Performance Model of the Externally-Fired Combined Cycle (EFCC) System

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INTRODUCTION

The Externally Fired Combined Cycle (EFCC) is an advanced power generation concept, using coal or other ash bearing fuels such as peat, wood waste, and bitumen emulsion, with a potential for higher thermal efficiency and a lower cost than conventional coal-fired power generating systems.[1] The concept incorporates the highly efficient gas turbine combined cycle technology for use with coal. In contrast to "direct fired" combined cycles, the EFCC concept does not require any special fuel preparation, coal beneficiation, or coal conversion.

The EFCC concept has yet to be demonstrated commercially. The concept is under development by Hague International and the U.S Department of Energy (DOE). The main obstacle in the development of a viable EFCC system has been the unavailability of a suitable heat exchanger which would allow for a sufficiently high gas turbine inlet temperature. Recent developments in ceramic heat exchanger (CerHx) technology for use in the EFCC process have been promising enough to warrant further development of this system.

This project involves development of engineering performance and cost models of the EFCC technology based on available performance and cost information. Since this technology is in the early stages of development, there are inherent uncertainties in the performance and cost parameter estimates. A probabilistic modeling capability will be incorporated to account for the uncertainties in the performance and cost parameters. Details of previous work on probabilistic modeling can be found elsewhere.[2-5]

The results obtained from the EFCC model simulation will include the possible ranges of values for the performance, environmental emissions, and cost parameters, and information about the probability of obtaining these results. These results will be used to characterize key uncertainties; optimize the flowsheet configuration and parameter values; identify priorities for further research; and probabilistically compare competing advanced coal based power generating technologies, such as Integrated Gasification Combined Cycle (IGCC) systems, with the EFCC technology in order to identify the risks and potential payoffs of the EFCC technology relative to the other technologies.

KEY FEATURES OF THE EFCC

In the EFCC process, a coal combustor and a CerHx, along with auxiliary components, replaces the gas turbine combustor of a natural gas-fired gas turbine. Flue gas from the coal combustor is used to heat high pressure air in the CerHx. Hot, high pressure air from the CerHx is expanded in the turbine to generate electricity. The exhaust air from the gas turbine, which is at approximately 1000 ^{o}F and contaminant-free, is used as the combustion air for the coal combustor. Hence, this process is also called Exhaust-Fired Combined Cycle. Since the temperature of the exhaust flue gas from the CerHx is around 1500 ^{o}F, it can be used to supply heat to a bottoming steam cycle for further power generation.

The potential advantages of the EFCC concept are:[1]

1. Conversion of fuel to electricity in small unit sizes (50 MW) with high efficiency.
2. Operation on a wide variety of ash-bearing fuels, with acceptable atmospheric particulate matter emissions when coupled with available pollution control technologies (e.g., fabric filter).
3. It consists of modular subassemblies that can be factory assembled for low initial-cost and short lead-time from order to initial operation, with minimum field erection cost.
4. It can be adapted to commercially available gas turbines, including aircraft derivatives, and it can accommodate a variety of turbine improvements such as high pressure ratios, higher firing temperatures, and steam injection.
5. Using air rather than fuel combustion flue gas as the working fluid for the turbine avoids the problem of corrosion, erosion, and deposition on turbine components.
6. The bottoming-cycle inlet temperature can be varied by adjusting the CerHx operating conditions and parameters, which allows for the optimization of the steam cycle.

7. Since the EFCC system can be built in small unit sizes, it is suitable for increasing the power generation capacity to meet small growth in demand for power, thereby reducing the financing costs compared with other coal-conversion alternatives.
8. It can be adapted to repower existing steam-cycle power plants, with increases in output and improvements in overall plant thermal efficiency.

DESIGN BASIS FOR THE EFCC

A conceptual process model was developed by Hague International (HI) to estimate the performance of a 300 MW EFCC system.[6] Figure 1 shows the flow diagram for this process.

In this process coal is combusted in an atmospheric pressure coal combustor. The combustor exhaust gases pass through a slag screen to remove large (> 12 micron) particles and then enter the shell-side of a ceramic heat exchanger. Clean filtered air is pressurized in a compressor before it enters the tube-side of the heat exchanger. In the heat exchanger, the thermal energy of the combustion flue gas is transferred to the high pressure air flowing in the tube-side. The temperature of the air is raised to the desired turbine inlet temperature. Internally insulated, high pressure piping is used to transport the hot, compressed air to the turbine, where it is expanded to provide the power to drive the compressor and the electric generator. Turbine exhaust air exits at a pressure slightly above one atmosphere, and enters the coal combustion chamber. Flue gas exiting the shell-side of the ceramic heat exchanger is at high enough temperature to fire the bottoming steam cycle through a Heat Recovery Steam Generator (HRSG). Table 1 lists typical process conditions for the stream numbers shown in Figure 1. These data are based on EFCC design studies.[6]

The gas turbine inlet air mass flow rate is less than that for compressed air because a bleed stream is extracted from the compressed air stream for turbine blade cooling. Leakage from the high pressure air stream in the CerHx to the low pressure flue gas stream further reduces the mass flow rate of the inlet air stream to the gas turbine. There is a slight increase in the mass flow rate of the flue gas flowing through the HRSG due to possible leakage of steam from the HRSG into the flue gas stream. An Induced Draft (ID) fan is located downstream of the fabric filter to overcome pressure drops in the slag screen, CerHx, HRSG, Flue Gas Desulfurization (FGD) unit, and the fabric filter.

STATUS OF THE EFCC

In 1987, the U.S. DOE and a consortium of electric utilities and industrial organizations initiated an EFCC Development Program. The program consists of a series of proof-of-concept tests, combined with research and development activities, to be followed by the construction, installation, and operation of a prototype.

Work done under Phase I of the program involved testing a low pressure ceramic heat exchanger. It was exposed to the products of combustion of a coal/water slurry for 40 hours. The experiments showed that ash buildup occurred on the heat exchanger tubes. This buildup indicated the need for an upstream ash collection system. Nonetheless, the ceramic tubes exhibited good durability under all test conditions.[7] Phase I was completed in March 1989.

Phase II of the program, now underway, involves design, construction, and operation of a full scale-test facility at Kennebunk, Maine. The components of this facility include a 500 KW gas turbine, ceramic heat exchanger, slag screen, and a 7.4 MW_t (25 x 10^6 Btu/hr) combustion system. The heat exchanger will function under actual gas turbine operating conditions. Therefore, the tubes will be pressurized and thermally cycled under gas turbine operating conditions. The primary objectives of this phase are to demonstrate that the ceramic heat exchanger can be reliably pressurized up to 165 psia and that it can withstand exposure to coal combustion products. Work on this phase began in December, 1991 and is nearing completion. The test results will be available beginning mid-1994.[9]

Phase III will involve work on a "Prototype Externally Fired Combined Cycle", and phase IV will involve a "Commercial EFCC Demonstration".[1]

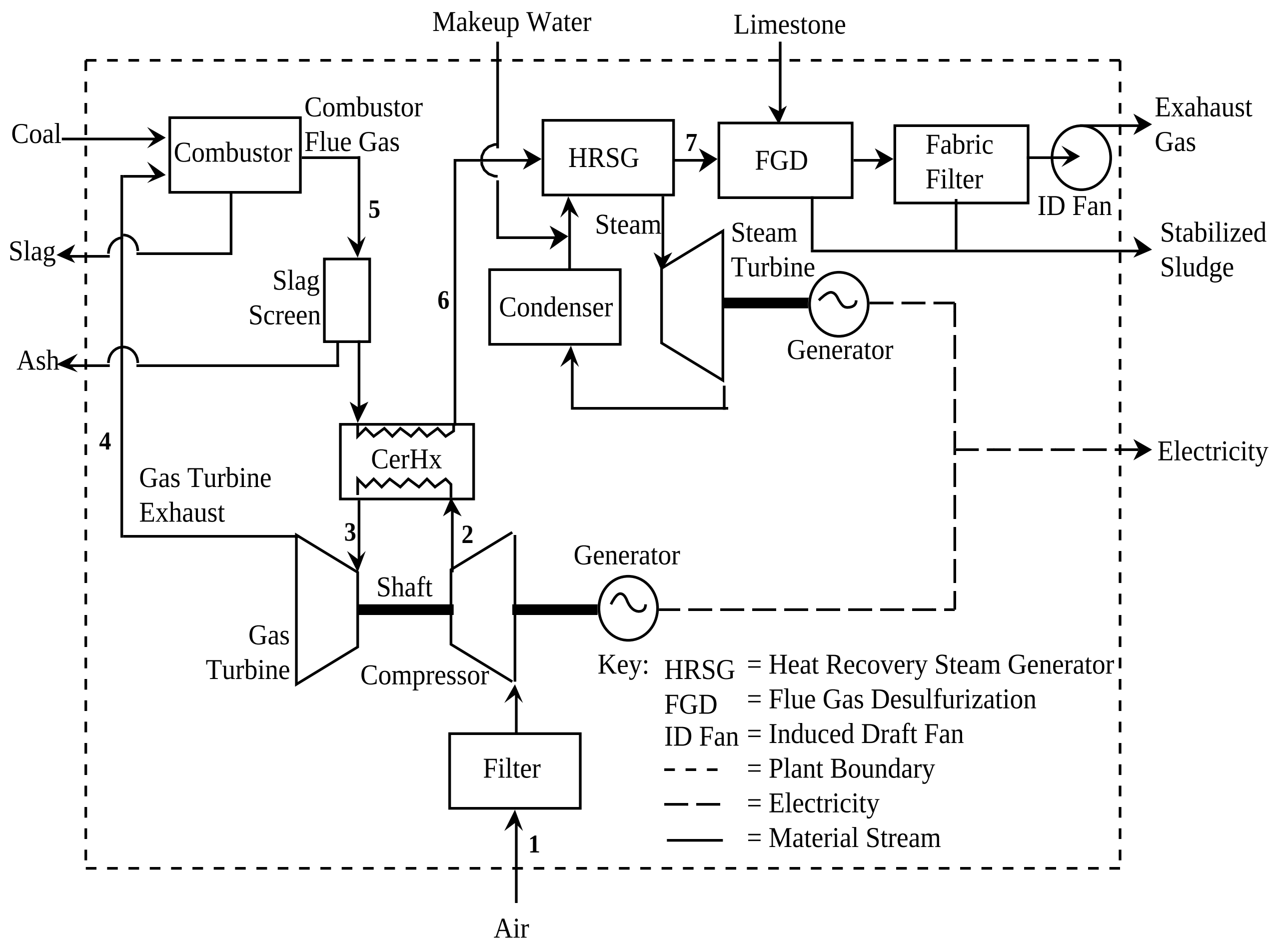

Figure 1. Process flow diagram of an EFCC conceptual model.[7]

Table 1. Typical stream process conditions for an EFCC system.[a,8]

Stream #	1	2	3	4	5	6	7
Stream Description	Inlet Air to Compressor	Compressed Air	Gas Turbine Inlet Air	Gas Turbine Exhaust	Combustor Exhaust Flue Gas	Heat Exchanger Exhaust	HRSG Exhaust
Flow Rate (lb/s)	918	918	872	872	1066	1074	1089
Temperature (^oF)	59	685	2183	1087	2701	1564	122
Pressure (psia)	14.7	196.9	193	15.1	14.9	13.9	13.6

[a] Steam Cycle: 2600 psia/1050 ^oF/1050 ^oF reheat

Phase III, or the demonstration phase, of the program was selected under Round V of the U.S Clean Coal Technology Program in May 1993. The objective of this phase is to repower an existing coal-fired powerplant in the Pennsylvania Electric Company (Penelec) system at Warren, Pennsylvania. To demonstrate the advantages of repowering an existing coal fired steam plant with an EFCC, Hague International developed a conceptual design for repowering an actual plant. This design formed the basis for the Warren plant repowering. The estimated start up date for this project is November 15, 1996.[9]

UNCERTAINTY IN THE EFCC

Development and analysis of conceptual process models for the EFCC power generation technology has shown the potential of high thermal efficiency and low cost, with acceptable environmental emissions. However, no "fifth-of-a-kind" or commercial EFCC plant is operational as yet. Therefore, making predictions regarding the mature commercial scale performance and cost of an EFCC plant involves uncertainties. A few examples are briefly described.

The CerHx for EFCC application has not yet been fully developed and tested under actual operating conditions. Most of the work done on the development of the CerHx has been related to modifying a low pressure recuperator for EFCC application. The performance of the CerHx under high pressure and in a corrosive coal combustion flue gas environment is still uncertain.

The inlet temperature to the bottoming steam plant is much higher than that experienced in a conventional coal-fired power plants, which introduces uncertainty in its performance. Several modifications have to be made to a commercially available gas turbine for use in an EFCC plant. Such modifications, although conceptually possible, have yet to be proven feasible on a commercial scale. Innovative sulfur removal technology based on an amine solvent has been proposed to control sulfur emissions, but such a system has not yet been proven successful on a commercial scale. Instead a wet limestone system could be used which is in commercial use and has established performance and cost.

The cost of several process equipment areas are also uncertain due to uncertainties in their performance and availability. Since the CerHx is the only process equipment in the EFCC process which is not commercially available, the process and cost parameters related to it are expected to be the most uncertain.

MODELING THE EFCC USING ASPEN

The Department of Energy (DOE) Morgantown Technology Energy Center (METC) has developed a performance model for a 264 MW_{net} EFCC system based on a Hague International (HI) conceptual design of the system. The model was developed as an ASPEN (Advanced System for Process ENgineering) input file. ASPEN is a Fortran-based deterministic steady-state chemical process simulator developed by the Massachusetts Institute of Technology (MIT) for DOE to evaluate synthetic fuel technologies.[10] The ASPEN framework includes a number of generalized unit operation "blocks", which are models of specific process operations or equipment (e.g., chemical reactions, pumps). By specifying configurations of unit operations and the flow of material, heat, and work streams, it is possible to represent a process plant in ASPEN. In addition to a varied set of unit operation blocks, ASPEN contains an extensive physical property database and convergence algorithms for calculating results in closed loop systems, all of which make ASPEN a powerful tool for process simulation.

The METC EFCC performance model has been used to calculate mass and energy balances for the EFCC system and to conduct sensitivity analyses of performance parameters. While the bulk of the model is comprised of generalized unit operation blocks, there are a number of Fortran blocks and design specifications which are specific to the EFCC system or to the flowsheet. There are also user models to handle coal properties, and there is a Fortran block used as a summary report writer to concisely present plant performance results. The flowsheets have been developed in a modular approach to allow sections to be "borrowed" from other flowsheets, substantially reducing development time of new EFCC simulation models.

The METC model represents a modified HI EFCC design. It consists of a slagging combustor fueled by Illinois No. 6 coal, a ceramic heat exchanger (CerHx), a 2300^{o}F turbine inlet temperature gas turbine, a heat recovery steam generation (HRSG) system, a 1785 psia, 1050^{o}F superheater, 1050^{o}F reheater steam cycle, and a flue gas desulfurization (FGD) unit. The flue gas exiting the combustor passes through the CerHx and HRSG, and is then treated in a wet limestone FGD scrubber to remove sulfur dioxide. The CerHx indirectly heats the gas turbine expansion stream to the turbine's inlet temperature.

Several modifications have been made to the existing METC model. These include scaling the auxiliary air requirement to the flow rate of coal, estimations of NO_x emissions, modification to the gas turbine to account for choked flow at the turbine inlet nozzle, estimation of auxiliary power consumption based on performance parameters, reheat of flue gas from the FGD unit, and addition of a slag screen and fabric filter to account for the pressure drops across these units.

Several of these modifications are described here.

Auxiliary Air Requirement

Auxiliary air is required to deliver the pulverized coal from the coal handling system to the coal combustor. Therefore, the auxiliary air requirement is proportional to the coal feed rate to the combustor. In the METC model the auxiliary air flow rate is initialized at 144,000 lb/hr, and does not change with a change in the coal feed rate.

Design specification AUXADJ was added to scale the auxiliary air requirement to the coal feed rate. In the METC base case model, 144,000 lb/hr of auxiliary air was assumed to be required to deliver 182,000 lb/hr of coal. Therefore, 0.79 lb auxiliary air per lb of coal feed rate is required. Based on this data, the auxiliary air requirement was scaled to the coal feed rate, which is estimated by the following equation:

$$m_{a,PA,i} = 0.79\, m_{cf,CH,i} \quad (1)$$

Air Leakage in the Ceramic Heat Exchanger

A portion of high pressure air leaks from the tube side to the shell side of the CerHx through the tube joint gaskets and due to tube string misalignments as a result of assembly. Cycle studies have indicated that for a three percent air leakage rate there is a resulting 1.5 percent loss in cycle efficiency. Hague International has developed a gasket design specifically for the high temperature operating conditions of the CerHx which reduces the air leakage. Initial tests of prototype tube strings by Hague International showed less than three percent leakage. Tests with production components have shown leakage rates of one percent and in some cases as low as 0.5 percent.[7] Due to the air leakage in the CerHx, the high pressure air mass throughput to the turbine is reduced, which results in a lower net work output from the gas turbine. The air which leaks into the shell side reduces the temperature of the flue gas entering the HRSG and increases its mass flow rate, which lowers the efficiency of the steam cycle and increase the ID fan power requirement. Therefore, air leakage in the CerHx imposes an energy penalty and reduces the plant efficiency.

Air leakage from the CerHx tubes is simulated in the performance model by splitting the high pressure air flow using an FSPLIT unit operation block. The air leak stream and the flue gas stream are mixed using a MIXER unit operation block. As an approximation to air leakage occuring internally in the CerHx, fifty percent of the leakage is assumed to occur from the high pressure inlet air stream, which mixes with the flue gas exit stream from the CerHx before entering the HRSG. The rest of the leakage is assumed to occur from the high pressure exit air stream, which mixes with the flue gas inlet stream to the CerHx before entering the CerHx. Performance model simulations assuming 100 percent of leakage at either the inlet or exit streams of the CerHx showed no change in net plant efficiency. Therefore, the simplified model of air leakage appears to provide predictions of efficiency penalties with reasonable accuracy.

Gas Turbine Mass Flow

The mass flow rate through the compressor is typically limited by the mass throughput capacity of the turbine. This, in turn, depends upon the critical area of the turbine inlet nozzle. By scaling the turbine mass throughput based upon the critical area of the nozzle, the gas turbine throughput under various conditions of pressure, temperature, and working fluid molecular weight can be predicted. Therefore, we developed a model of turbine throughput based on choked conditions.

The flow at the inlet of the gas turbine expander is choked (i.e., the Mach number of the gas stream is unity). This is true regardless of the fuel type because the pressure ratio across the first stage turbine nozzle is large enough to cause choking. The mass flow rate into the expander is then proportional to the critical area (the location in the expander inlet nozzle where the sonic velocity is reached) and the total pressure, and inversely proportional to the square root of the total temperature at the expander inlet. "Total" conditions characterize the state of the gas if it were isentropically bought to rest. An equation representing this relationship is given by (please see nomenclature section at end:[11]

$$m_{a,GT,i,choked} = m_{ref,GT,i} \frac{\dfrac{P_{a,GT,i}}{P_{ref,GT,i}} \sqrt{\dfrac{mw_{a,GT,i}}{mw_{ref,GT,i}}}}{\sqrt{\dfrac{T_{a,GT,i}}{T_{ref,GT,i}}}} \tag{2}$$

A mixture of air and natural gas was considered as the reference gas. Design specification TCHOKE was added to adjust the flow of hot air at the turbine inlet nozzle corresponding to choked flow conditions for other gas mixtures.

In the METC model the air for cooling the turbine blades is extracted from the discharge of the last compressor stage. The total cooling requirement has been assumed to be 19.6 percent of the compressor discharge air, of which 42 percent enters the turbine inlet and the rest bypasses it. In a heavy duty gas turbine the cooling flows are extracted from the discharge of each compressor stage. Therefore, the METC model has been modified to simulate cooling extraction streams from each compressor stage discharge. Six percent of the inlet air flow to the compressor is directed to the first and second stage turbine inlets from the third stage compressor discharge, three percent of the inlet air flow to the compressor is directed to the third stage turbine inlet from the second stage compressor discharge, and three percent of the inlet air flow to the compressor is assumed to bypass the turbine. FSPLIT unit operations blocks were used to split the compressor discharge flows and MIXER unit operation blocks were used to mix the inlet streams to the turbines. FORTRAN block AIRCOOL was used to set the cooling air stream fractions. The gas turbine model has been calibrated to a GE Frame 7F firing natural gas. Sensitivity analysis of the model revealed expected changes with respect to parameters such as ambient temperatures.

FGD Flue Gas Reheat

The flue gas exits the FGD unit at 127 ^{o}F. This temperature is not high enough to give the stack gas sufficient buoyancy for dispersion. Therefore, the temperature of the flue gas needs to be raised. This is done by heating it using low quality steam from the HRSG. Steam usage for FGD reheat imposes an energy penalty. FGD reheat was not included in the original METC model.

A HEATER unit operation block is used in the ASPEN performance model to estimate the heat duty of the reheater. Steam is extracted from the input stream to the second low pressure steam turbine stage for providing the heat input for the FGD flue gas. The enthalpy required for the FGD flue gas reheat is subtracted from the enthalpy of the stream entering the second low pressure steam turbine stage. The work output of this turbine stage is then scaled down in proportion to the reduction in the mass flow rate of steam input, which represents the efficiency penalty of the steam cycle. The gross power output of the steam cycle and the new plant efficiency is then estimated.

AUXILIARY POWER CONSUMPTION FOR THE EFCC

Some process areas of the EFCC plant consume significant amounts of electrical power for the operation of certain components (e.g., conveyor belt, pumps, fans, etc.). The net saleable power output of the plant is reduced due to these auxiliary power requirements. Previously developed ASPEN performance models do not adequately estimate these power requirements. New auxiliary power

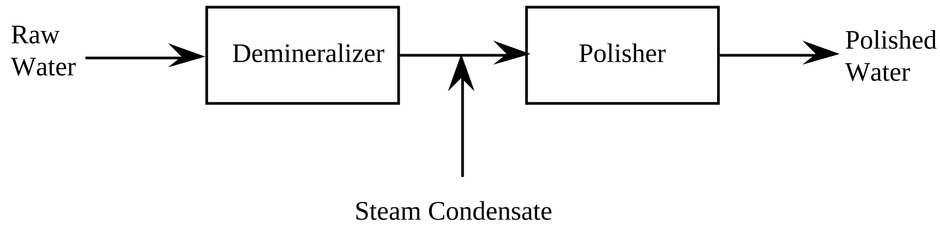

Figure 2. Boiler feedwater treatment system.

requirement models have been developed and integrated with the ASPEN performance model. These models are based on process variables such as flow rates.

In the METC performance model of the EFCC system the auxiliary power requirement has been assumed to be three percent of the net electrical power output. The auxiliary power requirement need not necessarily be three percent of the plant total, and it is expected to change with a change in the process variables of the system other than gross power output. A change in auxiliary power affects the net plant power output and plant efficiency. For example, steam injection to the gas turbine may significantly change gross power output without significantly changing auxiliary power loads. For these reasons a better estimate of the plant auxiliary power requirement is needed. Here we document the development of new models for auxiliary power consumption.

Coal Handling

The EFCC system uses dry, pulverized coal as feed to the coal combustor. Therefore, a coal handling system similar to that used in a Pulverized Coal Fired Steam (PCFS) plant is required for coal handling in an EFCC plant. For a 600 MW PCFS power plant with a mass flow rate of coal of 6,350 tons/day the auxiliary power requirement is reported to be 2480 kW.[12] Based on this data, the auxiliary power requirement for the coal handling section can be estimated by the following equation:

$$W_{e,CH} = 0.391\ m_{cf,CH,i} \tag{3}$$

A typical mass flow rate of coal for a 255 MW_{net} EFCC plant is 2,200 tons/day, and the auxiliary power requirement using the above equation is 850 kW.

Boiler Feedwater Treatment

The boiler feedwater system supplies the water for steam generation in the Heat Recovery Steam Generator (HRSG). The boiler feedwater consists of the raw water (makeup water) and the steam turbine condensate. Raw water is treated and mixed with steam condensate. The combined stream is then chemically polished. Figure 2 shows a simple schematic of the boiler feedwater treatment system.

The equipment in the boiler feedwater system consists of a water demineralization unit for raw water, a demineralized water storage tank, a condensate surge tank for storage of both demineralized raw water and steam turbine condensate water, a polishing unit, and a blowdown flash drum. The major streams in this process section are the raw water inlet and the polished water outlet.

The boiler feedwater section is generic to the steam cycle. Therefore, the following equation which estimates the auxiliary power requirement for the boiler feedwater treatment section in the steam cycle of an IGCC system[13] can be applied to the EFCC system:

$$W_{e,BF} = 20.8 + 2.13\text{x}10^{-4}\ m_{pw} \tag{4}$$

The coefficient of determination for this regression model is $R^2 = 0.975$. A total of 14 data point were used to develop the model. The standard error of the estimate is 38 kW.

A typical mass flow rate of polished water for a 255 MW_{net} EFCC plant is 800,000 lb/hr, which is within the valid range of values for this model.

Induced Draft Fan

An Induced Draft (ID) fan is required downstream of the fabric filter to overcome pressure drops in the slag screen, CerHx, HRSG, FGD unit, and the fabric filter. Therefore, the power requirement of the ID fan depends on the pressure drops across these units. In the METC performance model the ID fan has been modeled as a compressor required to boost the pressure of the flue gas to atmospheric pressure.

An ID fan is more realistically modeled as a fan since the pressure differential is less than 15 kPa (2.176 psi). Compressors are more complicated equipment which are used for applications where the pressure differential is 3.5 kPa (0.51 psi) to several hundred kPa (psi). Therefore, it is more practical and economical to use a fan to raise the pressure of the flue gas to one atmosphere.[14]

The power requirement of an ID fan is estimated by the following equation:[14]

$$W_{e,ID} = 0.0542 \left(\frac{m_{fg,ID,i} \times \Delta p_{ID}}{D_{fg,ID,i} \times \eta_{fan}} \right) \qquad (5)$$

The magnitude of the pressure difference across the ID fan depends on the pressure drop of the flue gas across the coal combustor, slag screen, ceramic heat exchanger, HRSG, FGD unit, and the fabric filter. For an EFCC plant, a typical ID fan pressure rise of approximately 1.4 psi is required. For a typical 255 MW_{net} EFCC power plant, this corresponds to a power requirement of 6.65 MW.

Primary Air Fan

A primary fan is required to add auxiliary air to the coal combustor. Auxiliary air is required to deliver the pulverized coal from the coal handling system to the coal combustor. Therefore, the auxiliary air requirement is proportional to the coal feed rate to the combustor. In a 264 MW EFCC system, 144,000 lb/hr of auxiliary air is assumed to be required for pneumatic transport of the pulverized coal feed. In the METC performance model the primary air mover has been modeled as a compressor. The pressure rise required for the auxiliary air is 1.7 psi. Therefore, for reasons outlined above, the primary air mover is more accurately modeled as a fan.

The equation for estimating the power requirement is similar to the one used for the ID fan.

$$W_{e,PA} = 0.0542 \left(\frac{m_{a,PA,i} \times \Delta p_{PA}}{D_{a,PA,i} \times \eta_{fan}} \right) \qquad (6)$$

The pressure rise across the primary air fan in a 255 MW_{net} EFCC system is 1.7 psi.

Steam Cycle Power Requirement

In the steam cycle auxiliary power is consumed by the condenser pump and the boiler feed pump. The power consumption is estimated directly from the ASPEN simulation.

The condenser pump and the boiler feedwater pump have been modeled in ASPEN as centrifugal pumps using the unit operation block "PUMP". The outlet pressure has been set at 17.5 psia for the condenser pump , and at 2000 psia for the boiler feedwater pump. Using the inlet stream information and outlet pressure requirement, "PUMP" calculates the electrical power requirement.

Flue Gas Desulfurization (FGD) Power Requirement

In the FGD unit, limestone slurry is injected into absorber towers to remove sulfur dioxide from the flue gas. Electrical power is consumed in the FGD by the different FGD process areas. Table 3 shows

Table 2. Electrical power consumption of base case utility plant FGD unit for FGD process areas.[12]

Area No.	Area Description	Process Variable	Process Variable Value	Power Consumed (kW)
71	Reagent Feed System	Reagent feed (gpm)	82	230
72	SO_2 Removal System	SO_2 concentration (ppm)	3571	3,090
73	Flue Gas System	Flue gas volumetric flow rate (ft^3/min)	971,000	1,550
74	Solids Handling System	Sludge flow rate (lb/hr)	30,800	70
75	General Support Equipment	Power consumed for other FGD Areas (kW)	4,940	30

the various FGD process areas which consume electrical power and the process variable related to the amount of power consumed.

The power consumed by the different process areas of the FGD unit in an EFCC plant can be estimated based on the reported values of the power consumed by similar FGD process areas in a base case utility plant. This is done by scaling the power consumption to the magnitude of the process variable related to the process area. The power consumed in the flue gas system of the FGD unit in the EFCC plant is estimated as part of the power consumption of the ID fan. The power consumed by the different process areas of a 300 MW base case utility plant FGD unit is shown in Table 2.

The power consumption of process area 73 is already accounted for in the ID fan power requirement. Based on the data in Table 3 the power consumed by the various process sections of an FGD unit in kW, can be estimated by the following equations:

$$W_{e,FGD,71} = 0.006564\ m_{L,FGD,i} \tag{7}$$

$$W_{e,FGD,72} = 0.865\ Y_{SO_2} \tag{8}$$

$$W_{e,FGD,74} = 0.0023\ m_{s,FGD,o} \tag{9}$$

$$W_{e,FGD,75} = 0.006 \sum_j W_{e,FGD,j} \tag{10}$$

where,

j = process areas 71,72,74

The total power consumption of the FGD unit, excluding the power consumption of the flue gas system, is given by:

$$W_{e,FGD} = W_{e,FGD,71} + W_{e,FGD,72} + W_{e,FGD,74} + W_{e,FGD,75} \tag{11}$$

General Facilities

The general facilities include power requirement for cooling water systems; plant and instrument air; potable and utility water; fuel system; effluent water treating; flare system; fire water system; interconnecting piping; buildings; railroad facilities, roads, and lighting; computer control system; and electrical system. The in-plant power consumptions for general facilities for a 600 MW PCFS plant is reported to be 3,400 kW. The total auxiliary power consumption for this plant is 40,500 kW. The general facilities power consumption is therefore approximately 9.3 percent of all other auxiliary power consumption. Since the components of general facilities of an EFCC plant are similar to that of the PCFS plant, it is assumed that the general facilities power consumption for an EFCC plant will be on a similar scale to that for the PCFS plant. The general facilities power consumption for the EFCC plant can therefore be estimate by the following equation:

$$W_{e,GF} = 0.093\ (W_{e,CH} + W_{e,BF} + W_{e,ID} + W_{e,PA} + W_{e,ST} + W_{e,FGD}) \qquad (12)$$

The total auxiliary power demand is the sum of the auxiliary power consumed by each of the process sections, and is given by:

$$W_{aux} = W_{e,CH} + W_{e,BF} + W_{e,ID} + W_{e,PA} + W_{e,ST} + W_{e,FGD} + W_{e,GF} \qquad (13)$$

Net Power Output and Plant Efficiency

The net power output of the EFCC plant is the total power generated from the gas turbine and steam turbines less the total auxiliary power demand.

The gas and steam turbines have been modeled in ASPEN as a series of compressors and turbines using the unit operation block "COMPR". The outlet pressure and isentropic efficiencies are parameters of this unit operation. The ASPEN performance model calculates the power consumed by the compressors and the power generated by the turbines.

The gas turbine energy balance accounts for multiple stages of the compressor and turbine, the flow of cooling air from the compressor to the turbine, and pressure drops at the compressor inlet (due to an intake air filter), ceramic heat exchanger, and turbine outlet. To represent multiple stages of the compressors and turbines, a series of "COMPR" unit operation blocks are employed. The cooling air flow to the gas turbine is extracted from the compressor outlet flow. The pressure rise across the compressor block is 184.3 psi, the pressure drop across the ceramic heat exchanger is 3.5 psi, and the pressure drop across the turbine block is 179.8 psi. The steam turbine consists of four stages: one high pressure stage; one intermediate pressure stage; and two low pressure stages.

The power output of the gas turbine and the steam turbine are calculated within the ASPEN performance model. The newly developed auxiliary power models are implemented as part of a FORTRAN subroutine called by the ASPEN input file. The net power output is given by:

$$MW_{net} = MW_{GT} + MW_{ST} - 0.001\ W_{aux} \qquad (14)$$

The net plant efficiency on a higher heating value basis is given by:

$$\eta_{plant} = \frac{3.414 \times 10^6\ MW_{net}}{m_{cf,CH,i} \times HHV} \qquad (15)$$

The coal feed rate and the higher heating value are estimated directly from the ASPEN simulation.

MODEL APPLICATIONS

In the original METC performance model of the EFCC system, the in-plant power consumption was modeled as a miscellaneous power requirement and auxiliary power requirement. The miscellaneous power requirement includes the power consumption of the FGD unit, primary air fan, induced draft fan, condenser pump, and boiler feed water pump. A regression model based on the SO_2 concentration in the flue gas and the flue gas flow rate to the FGD unit was employed to estimate the power requirement of the FGD unit. The primary air fan and the induced draft fan were modeled as ASPEN compressor unit operation blocks (COMPR), and the power requirement was directly estimated from the ASPEN performance model simulation. The condenser pump and the boiler feedwater pump was modeled as ASPEN pump unit operation block (PUMP), which calculates the power requirement of these units. The auxiliary power requirement was assumed to be three percent of the gross plant power output.

Several modifications have been made to the METC performance model, as described above, which affect the in-plant power consumption. The auxiliary power consumption in the modified model has been calculated, based on the performance parameters, for each process section. This approach gives a more realistic estimate of the auxiliary power consumption.

Table 3. In-plant power consumption of METC model and modified EFCC model

	Power Consumed (kW)	
Process Section	**METC Model**	**Modified Model**
Auxiliary Power	8,160	
Primary Air Fan	230	208
ID Fan	3,020	6,646
FGD Unit	7,300	3,347
Condensor Pump	14	14.3
Boiler Feedwater Pump	1,963	2005
Coal Handling		863
Boiler Feedwater Treatment		190
General Facilities		1234
Total In-Plant Power Consumption	20,687	14,507
FGD Reheat	0	16,000[a]
Net Plant Efficiency (%, HHV Basis)	44.1	42.05

[a] Converted to an equivalent electrical basis

The newly developed auxiliary power model was implemented as part of a modified version of the METC input file for the EFCC. The new performance model was run using the ASPEN chemical process simulator. Table 3 compares the in-plant power consumption of the METC model and the modified EFCC model.

The total in-plant power consumption of the METC model is approximately 43 percent higher than for the modified model. However, the METC model does not include the efficiency penalty associated with FGD reheat. When reheat is included in the modified model, the total equivalent electricity consumption is higher than that in the original model by 50 percent.

The model results are similar for the primary air fan and the boiler feedwater pump. The sum of the ID fan and FGD power requirements are within ten percent for the two cases. The ID fan power consumption in the modified model is higher than for the original METC model because pressure drops of all components through which the flue gas passes have been more realistically estimated.

There are a number of process areas which are explicitly modeled in the modified model that may have been assumed to be included within the "Auxiliary Power" value for the original METC model. These include coal handing, boiler feedwater treatment, and general facilities. These amount to approximately 2.3 MW of in-plant power consumption, compared to the previous estimate of 8.2 MW employed in the original METC model.

A sensitivity analysis of the net plant efficiency versus the CerHx air leakage rate and heat loss was performed based on a stack gas temperature of 181 ^{o}F. Because the air leakage rate of a commercial scale CerHx is uncertain, the rate was varied form 0.5 to 1.5 percent. The heat loss from the high temperature combustor employed in the EFCC may be greater than for conventional furnaces due to the lack of internal cooling and the large combustor surface area required due to high gas residence time requirements. The results of this analysis are presented in Figure 3. The net plant efficiency decreases linearly with

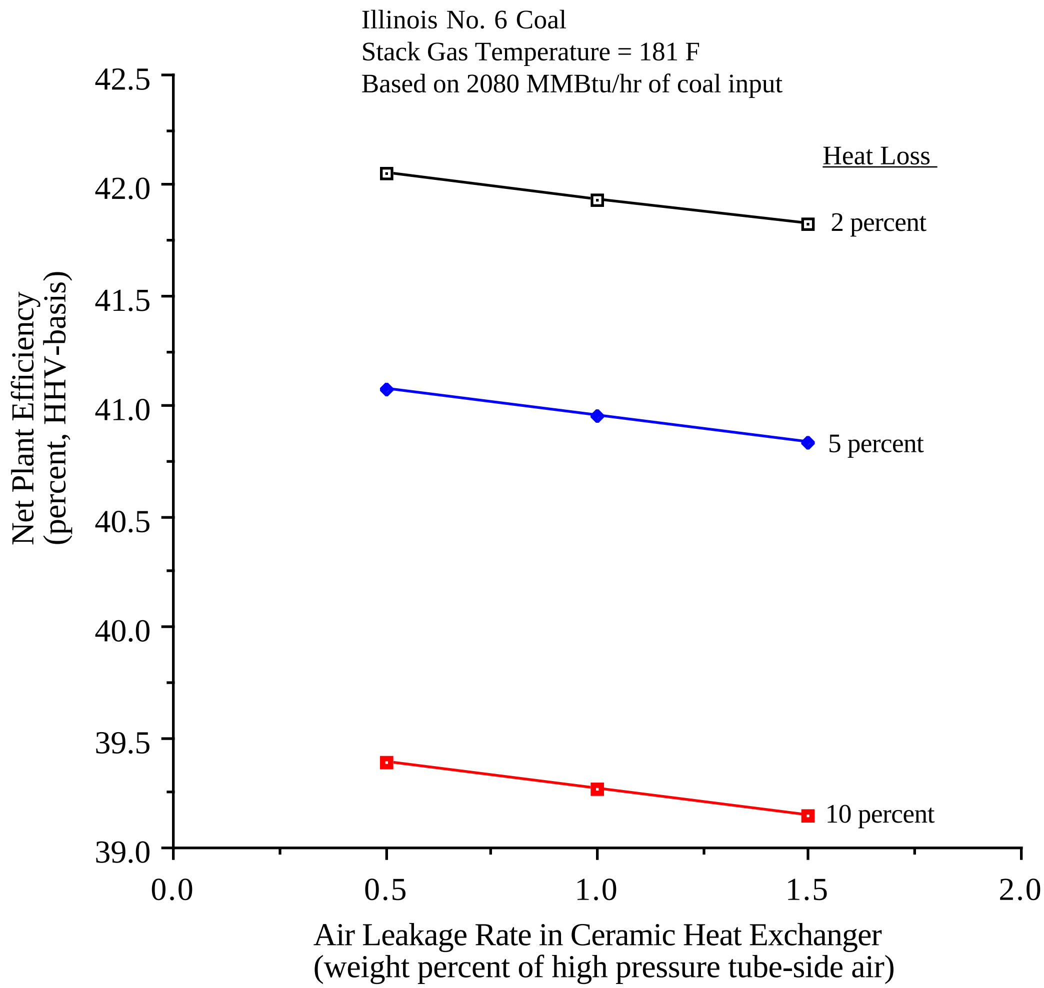

Figure 3. Sensitivity analysis of EFCC net plant efficiency

increasing air leakage rate and heat loss. For the base case model with 0.5 percent air leakage rate and 2 percent heat loss the net plant efficiency is 42.1 percent.

COST MODEL DEVELOPMENT

A new cost model is being developed for the EFCC. The model will include total capital costs, annual fixed and variable operating costs, and levelized costs. Direct capital cost models are being developed for each major process area as a function of key performance (e.g., flow rates) and design variables. These process areas include: coal handling; high temperature coal combustor, slag screen, ceramic heat exchanger, heat recovery steam generator, flue gas desulfurization, fabric filter, boiler feedwater treatment, induced draft fan, gas turbine, steam turbine, and general facilities. Total capital costs include the sum of all direct costs plus project and process contingencies, indirect construction costs, engineering and home office fees, taxes and permits, interest for funds used during construction, royalties and spare parts, preproduction (startup costs), inventory capital, initial catalysts and chemicals, and land. Fixed operating costs include operating and maintenance labor, maintenance materials, and administrative and support labor. Variable operating costs include fuel, chemicals and catalysts, other consumables, and disposal costs for slag, fly ash, and sludge.

The new cost models are being implemented as a stand-alone FORTRAN subroutine that is called by the ASPEN-based performance simulation model.

FUTURE WORK

The newly developed performance and cost models will be applied in a series of case studies in future work. These case studies include applying the model in a probabilistic modeling environment to identify and characterize the key sources of uncertainties; optimize the flowsheet configuration and parameter values; identify process areas for further research; and compare EFCC to other technologies under uncertainty.

Sensitivity analysis of the EFCC model will be done by simulating the following case studies:

1. Varying the steam injection ratio.
2. Altering the gas turbine design parameters such as the inlet firing temperature to 2300 ^{o}F, 2350 ^{o}F, and 2500 ^{o}F.
3. Changing the ambient atmospheric conditions, which affect the CerHx and gas turbine operating conditions.
4. Varying the CerHx gas stream exhaust temperature to optimize the steam cycle.
5. Increasing the CerHx effectiveness to account for possible future improvements in the performance of the CerHx.

Other case studies may be identified and analyzed as appropriate.

CONCLUSIONS

The results of a performance model simulation of an EFCC system indicates a much higher net plant efficiency than a conventional coal-fired power generating system. A more accurate estimate of the net power output of an EFCC plant was obtained by modifying an existing performance simulation model of a 264 MW_{net} EFCC plant. Modifications made included scaling the auxiliary air requirement to the coal input, incorporating air leakage from the tube side to the shell side of the ceramic heat exchanger, adjusting the flow at the inlet of the gas turbine for choked flow condition, accounting for an efficiency penalty due to FGD flue gas reheat, and estimating the auxiliary power requirement more accurately. A better estimate of the auxiliary power consumption was made by accounting for power requirement of each process area separately. As a result of these changes, the net plant efficiency of the EFCC plant was estimated to be 42.1 percent, using a set of base case assumptions, compared to 44.1 percent for the existing EFCC model using the same underlying assumptions. The plant efficiency was shown to be sensitive to combustor and heat exchanger heat losses, and, to a lesser extent, to the air leakage in the ceramic heat exchanger. In future work, uncertainties associated with these and other parameters will be more fully quantified.

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NOMENCLATURE

English Letter Symbols

$D_{i.j.k}$ = Density of species i at plant section j inlet or outlet k (lb/ft^3)
HHV = Higher Heating Value of coal (Btu/lb)
$m_{i,j,k}$ = Mass flow rate of species i at the plant section j inlet or outlet k (lb/hr in all cases except for coal, where the units are tons/day)
$mw_{i,j,k}$ = Molecular weight of species i at plant section j inlet or outlet k
$M_{i,j,k}$ = Molar flow rate of species i at the plant section j inlet or outlet k (lbmole/hr)
MW_j = Electrical output of plant section j (megawatts)
n = Number of data points used in a regression analysis (integer)
$P_{j,k}$ = Pressure at the plant section j inlet or outlet k (psia)
Q_{coal} = Energy flow of coal (MMBtu/hr)
R^2 = Coefficient of determination (decimal)
$T_{i,j,k}$ = Temperature of species i at the plant section j inlet or outlet k (^oF)
$W_{e,j}$ = Electricity requirement for plant section j (kW)
$W_{s,j}$ = Shaft work for plant section j

Greek Letter Symbols

η = Efficiency (decimal)
Δp_j = Pressure drop across plant section j (psi)

Subscripts

aux = Auxiliary
i = Inlet
o = Outlet
plant = EFCC plant
ref = Reference gas

Species

a = Air
cf = Coal feed
fg = Flue gas
L = Limestone
pw = Polished water
s = Sulfur
SO_2 = Sulfur dioxide

Equipment/Plant Sections

CH = Coal handling
PA = Primary air fan
C = Coal combustor
SS = Slag screen
HX = Ceramic heat exchanger
GT = Gas turbine
HR = Heat recovery steam generator
BF = Boiler feed water system
ST = Steam turbine
FGD = Flue gas desulfurization
FF = Fabric filter
ID = Induced draft fan
GF = General facilities
b = represents the base case corresponding to the particular equipment or process area