Assessment of PFBC and Gasification Repowering

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Introduction

One of the first implications of full competition in the utility industry is the reluctance to risk capital intensive investments in new plant construction. As the Department of Energy's Clean Coal Technology program readies a suite of technologies for commercial application, and as deregulation unfolds, the electric utility industry begins to look at the potential for repowering existing sites. This approach to power plant investment involves applications of repowering technologies, upratings, and refurbishing older stations. The decision to repower is influenced by factors that include market demand, power station characteristics, and technology choices. This paper describes the results of a comparative technical and economic evaluation of several clean coal technologies in a repowering application.

Objectives

The objectives of the study were to compare thermal and economic performance of a suite of clean coal technologies in a repowering application under a consistent set of guidelines.

Approach

The approach taken in this comparative evaluation of Advanced Technologies in a repowering application was to define a reference pulverized coal (PC) fired power station, and then apply each candidate technology in succession. Each case was modeled in a modified version of the ASPEN/SP flow sheet simulation program, along with a suitable combustion turbine, where applicable, and the host plant steam cycle. Pittsburgh No. 8 coal is used for most of the cases evaluated, except for one case involving a natural gas fired combustion turbine, another case where the technology variable is the use of a Process Derived Fuel (ENCOAL Corp. PDF) in place of coal, and a third case where coal is the primary fuel, but some natural gas is used for topping combustion.

The reference station configuration was based on an evaluation of a UDI data base containing the complete domestic U. S. generating fleet. In a series of queries of the data base, a set of bar graphs were generated showing the numbers of units in various discrete size categories, ages, and steam conditions. This exercise revealed that a large number of units existed that were between 100 and 200 MWe in size, were commissioned in the 1950's, and had main steam pressures between 1450 and 2400 psig. Main and reheat steam temperatures of 1000F were by far the most prevalent value.

Based on these findings, a Reference PC host plant was defined, consisting of a site containing twin 150 MWe, net, PC units, with steam conditions of 1800 psig/1000F/1000F. The units each utilize a steam turbine with a triple flow LP turbine section, with 23 inch dia. last stage buckets exhausting to a single pressure condenser at 1.0 in. Hga.

In this study, the original steam turbines are refurbished and reused, along with much of the steam cycle equipment. This is an important consideration, as it constrains the configuration of the power conversion cycle, whereas in a greenfield plant the designer can select optimal steam cycle design parameters and equipment. However, certain advantages accrue from this approach, such as the ability to retain the original once through cooling system, which provides low condensing pressure and auxiliary power requirements. Refurbishment of the original turbine includes replacement of selected steam path components, improving adiabatic efficiency by about 1-1/2% relative to the original machine, when new.

As each advanced technology was evaluated, a combustion turbine was selected for the topping cycle portion of the power conversion system. Based on a time frame for application in the years 2000 to 2010, the Westinghouse 501G machine was selected for use where feasible. This large, efficient combustion turbine provides sufficient exhaust heat for the bottoming cycle to match effectively with most of the cases evaluated, while only requiring a single machine to be installed. In the cases involving the first and 1-1/2 generation Circulating Pressurized Fluid Bed Combustors, the W501D5 machine was used, as it provided a more suitable match for the overall system. The bubbling bed Pressurized Fluid Bed case relies on the ASEA GT-140 machine.

Description of Technologies

1. Reference Pulverized Coal Plant. See Reference Plant Definition, above.

2. Atmospheric Fluid Bed Combustor. This is based on a Foster Wheeler design available for commercial service at this time. Existing coal handling equipment and other infrastructure are refurbished and reused. Plant performance is relatively unchanged except for emissions, which are significantly reduced. Solid waste production is increased.

3. Refueling with Process Derived Fuel (Encoal Corp.). This case represents a refueling rather than a repowering. The original boilers are refurbished along with the steam turbines and other site equipment, and are fired with 100% Encoal Corp. PDF, which is a dried and mildly pyrolised Powder River Basin coal. The fuel is specified to contain low sulfur as delivered, (0.3% sulfur, by weight). For the purposes of this study, the original boiler capacity is maintained, with some enhancement of soot blowing capacity, and other modifications to compensate for the somewhat different combustion characteristics of the process derived fuel. This refueling results in a slight reduction in net output to 293 MWe, and a slight reduction in net heat rate to 8890 Btu/kWh.

4. Pressurized Fluid Bed Combustor (Bubbling Bed). This technology is represented by the ABB P-800 commercial module, incorporating an ASEA Stahl GT-140 gas turbine. In the current repowering study, the combustor is located inside a pressure vessel that is 57 feet in diameter and 160 feet high, operating at a nominal pressure of 245 psig. The new equipment, comprising the PFBC package and the gas turbine and its associated equipment, is arranged adjacent to the original powerhouse. Net plant output is increased to 348 MWe, while net plant heat rate is reduced to 8729 Btu/kWh.

5. Pressurized Fluid Bed Combustor (Circulating Bed, First Generation), based on Foster Wheeler technology. This concept utilizes a circulating pressurized bed for complete combustion of the coal. Hot air/gas leaving the bed is cleaned in a series of cyclone and ceramic candle filters, and is then ducted to a gas turbine for expansion. Most of the gas turbine compressor discharge air is used in the circulating bed; the hot gases returning to the turbine for expansion are limited in temperature to 1600F. A machine based on the W501D5 is used in this arrangement, with a single drum HRSG in the exhaust to supplement the steam production in the circulating bed heat exchanger. Plant net output is increased to 314 MWe, while net heat rate is reduced to 8506 Btu/kWh.

6. Pressurized Fluid Bed Combustor (Circulating Bed, One and One-Half Generation). This version of CPFBC technology is similar to the first generation scheme mentioned above. However, in this case, natural gas is fired in the combustion turbine to reach the original design turbine inlet temperature of the machine. An external, motor-driven boost compressor is used to compensate for the unrecovered pressure drop in the CPFBC circuit external to the gas turbine. The W501D5 is again selected, exhausting through economizer coils for condensate and feedwater heating. Steam is produced in the CPFBC heat exchanger to drive both of the existing steam turbines. Plant net output is increased to 368 MWe, while net heat rate is reduced to 8087 Btu/kWh.

7. Pressurized Fluid Bed Combustor (Circulating Bed, Second Generation). In this CPFBC case, a pyrolizer is added to the process upstream of the circulating bed combustor. Low Btu fuel gas produced by the pyrolizer is conveyed to the gas turbine where it is mixed with the returning vitiated air from the CPFBC and combusted to produce the design basis firing temperature of the turbine. This configuration is based on the use of a modified W501G machine, with an external, motor-driven boost compressor as in the previous case. Steam is produced in a HRSG and in the CPFBC heat exchanger to drive both of the steam turbines in the existing station. Net output is increased to 433 MWe, while net heat rate is reduced to 7043 Btu/kWh.

8. Integrated Gasification Combined Cycle (IGCC) (Air Blown KRW Gasifier). This case utilizes the air blown, fluidized bed, KRW type gasification process, including hot gas cleanup and a transport type gas polisher (desulfurizer) to supplement the sulfur removal that occurs in the gasifier bed. The clean hot low Btu gas that is produced is fired in a modified W501G gas turbine, which is coupled to a HRSG for steam production. Both existing steam turbines are repowered in this example, providing a net station power increase to 407 MWe, and a reduction in net heat rate to 7355 Btu/kWh.

9. Integrated Gasification Combined Cycle (Oxygen Blown Entrained Bed Gasifier) . In this example, a two-stage, entrained flow gasifier is supplied with 95% pure oxygen from a dedicated air separation plant located on-site. A single gasifier module produces medium Btu fuel gas which is desulfurized in a GE moving bed cleanup system, and is then fired in a modified W501G machine. The turbine exhausts through a HRSG to produce steam to drive one of the two existing steam turbines. A Monsanto type (H_2S burning, catalytic conversion) sulfur recovery process produces commercial grade sulfuric acid for sale as a byproduct. The net station output is increased to 353 MWe, while net heat rate is reduced to 7379 Btu/kWh, (including the air separation plant and other auxiliary loads).

10. Integrated Gasification Combined Cycle (British Gas/Lurgi Oxygen Blown Gasifier). This fixed bed gasifier is supplied with 95% pure oxygen from an on-site air separation unit. The gasifier produces a cold medium Btu gas, which is desulfurized in a Purisol cleanup train. Tail gas from the Purisol unit is converted to commercial grade sulfuric acid for sale, in a Monsanto type H_2S burning and catalytic conversion unit. The fuel gas is fired in a modified W501G machine, which exhausts through a HRSG to produce steam to drive one of the existing steam turbines. A portion of the compressor discharge air is supplied to the high pressure air separation plant, eliminating the need for a separate air compressor. This repowering example produces a net power increase to 313 MWe, and a heat rate reduction to 7669 Btu/kWh.

11. Integrated Gasification Combined Cycle (Air Blown Transport Reactor). This IGCC concept is based on the air blown transport reactor. The hot low Btu gas is desulfurized in the reactor, followed by a polishing step in a transport desulfurizer, chloride removal in a chloride guard bed, and filtration in a ceramic candle filter array. The fuel gas is fired in a modified W501G machine and exhausted through a HRSG to produce steam for one of the existing steam turbines. The transport gasifier concept evaluated in this study is based on concepts being evaluated at the DOE Power Systems Development Facility in Wilsonville, AL. This concept may not be commercially available at the beginning of the reference time frame, but can be expected to be ready for service at the end of this time period. The transport reactor in this repowering application results in an increase in net output to 368 MWe, and a reduction in heat rate to 6854 Btu/kWh.

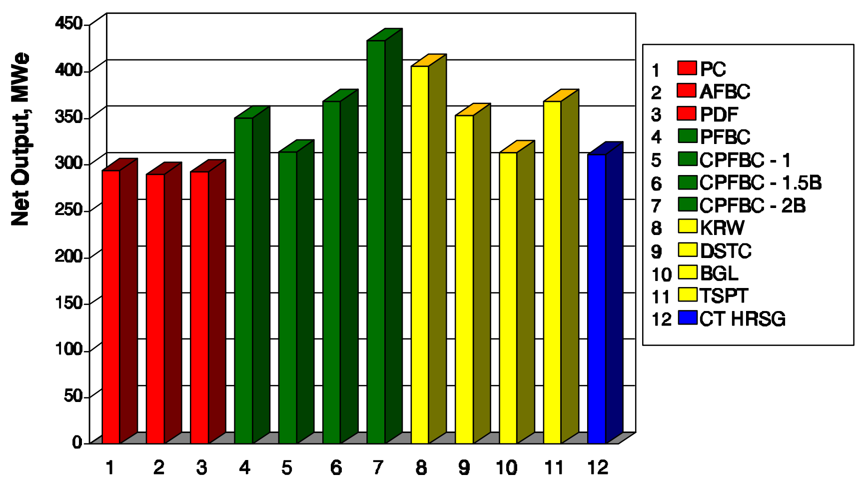
12. Combustion Turbine/Combined Cycle. A natural gas fired, state-of-the-art combustion turbine is used in conjunction with a HRSG to repower one of the two existing steam turbines in this case. The W501G machine is coupled to a multi-pressure HRSG to provide a net station output that is 312 MWe, with a net heat rate of 7080 Btu/kWh. Two gas turbines repowering both existing steam turbines were not used, since the resulting net power would be more than double the original output, and in excess of study guidelines. The second of the two original steam turbines is placed in reserve status.

Results

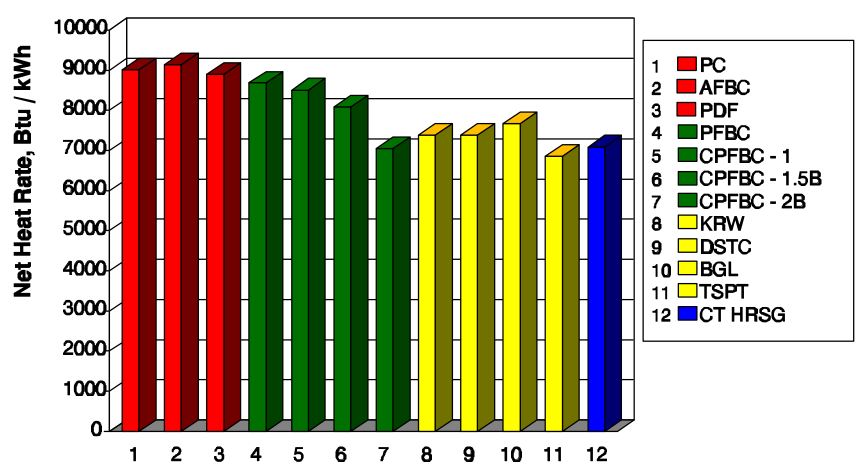
The completed study provides thermal performance for each repowering application, as well as a conceptual cost estimate and economic projections. The study results should be interpreted with caution, since changes in site conditions, financial ground rules and inputs, or other factors could impact the relative performance of the technologies. Based on the inputs adopted for this study, stated in the report, the following comparisons are presented:

The first two graphs illustrate net electric output and heat rate for the various repowering configurations. In several instances, only one of the two existing steam turbines is reused. For these cases (CT/HRSG, Transport Gasifier, Destec, and BG/L Gasifiers), utilization of the second steam turbine would have required additional combustion turbine capacity, and would have yielded about twice the net power output. This large increment of power was considered to be beyond the site transmission capacity, and therefore was not attempted.

TOTAL NET PLANT GENERATION

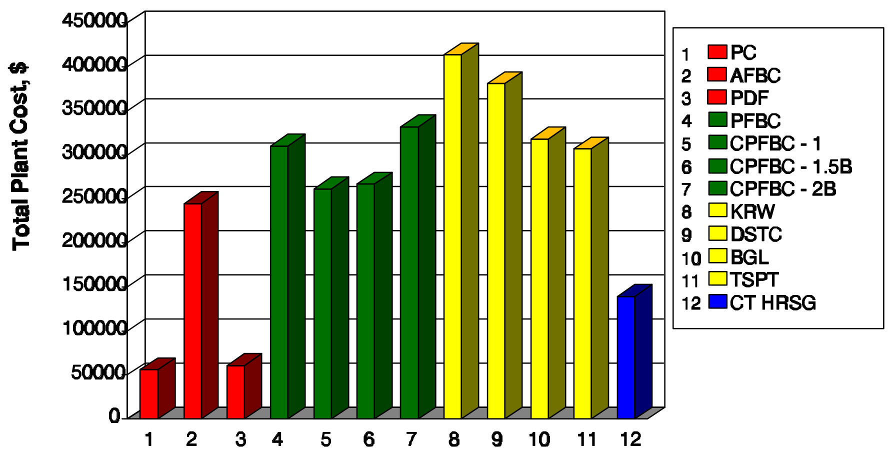


HEAT RATE COMPARISON

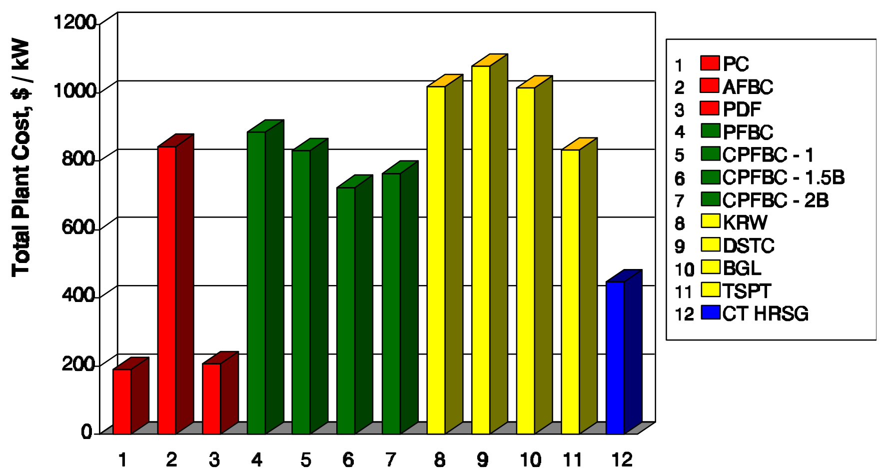


The second set of graphs presents plant capital costs on a Total Plant Cost (TPC) basis, both in absolute and in per kWe terms. As a group, the advanced technologies range from about $700 to $1000 per kWe, in this repowering application.

TOTAL PLANT COST

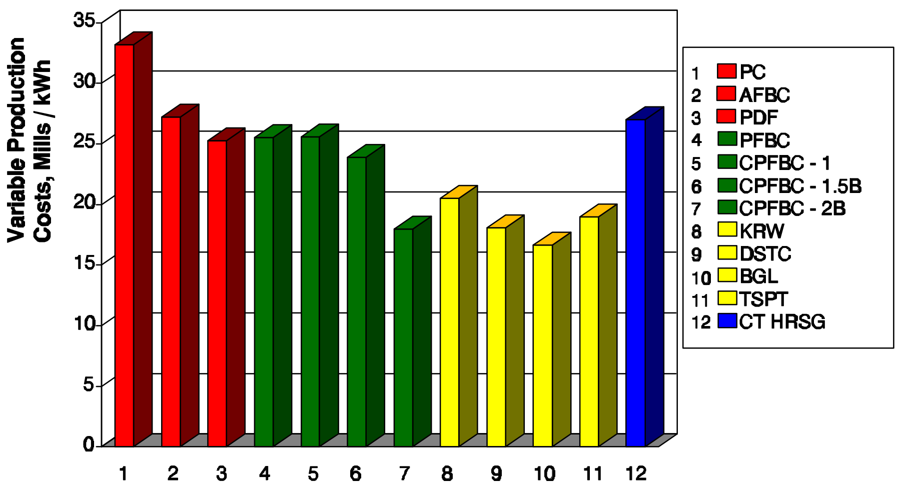


TOTAL PLANT COST/kW

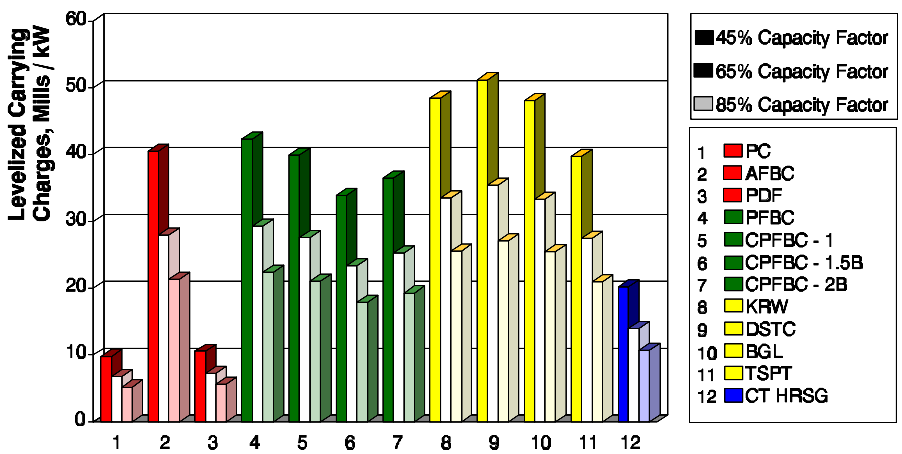


The next charts compare variable and fixed costs for the technologies evaluated. The first chart compares variable costs, which are comprised of the following components: fuel, sorbent, consumables, emissions credits or charges, byproduct credits or charges, and the variable portion of operation & maintenance. The second chart shows the effects of capacity factor on levelized carrying charges for a range of values (45, 65, and 85%).

VARIABLE PRODUCTION COSTS



LEVELIZED CARRYING CHARGES



In general, cases involving relatively large capital investment should (and do) result in plants that offer better operating efficiencies and costs. Cases that only require minimal capital investment may offer little or no change in variable operating costs. The combination of levelized capital carrying charges and variable production costs provides insight into the ultimate economic benefits of the repowerings. The most valid appraisal of each case may be obtained by evaluating it in a specific production costing simulation representing an actual application. The relative ranking of the repowering alternatives may vary from one actual application to another, depending on how all of the cost, financial, and economic parameters resolve into final data.

Contract Information

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