.51	$ 39.02	$ -	$ 623,542	$ 0.29487
SCR Catalyst	ft^3	-	5.61	$ 2.57	$ -	$ 4,471	$ 0.00211
Subtotal					**$ -**	**$ 3,435,036**	**$ 1.62439**
By Products							
Gypsum	ton	-	423	$ -	$ -	$ -	$ -
Subtotal			423	$ -	$ -	$ -	$ -
Variable Operating Costs Total:					**$ 1,066,776**	**$ 16,703,855**	**$ 7.89906**

Fuel Cost

Illinois Number 6	ton	-	2,410	$ 53.35	0	$ 39,899,177	$ 18.86786
Fuel Cost Total						**$ 39,899,177**	**$ 18.86786**

AECOM

AUSC with CCS

Initial & Annual Operating and Maintenance Costs

Rev 9
Date: 4/15/2020
Est: C.Yost

Advanced Ultra-Supercritical Pulverized Coal-Fired Power Plant with Carbon Capture & Sequestration (AUSC PC w CCS)

MW net	227	MW
MW gross	278	MW
Plant Cost	$1,111,308,000	

Operating & Maintenance Cost

Operating Labor	2020 $			Operating Labor Reqm't per Shift	
Operating Labor Rate	39.53	$/hour		Skilled Operator	2.0
Operating Labor Burden	30.00	% of base		Operator	10.0
Labor O-H Charge Rate	25.00	% of labor		Foreman	1.0
			-	Lab Techs, etc.	2.0
				Total	**15.0**

Fixed Operating Cost

Annual Operating Cost

			Annual Cost ($)	($/kW-net)
Annual Operating Labor			$ 6,752,822	$ 29.748
Maintenance Labor	% of Maint	40.00%	$ 7,408,757	$ 32.638
Administration & Support Labor	Labor O-H Rate	25.00%	$ 3,540,395	$ 15.596
Property Taxes and Insurance (2% of Plant Cost)			$ 22,226,160	$ 97.913
Fixed Operating Costs Total			**$ 39,928,134**	**$ 175.895**

Variable Operating Costs

Maintenance Material		% of Maint Lal	($)	$/MWh-net
Maintenance Material (1% of Plant Cost)	% of Maint	60.00%	$ 11,113,080	$ 6.57485
Subtotal			**$ 11,113,080**	**$ 6.57485**

Consumables	UOM	Initial Fill	Per Day	Unit Cost	Initial Fill	Annual Cost	$/MWh-net
Water	1000 gals	-	2,382.49	$ 1.9509	$ -	$ 1,442,059	$ 0.85317
Makeup and Waste Water Treatment Cl	lbs	-	7.11	$ 564.7400	$ -	$ 1,245,997	$ 0.73717
Brominated Activated Carbon	ton	-	0.55	$ 1,642.8800	$ -	$ 280,508	$ 0.16596
Enhanced Hydrated Lime	ton	-	14.07	$ 246.4320	$ -	$ 1,076,047	$ 0.63662
Ammonia	ton	-	23.41	$ 308.0400	$ -	$ 2,237,454	$ 1.32375
SCR Catalyst	ft^3	5,694	5.59	$ 154.0200	$ 877,003	$ 267,287	$ 0.15814
CO_2 Capture System Chemicals	Proprietary					$ 3,304,995	$ 1.95534
Triethylene Glycol	gal	w/equip	194.89	$ 6.9822	$ -	$ 422,171	$ 0.24977
Subtotal					**$ 877,003**	**$ 10,276,519**	**$ 6.07991**
Waste Disposal							
Fly Ash	ton	-	231.88	$ 39.02	$ -	$ 2,807,024	$ 1.66072
Bottom Ash	ton	-	51.51	$ 39.02	$ -	$ 623,542	$ 0.36891
SCR Catalyst	ft^3	-	5.61	$ 2.57	$ -	$ 4,471	$ 0.00264
Triethylene Glycol	gal	-	194.89	$ 0.36	$ -	$ 21,729	$ 0.01286
Thermal Reclaimer Unit Waste	ton	-	1.26	$ 39.02	$ -	$ 15,222	$ 0.00901
Prescrubber Blowdown Waste	ton	-	18.66	$ 39.02	$ -	$ 225,945	$ 0.13368
Subtotal					**$ -**	**$ 3,697,932**	**$ 2.18781**
By Products							
Gypsum	ton	-	348.10	$ -	$ -	$ -	$ -
Subtotal			**348.10**	**$ -**	**$ -**	**$ -**	**$ -**
Variable Operating Costs Total:					**$ 877,003**	**$ 25,087,532**	**$ 14.84257**

Fuel Cost

Illinois Number 6	ton	-	2,354.17	$ 53.35	0	$ 38,967,703	$ 23.05451
Fuel Cost Total						**$ 38,967,703**	**$ 23.05451**

5.6 Cost Study Estimating Methodology for GE Equipment

The capital Cost Estimate is for a greenfield 300 MW Gross 209 MW Net AUSC power plant. The in furnace combustion controls uses TFS XP^{TM} Ultra Low NO_X Firing System. The post combustion equipment consists of SCR, NID (FGD / Baghouse) and an Amine based CCP Plant capturing 90% of the CO2.

5.7 Boiler AQCS Costs description

The boiler and AQCS were priced based on analogy to similarly sized equipment with modifications to account higher than typical temperatures and pressures.

Equipment and manufacturing cost basis is predominantly US (>80%) except where impractical or unavailable. Engineering costs are a combination hourly rates from the US as well as leveraging some low-cost engineering from a GE owned and managed centre.

Pricing considers modular configurations to reduce field construction durations and labor costs.

The accuracy of the cost estimate is within the required range of -15 %/+30 %

The proposed steam turbine 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.

5.8 CCS Costs description

According AACE International recommended Practice No. 18R-97 for each case a Class 4 cost estimate has been prepared. With Baker Hughes' internal developed and over several years used and experienced cost estimation tool Qfact we run a pure inhouse "Equipment Factorized Cost Estimate" based on major equipment data (dimensions, design conditions, material selection etc.). Each equipment has been estimated piece by piece, afterwards based on consolidated equipment data the tool Qfact generates estimated quantities for bulk material and construction. For engineering service, the overall equipment piece count is the relevant basis.

The cost level for estimates are based preferably on US cost basis:

- on equipment and material over 80 % of cost are based on US local content, while cost for Baker Hughes equipment, e.g. compressor, air coolers and some pumps, and some noncritical low-cost equipment items, e.g. vessels, shell & tube exchangers, are based from other countries
- on detailed engineering services an average rate of local US contractor rates in combination with rates of a low-cost engineering center (Asian region) have been applied.

Regarding scope, as requested, the cost estimate covers cost for the entire process plant such as equipment, bulk material and engineering, but excluded electrical equipment, e.g. switchgear & transformers. The first fill for the process plant with amine solution and lubricants is included in the cost estimate as well. For construction major quantities are provided.

Due to the fact, that the major process equipment has large dimensions, modularization for this equipment is not reflected in the cost estimate. For smaller equipment (especially the smaller pumps, the exchangers and the filter packages) steel structures have been foreseen.

Regarding spares, construction and commissioning spares are included, only, while operational spares, capital spares and installed spare equipment are excluded. The plant has been designed for average five thousand (5000) full load operating hours per year (for yearly consumptions/productions calculations) and a plant availability of eight thousand (8000) hours per year as defined in the Basis of Design. The remaining time periods can be used for maintenance. Cost elements - like license fee - which are depending on yearly plant capacity have been based on the above mentioned average five thousand (5000) full load operating hours per year.

All cost of the estimate is based on today's cost, no escalation has been foreseen.
The accuracy of the cost estimate is within the required range of an AACE Class 4 estimate. The cost estimate and given quantities have been benchmarked against other experienced cost estimates done in the past for subject process.

Reference Documents and Resources:

The following documents and resources were used to develop the estimate summary and estimate detail.

1. U.S. Energy Information Administration, “Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies”, February 2020
2. AACE International, “Recommended Practice 58R-10, Escalation Estimating Principles and Methods Using Indices”, May 25, 2011
3. AACE International, “Recommended Practice 59R-10, Development of Factored Cost Estimates – As Applied in Engineering, Procurement, and Construction for the Process Industries”, June 18, 2011
4. U.S. Department of Labor, Bureau of Labor Statistics, ”Consumer Price Index”, January 2020

5. Please note that the cost estimates provided herein are dependent upon the various underlying assumptions, inclusions, and exclusions utilized in developing them. Actual project costs will differ, and can be significantly affected by factors such as changes in the external environment, the manner in which the project is implemented, and other factors which impact the estimate basis or otherwise affect the project. Estimate accuracy ranges are only projections based upon cost estimating methods and are not a guarantee of actual project costs.

6 Technology Gap Analysis and Commercial Pathway

6.1.1 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 1200°F (649°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.[1]

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.

6.1.2 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

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

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 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.

- <u>Emissions</u>: 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.

- <u>Water Use</u>: Water consumption in the proposed concept is addressed by use of GE's NID™ technology for flue gas desulfurization.

- <u>Modular</u>: The proposed concept incorporates shop modularization of selected boiler convective pass, AQCS, and steam turbine components.

- <u>Cost</u>: 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.

6.1.3 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 in a more compact design 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 more compact configuration..
- 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 Advanced Amine Process (AAP) was selected for this Plant Concept. While this technology is not transformative, it has already been extensively validated at the pilot scale (1MW) on a slip- stream flue gas from a hard coal-fired power plant. At the demonstration facility, the pilot plant was operated efficiently and safely both at steady-state and under transient conditions. AAP comprises a proprietary amine-based solvent in a proprietary flow scheme for flue gas applications. The AAP technology applied to this Plant Concept is based on a reference design for large scale post-combustion capture plants, but downscaled to process the flue gas from target host plant capacity (equivalent of 300 MWe). Therefore, no technology gap associated with the validated design scaled down to 300 MWe is expected. Potential technology gaps may result from multi-year plant operation at the 300 MWe- scale but are not identified nor anticipated at this time.

6.1.4 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 Pre-FEED effort (DOE Contract 89243319CFE000023),
2. The A-USC ComTest Phase II effort (DOE DE-FE0025064),
3. Separate boiler design R&D effort,
4. Separate steam turbine design R&D effort.

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.

6.1.5 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.[2]

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.

GE has identified a set of steam turbine components, and associated R&D development activities, as summarized in Section 6.2.2, which would serve to address the remaining technology gaps. The component areas identified include the following:

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

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)

6.2 The Plant

6.2.1 Inventory of Commercial Equipment

The proposed small-scale flexible advanced ultra-supercritical coal-fired power plant with integrated carbon capture includes the following components:

- Boiler/AQCS island – Vendor: General Electric
  - Once-through AUSC pulverized coal-fired boiler in a close-coupled configuration with SH, RH, Economizer, Waterwalls and Separator
  - Start-up System
  - PA,FD and ID fans
  - Regenerative air preheater
  - SSC (submerged scraper conveyer)
  - Bowl Mills
  - Ultra-Low NOx Tangential Firing System
  - Scanning system
  - Selective Catalytic Reduction system (SCR)
  - Novel Integrated Desulfurization (NID™) dry FGD/fabric filter system
- Steam Turbine Island- Vendor: General Electric
  - HP turbine module
  - IP turbine module
  - LP turbine module
  - Main steam stop & control valve
  - Reheat stream stop & control valves
  - Bearing pedestals
  - Generator
- Balance of Plant by AECOM including:
  - Condenser and condensate pump
  - Deaerator
  - Boiler feed pump
  - Low pressure (LP) and high pressure (HP) feedwater heaters
  - Coal and Ash Handling Systems
  - DCS
  - Electrical Equipment including Transformers and Switchgear
  - MCC
  - Civil and Site Infrastructure

    - Waste Water, Cooling Water, Instrument and Service Air and Water
- Integrated Carbon Capture System Block – Vendor: Baker Hughes / General Electric:
    - Flue Gas Handling System
        - Flue Gas Cooler
        - Flue Gas Cooler Exchanger
        - Axial Booster Fan
    - CO2 Absorption System
        - CO2 Absorber
        - Absorber Water Wash Cooler
        - Lean Solution Cooler
    - Regeneration System
        - Regenerator Column
        - Regenerator Water Wash Cooler
        - Rich/Lean Solution Exchangers
        - Regenerator Reboiler
    - CO2 Compression and Dehydration
        - CO2 Compressor
        - CO2 Dryer Skid
    - Solvent Filtration and Reclamation System
        - Solvent Solution Filter System
        - Solvent Reclaimer Unit
    - Tanks
        - Solvent Storage Tank
        - Auxiliary Storage Tank
        - Chemical Storage Tanks
        - Anti-Foam Tote
        - Solvent Drain Tank
        - Make-up Water Tank
    - Various drums, pumps and heat exchangers

6.2.2 **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 in a more compact design 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.

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.

6.2.3 Steam Turbine

The 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 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 6.3-1 and Figure 6.3-2)

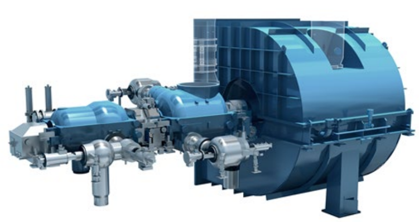

Figure 6.3-1 – Steam Turbine Train

(side exhaust option)

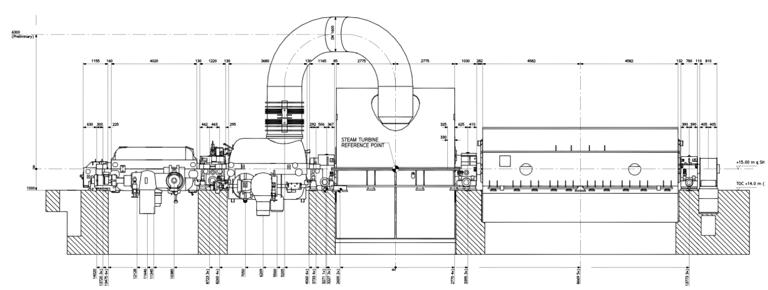

Figure 6.3-2 – Steam Turbine Train Including Generator

(downwards exhaust option)

6.2.4 Steam Generator and Auxiliaries

The design intent of the pulverized coal steam generator is to utilize only commercially available materials to avoid a Technology Gap. Although commercially available, it should be noted that further supply chain development will be needed to fabricate the advanced nickel-based alloys at the required scale.

The 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 at TMCR and no process steam extraction to CPP. Material selections and temperature/pressure conditions are shown in **Figure 6-4-1**.

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 addresses differential expansion between wall sections allowing faster start-up and higher load ramp rates.

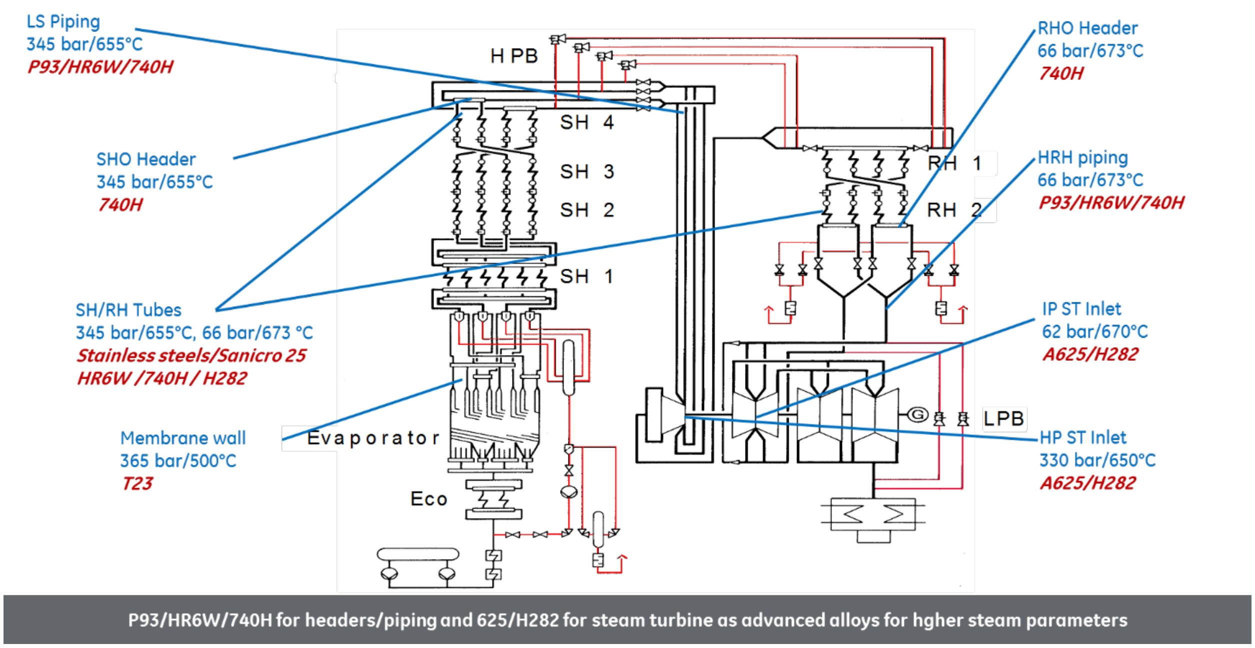

Figure 6-4-1 Boiler Pressure Part Components

All the Boiler auxiliary equipment such as the bowl mills, start-up system, PA, FD, ID fans and regenerative air pre-heater are commercially available mature technologies with no Technology Gaps.

6.2.5 AQCS systems

GE Power Inc.'s most recent development is the TFS XP™ Ultra Low NO_X Firing System. This system represents over 45 years of progressively developed global and local staging techniques designed to minimize O_2 availability during the critical early phases of combustion when the volatile (fuel) nitrogen species are formed. A key feature of this firing system is the tri-level OFA design consisting of "close coupled" overfire air (CCOFA) and two(2) levels of separated overfire air (SOFA). Moving the upper most SOFA windboxes from the traditional "corner" location to the furnace walls in a "counter" fireball orientation completed the design by providing superior mixing, minimum gas-side energy imbalance (GSEI) and control of CO emissions while operating at minimum NO_X emissions levels.

The TFS XP™ firing system has some additional important features including;

- Dynamic classifiers for improved mill performance (fineness and capacity)
- Concentric firing to maintain "oxidizing" conditions along the furnace walls in the firing zone, and
- Enhanced ignition coal nozzle tips for more rapid release of fuel nitrogen, improved coal combustion (lower UBC HL) and low load flame stability

The SCR system is a well proved post combustion technology for converting by-product NO_x to atmospheric N_2 at reduction efficiencies of +90%. The process involves injecting ammonia (anhydrous, aqueous or as urea) into the flue gas stream of an appropriate temperature and then passing the flue gas through a reactor vessel containing catalyst. An economizer gas bypass system will be used to control SCR inlet gas temperature. The reactor box is a standard multi-layer design with inlet turning vanes, flow straighteners, ash moving devices and integrated catalyst module removal system.

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 4 operating NID™ modules at the full-capacity, and in turndown the controls can allow just two NID™ modules 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.

6.3 Carbon Capture Plant

The carbon capture plant (CCP) is part of the planned air quality control system (AQCS) with the specific target to reduce the CO_2 emissions of the host power plant. The proposed CCP concept utilizes a proven Advanced Amine Process (AAP), comprising a proprietary amine-based solvent in a proprietary flow scheme for flue gas applications. The AAP technology applied is based on a reference design for large scale post-combustion capture plants, but downscaled to process the flue gas from target host plant capacity (equivalent of 300 MWe).

The main CCP plant performance target is 90% CO_2 capture from the pretreated flue gas of up-stream AQCS components, while producing a CO_2 product with specified quality in terms of composition and battery limit conditions – pressure and temperature – for further utilization.

These targets are accomplished with the objectives to achieve minimized utility consumptions, primarily steam and electrical power, but also cooling water and chemical consumptions, primarily amine make-up. Additional CCP plant integration options with the host power plant water/steam cycle could further improve the overall operations expenditures (OPEX) on cost of additional capital expenditures (CAPEX). Generally, amines-based processes are proven technologies for decades in the Oil & Gas industry. In this application, the process has been optimized to combustion flue gas under atmospheric pressure and power plant operations.

6.4 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.

7 Business Case from Conceptual Design

7.1 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.

7.2 **Domestic and International Market Applicability**

7.2.1 **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.

7.2.2 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.

7.3 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 43.1% (HHV) plant net efficiency at TMCR with no process steam to CPP, capable of flexible and low-load operation. The cycle has a gross generation capacity of 300 MW at TMCR with no steam extraction to CPP 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 to 2.4 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%.

7.4 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[3] 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[4] (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[5] 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.

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

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

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

[5] "*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

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).

Appendix I Project Execution Plan

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

Pre-FEED Contract: Coal-Based Power Plants of the Future
Project Execution Plan

March 26, 2020

U. S. Department of Energy

Contract: 89243319CFE000023 (Mod. 003)
Proposal: RFP 89243319RFE000015

Principal Investigator:
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Contractor:
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Palo Alto, CA 94304

Period of Performance: 4/15/2019 to 4/15/2020

Project Scope

Project Scope

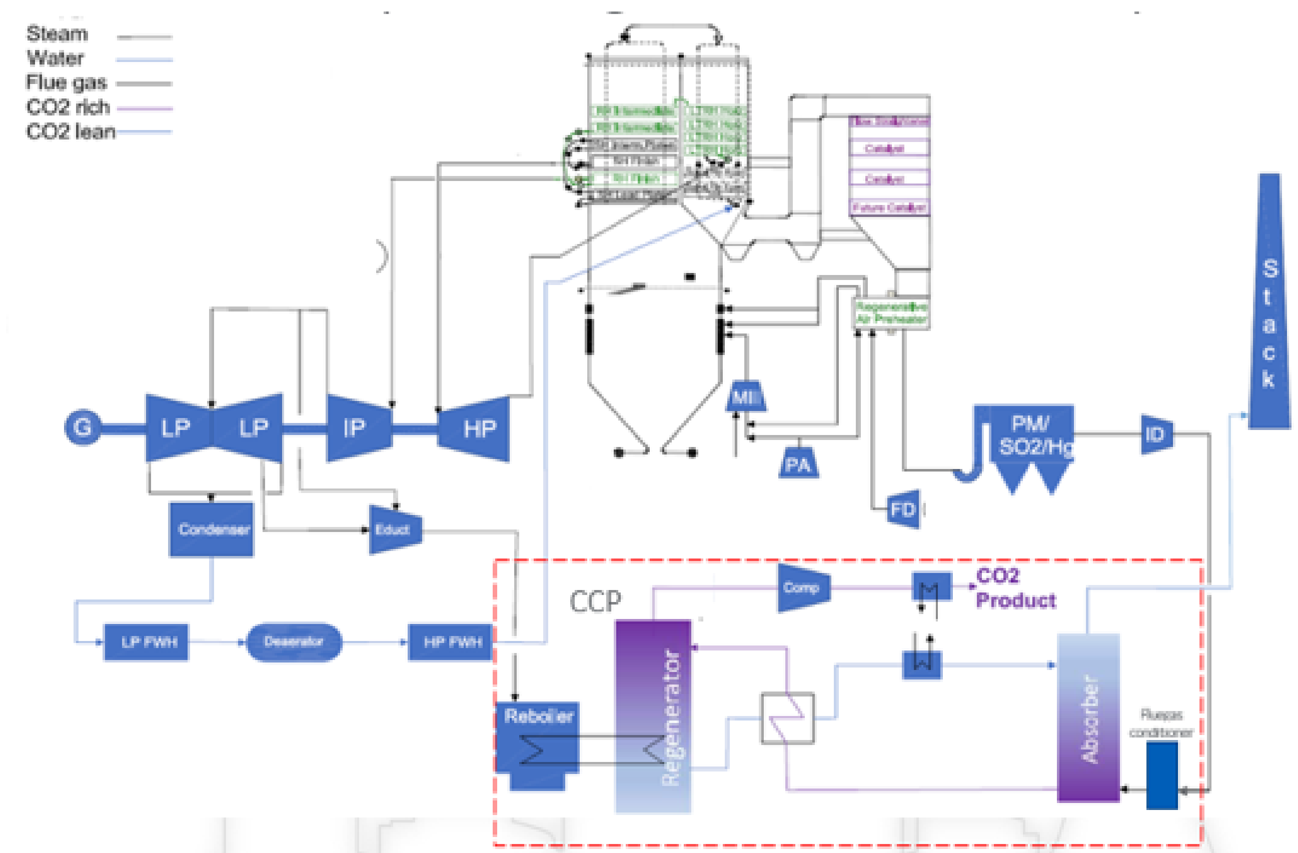
Introduction

The DOE has contracted AECOM and GE to develop the detailed design to provide an integrated plant concept & configuration for a is a Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant with post-combustion carbon capture at nominal 300 MWe gross size.

- To be located in the Midwestern Region of the US.

Major components:

- Pulverized coal-fired boiler in a close-coupled configuration
- Air quality control system (AQCS) consisting of:
  - An ultra-low NOx firing system
  - Selective catalytic reduction (SCR) system for NOx control
  - Dry scrubber/fabric filter for particulate matter (PM), SO2, Hg, and HCl control
- Amine-based post combustion carbon capture system
- Synchronous steam turbine/generator.



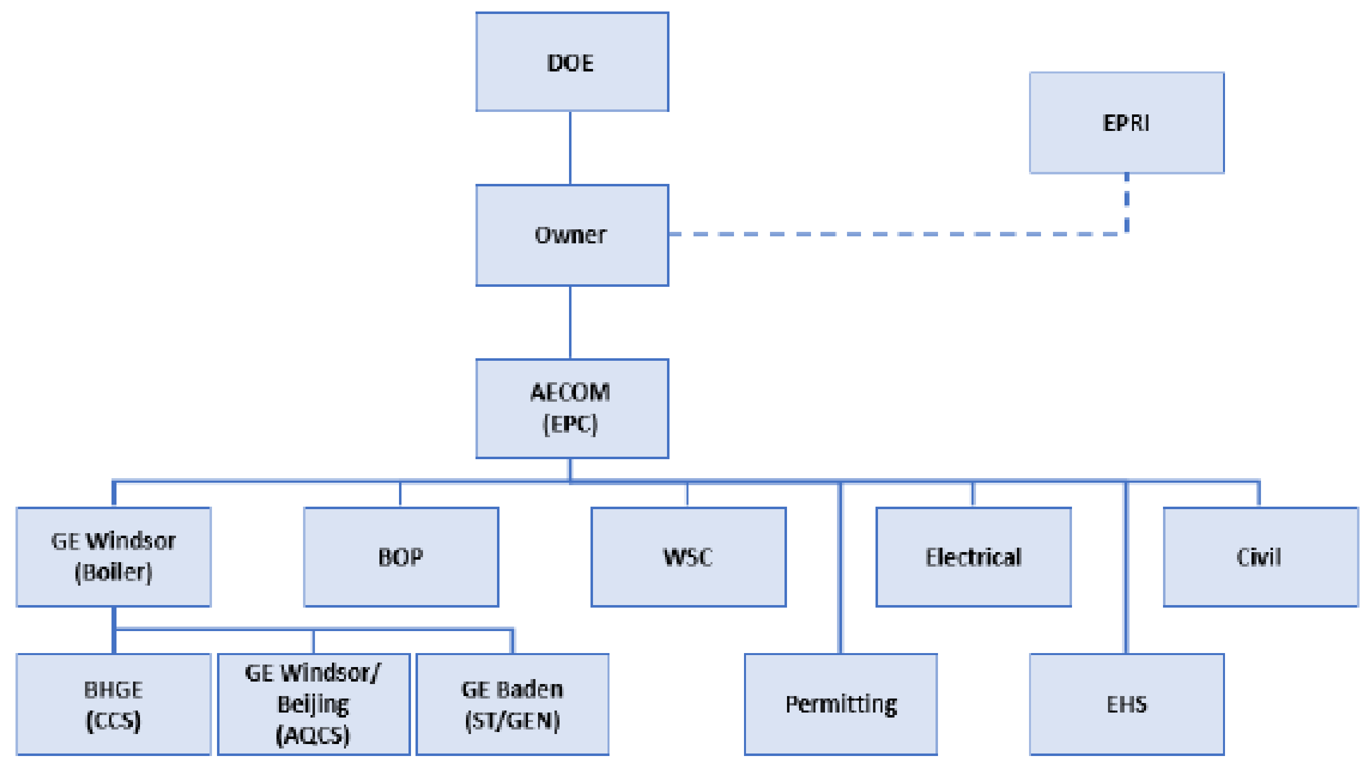
Concept 1 Plant Diagram

Note: The block diagram shows only the steam extractions for the carbon capture system for simplicity and clarity of the diagram.

Project Scope

Project Management

- AECOM, as EPC, will provide engineering services on the project including:
  - Project management
  - Site evaluation & selection
  - Site upgrades
  - Infrastructure and facilities
  - Utilities
  - Balance of plant design, including architectural, civil, structural, mechanical, piping, electrical, process and instrumentation & controls and interconnecting piping
- GE will assign a project manager to be single point of responsibility for
  - Communications between AECOM and GE
  - Development of project schedules
  - Coordination of engineering, test and start-up activities associated with the Steam Boiler, AQCS, Steam Turbine and Generator and the CCS



Project Scope

Engineering & Design

Engineering

- GE Engineering will be responsible for the design of the GE equipment supplied for the project. GE engineering leaders will interface directly with the GE Project Engineer Lead and that person will be the primary lead between GE engineering and the customer related to any engineering questions, designs and or drawing requirements from the customer.
- GE Engineering will perform all work, design reviews and freezes, drawing, etc. per GE's detailed processes and procedures.

Design

- GE will design all equipment per the contract meeting all applicable laws and codes.

Contract Execution

Following Contract award and hand over from Sales to the Project Team for execution, the Front End Engineering Design (FEED) goes through three phases until completion. These are Project Kickoff, FEED Design, and Detailed Design and these three phases are described below.

- **Project Kickoff :** Project Kickoff forms the first phase of the project execution process and the following activities are planned and initiated during this phase.
- **FEED Design:** During this next phase, many of the processes and activities planned and initiated during the Kickoff phase are developed and progressed.
- **Detailed Design:** During this final phase, the design is updated in order to include design data from Suppliers in order to prepare for fabrication and manufacturing.
- Each Design Phase is culminated in a design review with the DOE & Owner to gain approval before proceeding to the next phase.

Scope of Supply

FEED Design Deliverables

The project team will perform the basic design activities to define the process engineering design basis and the technical and engineering specifications for the equipment and process control systems that will be installed. The project team will conduct sufficient engineering design work to perform a FEED level cost estimate. The FEED design applies to the plant as a whole as well as the AUSC equipment.

AECOM

- Process Flow Diagrams
- Heat and Material Balance
- Equipment List(s)
- Utility Summary
- Emission Profile
- Influent/Effluent Summary
- Piping and Instrumentation Diagrams
- General Arrangement Layout(s)
- Process Narratives
- Control Logic Narratives
- Basis of Design
- Site Specification Documents
- Hazardous Operations Review (HAZOP)
- Preliminary Process Control and Safety Interlock Diagrams.
- FEED Cost Estimate (+/- 20%)
- Requests for Quotation for long lead items
- Issue POs for scope requiring sub-supplier Engineering (upon Owner release)

GE

- Preliminary GAs for GE equipment
- Preliminary foundation loads
- Preliminary Electrical Load List
- Preliminary I/O list
- Preliminary P&IDs
- Heat and Material Balances
- Plant Effluent Data Report
- Requests for Quotation for long lead items
- Issue POs for scope requiring sub-supplier Engineering (upon Owner release)

Scope of Supply

Detailed Design deliverables

Detailed Design of the AUSC plant – The project team will perform the following Detail Engineering design activities that are needed for the procurement, installation and operation of the AUSC plant.

AECOM

- Finalize **process engineering calculations** including the
    - Heat & mass balances
    - Process flow diagrams
    - Piping and instrumentation diagram
    - Equipment list(s)
    - Motor & utilities list
    - Final layout and general arrangement drawings
    - Final electrical single line diagrams
    - Facility process control strategy
- Design all **civil and structural works** including the:
    - Foundations
    - Structural Steel
    - Piping racks
    - Site modifications
    - Conveyors, buildings and facilities, and other structures.

AECOM

- Design and specify all of the **equipment** necessary for the project.
- Design all **piping** required for the project. Generate the **piping isometrics** required for the fabrication of all piping system components.
- Develop an **electrical power plan** to Electrical Code and National Fire Protection Association (NFPA) standards including the single line diagram, conduit and cable schedules, design of any necessary motor control equipment, heat tracing, and other ancillary electrical items.
- Develop the **instrumentation and control system** per Electrical Code and NFPA standards for the project including the instrument loop and wiring diagrams; the specification of the control system, data historian architecture and communication system; and all instrumentation and valves.
- Finalize process control and safety interlock diagrams.
- Conduct and document a plant operability meeting with all project participants to discuss safety, commissioning planning, and startup of all systems.
- Implement findings from **HAZOP** review conducted during FEED and conduct the final HAZOP reviews.
- Finalize the **construction strategy** and obtain all required construction approvals, permits and licenses.
- Generate and issue **Requests for Quotations (RFQ's)** for all remaining equipment items required to build the AUSC plant. Obtain and evaluate all bids, and select a preferred supplier for each equipment item.

Scope of Supply

Detailed Design deliverables

Detailed Design of the AUSC plant – The project team will perform the following Detail Engineering design activities that are needed for the procurement, installation and operation of the AUSC plant.

GE

- Design and specify all of the **equipment** necessary for the project.
- Design all **piping** required for the project. Generate the piping isometrics required for the fabrication of all piping system components.
- Develop 90% **General Arrangement Drawings** and **Pressure Part Arrangements** for GE equipment
- Design and specify instrumentation and valve requirements, and issue **Instrument, Valve, Electrical Load, and I/O Lists**
- Develop and issue **Foundation loads**
- Generate **P&IDs** for all equipment
- Develop component **Modes of Operation** and **Control Narratives**
- Participate in a plant operability meeting with all project participants to discuss safety, commissioning planning, and startup of all systems.
- Implement findings from **HAZOP** review conducted during FEED and conduct the final HAZOP reviews.
- Generate and issue **Requests for Quotations (RFQ's)** for all remaining equipment items required to build the GE scope of equipment. Obtain and evaluate all bids, and select a preferred supplier for each equipment item.

Scope of Supply

Project Completion

Project Completion occurs upon release of construction documents (drawings, specifications, equipment details and specifications, erection document packages) to be used for bid and permitting:

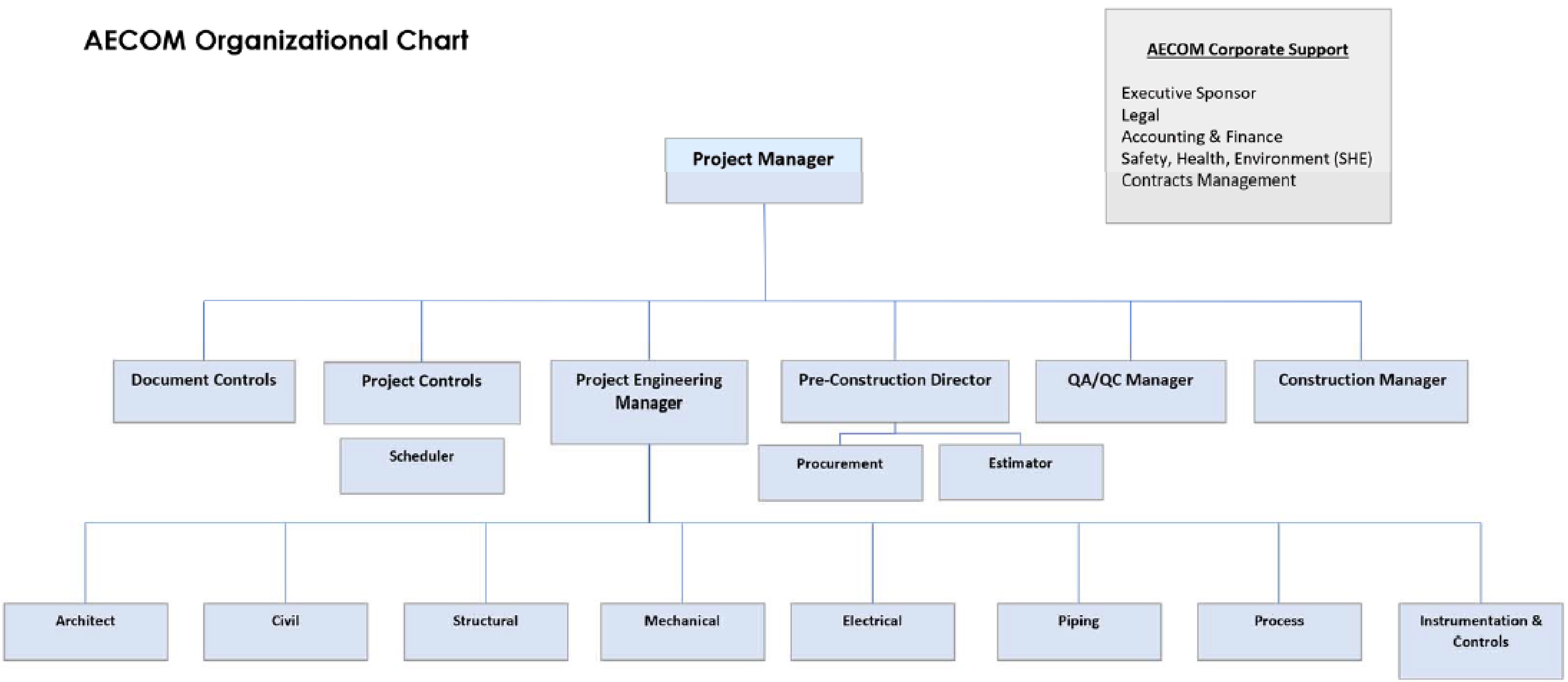
30%, 60%, and 90% design reviews – complete and accepted.

Long lead items identified by project teams and POs placed (as approved by the DOE and/or Owner)

Project Management Plan

Project Structure

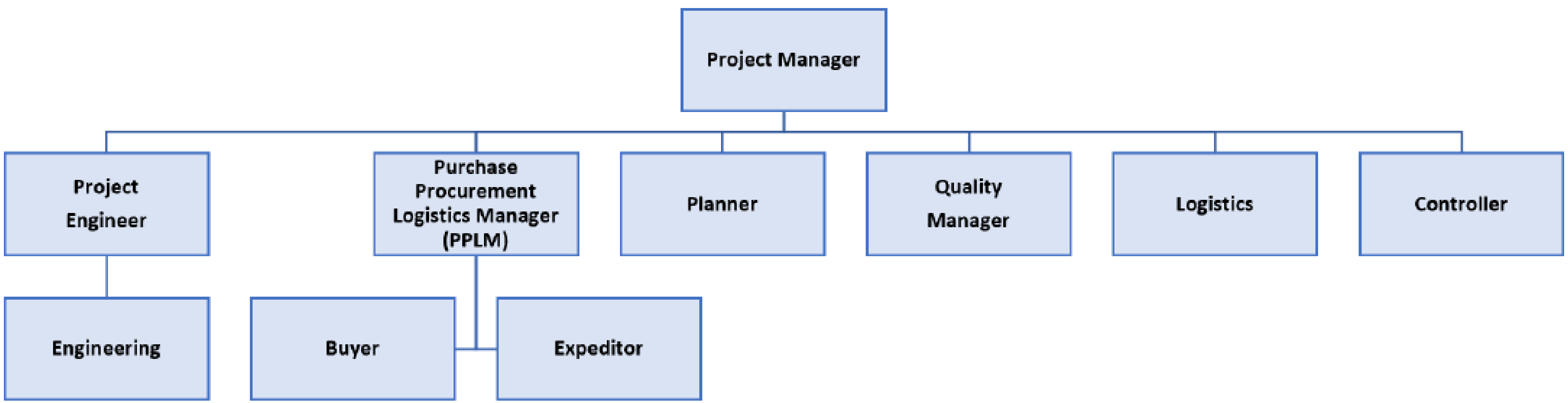
AECOM Organizational Chart



Project Structure

GE's Project Structure

GE Organizational Chart



Project Reviews

Project Team Reviews

A project team meeting shall be held on a regular basis to review the current status of the Project. All team members are required to attend in order to review:

- Project Overall – General Issues
- Customer correspondence, meetings, interfaces and requirements
- Progress and Planning
- Procurement
- Engineering status and progress
- Constructability
- Documentation
- Quality
- Participants status of Work
- Contract(s) Management
- Financial and commercial status
- Value Engineering

Such meetings provide a Project update for all team members. The meetings follow-up actions from previous meetings; again review the status in the above listed areas; and identify new issues and decide upon the required actions.

It allows interfaces between the Customer, disciplines, Participants and sub-suppliers to be identified, coordinated and progressed. In particular, Customer correspondence, meetings and requirements are reviewed and any necessary actions agreed

Project Reviews

Owner & DOE Review Meetings

A Owner & DOE review meeting shall be convened on a monthly basis to review the status of the Project. The topics discussed and reviewed shall cover:

- General and administrative topics – Organizations, Communications
- Financial topics – Insurances
- Project Progress and Scheduling
- Engineering including Layout and Documentation
- Procurement activities for the major items of equipment (selection/pre-qualification of vendors, soliciting of bids, clarifications with bidders, etc.)

The Owner & DOE review meetings provide essential feedback to the Project Team. From this feedback decisions and actions can be made to address any Owner & DOE concerns regarding the status of the Project. This feedback also provides information for the Project Team and allows to identify any issue and analyze the effectiveness of the Quality Management Systems.

Owner & DOE Related Processes

Requirements

Determine Customer Requirements: Project Kick-Off Meeting

- The Project 'Kick-Off' meeting with the Customer is one of the key activities at the start of the Project. In addition to establishing the Project administration procedures, it allows the Project Team to identify other Customer requirements.
- Such requirements may not be clearly specified under the Contract, but such clarification may assist and support in the timely and effective execution of the Project.
- The meeting also allows the Project Team to identify the Customer position and approach to the Project in terms of the Customer expectations, required support for local activities and in meeting local requirements.

Review Customer Requirements

- The Project Team reviews and assesses the Customer expectations and identified requirements to confirm how these will be met.
- Any Customer requirement for a Contract variation will not be accepted or implemented until similarly reviewed, documented, and then confirmed with a Contract Variation Order.
- Any change in scope will be processed in accordance to AECOM's Change Management procedures (Potential Deviation, Change Notice, Change Order). A Master Change Management Log will be used to identify, track, and report the status of all project deviations and changes.

Owner & DOE Related Processes

Communications

Customer Communication

- The establishment and implementation of an effective and efficient communication arrangement between the Customer and the Project Team is essential for the execution of the Project. At the Project 'Kick-off' meeting the agreement on, and establishment of, the Communication procedure is one of the main agenda items.
- The Project Team forms the communication center with the Customer and this, together with regular Customer Project Review meetings, ensures the establishment and implementation of an effective communication arrangement with the Customer.
- This arrangement keeps the Customer fully informed of all Project aspects, as well as providing Customer feedback. Customer feedback will also be addressed by GE management with periodic Customer meetings and surveys

Owner Development

Owner Development

Owner Identification & Integration

- The Owner will be identified and integrated into the project team by the Project Team

Project Financing

- Project financing will be arranged by the Owner. It will be a combination of:
  - DOE: Federal Funding
  - Owner: Host Site & Cost Share
  - Industry Partners: Cost Share

Site Selection

- The plant will be located on a 300 acre greenfield site with level topography and the necessary utilities including power, natural gas, potable water, sanitary sewers and be connected to rail. The specific site will be selected by the project team.

Permit & Regulatory

- AECOM will provide assistance and support to the Owner for permitting to the extent required in the Detailed Design phase. All the required permits necessary for constructing and operating the AUSC plant will be initiated. The project team will determine site environmental requirements and evaluate requirements for permit applications.
- The project team will determine what environmental emissions control equipment and systems are required and develop the engineering data and specifications for that equipment.
- The project team will develop the plan and schedule for an Environmental Assessment (EA) to satisfy the requirements of the National Environmental Policy Act (NEPA). The project team will work with the NEPA office at the National Energy Technology Laboratory (NETL) to prepare and submit to the DOE the documents needed to obtain a positive Record of Decision within a timeframe that is consistent with other key milestone dates of the project.
- The project team will work with the Owner to obtain all permits necessary for construction and operation of the facility.

Engineering Management

Engineering Management

AECOM, as lead organization, provides the overall Engineering and Design Management and Integration for the Project. GE Power Portfolio will lead and coordinate the overall Engineering and Design Management and Integration for the GE products in the Project. The other concerned GE Participants provide the engineering and design management for their respective business scope of work.

The Project Team will be responsible for:

- Engineering Planning
- Engineering Design Inputs
- Engineering Outputs
- Proposal Review
- Supplier Design Integration
- Control of Engineering Design Changes

Procurement Management

Procurement Management

The Project Participants manage the Procurement processes and activities for their respective Project scope of work.

For each GE Participant, the overall Procurement process covers the following sub-processes and as such each Participant is responsible for the following:

- **Procurement Process:** To ensure that the Suppliers of material and equipment comply with both the Customer and GE technical and commercial requirements, meet the required delivery time, the costs and the specified quality requirements defined in the Contract and also required by GE.
- **Transportation Management Process:** To plan, estimate the transport of material and equipment through the entire logistics supply chain. Special focus on Heavy Load Transport

Procurement Management

Procurement Team Kickoff

- Procurement concept:
  - Consists in a document defining the Project specific sourcing concept and for example:
    - Project description
    - General information
    - Negotiable terms between GE and Suppliers
    - Procurement procedure
- Engineering Procurement Plan (EPP) :
  - Defines the strategy to be applied on the different packages/equipment of the Project such as:
    - Complexity of the technical specifications
    - Long lead item
    - Turnkey approach
    - Engineer & Purchaser in charge of each equipment
    - Suppliers to be considered during the RFQ process
- Preliminary Vendors List:
  - Preparation of a Vendors List based on long time experience of GE in Power Plant business worldwide and more specially in Europe.
- Project RFQ Process:
  - Once the list of suppliers to be contacted has been defined through the EPP and the specifications have been received from the engineering department. The procurement department will send the RFQs to the relevant suppliers and will ensure to receive them on-time.
- Master Procurement Schedule (MPS):
  - Dashboard for the purchasing activities which consists in managing costs and timing as well as follow-up of RFQs. It is updated on a weekly basis and gives a good overview of the RFQ process:
    - Suppliers contacted
    - Date of RFQ issuance
    - Expected reception date
    - Cost level of offer received

Non-Commercial Component Technology Development

Non-Commercial Component Technology Development

- The AECOM and GE designs focus on **adapting existing technologies** to new operational requirements in order to generate the flexibility that is required of this AUSC Plant.
- While this is not a typical New Product Introduction (NPI) project, GE will still use the principles set out in its NPI product development gate process to ensure the integrity of the new portions of the design, such as:
  - Flexible Operations: Modes of Operations design and stress analysis to closely address required transient conditions
  - Integration of atypical boiler and turbine materials and fabrication methods into ASME code

Project Timeline

Timeline Summary

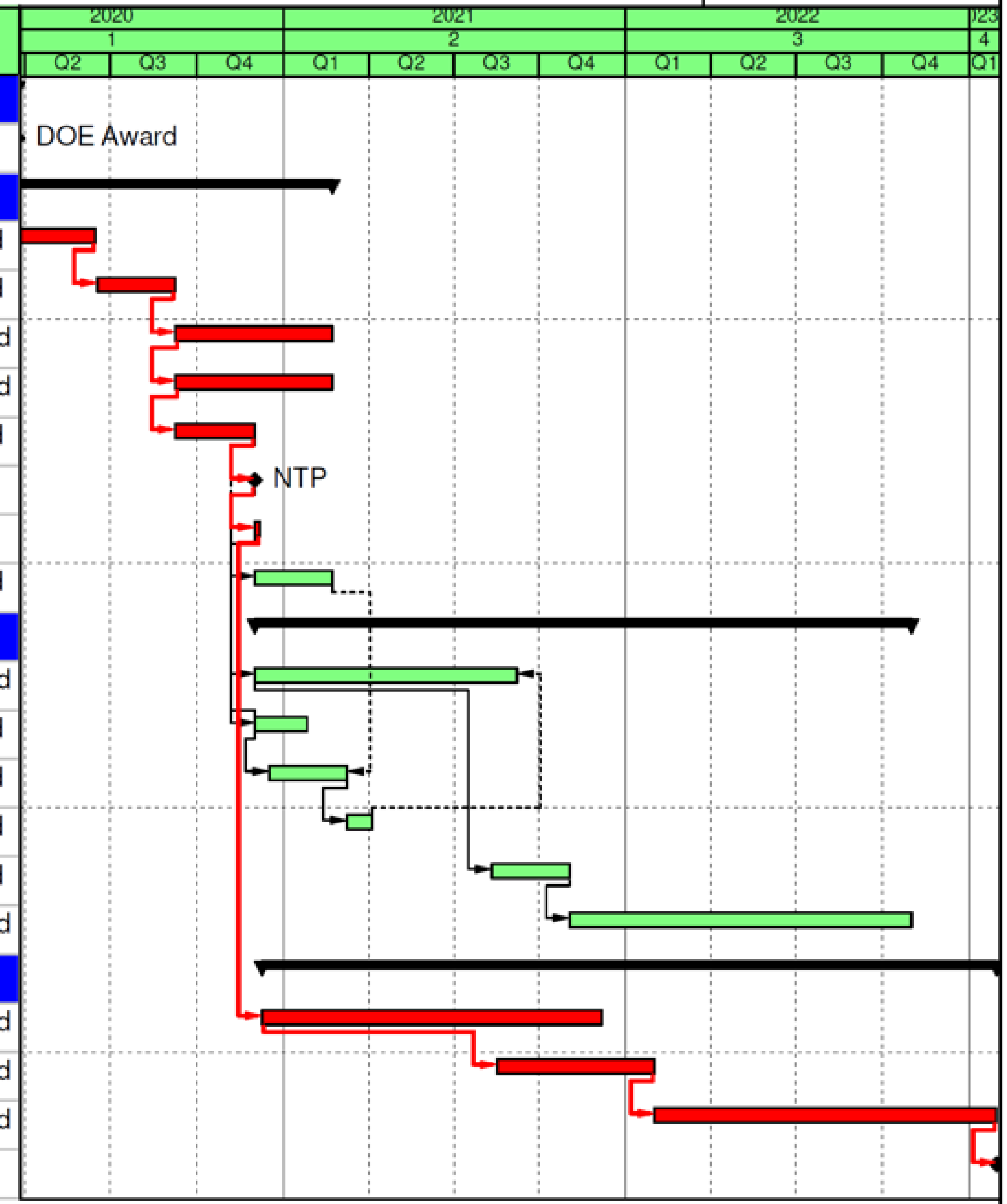
- **Non-Commercial Component Development** - This project adapts existing technologies from GE's portfolio to develop this flexible 300MW AUSC Power Plant.
- **Partnering with Technology Providers** - GE, as a partner in this project, is the technology owner for special equipment, including the Carbon Capture System. There are no special agreements required to use this technology.
- **Project Financing** – will be a combination of:
  - DOE: Federal Funding
  - Owner: Host Site & Cost Share
  - Industry: Cost Share
- **Site Selection** – is a critical step in the development process and will be accomplished with the integration of the Owner and project team to select potential sites and make a final selection.
- **Permitting assumptions** – the permitting process takes approximately 18 months not including the engineering to support the application. The permitting phase and design/construction phase will partially overlap to decrease the overall implementation period.

AECOM
Built to deliver a better world

Small-Scale Flexible Advanced Ultra-Supercritical Coal-Fired Power Plant With Integraded Carbon Capture

10-Apr-20

ID	Description	OD
DOE		
CFPP1000	DOE Award	0d
Pre-Contract Activities		
CFPP1100	Identify Owner	60d
CFPP1200	Negotiate Owner Contract	60d
CFPP1300	Owner Financing & Insurance	120d
CFPP1400	Site Selection	120d
CFPP1500	Negotiate EPC Contract with Owner	60d
CFPP1900	NTP	0d
CFPP2000	Owner, EPC & DOE Kickoff	5d
CFPP2100	Issue POs for Major GE Equipment for Engi	60d
Design		
CFPP2200	FEED Design	200d
CFPP1600	EPC Specification to GE	40d
CFPP1700	GE Review of EPC Specification	60d
CFPP1800	GE Contract EPC	20d
CFPP2300	Issue Supplier POs for Engineering	60d
CFPP2400	Detail Design	260d
Permitting		
CFPP2500	Conceptual Engineering to Support Permits	260d
CFPP2600	Prepare and Submit Applications	120d
CFPP2700	Regulatory Review of Applicatons	260d
CFPP2800	Approval of Required Permits	0d



Remaining Level of Effort | Remaining Work
Actual Work | Critical Remai...

Page 1 of 1

TASK filter: All Activities

Note: Schedule durations are in 5 day work weeks (20 day work months)