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Techno-Economic Analysis of a Secondary Air Stripper Process

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Abstract

We present results of an initial techno-economic assessment on a post-combustion CO_2 capture process developed by the Center for Applied Energy Research (CAER) at the University of Kentucky using Mitsubishi Hitachi Power Systems' H3-1 aqueous amine solvent. The analysis is based on data collected at a 0.7 MWe pilot unit combined with laboratory data and process simulations. The process adds a secondary air stripper to a conventional solvent process, which increases the cyclic loading of the solvent in two ways. First, air strips additional CO_2 from the solvent downstream of the conventional steam-heated thermal stripper. This extra stripping of CO_2 reduces the lean loading entering the absorber. Second, the CO_2-enriched air is then sent to the boiler for use as secondary air. This recycling of CO_2 results in a higher concentration of CO_2 in the flue gas sent to the absorber, and hence a higher rich loading of the solvent exiting the absorber.

A process model was incorporated into a full-scale supercritical pulverized coal power plant model to determine the plant performance and heat and mass balances. The performance and heat and mass balance data were used to size equipment and develop cost estimates for capital and operating costs. Lifecycle costs were considered through a levelized cost of electricity (LCOE) assessment based on the capital cost estimate and modeled performance.

The results of the simulations show that the CAER process yields a regeneration energy of 3.12 GJ/t CO_2, a $53.05/t CO_2 capture cost, and LCOE of $174.59/MWh. This compares to the U.S. Department of Energy's projected costs (Case 10) of regeneration energy of 3.58 GJ/t CO_2, a $61.31/t CO_2 capture cost, and LCOE of $189.59/MWh. For H3-1, the CAER process results in a regeneration energy of 2.62 GJ/tCO_2 with a stripper pressure of 5.2 bar, a

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capture cost of $46.93/t CO_2, and an LCOE of $164.33/MWh.

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1. Introduction

The University of Kentucky's Center for Applied Energy Research (CAER) has developed a process, shown in Fig. 1. The process uses a two-stage stripping unit for solvent regeneration. The additional air-based second stage stripping process is inserted between a conventional rich-lean crossover heat exchanger and a lean solution temperature-polishing heat exchanger. This additional stripper increases the cyclic loading of the solvent in two ways. First, air strips additional CO_2 from the solvent downstream of the conventional steam-heated thermal stripper. This extra stripping of CO_2 reduces the lean loading entering the absorber. Second, the CO_2-enriched air is sent to the boiler for use as secondary air. This recycling of CO_2 results in a higher concentration of CO_2 in the flue gas sent to the absorber, and hence a higher rich loading in the solvent exiting the absorber.

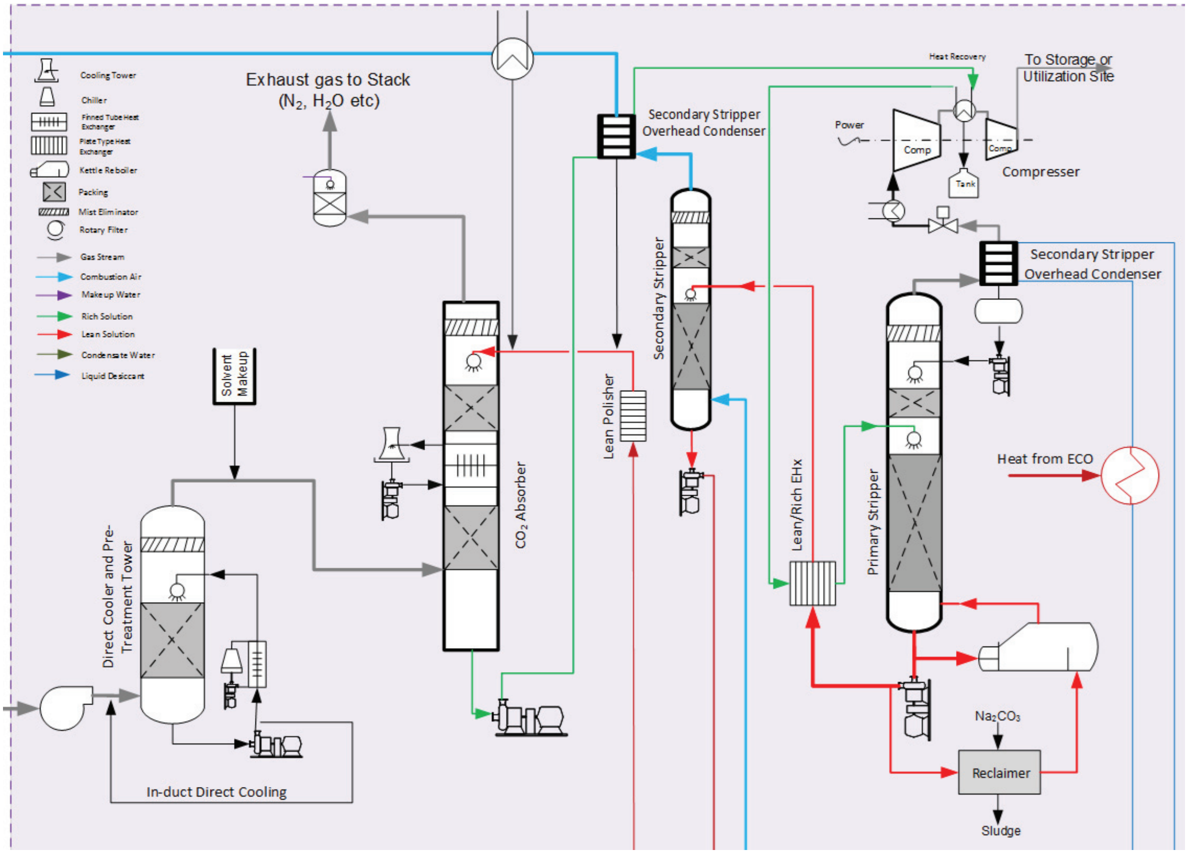

Fig. 1. A secondary air stripper is used to further strip the solvent of CO_2. This air is sent to the boiler to increase the concentration of CO_2 in the flue gas that is sent to the absorber.

The second key feature in the process is the deployment of an integrated cooling tower system using a liquid desiccant. The entire process was tested on a 2 MWth (0.7 MWe equivalent) slipstream located at LG&E-KU's E.W. Brown Generating Station, located near Harrodsburg, Kentucky. The test campaigns used 30-wt% MEA solvent to obtain baseline data and Mitsubishi Hitachi Power System's proprietary solvent H3-1. Though the full process concept and the pilot unit use the desiccant loop, we did not include this subsystem in this assessment because the desiccant system is beneficial to overall plant performance at ambient conditions that are warmer and drier than the standard conditions used in the U.S. Department of Energy baseline cases.

2. Approach

All physical and chemical properties were used in an AspenPlus model of the overall process, consisting of a coal-fired power plant and the CO_2 capture and compression process. Three cases were conducted: (a) MEA model based on thermodynamic and kinetic data for MEA, (b) An H3-1 model using equilibrium thermodynamic data only, and (c) an H3-1 model using both thermodynamic and kinetic data. For H3-1, properties were measured in a laboratory at CAER or otherwise provided by Mitsubishi Hitachi Power Systems.

Once the simulations were confirmed with pilot data, the solvent property data and process operating conditions were incorporated into a full-scale supercritical pulverized coal power plant model to determine the plant performance and heat and mass balances. The performance and heat and mass balance data were used to size equipment and develop cost estimates for capital and operating costs. Lifecycle costs were considered through a levelized cost of electricity (LCOE) assessment based on the capital cost estimate and modeled performance.

The performance modeling, cost estimates and LCOE assessments were performed so that the results could be compared to baseline cases developed by the U.S. Department of Energy National Energy Technology Laboratory [1]. Results show that the energy demand for post-combustion CO_2 capture and LCOE are both reduced relative to the baseline. The key factors contributing to these reductions were the CO_2 partial pressure increase at the flue gas inlet and performance of the Mitsubishi Hitachi Power Systems H3-1 solvent. The evaluation also shows the effect of the critical parameters on the LCOE, with the main variables being the approach temperature of the cross exchanger and CO_2 partial pressure increase at the flue gas inlet.

3. Performance Summary

The high-level performance results for the UKy-CAER CCS process with MEA and H3-1 are shown in Table 1. The NETL Baseline report shows an HHV efficiency of 26.2% with the Reference Case 10 plant which uses MEA as a solvent. The CAER process improves that efficiency to 27.2% when using MEA and further improves that to 29.7%–29.9% using the H3-1 solvent.

The CAER process also lowers energy consumption for MEA to 3.12 GJ/t CO_2 (1340 Btu/lb-CO_2) captured as compared to 3.58 GJ/t CO_2 (1540 Btu/lb-CO_2) in Case 10. Using the equilibrium H3-1 model, the regeneration energy is 2.26 GJ/tCO_2 (973 Btu/lb CO_2), while the kinetic H3-1 model shows the energy consumption as 2.62 GJ/tCO_2 (1126 BTU/lb CO_2), 16% larger than the equilibrium model. At the same time, the stripper pressure was 1.88 bar (27.3 psia) in the equilibrium model compared to 5.2 bar (75 psia) in the kinetic model. Though the reboiler duty increased by using the kinetic H3-1 model, the higher stripper pressure reduced the compression work, so the net plant efficiency for H3-1 changed from 28.9% to 28.7% on an HHV basis. This change is small, and hence we selected to assess the H3-1 economics using the equilibrium H3-1 model results as they were conducted early in the project.

Table 1. Performance Summary of CAER Process

POWER SUMMARY (Gross Power at Generator Terminals kWe)	MEA	H3-1 Equilibrium Model	H3-1 Kinetic Model
TOTAL (STEAM TURBINE) POWER, kWe	691,000	722,300	708,900
AUXILIARY LOAD SUMMARY, kWe			
Coal Handling & Conveying	540	540	540
Pulverizers	4,180	4,180	4,180
Sorbent Handling & Reagent Preparation	1,370	1,370	1,370
Ash Handling	800	800	800
Primary Air Fans	1,980	1,980	1,980
Forced Draft Fans	2,890	2,890	2,890
Induced Draft Fans	11,410	11,410	11,410
SCR	70	70	70
Baghouse	100	100	100
Wet FGD	4,470	4,470	4,470
CO_2 Removal System Auxiliaries	22,122	21,485	19,520
CO_2 Compression	48,930	48,930	33,360
Miscellaneous Balance of Plant[2,3]	2,000	2,000	2,000
Steam Turbine Auxiliaries	400	400	400
Condensate Pumps	750	870	820
Circulating Water Pump	8,830	9580	9,290
Ground Water Pumps	720	780	750
Cooling Tower Fans	4,590	4,990	5,710
Transformer Losses	2,410	2,520	2,480
TOTAL AUXILIARIES, kWe	118,562	119,365	102,140
NET POWER, kWe	572,438	602,935	606,760
Net Plant Efficiency (HHV)	27.2%	28.7%	28.9%
Net Plant Heat Rate, Btu/kWhr HHV (kJ/kWhr)	12,533 (13,222)	11,899 (12,553)	11,824 (12,475)
Net Plant Efficiency (LHV)	28.2%	29.7%	29.9%
Net Plant Heat Rate, Btu/kWhr LHV (kJ/kWhr)	12,088 (12,753)	11,477 (12,108)	11,405 (12,033)
COOLING TOWER DUTY, MBtu/hr (GJ/hr)	4,200 (4,431)	4,560 (4,811)	4,410 (4,653)
Consumables			
As-Received Coal Feed, lb/hr (kg/hr)	614,994 (278,956)	614,994 (278,956)	614,994 (278,956)
Limestone Sorbent Feed, lb/hr (kg/hr)	62,235 (28,229)	62,235 (28,229)	62,235 (28,229)

1. *HHV of As-Received Illinois #6 coal is 27,135 kJ/kg (11,666 Btu/lb)*
2. *Boiler feed pumps are turbine driven*
3. *Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads*

4. Economic Summary

The comparison in operating parameters and costs between DOE Case 9 and 10, the UKy-CAER CCS process with MEA case, and the UKy-CAER CCS process with H3-1 case is shown in Table 2. The CAER Process + H3-1 case has the following key advantages compared to the CAER Process + MEA case:

- An extra 30.5 MW of generation (52.9 MW more than DOE Case 10) with the coal feed rate
- A lower net plant heat rate by 634 Btu/kWh (669 kJ/kWh), a 5% improvement in efficiency (1147 Btu/kWh [1211kJ/kWh] lower than DOE Case 10)
- A lower variable operating cost by $0.60/MWh ($1.48/MWh less than DOE Case 10), a 4.8% reduction.

Table 2
Comparison of Operating Parameters and Costs between the MEA, H3-1, and DOE Cases

	Case 9	Case 10	CAER MEA	CAER H3-1
OPERATING PARAMETERS				
Net Plant Output, MWe	550.0	550.0	572.4	602.9
Net Plant Heat Rate, Btu/kWh HHV (kJ/kWh	9,277 (9,787)	13,046 (13,764)	12,533 (13,222)	11,899 (12,553)
CO_2 Captured, lb/MWh (kg/MWh)	0 (0)	2,390 (1,084)	2,297 (1,042)	2,180 (989)
CO_2 Emitted, lb/MWh net (kg/MWh net)	1,888 (856)	266 (121)	256 (116)	242 (110)
COSTS				
Risk	Low	High	High	High
Capital Costs (2012$/kW)	2,000	3,689	3,303	3,081
Total Overnight Cost (2012$/kW)	2,477	4,548	4,079	3,817
Bare Erected Cost	1,629	2,836	2,556	2,399
Home Office Expenses	147	257	233	218
Project Contingency	224	465	412	379
Process contingency	0	131	104	85
Owners Costs	477	860	776	737
Total Overnight Cost (2012$x1,000)	1,362,516	2,501,457	2,334,024	2,301,459
Total As Spent Capital (2012$/kW)	2,809	5,185	4,650	4,352
Annual Fixed Operating Costs ($/yr)	39,039,238	66,263,173	62,406,060	61,372,514
Variable Operating Costs ($/MWh)	7.63	13.35	12.47	11.87
Fuel				
Coal Price ($/ton)	69.00			

The comparison in LCOE between DOE Case 9 and 10, the CAER process with MEA case, and the CAER process with H3-1 case is shown Table 3. The CAER Process with H3-1 case has the following key advantages compared to the CAER Process with MEA case:

- A lower COE by \$8.09/MWh (\$20.05/MWh lower than DOE Case 10), a 5.9% reduction
- A lower LCOE by \$10.26/MWh (\$25.26/MWh lower than DOE Case 10), also a 5.9% reduction
- A lower cost of CO_2 captured by \$6.12/tonne CO_2 (\$14.38/tonne CO_2 lower than DOE Case 10), a 11.5% reduction
- A lower cost of CO_2 avoided by \$12.18/tonne CO_2 (\$28.17/tonne CO_2 lower than DOE Case 10), a 16.4% reduction.

Table 3. Comparison of LCOE between the MEA, H3-1, and DOE Cases

	Case 9	**Case 10**	**CAER MEA**	**CAER H3-1**
COE (\$/MWh, 2012\$)	**83.19**	**149.65**	**137.69**	**129.60**
CO_2 TS&M Costs	—	5.80	5.57	5.29
Fuel Costs	27.43	38.57	37.06	35.19
Variable Costs	7.63	13.35	12.47	11.87
Fixed Costs	9.53	16.18	14.64	13.67
Capital Costs	38.59	75.75	67.93	63.57
LCOE (2012\$/MWh)	105.36	189.59	174.59	164.33
Cost of CO_2 Captured (\$/tonne CO_2)	—	61.31	53.05	46.93
Cost of CO_2 Avoided (\$/tonne CO_2)	—	90.35	74.36	62.18

5. Future Work

Further improvements to the modeling of the H3-1 solvent will be achieved by using experimental data from the 0.7 MWe pilot unit. These include prediction of temperature profiles in the absorber, for which kinetic data are important.

References

[1] Cost and Performance Baseline for Fossil Energy Plants. DOE/NETL-2010/1397, Revision 2a, September 2013.