Advances in Materials Technology for Fossil Power Plants
Proceedings from the Seventh International Conference
October 22–25, 2013, Waikoloa, Hawaii, USA
https://doi.org/10.31399/asm.cp.am-epri-2013p0060

D. Gandy, J. Shingledecker, editors

ADVANTAGES OF A-USC FOR CO_2 CAPTURE IN PULVERIZED COAL UNITS

H.L. Hendrix
Electric Power Research Institute, Charlotte, NC USA

ABSTRACT

Increasing the steam temperature of a coal-fired pulverized coal (PC) power plant increases its efficiency, which decreases the amount of coal required per MW of electrical output and therefore decreases the emissions from the plant, including CO_2. However, increasing the steam temperature requires that the materials for the boiler pressure parts and steam turbine be upgraded to high-nickel alloys that are more expensive than alloys typically used in existing PC units. This paper explores the economics of A-USC units operating between 595°C and 760°C (1100°F to 1400°F) with no CO_2 removal and with partial capture of CO_2 at an emission limit of 454 kg CO_2/MW-hr (1000 lb CO_2/MW-hr) on a gross power basis. The goal of the paper is to understand if the improved efficiency of A-USC would reduce the cost of electricity compared to conventional ultra-supercritical units, and estimate the economically "optimal" steam temperature with and without CO_2 removal.

INTRODUCTION & BACKGROUND

Over the history of power generation, the thermal efficiency of PC power plants has improved as steam temperatures and pressures have increased. There are many benefits to increased thermal efficiency including the decrease in operating costs associated with purchasing coal, limestone for the flue gas desulfurization (FGD) unit, ammonia for the selective catalytic reduction (SCR) unit, reduced CO_2 emissions, and reduced water consumption. The higher efficiency will decrease the expense of all of these variable operating costs and allow the power plant to be dispatched earlier, which will allow it to be operated primarily as a base-loaded plant.

Ultra supercritical steam (USC) conditions are roughly defined at having temperatures in excess of 593°C (1100°F). Advanced ultra-supercritical (A-USC) steam conditions are at temperatures above that of USC, typically in the range of 705-760°C (1300–1400°F). The maximum steam temperature achievable using currently available ferritic steels is 620°C (1148°F). Utilizing higher steam temperatures requires a transition to high-nickel alloys. The U.S. Department of Energy (DOE) and the Ohio Coal Development Office (OCDO) began a research program in 2001 for the development and certification of these alloys. The research program formed a consortium of companies and organizations which currently includes DOE/NETL, OCDO, Energy Industries of Ohio (EIO), EPRI, ALSTOM Power, Babcock and Wilcox, Foster Wheeler, General Electric, Oak Ridge National Laboratory and Riley Power, Inc. One of the recent achievements for the consortium was the successful approval of Inconel Alloy 740 by the ASME B&PV Code for Section 1 and B31.1 in 2011 and 2012. This material is rated for continuous operation at steam conditions of up to 800°C (1472°F).

The business "driver" for operating at the higher efficiency of an A-USC power plant is largely dependent on the geographic region. For example, as fuel costs are higher in Asia than the USA, improved efficiency to lower fuel usage results in greater cost savings and a correspondingly lower cost of electricity.

In the U.S. and Europe, one of the primary drivers is the likelihood that there will be limitations on the emissions of CO_2. In March 2012, the U.S. Environmental Protection Agency issued a "Standard of Performance" that would limit CO_2 emissions on new fossil power plants to 454 kg

CO_2/MW-hr (1000 lb CO_2/MW-hr) on a gross power basis. This Standard of Performance is currently in a period of comment and review, but if it becomes an emission regulation then all new coal fired power plants in the U.S. would require some form of CO_2 capture. CO_2 emission regulations or a tax on CO_2 emissions are already in place or have been proposed in Canada, the United Kingdom, South Korea, Australia, Japan, and India.

A key approach to lowering all emissions from a PC power plant is increasing the efficiency of the generating unit. Raising the efficiency decreases the amount of coal required to generate a given output, which decreases the CO_2 emissions from the unit. With less CO_2 being generated, the energy penalty associated with adding CO_2 removal will be less.

EPRI has been evaluating the performance and economics of USC and A-USC power plants with and without PCC for several years [1-5]. These projects have evaluated CO_2 removal at 90% and at a level equivalent to a natural gas fired combined cycle power plant. One conclusion from these reports is that as the steam cycle temperature increases, the cost of the coal system, the Air Quality Control Systems (AQCS) (particulate removal, flue gas desulfurization (FGD). NOx control) and the PCC system decreases as the overall efficiency increases. However, as the steam temperature increases, the quantity of high-nickel alloys required in the boiler, steam piping, and steam turbine increases. These alloys are substantially more expensive than carbon steel or advanced ferritic alloys and increase the cost of the boiler pressure parts and the steam turbine.

These studies have lead to several important questions – what are the "optimum" steam conditions for an A-USC power plant? As the steam temperature increases and fuel requirements decrease, does the cost increase of the boiler and turbine offset the balance-of-plant cost savings? Does the efficiency increase of operating at higher steam cycle pressures justify the extra thickness of the nickel alloy pressure parts? Does the efficiency increase associated with double reheat justify the additional material and equipment cost? Using in-house performance and cost estimation tools, EPRI has embarked on a study to evaluate the relative cost of single reheat A-USC power plants operating at 3 pressures: 275, 345, and 415 bar (4000, 5000 and 6000 psia) and four main steam temperatures: 595^{o}C, 650^{o}C, 705^{o}C, and 760^{o}C (1100^{o}F, 1200^{o}F, 1300^{o}F, and 1400^{o}F). Double reheat cycles operating at 345 bar (5000 psia) and the four steam temperatures will also be evaluated. Performance and economics will be determined for the units with no CO_2 capture system, and with a 30 wt% monoethanolamine (MEA) Post Combustion Carbon Capture (PCC) system designed to meet the U.S. EPA proposed Standard of Performance at 1000 lb CO_2/MWhr gross.

This paper discusses the initial results of the 345 bar (5000 psia) single reheat cases at 595^{o}C, 650^{o}C, 705^{o}C, and 760^{o}C (1100^{o}F, 1200^{o}F, 1300^{o}F, and 1400^{o}F) main steam temperatures with and without the PCC system.

STUDY BASIS

The base units evaluated in this study have a gross turbine output of 850 MW, are fired with sub-bituminous coal and achieve emissions performance for criteria pollutants lower than currently permitted values. In the cases with the PCC system the 30% MEA system is described elsewhere [2]. A portion of the flue gas leaving the FGD system flows through the MEA absorber and 90% of the CO_2 entering is removed. The remaining flue gas is bypassed around the absorber and the two streams combine before flowing out of the stack. The CO_2 removed by the PCC system is compressed to pipeline pressure and this cost and power consumption is included in the calculations.

The plant of is located in Kenosha, Wisconsin. For weather protection the boiler and steam turbine are enclosed, and the site is clear and level in a Seismic Zero zone requiring 30-m (100-

feet) deep pile foundations. Available at the site boundary are rail and transmission access, raw water supplied from Lake Michigan, and natural gas. The fuel delivered by rail is Wyoming Powder River Basin (PRB) sub-bituminous coal, with characteristics as detailed in Table 1.

The A-USC PC plant is designed with an annual capacity factor of 80%. Annual capacity factor is defined as the actual annual production divided by the plant rated capacity times 8,760 hours. The plant design is based on using components suitable for a 30 year life, with provision for periodic maintenance and replacement of critical parts.

Steam Generator

The boiler island scope and general design basis are summarized below.

- Greenfield, balanced-draft unit designed for base-load operation.
- The unit is sized to have a gross output of 850 MW before the addition of the PCC system.
- Low-NO_X axial-swirl burners with over-fired air and SCR is used to achieve emission limits of 0.03 lb/MBtu (0.013 kg/GJ).
- Separator, recirculation pump and start-up system, and economizer.
- A bottom ash system (submerged chain conveyor) to remove ash from the hopper throat feeding it into a water-filled trough.
- Soot-blowing system and mechanical draft cooling tower.
- Single fans for forced-draft (FD) and primary-air (PA) duty.

The design stack gas emission limits for the unit are listed in Table 2. To meet these emissions, the AQCS consists of the following components:

- NO_X Control: low-NO_X burners with SCR.
- Electrostatic Precipitator (ESP) for particulate control.
- Wet FGD for sulfur control.
- Mercury Removal –Halogen injection into the boiler promoting mercury oxidation over SCR catalyst with co-capture in the FGD. Possible supplemental capture using activated carbon injection ahead of the ESP, if required.

The PCC technology for this study includes a conventional two column absorber/regenerator scheme designed for 90% CO_2 removal and utilizing 30 wt% MEA as the solvent.

Table 1
Coal Analysis for Wyoming Sub-Bituminous Coal

Proximate Analysis Weight Percent As Received	
Moisture	30.24
Ash	5.32
Volatile	31.39
Fixed Carbon	33.05
Ultimate Analysis Weight Percent As Received	
Carbon	48.18
Hydrogen	3.31
Nitrogen	0.70
Chlorine	0.01
Sulfur	0.37
Oxygen	11.87
Ash	5.32
Moisture	30.24
Heating Value As Received	
HHV, kJ/kg (Btu/lb)	19,400 (8,340)
LHV, kJ/kg (Btu/lb)	17,900 (7,710)

Table 2
Emissions Limitation – HHV Basis

Pollutants	Emission Limits	
PM_{10}	0.01 lb/MBtu	~10 mg/m^3
$PM_{2.5}$	0.013 lb/MBtu	~13 mg/m^3
SO_2	0.03 lb/MBtu	~30 mg/m^3
NO_X	0.03 lb/MBtu	~30 mg/m^3
VOC	0.0025 lb/MMBtu (0.0011 kg/GJ)	
Mercury	90-percent capture	
Carbon Dioxide	Varies	

The portion of the flue gas exiting the FGD unit and entering the PCC system first enters a flue gas scrubber where it is contacted with circulating, cooled water. This scrubber cools the flue gas, which by decreasing volumetric flow and condensing water improves absorber performance. By adding a dilute caustic solution to the circulating water, residual SO_2 in the flue gas can be removed reducing degradation product formation

From the scrubber, the cooled flue gas enters a blower that provides the head to overcome the pressure drop of the absorber and piping without increasing the back-pressure on the FGD system.

The flue gas enters at the bottom of the column and flows upward, and the CO_2-lean solvent enters at the top of the column and flows downward. The CO_2-depleted flue gas enters the upper "wash" section of the column and is brought in contact with circulating water that cools the flue gas and scrubs out any amine present. The cleaned flue gas then flows to the stack for discharge to the atmosphere.

The CO_2-rich solvent exits the bottom of the absorber where it is pumped through the rich/lean solvent exchanger and into the regenerator. The hot rich solvent enters the top of regenerator where the absorbed CO_2 is released by the addition of heat. The heat breaks the chemical bonds between the CO_2 and the solvent, liberating the CO_2 and regenerating the solvent so that it can be returned to the absorber for CO_2 removal. The heat is provided by the condensation of low pressure (~4 bar (60 psi) steam) in the regenerator's kettle-type reboilers, the steam being extracted from the crossover between the IP and LP steam turbines. Heating the rich solvent before it enters the regenerator decreases the extraction steam required.

The gas leaving the regenerator is cooled before being sent to the reflux drum. The gas exiting the reflux drum is the product CO_2 which is sent to the CO_2 compressor system and compressed to approximately 150 bar (~2200 psia) before entering the pipeline.

The lean solvent exits the bottom of the regenerator and flows through the rich/lean solvent exchanger where it is cooled. The exiting lean amine is cooled in a trim cooler before returning to the absorber.

MODELING

PC Cost is a Microsoft Excel® based costing tool developed by EPRI that has "evolved" over a 24 year period of time. Its purpose is to allow engineers and planners to estimate the conceptual and preliminary costs of PC-fired, subcritical and supercritical power plants [6]. It calculates the heat and material balance for the unit and the overall plant performance based on the fuel specification and then determines the cost of the major equipment subsystems by scaling from reference costs. These reference costs are based on budgetary quotes and/or in-house developed estimates which have been updated periodically over the life of the costing tool. The goal is to provide a +/- 30% estimate for the costs for the equipment and materials within the plant boundary, which includes all the direct and indirect costs for: site preparation, earthwork, concrete and structural steel, building construction, major equipment, auxiliary equipment, piping, electrical/instrumentation/control equipment as well as construction labor, bulks, and subcontractors.

Beginning in 2011, PC Cost was modified to allow it to estimate the performance and cost of A-USC units. As part of that modification, it was decided to use AspenTech's AspenPlus® to perform the majority of the heat and material balance calculations. This would also allow for the use of the physical properties generated by AspenPlus® to be used for heat transfer calculations. Additional capability was added to allow PC Cost to be able to choose the most cost effective material for each row of tubes in the boiler backpass, depending on the design pressure and calculated metal temperature. The possible material selections include carbon steel, T91, S304H, HR3C, HR6W, IN617, HR230 and IN740.

PC Cost assumes a boiler configuration to perform its heat transfer calculations. This configuration and the corresponding AspenPlus model are shown in Figure 1. Sizing of the PC furnace is performed using proprietary methods. PC Cost sizes the backpass of the boiler using conventional heat transfer methods using the flowrates, temperatures, and physical properties from AspenPlus® to determine the heat transfer coefficients and the surface area. The temperature and pressure of the steam/water are used to determine the wall thickness of the tubes, tube weights, and then the cost is determined by using unit costs ($/kg) for the boiler components.

One of the main objectives of this project was to produce these studies on a consistent basis as the pressure and temperature changed. However, one early conclusion from this study is that using the same boiler geometry for all temperature cases significantly penalizes the higher temperature cases. PC Cost inherently assumes a long piping run from the top of the boiler to the steam turbine. As the temperature increases, the material of piping quickly transitions to Inconel 740, which is roughly 10 times the cost (per kg or lb) than T91. Boiler and turbine manufacturers are designing plant layouts that minimize the amount of high-nickel alloy required. One option is a horizontal boiler design proposed by Siemens, [7] which would minimize the length of piping between the boiler and the turbine. An alternate design would separate the HP and IP turbines into multiple components [8]. A high temperature HP section would be located near the top of the boiler, and this would exhaust at a lower temperature and pressure into a conventional HP steam turbine. After the steam is reheated, the high temperature, hot reheat steam would enter a similar IP section near the top of the boiler which would exhaust into a conventional IP turbine.

For the remaining equipment, the costs are scaled from reference plant costs using industry-accepted algorithms whose exponents and constants are tailored to each type of equipment. Additional changes were made to the cost estimate calculation of the steam turbine. Since there is no commercial A-USC turbine at this time, a method was devised to estimate its cost relative to a USC turbine. The temperature limit for the steam turbine estimated in PC Cost is 595^{o}C (1100^{o}F). After discussions with steam turbine consultants, it was decided to apply a multiplication factor to this estimated steam turbine cost to account for the change in materials required for the higher operating temperature. At 595^{o}C (1100^{o}F), this multiplication factor was 1.0, and it linearly increased to 1.2 at 760^{o}C (1400^{o}F). Several organizations are currently working to provide a preliminary design of an A-USC turbine, and a more accurate cost. When this information becomes available, it will be incorporated into PC Cost.

The steam system heat balance was modeled in Gate/Cycle using Spencer-Cotton-Cannon algorithms to predict the efficiency of the turbine under the various operating conditions. A simulation was created for the base plant (no-PCC) and converged on a steam turbine gross power of 850 MW. This information was used by PC Cost/AspenPlus® to calculate the coal flow rate and the heat and material balance for the boiler systems. The power consumption within the steam cycle (HP BFW pumps, condensate pumps, etc) was calculated by Gate/Cycle, and the auxiliary loads for the boiler and AQCS systems were calculated by AspenPlus based on the calculated flowrates. Values not calculated by AspenPlus for certain plant equipment (mill power, for example) were estimated from previous EPRI reports.

For the PCC cases, the coal feed and the steam/water flows calculated for the non-PCC cases were fixed. The LP steam extraction for the PCC system was removed from the IP/LP crossover. This steam was condensed in the PCC regenerator reboilers and returned to the steam cycle. However, as expected, the steam extraction resulted in a significant decrease in gross power.

Within the PCC system, there are opportunities to recover useful heat and use this energy to heat the boiler feed water leaving the condenser. This allows the steam that would normally be extracted from the steam turbine for boiler feedwater heating to be used to generate power. A "heat integration" study was carried out for all cases based on the experience gained in previous reports (References 2-5). This allowed for the increase of gross power and improved the plant's performance as well as reducing load on the cooling tower. Typically 30% of the heat in PCC system was transferred to the boiler/steam turbine system.

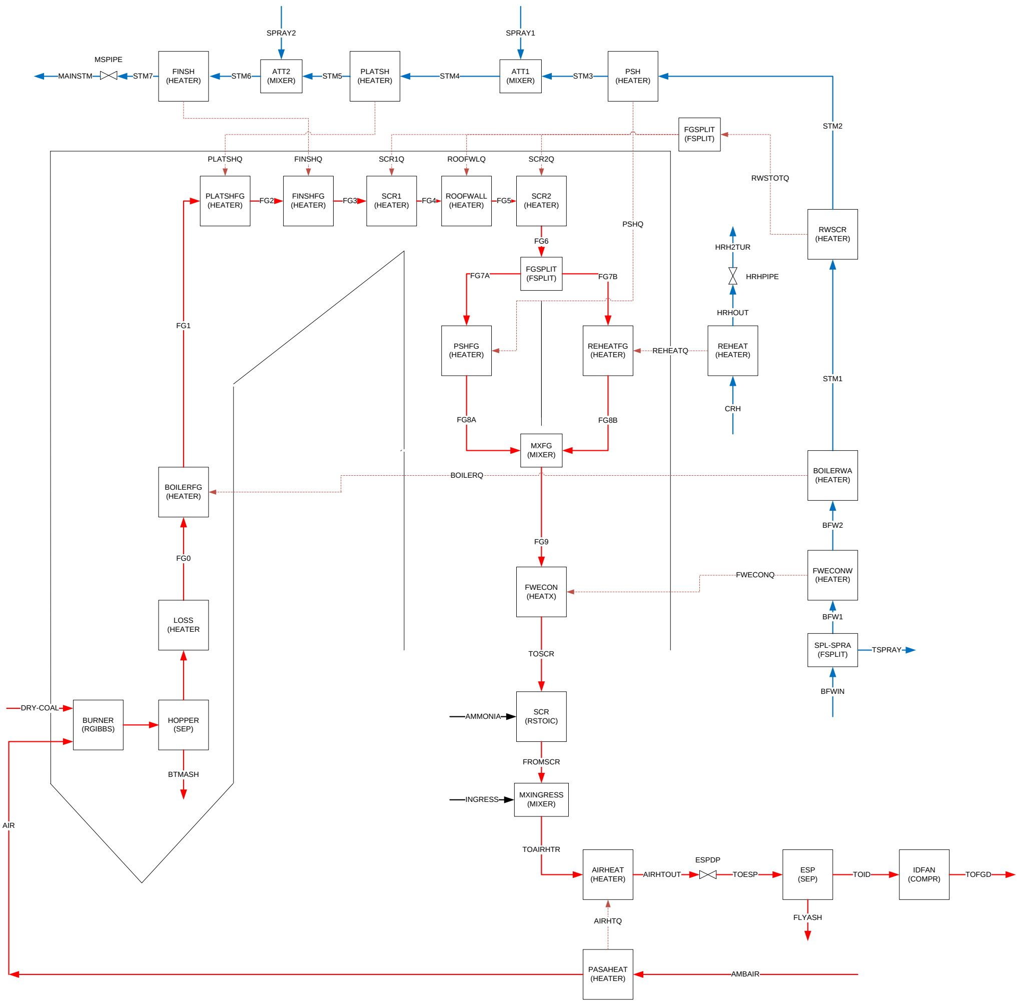

Figure 1
PC-Cost Boiler Configuration

In addition to the loss of gross power, there is a significant increase in the auxiliary power with the addition of the PCC system, primarily due to the large CO_2 compressors. The decrease in gross power and increase in auxiliary power creates a substantial decrease in net power, especially for the 90% CO_2 removal cases.

It is intuitive that reducing the percentage of the CO_2 removed from the flue gas would have a significant improvement on the plant's performance and economics. To meet the EPA's "Standard of Performance" approximately half of the CO_2 would have to be removed from the flue gas compared to 90% CO_2 removal. This reduces the LP steam extracted which reduces the effect on gross power, as well as the auxiliary power load.

BASE PLANT RESULTS (NO PCC CASES)

The results of the Base Plant cases are shown in Table 3. As steam temperature increased, the overall plant efficiency increased and CO_2 emissions decreased. Since the coal flow decreased with increasing temperature, the power requirements associated with coal feeding and the AQCS systems decreased. As steam flowrate per MW decreased, the HP BFW pump power also decreased. These improvements decreased the auxiliary load and increased the net power.

As coal flow decreases, the capital costs for the coal feed system, ash removal, and the AQCS systems all decrease. As the steam temperature increases, the cost of the boiler increases primarily for three reasons:

- In general, alloy mechanical strength decreases with increasing temperature. Therefore, the tubing thickness increases with increasing steam temperature.

- Beyond a certain temperature, the strength is too low and/or corrosion rates too high for one material and another material must be substituted for the application. Typically, these "upgraded" materials are more expensive on a per pound or per kilogram basis.

- Even though the steam temperature is increasing, the temperature profile of the flue gas through the boiler is approximately the same. Therefore, the "driving force" for heat transfer is decreasing which requires a larger surface area for a given heat duty.

This can be evidenced in Table 3 which shows the capital cost increasing by 15% between the 595^{o}C (1100^{o}F) case and the 760^{o}C (1400^{o}F) case.

Although the coal feed decreases with increasing steam temperature, the cost of electricity (COE) increases due to the increasing capital cost. For example in going from 595^{o}C to 760^{o}C (1100 F to 1400F) the CO_2 emissions fall 7.3% but the COE increases 9.1%. One important observation is that the results in Table 3 reflect conditions in the U.S. market. EPRI has been working with members in Asia to understand the differences between projects in the U.S. and Asia, and work is ongoing in this area. The COE in Table 4 shows a comparison between the U.S. market and Asia based on the following assumptions:

Table 3
Preliminary Performance and Economics of 345 bar (5000 psia) units with no PCC.

Description	595°C/615°C 1100°F/1140°F	650°C/671°C 1200°F/1240°F	705°C/727°C 1300°F/1340°F	760°C/760°C 1400°F/1400°F
Gross plant output, kW	850,000	850,000	850,000 kW	850,000 kW
Auxiliary load, kW	87,716	82,894	78,925	76,055
Net plant output, kW	762,284	767,101	771,075	773,945
Net plant heat rate	8,534 Btu/kWh 9,056 kJ/(kWh)	8,282 Btu/kWh 8,738 kJ/(kWh)	8,054 Btu/kWh 8,497 kJ/(kWh)	7,885 Btu/kWh 8,319 kJ/(kWh)
Net plant efficiency (HHV)	39.7%	41.2%	42.4%	43.3%
Plant fuel consumption	784,500 lb/hr 355,900 kg/hr	761,800 lb/hr 345,500 kg/hr	744,600 lb/hr 337,700 kg/hr	731,700 lb/hr 331,900 kg/hr
CO_2 Emission	1,382,000 lb/hr 627,400 kg/hr	1,342,000 lb/hr 609,200 kg/hr	1,312,000 lb/hr 595,500 kg/hr	1,287,000 lb/hr 584,100 kg/hr
CO_2 Emission	1,625 lb/MW (g) 738 kg/ MW (g)	1,579 lb/MW (g) 717 kg/ MW (g)	1,543 lb/MW (g) 700 kg/ MW (g)	1,514 lb/MW (g) 687 kg/ MW (g)
Capital Cost, $1000	$1,732,000	$1,766,000	$1,834,000	$2,001,000
Capital Cost, $/kW	$2,270	$2,300	$2,380	$2,590
Total Annual Costs, $1000/yr	$363,000	$365,000	$378,000	$402,000
Cost of Electricity, $/MWh	$67.90	$68.00	$70.00	$74.10

- EPRI has learned anecdotally that capital costs on a \$/kW basis in Asia are 50-70% of the cost based on U.S. estimates. For this comparison it is assumed that the capital cost is 60% of what is estimated by PC Cost.

- Richardson International Cost Factor Manual [9] estimates the labor index relative to the U.S. market. The average labor index for Asia given in the manual (Taiwan, Korea, and India) is 0.4. This was used to adjust the operating and administrative labor rates.

- Platt's Coal Trader International [10] predicts a value of approximately \$3.70 to \$4.55/GJ (\$3.90 to \$4.80/MMBTU) for comparable coal shipped to Asia from Indonesia or South Africa in the 2013-2016 timeframe. The midpoint of this range, \$4.12/GJ (\$4.35/MMBTU) is used instead of the U.S. coal price of \$1.71/GJ (\$1.80/MMBTU) for PRB to Kenosha, WI.

Table 4
Comparison of the COE between the U.S. and Asia

Steam Cycle	U.S. COE	Asia COE
595°C/615°C (1100°F/1140°F)	\$67.90	\$68.70
650°C/671°C (1200°F/1240°F)	\$68.00	\$67.80
705°C/727°C (1300°F/1340°F)	\$70.00	\$68.20
760°C/760°C (1400°F/1400°F)	\$74.10	\$70.20

In the U.S. the COE is largely determined by the capital cost and the coal component is relatively small. In Asia the reverse is true; the coal cost is a significant portion of the COE. This is illustrated in Figure 2, which shows the major components of the COE for the 595°C (1100°F) case. The coal component is about 22% of the COE in the U.S. and about 50% in Asia. Therefore, operating at higher efficiency is economically important.

As Table 4 shows, the COE is less for the 650°C and 705°C cycles (1200°F and 1300°F) than for the 595°C (1100°F) cycle. If coal prices increase, this difference becomes more significant. Because these units all have the same boiler/turbine configuration, the higher temperature cases are penalized because of the long runs of Inconel 740 main/reheat steam piping. EPRI will evaluate the cost savings of alternate A-USC plant designs in future work.

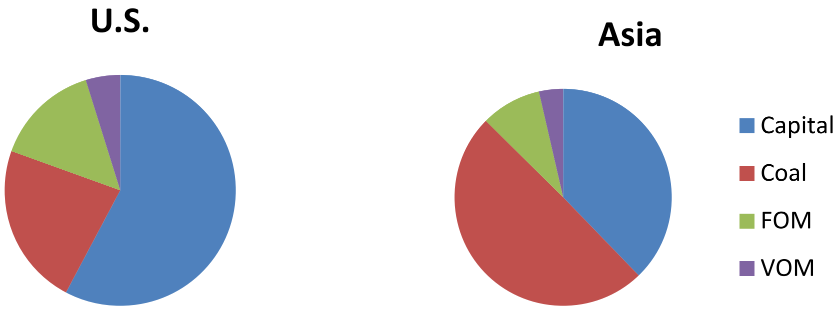

Figure 2
Cost of Electricity Components in the U.S. and Asia[1]

A-USC AND CO_2 CAPTURE

The most significant economic driver for A-USC in the U.S., Europe, and other countries may be CO_2 removal from PC power plants. As previously mentioned, the EPA has released a "Standard of Performance" for the removal of CO_2 from fossil plants exhaust gas. The Standard proposed a limit of 1000 lb CO_2/MW on a gross basis. Since its release the Standard has been in a comment and review period, but it is expected that a final limit will be released by the EPA by the end of 2013.

To meet the partial capture limit, slightly less than half of the flue gas enters the PCC absorber. Because of this, less steam is extracted from the steam turbine and the reduction in gross power decreases. To meet the EPA's Standard of Performance for the partial CO_2 capture cases the decrease in efficiency was about 4 percentage points as shown in Table 5.

Because of the loss of net power, there is an "amplification" of the capital cost on a \$/kW basis. For example, in the 595^{o}C (1100^{o}F) case, the overall capital cost increases 14% over the unit with no PCC. However, on a \$/kW basis, the capital cost increased 27% over the case with no PCC system. On average, the COE increased approximately 30% over the non-PCC cases.

[1] Note: FOM – Fixed Operating & Maintenance Costs, VOM –Variable Operating & Maintenance Costs.

Table 5
Preliminary Performance and Economics of 345 bar (5000 psia) units with 1000 lb CO_2/MW(g) Emissions Target

Description	595°C/615°C 1100°F/1140°F	650°C/671°C 1200°F/1240°F	705°C/727°C 1300°F/1340°F	760°C/760°C 1400°F/1400°F
Gross plant output, kW	815,348	816,484	818,526	821,256
Auxiliary load, kW	130,018	122,143	115,705	110,821
Net plant output, kW	685,330	694,341	702,821	710,435
Net plant heat rate	9,547 Btu/kWh 10,072 kJ/(kWh)	9,150 Btu/kWh 9,653 kJ/(kWh)	8,836 Btu/kWh 9,322 kJ/(kWh)	8,590 Btu/kWh 9,062 kJ/(kWh)
Net plant efficiency (HHV)	35.7%	37.3%	38.6%	39.7%
CO_2 Emission	816,000 lb/hr 370,000 kg/hr	817,000 lb/hr 370,000 kg/hr	819,000 lb/hr 371,000 kg/hr	821,000 lb/hr 373,000 kg/hr
CO_2 Emission	1,001 lb/MW (g) 454 kg/ MW (g)	1000 lb/MW (g) 454 kg/ MW (g)	1,000 lb/MW (g) 454 kg/ MW (g)	1,000 lb/MW (g) 454 kg/ MW (g)
Capital Cost, $1000	$1,975,000	$2,002,000	$2,063,000	$2,225,000
Capital Cost, $/kW	$2,881	$2,883	$2,936	$3,133
Total Annual Costs, $1000/yr	$435,000	$434,000	$440,000	$462,000
Cost of Electricity, $/MWh	$90.50	$89.20	$89.50	$92.80

CONCLUSIONS AND FUTURE WORK

As with any engineering performance and economic study, the conclusions are largely dependent on the assumptions made. From this work it is apparent that the economic advantage of using A-USC will depend on:

- The boiler/turbine configuration. One significant conclusion from this study has been that the cost of the long main and reheat steam lines between the boiler and the steam turbine significantly increases the capital cost at the higher steam temperatures. Alternate boiler/steam turbine configurations will be necessary for A-USC designs to be economically competitive at temperatures higher than 700°C (1300°F).

- The alloy costs. Currently Inconel 740 pipe and tubing is estimated to cost 25 times more on a per pound or kilogram basis than carbon steel. However, Inconel 740 pipe and tubing have not been manufactured in commercial quantities, so this cost is largely speculation. As the first A-USC units are built, the price for these materials is expected to decrease.

- The cost of the turbine. The cost for an A-USC turbine is unknown. As the market develops, the price for an A-USC turbine will become better understood.

- The applicability of A-USC in Asia will largely be driven by coal price. A-USC power plants will become more economic at higher coal prices.

- The plant availability. The Cost of Electricity for these studies is based on a plant availability of 80%, which is typical of U.S. units in today's market due to increased renewable energy usage for power generation. Coal fired units in Asia may be operating closer to 90%, which would decrease the COE.

- CO_2 capture requirements. If coal is burned in future U.S. power plants, some amount of CO_2 capture will be required. The final regulations for CO_2 removal in new fossil power plants are expected by the end of 2013. The limit set by this regulation will determine to a large extent the economics of future coal fired units in the U.S.

Finally, significant work is ongoing in many areas of the world related to A-USC:

- Both China and India have announced plans to build 700^{o}C A-USC units within the next 5-7 years.

- Turbine manufacturers are working to develop A-USC steam turbine designs and estimate the cost to build an A-USC turbine.

- Due to the high cost of the nickel alloys, the cost of the main and reheat steam lines from the boiler to the turbine will be a significant percentage for the overall power plant capital cost. Boiler, turbine manufacturers, and EPCs are evaluating plant layout configurations to minimize the length of these lines, which could change the economic conclusions reached by this paper

- The DOE/OCDO A-USC Materials Consortium continues to evaluate materials performance at high temperatures. As part of this work, the consortium is working to identify a host for a 760^{o}C (1400^{o}F) Component Test (COMTEST 1400). This test loop would take steam from a host utility's main steam line, heat it to 760^{o}C and then flow the steam through a small (~4 MW) A-USC steam turbine.

- The Materials Consortium continues to work with materials suppliers to understand alloy prices in commercial quantities.

- Because the EPA regulation is based on gross output, there may be advantages to using CO_2 removal technologies that do not decrease gross power. EPRI is currently researching the use of membranes for the removal of CO_2. The results of this work are planned for release later in 2013.

REFERENCES

[1] *Engineering and Economic Evaluation of 1300°F Series Ultra- Supercritical Pulverized Coal Power Plants: Phase 1*, EPRI, Palo Alto, CA 2008, 1015699.

[2] *An Engineering and Economic Assessment of Post-Combustion CO_2 Capture for 1100^{o}F Ultra-supercritical Pulverized Coal Power Plant Applications: Phase II Task 3 Final Report*, EPRI, Palo Alto, CA 2010, 1017515.

[3] *Engineering and Economic Evaluation of 1300^{o}F Series Ultrasupercritical Plant with Post-Combustion Capture: Engineering and Economics,* EPRI, Palo Alto, CA 2012, 1026645.

[4] *Engineering and Economic Analysis of a 1300F Series USC Demonstration Plant with Natural Gas Equivalency Post-Combustion Capture.* EPRI, Palo Alto, CA, 2013. 1026644.

[5] *Minimizing the Derate of Adding Post Combustion Capture to Pulverized Coal Units* EPRI, Palo Alto, CA: 2012. 1023864.

[6] Hoskins, Bill (URS), and Booras, George (EPRI), "Assessing the Cost of New Coal-Fired Power Plants," Power Magazine, October 2005, pg 24-28.

[7] Smith, David, "Horizontal Boilers make 700^{o}C Steam Economic," Modern Power Systems, May 2000, pg 36-41.

[8] Feng, Weizhong, "Technology Innovation of Most Efficient Coal Power Plant and Plan for Future," presented at EPRI's CoalFleet Technical Meeting, Mobile, AL, December 2012.

[9] Richardson International Construction Factor Manual, Cost Data On Line, Inc., Prescott, AZ, 2011.

[10] *Coal Trader International*, Platts, Volume 13, Issue 135, July 13, 2013