THERMODYNAMIC AND COST ANALYSES OF A ZERO-ATMOSPHERIC EMISSIONS COAL POWER PLANT

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ABSTRACT

This paper presents the thermodynamic analysis of a coal-based zero-atmospheric emissions electric power plant. The approach involves an oxygen-blown coal gasification unit. The resulting synthetic gas (syngas) is combusted with oxygen in a gas generator to produce the working fluid for the turbines. The combustion produces a gas mixture composed almost entirely of steam and carbon dioxide. These gases drive multiple turbines to produce electricity. The turbine discharge gases pass to a condenser where water is captured. A stream of carbon dioxide then results that can be used for enhanced oil recovery, or for sequestration.

This analysis is based on a 400 MW electric power generating plant that uses turbines that are currently under development by a U.S. turbine manufacturer. The power plant has a net thermal efficiency of 42.6 %. This efficiency is based on the lower heating value of the coal, and includes the energy necessary for coal gasification, air separation and for carbon dioxide separation and sequestration. The paper also presents an analysis of the cost of electricity (COE) and the cost of conditioning carbon dioxide for sequestration for the 400 MW power plant. Electricity cost is compared for three different gasification processes (Texaco, Shell, and Koppers-Totzek) and two types of coals (Illinois #6 and Wyodak). Cost of electricity ranges from 5.16 ¢/kWhr to 5.42 ¢/kWhr, indicating that the cost of electricity varies by 5% for the three gasification processes considered and the two coal types used.

INTRODUCTION

Currently coal provides the fuel for more than half of the electricity generated in the United States (52%). The electricity produced from coal in the U.S., is likely to increase since the U.S. has about 25% (275 billon tons) of the world's coal reserves. Pollution from coal-fired power plants is a pressing environmental problem and the emission of carbon dioxide is of increasing concern in regard to global warming.

Carbon dioxide capture and geologic storage offer a new set of options for reducing greenhouse gas emissions that can complement the current strategies of improving energy efficiency and increasing the use of non-fossil energy resources.

Production of electric power from coal with zero-atmospheric emissions is a goal of the FutureGen Program of the U.S. Department of Energy (DOE) [1]. A decade ago, such a concept would not have been considered to be viable. However, recent research [2-10] has addressed technical and economic issues associated with the concept, making it a viable option.

The power plant concept uses a Rankine cycle to drive three turbines connected in series. However, unlike conventional steam power plants, the plant does not use a boiler to generate steam. Use of a boiler presents two disadvantages to the efficiency of the Rankine cycle. First, the maximum cycle temperature is limited by the maximum metal temperature that boiler components can withstand; and second, 10 to 15 per cent of the energy in the fuel is lost by the exhaust gases that are vented to the atmosphere.

In this study, the turbine working fluid is produced in a gas generator by the stoichiometric combustion of syngas and oxygen. Hence, the maximum operating temperature of the Rankine cycle is no longer controlled by the maximum operating temperature of a boiler. Rather, the maximum operating temperature that the turbines can withstand becomes the efficiency-limiting temperature.

The adiabatic flame temperature of the stoichiometric combustion of syngas is too high for today's turbine technology. Therefore, in the gas generator, water is premixed with the syngas and oxygen before the mixture enters the combustion chamber. In addition, the gas generator [8-10] has several sections in which water is added to the combustion products to bring the gas temperature to a level acceptable to available turbines.

The turbine discharge gases pass to a condenser where water is captured as liquid and gaseous carbon dioxide is pumped from the system. The carbon dioxide can be compressed for enhanced recovery of oil or coal-bed methane, or the compressed carbon dioxide can be injected for sequestration into a subterranean formation. The technology described in this paper is the subject of several U.S. patents [11-20].

The electric power industry has developed new plants applying coal gasification to fuel combined-cycle power plants [21-23]. These integrated gasification-combined-cycle (IGCC) power plants provide performance and cost advantages over conventional coal-fired steam power plants with flue gas desulfurization.

In this paper the gasification technologies by Texaco [24,25], Shell [26], and Koppers-Totzek [27] are used to study the influence in performance and cost of the gasification process in the zero-atmospheric emissions power plant.

The next section describes the specific plant configuration analyzed in this paper. The analysis section discusses the methodology used for analyzing the power plant.

POWER PLANT CONFIGURATION

Figure 1 presents the power plant configuration analyzed in this paper. The power plant has four major sections: 1) coal gasification and syngas compression, 2) air separation and oxygen (O_2) compression, 3) power generation, and 4) carbon dioxide (CO_2) separation and sequestration. Each of these sections consists of multiple components as shown in the Figure 1. For this analysis, the plant is assumed to operate on syngas that is combusted with oxygen. The syngas is produced in a coal-gasification plant, and it is compressed to the inlet pressure of the gas generator (1480 lb/in^2, point 22, Figure 1). Part of the syngas is compressed to a pressure of 310 lb/in^2 for Reheater 1 that is installed between the high-pressure turbine and the intermediate-pressure turbine (point 5). The compression system for the syngas consists of four compressors (Compressors 1 to 4) and three intercoolers (Intercoolers 1 to 3). Oxygen is generated in an air separation plant and is compressed to feed the gas generator and two reheaters. The oxygen compression system consists of four compressors (Compressors 5 to 8) and three intercoolers (Intercoolers 4 to 6).

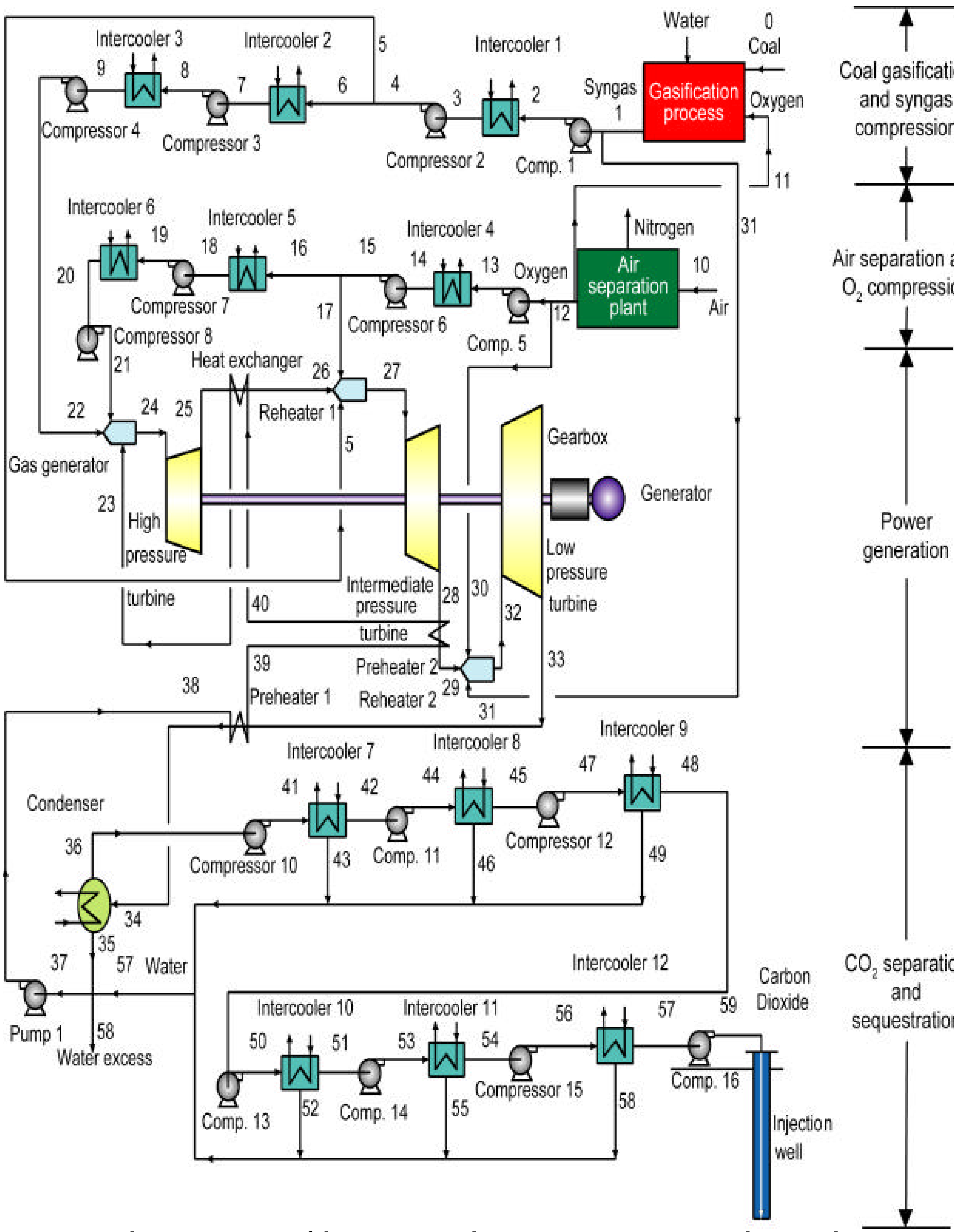

Figure 1. Schematic Diagram of the Zero-Atmospheric Emissions 400 MW Coal Power Plant.

The water for this cycle is generated by the cycle itself. The water leaving the condenser is heated in Preheaters 1 and 2 before the water is injected into the combustion products in the gas generator. These preheaters increase the efficiency of the cycle.

In this study, the preheaters are located in the discharge lines of both the intermediate-pressure turbine and the low-pressure turbine. The preheaters heat the water that is routed from the condenser to the gas generator where the water is evaporated to cool the combustion products in the gas generator. If the water were not preheated, a smaller amount of water would be required to cool the gases in the gas generator. However, taking thermal energy out of the discharge of the drive gas from the low-pressure turbine reduces the energy that is delivered to the condenser. As a result, less heat is transferred in the condenser to the condenser cooling water. This reduced condenser cooling water heat loss increases plant efficiency. The location of the preheaters, the amount of heat removed from the turbine drive gas and the temperature of the cooling water entering the gas generator, all affect cycle efficiency. How this increase in efficiency is obtained is not a-priori clear, but is determined from optimization studies of the entire cycle.

Combustion products from the gas generator are delivered to the high-pressure turbine (point 24) where the mixture of steam and carbon dioxide expands, thereby producing power in the turbine and electrical generator system. The mixture consists of a 0.92 mass fraction of steam and 0.08 mass fraction of carbon dioxide. After the steam and carbon dioxide mixture leaves the high-pressure turbine, the mixture interchanges heat with the water that comes from the Preheater 2 and the enthalpy of the mixture increases then the mixture goes to the Reheater 1 (point 26). The reheater increases the temperature of the mixture before it enters the intermediate-pressure turbine. After the reheater, the working fluid entering the intermediate-pressure turbine consists of a 0.77 mass fraction of steam and a 0.23 mass fraction of carbon dioxide. After leaving the intermediate-pressure turbine, the mixture goes through Preheater 2 and then it goes to a second reheater before entering the low-pressure turbine for its final expansion (point 32). The exhaust from the low-pressure turbine flows through Preheater 1 to preheat the water that was separated from the turbine working fluid in the condenser.

Most of the water that is generated in the cycle is separated from the turbine working fluid mixture in the condenser. Liquid water is extracted from the condenser by Pump 1 and is recycled to the system. The water temperature is increased in Preheaters 1 and 2, before the water goes to the gas generator (point 23) to control the temperature of the combustion products.

A mixture consisting primarily of carbon dioxide, but containing a substantial amount of moisture, is extracted from a port (point 36) at the top of the condenser. The carbon dioxide with the remaining moisture from the condenser is then delivered to several compressors and intercoolers to obtain high-pressure carbon dioxide with almost no moisture. The compression-sequestration system consists of seven compressors (Compressors 10 to 16) and six intercoolers (Intercoolers 7 to 12).

ANALYSIS

The power plant system consists of an oxygen separation plant, a coal gasification plant, gas generator, three turbines, two reheaters, a condenser, fifteen compressors, a pump to recirculate the water from the condenser to the gas generator, a pump for the condenser cooling water, twelve intercoolers, two preheaters, a heat exchanger and an electric generator. Energy and mass conservation laws are applied to every system component. The equations used to describe the power plant components are solved simultaneously in a computer code. A computer code using F-Chart software [28] was developed to analyze plant efficiencies. Individual system components are described next.

Oxygen Separation Plant

The power to operate the oxygen separation plant, 0.22 kWh per kg of oxygen, was obtained from data presented in the literature [29] for a cryogenic air separation plant. Advances in oxygen separation are expected to reduce this power, especially when the ion transport membrane (ITM) technology matures.

Coal Gasification Plant

Three different power plant configurations are compared. Each configuration uses a different oxygen-blown gasifier (Texaco [24, 25], Shell [26], and Koppers-Totzek [27]). Efficiency of the power plant is compared for these three gasification processes operating on Illinois #6 coal and Wyodak coal.

Gas Generator and Reheater

Syngas and oxygen are combusted in the gas generator to produce the turbine working fluid. The temperature of the combustion products of syngas with oxygen is controlled by adding water to the combustion products in the gas generator. The mass flow rate of water into the gas generator depends on the desired inlet temperature of the working fluid for the high-pressure turbine.

A reheater is used to increase the temperature of high-pressure turbine exhaust to the desired temperature for the intermediate-pressure turbine. The reheater produces this temperature increase by burning syngas with oxygen and mixing the combustion products with the high-pressure turbine exhaust.

In the gas generator and the reheaters, assuming an adiabatic process, the rate of change with time of the absolute enthalpy (including both sensible enthalpy and enthalpy of formation) of the products is equal to the rate of change of the absolute enthalpy of the reactants. Complete combustion is considered in the gas generator and in the reheater.

Turbines

Turbines are modeled by the equation of isentropic efficiency [30]. The turbine efficiencies for the high-pressure turbine, the intermediate-pressure turbine and the low-pressure turbine were assumed to be 90%, 91% and 93 % respectively (see Table 1). The efficiency of the high-pressure turbine takes into account the use of short blades; the efficiency of the intermediate-pressure turbine takes into account the blade cooling losses. These efficiencies compare to values of 93% used by Bannister et al. [31], 85% used by Bolland et al. [32] and 93% by Aoki et al. [33].

Heat Exchangers

To determine the performance of the heat exchangers (intercoolers, preheaters, and condenser) an effectiveness equation is used. The heat exchanger effectiveness is defined as the ratio of the actual rate of heat transfer in a given heat exchanger to the maximum possible rate of heat exchange.

This analysis assumes an effectiveness of 85% for intercoolers and preheaters (see Table 1) [32]. The temperature of the environment and cooling water is assumed to be 59 °F to be consistent with the environment temperature used in the analysis of combined cycle plants.

Compressors

Compressors are modeled by the equation of isentropic efficiency [30] defined as the ratio of power needed to compress gases in an isentropic process and the actual power needed in the compression of the gases. The compressors were assumed to have an isentropic efficiency 85 %. Previous researches [31-33] have used compressor efficiencies in the range of 85-89%.

Table 1. Values of the Parameters Used in the Simulation of the Zero-Atmospheric Emissions Power Plant.

System Parameters	**Value**
Preheater effectiveness	0.85
Condenser effectiveness	0.90
Intercooler effectiveness	0.85
Ambient temperature	59 °F
Isentropic efficiency of the high-pressure turbine	90%
Isentropic efficiency of the intermediate-pressure turbine	91%
Isentropic efficiency of the low-pressure turbine	93%
Isentropic efficiency of the compressors	85%
Efficiency of the water pump	85%
Efficiency of the electric generator	98%

Water Recirculation Pump

The isentropic efficiency of the water pump is assumed to be 85%. Previous researchers [31-33] have used pump efficiencies in the range of 85-99%.

Oxygen Separation Plant

The power to operate the oxygen separation plant, 0.22 kWh per kg of oxygen, was obtained from data presented the literature [29] for a cryogenic air separation plant. Advances in oxygen separation are expected to reduce this power, especially when the ion transport membrane (ITM) technology matures.

Computational Assumptions

Complete combustion was assumed in the gas generator. This assumption is justified because the gas generator uses platelet injectors that provide extremely uniform mixing of oxygen, fuel and water. In addition, bench-scale tests recently made at the University of California at Davis show an absence of hydrocarbons in the exhaust and only minor concentrations of carbon monoxide. These results are in agreement with predictions based on the use of the chemical kinetics code Chemkin-II [34, 35].

Pressure drops are considered negligible in all pipelines. Heat transfer losses to the environment from lines connecting plant components are also considered to be negligible. Heat losses to the environment from heat exchangers are neglected. A commercial oxygen separation plant for this type of application would produce an oxygen stream that contains about 1 to 2 per cent argon. In this analysis, the contribution of the argon in the turbine working fluid is neglected. Addition of argon to the working fluid mixture of steam and carbon dioxide makes the convergence of the iterative computations more complex. Studies show that the non-combustible gas does not change significantly the efficiency calculations, but primarily change the output power due to the change in molecular of the working fluid.

The system of equations is solved with an iterative equation solver [28] by using computer-based tables of properties for all the substances involved (water [36], carbon dioxide [37], oxygen [38], carbon monoxide [38], and hydrogen [39]). Table 1 shows the values of the system parameters used in the analysis.

Cost Analysis

A method for assessing the economics of a power plant is to calculate the unit cost of electricity (COE) produced by the plant [40]. To determine this cost, the following information is used:

A - Unit capital cost, ($/kWh)
B - Plant net thermal efficiency
C - Fuel cost, ($/kWh)
D - Operating and maintenance cost, ($/kWh).

If income from plant by-products is excluded to simplify the calculations, the cost of electricity is given by: COE = A + C + D, where C is a function of B, and where D is conservatively estimated to be D = 0.15 x (A + C). Plant capital cost was based on 85% utilization, 20-year life span, and 15% capital recovery cost.

RESULTS

Figure 2 shows energy of the syngas per ton of coal for the three gasification processes; Texaco, Shell, and Koppers-Totzek and for the two types of coal; Illinois #6 and Wyodak. Red in every column represents energy from CO, green represents energy from hydrogen, and yellow represents energy losses. The three gasification processes considered in this analysis have efficiencies, ranging from 76 to 81%. The Texaco process using either Illinois #6 or Wyodak coal is the most efficient process. The syngas produced in the Texaco process with Wyodak coal is, on volume basis, 34.5 % of hydrogen, 49 % of carbon monoxide, and 16.5 carbon dioxide. This syngas has 13.2 MMBTU per ton of coal with 6.9 MMBtu from hydrogen and 6.3 MMBtu from CO. An amount of 3.1 MMBTU is consumed in the gasification process.

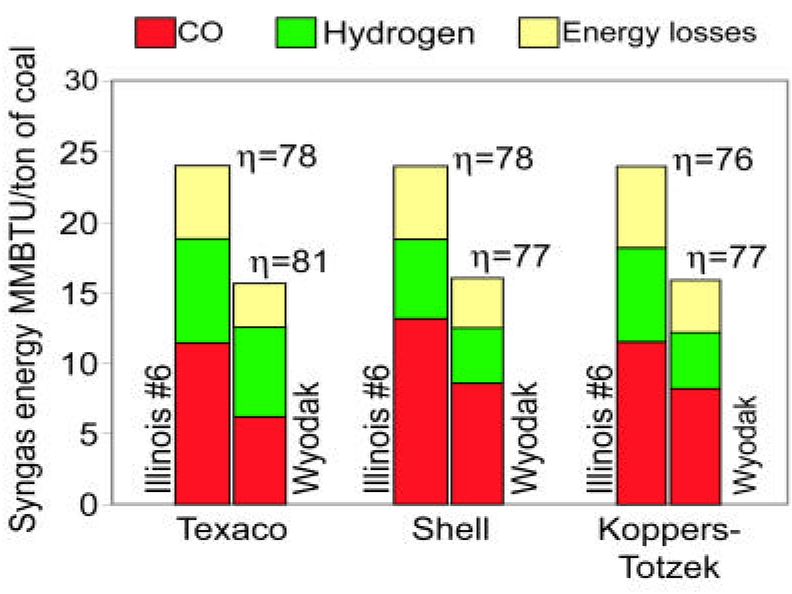

Figure 2. Syngas Energy per Ton of Coal for Three Different Gasification Process (Texaco, Shell, and Koppers-Totzek) and Two Types of Coal (Illinois #6 and Wyodak). The Figure also shows efficiency (?) for every gasification process.

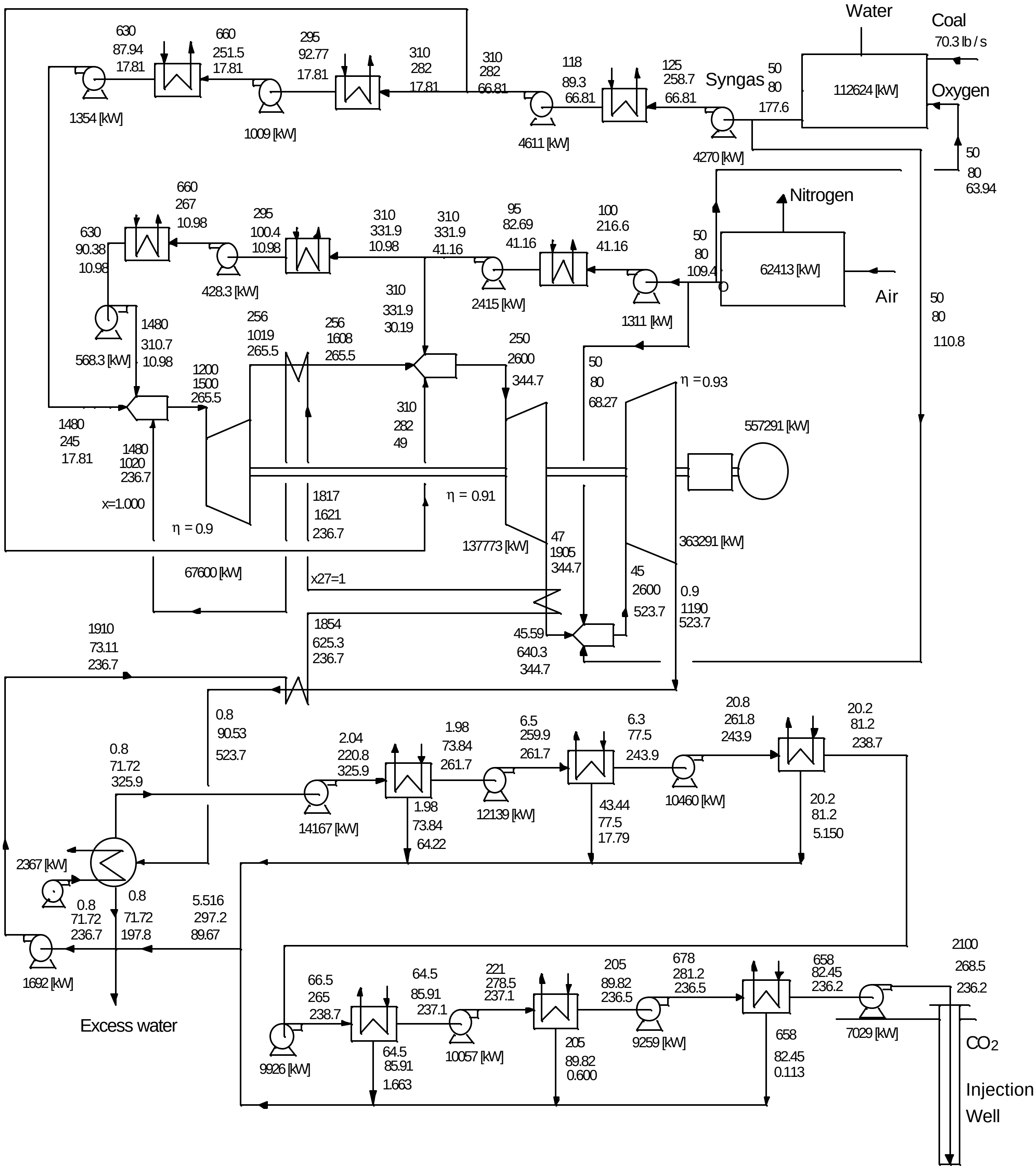

Figure 3. Zero-Atmospheric Emissions Power Plant Data for Base Case Analysis.
Notation: Pressure – lb/in^2 (top), Temperature -°F (middle), Mass flow - lb/sec (lower).
Input Power = 939.3 MW LHV, Electric Power Generated = 539.0 MW,
Parasitic Power =139.0MW. Net Electric Power = 400.0 MW,
Net LHV Thermal Efficiency = 0.426

Figure 3 shows the results for the base case power plant analysis. Figure 3 shows pressures, temperatures and mass flow rates for this power plant at more than fifty locations. In Figure 3, power is given in kW, pressure in lb/in^2, temperatures in °F, and mass flow rates in lb/s. The base case assumes a high-pressure turbine with an inlet temperature of 1500 ^{o}F (1089 K) and isentropic efficiency of 90%. The intermediate-pressure turbine operates at 2600 ^{o}F (1478 K) and isentropic efficiency of 91%, and the low-pressure turbine operates at an inlet temperature of 2600 ^{o}F (998 K) and isentropic efficiency of 93%.

This power plant configuration has a net thermal efficiency of 42.6 % and a net electrical output of 400 MW. The net thermal efficiency is based on the lower heating value of coal, and includes the energy required to separate oxygen from air and the energy required to compress the carbon dioxide for underground sequestration at a pressure of 2100 lb/in^2 (14.5 MPa). This sequestration pressure is sufficient to inject the carbon dioxide either into an oil zone for enhanced oil recovery, or into a subterranean aquifer at an approximate depth of 3937 ft (1200m).

In the current analysis, the power plant and the air separation plant were treated as individual units. By integrating the air separation plant and the power plant and by optimizing the performance of the combined units, a higher overall efficiency and therefore lower cost of electricity could be obtained. For example, the air separation plant produces nitrogen that can be compressed and then heated in a heat exchanger using hot gases from a reheater installed between the high-pressure and low-pressure turbines. The compressed and heated nitrogen can then be expanded in a turbine, thereby adding to the electrical output of the plant.

An evaluation of the efficiency of a 400 MW coal syngas plant in which the power plant and the air separation plant were integrated and then optimized was presented by Marin et al. [41]. The authors presented efficiencies that are higher than the 42.6 per cent calculated in this paper.

Figure 4 shows cost of electricity in the zero emission power plant for the three different gasification processes and two types of coal. Cost of electricity varies from US$0.054 per kWh for the Shell process and Illinois #6 coal to $0.052 per kWh for the Shell process with Wyodak coal. This represents a 5% maximum variation for three different gasification processes and two types of coal. This is an indication that the kind gasification process and the type of coal have little influence in the electricity cost.

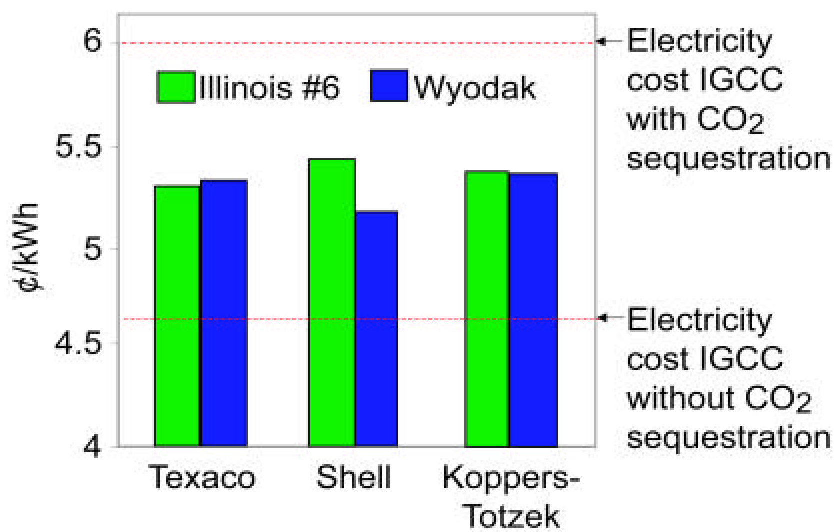

Figure 4. Cost of Electricity for Three Different Gasification Process (Texaco, Shell, and Koppers-Totzek) and Two Types of Coal (Illinois #6 and Wyodak). Cost of Electricity for IGCC with and without CO_2 sequestration are also included.

A comparison of the cost of electricity for electric power plants operating on both syngas derived from coal and on natural gas is presented in Figure 5. Points 1 to 8 are cost of electricity for different technologies using natural gas and points 9 to 14 are cost of electricity for different technologies using coal. The analysis done to make this figure considers the price of natural gas as US$3.33/MM Btu and coal price of US$1.25/MM Btu, capital charges of 15% per year, 85% utilization. The figure includes electricity costs for plants with and without exhaust gas sequestration [42].

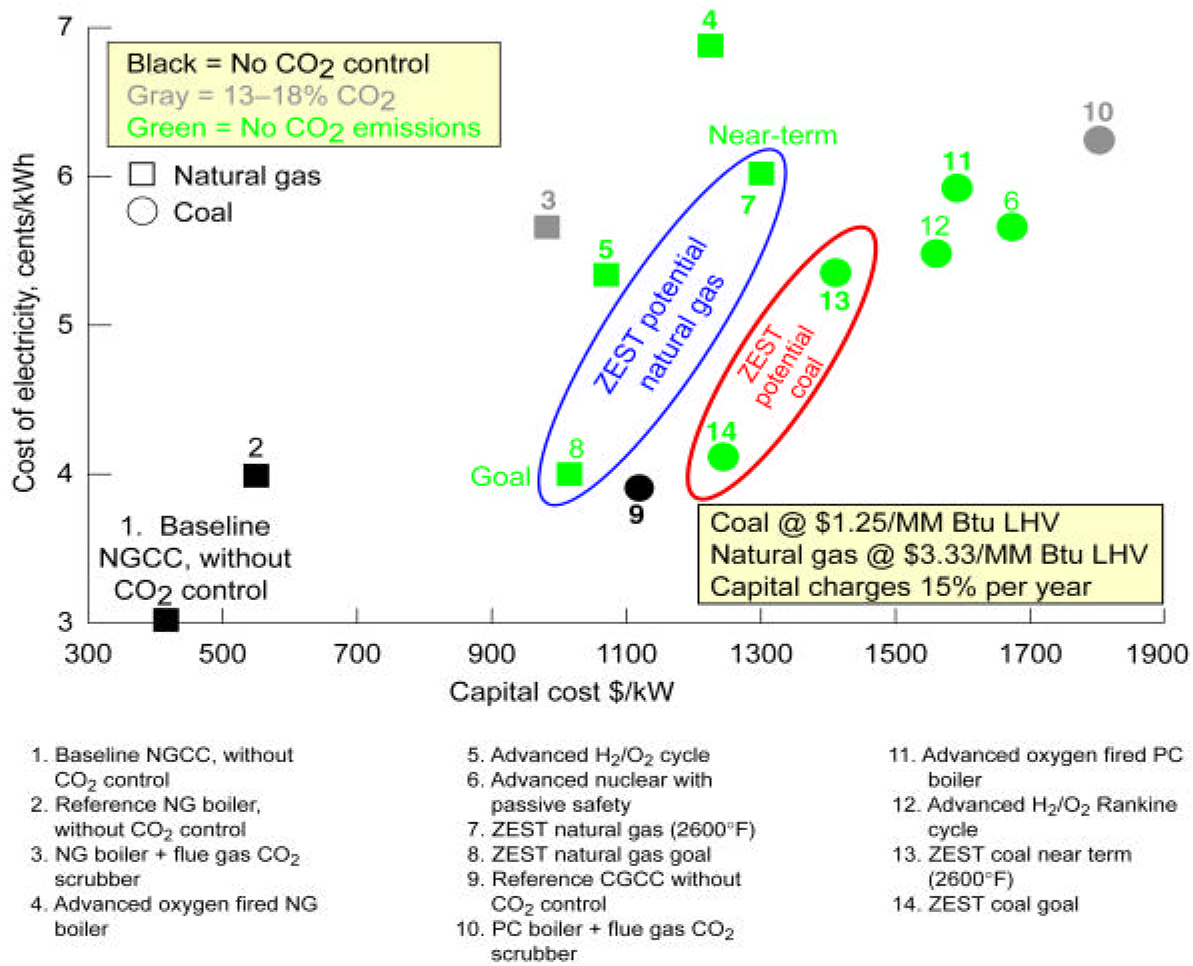

Figure 5. Cost of Electricity as a Function of Capital Cost for Zero Emission Steam Technology (ZEST) and Others Technologies for Comparison.

Figure 5 indicates that the lowest of electricity is US$0.03/kWh for natural gas combined cycle plant without exhaust gas sequestration. The figure includes cost of electricity for different technologies that facilitate CO_2 sequestration. An advantage of the ZEST technology over combined cycle technology is the lower cost to condition CO_2 for sequestration of US$4.6 per metric ton versus US$29.1 per metric ton. This lower CO_2 conditioning cost could provide additional revenue for ZEST plants where the CO_2 could be used for enhanced oil or coal bed methane recovery, or could be sold as an industrial by-product. Point 13 in Figure 5 represents the power plant analyzed in this document with cost of electricity between US$0.052 and US$0.055 depending of the gasification process used and coal type. Point 14 represents a ZEST technology goal that can be reached only with the development of higher temperature steam turbines.

CONCLUSIONS

This paper presents a thermodynamic analysis of a zero-atmospheric emissions power plant. The simulation considers the compression process of syngas and oxygen to feed the gas generator and the reheater, a Rankine cycle with three turbines and the carbon dioxide separation and sequestration processes.

The analysis predicts a 42.6% net thermal efficiency in a zero-atmospheric emissions 400 MW power plant that can be constructed with turbine technology that is under current development. The net thermal efficiency is based on the lower heating value of coal, and includes the energies required to separate oxygen from air, to make syngas from coal and the energy required to compress the carbon dioxide for underground sequestration.

The separation and sequestration processes of the carbon dioxide demand only a small part of the auxiliary power of the system. Current research and development of the air separation technology is expected to reduce the energy required to separate oxygen from air. This would increase the efficiency of the power plant and reduce electricity cost.

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