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Process simulation and thermodynamic analysis of an IGCC (integrated gasification combined cycle) plant with an entrained coal gasifier

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A B S T R A C T

An IGCC (integrated gasification combined cycle) is a widely used electrical power generation system that allows for a variety of feedstocks with high efficiencies. In this study, a 300 MW class IGCC plant was simulated using the PRO/II software package, and thermodynamic analysis was performed. The simulated results were compared to the basic design data for a 300 MW Class IGCC demonstration plant to evaluate the validity. Since changing the feed coal grade causes one of the most significant issues in operating an IGCC system, this study investigated the coal sensitivity of the system by examining two different grade coals (Coal #1: 25,439 kJ/kg and Coal #2:21,338 kJ/kg). Their net powers were determined via thermodynamic analysis and by evaluating the power generation and power consumption and were found to be 324.4 MW and 279.1 MW for Coal #1 and Coal #2. Based on the inlet coal energy, the overall efficiencies under the same conditions were found to be 40.38% for Coal #1 and 41.42% for Coal #2. This paper presents Sankey diagrams for the energy and exergy flow associated with the first and second laws of thermodynamics, and discusses how they influence the major components of the IGCC. As a final point, in order to elucidate the preferable coal in terms of financial sense, economic analysis was carried out on the viability of the cases considered. The costs of electricity for Coal #1 and Coal #2 were evaluated as 0.07 US$/kWh and 0.08 US$/kWh. Hence, Coal #1 can confidently be chosen as a more economic option even though, it costs relatively higher than the other Coal #2.

1. Introduction

The IGCC (integrated gasification combined cycle) is a representative technology for utilizing coal as feedstock and, consequently, it is playing a more important role as one of the alternative energy sources to cover the global energy demand [1].

Compared to other IGCC plants, such as biomass IGCC plants and heavy residue IGCC plants, a coal-based IGCC plant is generally applied to large capacity power system, resulting in a large investment cost of construction. Due to higher operating pressures and temperatures, reducing the operating costs and energy consumption has emerged as one of the key issues in the industry such as improving efficiency of an existing IGCC plant including CO_2 removal by Descamps et al. [2]. It is therefore advantageous to accurately predict the composition and temperature of the gases for each stream in the system, as well as, determine the energy efficiencies using process modeling and simulation.

Process simulation using commercially available simulation software programs, such as ASPEN PLUSand HYSYS, is usually applied for IGCC plants. In simulating IGCC plant using ASPEN [3], Gibbs reactors and conversion reactors – were employed to model a gasifier. For conceptual design purpose, simple modeling approach was employed in the framework of HYSYS [4]. Accordingly, for both cases, complicated reaction kinetics was not considered. However, in a simulation of IGCC plants, a gasifier is considered to be a highly significant unit as the composition of syngas from the gasifier is a key parameter in determining the overall efficiency. The plant performance of IGCC plants is one of the key operational issues and efforts have been made to evaluate quantitatively using process simulation, as well as, thermodynamic analysis. Comparison of syngas compositions of the operation data or design data to those of the simulation results is one such method

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Nomenclature

AGRU	acid gas removal unit
ASU	air separation unit
BFW	boiler feed water
CCS	carbon capture and storage
CC	combined cycle
COS	carbonyl sulphide
E	total exergy (J/mol)
GU	gasification unit
HCN	hydrogen cyanide
HHV	higher heating value (kJ/kg)
HP	high pressure
HRSG	heat recovery steam generation
h_o	standard enthalpy, environmental conditions (J/mol)
h	molar enthalpy (J/mol)
IGCC	integrated gasification combined cycle
IP	intermediate pressure
LP	low pressure
MDEA	methyl diethanolamine
N	molar flow (mol/s)
$P_{calculated}$	calculated parameter
$P_{specified}$	specified parameter
R	gas constant (J/mol-K)
SRU	sulfur recovery unit
s	molar entropy (J/mol-K)
s_o	standard entropy environmental conditions (J/mol)
T_o	standard temperature (K)
x_i	mole fraction
Subscript	
gas	syngas
Greek symbols	
ε_{ph}	molar physical exergy (J/mol)
ε_{ch}	molar chemical exergy (J/mol)
$\varepsilon_{o,i}$	standard molar chemical exergy (J/mol)
$\eta_{overall}$	energy efficiency of IGCC plant

in an indirect sense. On the other hand, thermal efficiency, which is defined by the ratio between the generated power and feed heating value, is a measure to evaluate the plant performance.

Applying the simulations, thermodynamic energy and exergetic analysis can provide criteria to develop process configurations and operating conditions to save energy. With the fact that exergy combines the first and second laws of thermodynamics, it can be defined as the "quality of energy" and is a more appropriate measure for analyzing energy processes. Analyses of energy and exergetic systems have been employed to evaluate various energy processes, such as conventional thermal power generation processes [5,6], and engine combined cycles [7]. The exegetic analysis of IGCC process has been carried out for life cycle assessment to evaluate environmental impacts and exegetic life cycle assessment to account for exergy input to the system [8]. Kim et al. [9] has employed exergy analysis to investigate the exergy distribution of sub-systems in IGCC and reported the improvement of efficiency by minimizing exergy losses mainly caused by syngas coolers. Recently, a detailed exergetic analysis of an IGCC process with carbon capture was performed to find out where and why the losses occurred [10].

Several studies performed detailed parametric sensitivity analyses in order to evaluate the effect of efficiency, total capital investment, and other parameters. For instance, a comparison of the performances of four IGCC plants—employing Shell, Texaco, BGL, and KRW gasifiers—was analyzed using ASPEN Plus [11]. The performance efficiency of an IGCC depends on several parameters of different coal qualities such as New Zealand lignite and sub-bituminous coals [12].

The heating value of the feed coal determines the IGCC plant dimensions and its generating capacity. Similarly, the moisture content of a coal feed affects gasifier efficiency and influences the decision as to whether the process should be dry or slurry fed. Higher moisture content becomes problematic since much energy is expended in the form of additional coal and oxygen, in order to maintain gasifier temperature. Several other properties such as ash and mercury content, volatile material and char reactivity all play important roles in determining the performance of the IGCC system. It is therefore vital to perform a sensitivity analysis of the various grades of coal feed to be used in the IGCC plant in order to draw an optimized balance between cost of investment and overall efficiency of the IGCC system.

This study is aimed at process simulation for an IGCC plant, and sensitivity analysis for different grade coals. Process simulation was carried out using the operating and design conditions from the commercial IGCC plant as well as a comparison between the simulation results and the design data from a 300 MW class IGCC [13] was made to validate this work. In addition, since the sensitivity of the plant efficiency with respect to different grades of coals is an exigent issue, the plant efficiency was analyzed for different grade coals. Since energy saving was one of the main objectives in this study, an attempt was made to analyze the energy and exergy flow on the basis of the simulation results and exergy calculation. Finally, in view of fuel costing, economic analysis was executed to consider the cost of electricity for two different coals.

2. Process description

The IGCC process used in this study consisted of five important units: (1) a GU (gasification unit), (2) an AGRU (acid gas removal unit), (3) a SRU (sulfur recovery unit), (4) an ASU (air separation unit), (5) a CC (combined cycle) including the gas turbine, a steam turbine and a HRSG (heat recovery steam generator), as shown in Fig. 1. In this section, we briefly describe the general characteristics of the IGCC process that we will model in this work.

The GU, which is composed of a coal feeding system, an entrained-type gasifier, syngas coolers, a filter, and hydrolysis reactors, produces syngas from the coal feed. Pulverized coal carried by pressurized nitrogen is fed to burners with oxygen at the bottom of the gasifier, where the syngas is then generated through various reactions. The reactions include pyrolysis reactions, heterogeneous reactions, and homogeneous gas phase reactions. The gasifier has a membrane wall tubes intended to recover the reaction heat through both the cooling of the gasifier temperature and the generating steam. At temperatures above the ash softening point, the ash becomes sticky and will agglomerate, causing a blockage or fouling the equipment. In order to avoid this situation, quenching gas is supplied into the topside of the gasifier to cool down both the temperature of the syngas and the fly ash.

Quenched syngas is further cooled in the syngas coolers where IP and HP steam is produced to recover the sensible heat. Since the syngas contains small amounts of HCN and COS, which cause environmental problems and corrode the equipment, hydrolysis reactors remove them after fly ashes are filtered in the filter vessel.

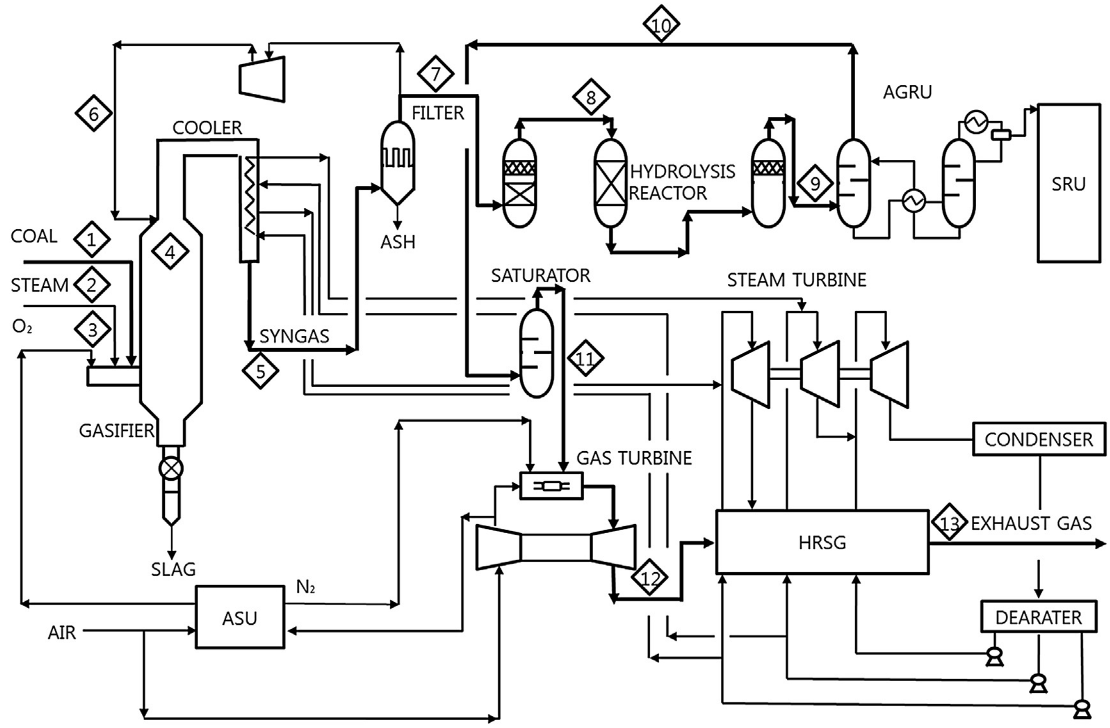

Fig. 1. Schematic of IGCC for process simulation.

The main function of the AGRU is to reduce the content of CO_2 and H_2S. The acid gases must be removed in order to avoid damage to the process lines and the gas turbine. In this paper, the AGRU system comprises an absorber, a regenerator, and auxiliary equipment with a mixture of MDEA and sulfolane as a solvent [14]. The SRU, consisting of furnaces and catalyst bed reactors, is primarily responsible for recovering sulfur by converting hydrogen sulfide to solid sulfur. The ASU generates oxygen and nitrogen under cryogenic conditions. The generated oxygen is supplied into the gasifier and utilized for combustion reactions. The generated nitrogen is used for various purposes, which include conveying the pulverized coal at the feeding system, separating fly ashes from syngas at the filter, minimizing NO_x generation, and maximizing power generation at the gas turbine. It is a normal practice in the industry to integrate the ASU with the gas turbine, in the pursuit of improving the overall efficiency. To reduce the power consumption of the ASU compressor, some portion of the air is supplied from the gas turbine compressor. Then, the percent of air required by the air separation unit is taken as the degree of integration.

The CC is the unit responsible for generating electricity, and it comprises a gas turbine, steam turbines, and a HRSG. Nitrogen and moisture are added to the syngas in the saturator to reduce NO_x and maximize power output. The gas turbine contains a combustor, a compressor, and an expander, where combustion, air compression, and power generation occur.

The HRSG and three steam turbines are integrated in order to generate HP, IP, and LP steam produced from BFW (boiler feed water) in conjunction with the heat transfer from hot syngas, thereby generating electric power.

3. Methodology

3.1. Process modeling approach

The schematic of the target IGCC process, including the GU, AGRU, SRU, ASU, and CC, is illustrated in Fig. 1, which was used for the process simulation model. The components in our simulation study C, CO, CO_2, CH_4, H2, H_2O, O_2 and N_2 operate at absolute pressures up to 30 bar. So equation of state approach is more suitable than liquid activity coefficient approaches. Furthermore, the involvement of polar components in this system such as CO, CO_2 and H_2O, compelled our choice of SRK equation of state model with modified Panagiotopoulos mixing rules (SRKM) rather than using SRK equation of stat.

In the gasifier, three kinds of reaction sets were considered, including pyrolysis reactions, heterogeneous reactions, and homogeneous reactions. The reaction sets and relevant reaction kinetics parameters exploited in this work are described in Table 1.

Considering most of the reactions took place in a gasifier, it was decomposed into 4 reaction zones as shown in Fig. 2. Since the hydrogen combustion occurred immediately after pyrolysis and its reaction rates were dominantly high, a conversion reactor was employed with the assumption of the complete combustion of hydrogen. Heterogeneous reactions including char combustion and char gasification took place consequently. Finally taking into account the characteristics of an entrained flow gasifier, a plug flow reactor was used for homogeneous reactions.

Associated with HP and IP boiler feed water, the gas coolers were modeled to calculate the quantity of the generated steam and the amount of heat recovery. For the sake of simplicity, the hydrolysis reactors, where HCN and COS were removed, were modeled using conversion reactors.

The simulation of the AGRU focused on the quantity of the absorbed CO_2 and H_2S, as well as on the energy balance—particularly at the regenerator. The gas turbine and ASU were integrated to perform case studies with the integration ratio of 44.7%.

The simulation of the AGRU focused on the quantity of the absorbed CO_2 and H_2S, as well as on the energy balance—particularly at the regenerator. The AGRU consists of an absorber column with six(6) theoretical stage no. and a regenerator column with twelve(12) theoretical stage no. at 0.07 MPa pressure. The mixture of MDEA and sulfolane was used as a solvent. The Claus process was

Table 1
Reactions in IGCC process.

Reaction	Rate	Reference
Pyrolysis reaction in gasifier		
Coal $\rightarrow \alpha_1H_2 + \alpha_2CH_4 + \alpha_3CO + \alpha_4CO_2 + \alpha_5C_2H_6 + \alpha_6H_2S$ + Char		
Heterogeneous reaction in gasifier		
$C_{(s)} + 0.5\ O_2 \rightarrow CO$	$R_1 = 5.67*10^9*e^{-1.60E+8/RT}$	[19]
$C_{(s)} + CO_2 \rightarrow 2\ CO$	$R_2 = 1.6*10^{12}*e^{-2.24E+7/RT}$	[20]
$C_{(s)} + H_2O \rightarrow CO + H_2$	$R_3 = 1.33*10^3*T*e^{-1.75E+7/RT}$	[21]
Homogenous reaction in gasifier		
$H_2 + 0.5\ O_2 \rightarrow H_2O$	$R = 1.00*10^{14}*e^{-4.20E+7/RT}$	[19]
$CO + 0.5\ O_2 \rightarrow CO_2$	$R_1 = 2.20*10^{12}*e^{-1.67E+8/RT}$	[22]
$CH_4 + 2\ O_2 \rightarrow CO + 2H_2O$	$R_2 = 3.00*10^8*e^{-1.26E+8/RT}$	[23]
$CO + H_2O \rightarrow CO_2 + H_2$	$R_3 = 2.78*10^3*e^{-1.26E+7/RT}$	[19]
$CH_4 + H_2O \rightarrow CO + 3H_2$	$R_4 = 4.40*10^{11}*e^{-1.68E+8/RT}$	[23]
COS/HCN reaction in gas turbine combustor		
$COS + H_2O \rightarrow CO_2 + H_2S$	[a]	
$HCN + H_2O \rightarrow CO + NH_3$	[a]	
Combustion reaction in gas turbine combustor		
$H_2 + 0.5\ O_2 \rightarrow H_2O$	$R = 1.00*10^{14}*e^{-4.20E+7/RT}$	[19]
$CO + 0.5\ O_2 \rightarrow CO_2$	$R_1 = 2.20*10^{12}*e^{-1.67E+8/RT}$	[22]
$CH_4 + 2\ O_2 \rightarrow CO_2 + 2H_2O$	$R_2 = 3.00*10^8*e^{-1.26E+8/RT}$	[23]

[a] Conversion reactor used.

applied for the modeling, which consists of a set of ~~a~~ furnace, condensers and three Claus reactors. Consequently, the result of SRU modeling does not have any effect on the other units, so the modeling was simplified with functions of conversion reactor and heat exchanger in PRO/II with the following stoichiometric equations

$$H_2S + 11/2O_2 \rightarrow SO_2 + H_2O\ \text{(33\% conversion in the furnace)}$$

$$31/2\ O_2 + 2\ NH_3 \rightarrow 3H_2O + 2\ NO_2\ \text{(99 \% conversion in the furnace)}$$

$$2\ H_2S + SO_2 \rightarrow 3S + 2\ H_2O\ \text{(70\% conversion in three reactors)}$$

Furthermore, cryogenic process was modeled for ASU, therefore, it got its power consumption from compressors and pumps. Ar component was ignored in the modeling.

The applied reactions for the simulation of the IGCC process are listed in Table 1. Taking into account that the coal specification has a significant effect on the syngas composition and the overall IGCC efficiency, two kinds of coals were chosen to simulate the composition of the produced syngas. The HHVs of the two types of coal were 25,429 and 21,338 kJ/kg for Coal #1 and Coal #2. Table 2 further details the specification of the two coals used.

Table 2
Analysis data for Coal #1 and Coal #2.

	Coal#1 (wt%, dry)	Coal#2 (wt%, dry)
Proximate analysis		
Moisture	5.0	20.5
Ash	15.0	4.5
Volatile matter	28.0	42.0
Fixed carbon	52.0	33.0
	100.0	100.0
Ultimate analysis		
Moisture	–	–
Carbon	69.0	68.4
Hydrogen	4.3	5.8
Oxygen	8.7	19.3
Nitrogen	1.4	0.9
Sulfur	0.8	0.1
Ash	15.8	5.7
	100.0	100.0
HHV (KJ/kg)	25,429	21,338

3.2. Thermodynamic analysis

The performance of the power plants is estimated through energetic criteria based on the first law of thermodynamics, which includes electrical power and thermal efficiency [15] using the industrial data by KEPCO shown in Table 3.

The energy efficiency of the IGCC plant in this study was described as the ratio of net power generation to energy input, which can be expressed in terms of the HHV (higher heating value) of the given coal as follows:

$$\eta_{\text{overall}} = \frac{\text{Net power generation}}{\text{Input energy supplied}} \tag{1}$$

Note that exergy is a measure of the maximum capacity of a system to perform useful work as it proceeds to a specified final state in equilibrium with its surroundings [16]. Because exergy is not generally conserved as energy but is destroyed in the system, exergy destruction is the measure of irreversibility, which is the source of performance loss. Therefore, even though power plants are normally examined using energy analysis, a better understanding can be attained when the second law of thermodynamics is considered in conjunction with exergy methods.

The total exergy of a material stream can be given by Ref. [17].

$$E = N\left(\varepsilon_{\text{ph}} + \varepsilon_{\text{ch}}\right) \tag{2}$$

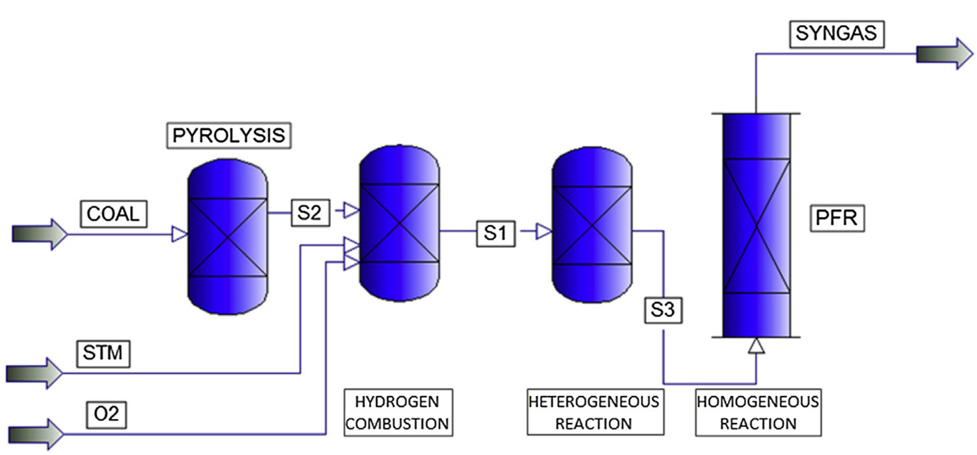

Fig. 2. Simulation structure of a gasifier.

Table 3
Operating and design conditions for a gas and steam turbine.

Gas turbine	
GT compressor efficiency	Adiabatic efficiency 80.8%
GT compressor pressure ratio	0.1 MPa/1.8 MPa
GT expander efficiency	Adiabatic efficiency 92.2%
GT expander pressure ratio	1.8 MPa/0.12 MPa
Air flow ratio of GT compressor/ASU air compressor	11/89
Steam turbine	
HP ST efficiency	Adiabatic efficiency 86.7%
IP ST efficiency	Adiabatic efficiency 91.7%
LP ST efficiency	Adiabatic efficiency 92.4%
HP ST pressure ratio	12.4 MPa/3.2 MPa
IP ST pressure ratio	3.2 MPa/0.5 MPa
LP ST pressure ratio	0.5 MPa/0.005 MPa
Condenser	
Outlet temperature	32 °C
Pressure	0.005 MPa

where N is the flow rate in mol s^{-1}, ε_{ph} is the molar physical exergy, and ε_{ch} is the molar chemical exergy.

The relationship of the molar physical and chemical exergy of a material steam to the reference environmental conditions can be expressed as.

$$\varepsilon_{ph} = (h - h_0) - T_0(s - s_0) \tag{3}$$

$$\varepsilon_{ch,gas} = \sum_i x_i \varepsilon_{0,i} + RT_0 \sum_i x_i \ln x_i \tag{4}$$

where h and s are the molar enthalpy and molar entropy, at a given temperature and pressure. To determine the chemical exergy, x_i indicates the mole fraction and $\varepsilon_{0,i}$ denotes the standard molar chemical exergy of each component i in units of J mol^{-1}. The standard environmental conditions of PRO/II (e.g., T_0 = 298.15 K, p_0 = 1.013 bar) were adopted as reference conditions in the study.

All the information required to calculate exergy, such as the mole flow, mole fraction, enthalpy, and entropy of each material steam, was obtained from the PRO/II simulation results. Chemical exergies for various gases at the reference state are given in many published references [18].

4. Results & discussion

4.1. Validity of simulated results

A validity test is an essential task to justify the accuracy, reliability—and hence, the applicability—of the process simulation via either experimental data or published data. Many of the calculations in PRO/II are iterative, and require certain relationships to be satisfied within specified tolerances to reach a solution. The tolerance can be expressed in either absolute or relative basis.

$$\text{Relative tolerance} = \left| \left(P_{\text{calculated}} - P_{\text{specified}}\right) \big/ P_{\text{specified}} \right| \tag{5}$$

$$\text{Absolute tolerance} = \left| P_{\text{calculated}} - P_{\text{specified}} \right| \tag{6}$$

In performing the process simulation, we used a relative tolerance of 0.001 for temperature specifications and heat balance equations. A relative tolerance of 0.005 for pressure, heater/cooler duty specifications and component balance equations was also employed. For other calculations, such as flash, pressure, etc. a relative tolerance of 0.01 was used.

Table 4
Design data of a commercial plant.[a]

Stream description	Unit	Gasifier cooler outlet	Syngas from scrubber	Syngas outlet from AGRU
Temperature	°C	250	250	48
Pressure	MPa	4.16	4.1	3.65
Total mass rate	kg/s	116	57	54
Total molar comp	%			
Coal		–	–	–
H_2		25.33	23.2	25.58
O_2		–	–	–
N_2		9.159	16.788	10.28
H_2O		1.5	1.374	0.29
CO_2		1.3	1.2	0.75
H_2S		0.23	0.211	0
COS		0.03	0.0275	0
CO		62.45	57.18	63.08
CH_4		0.0015	0.02	0.02

[a] Reference data were obtained from Basic Design Package for a 300 MW commercial IGCC plant in Korea.

In this work, we compared the syngas composition from the simulation with the basic design data of a 300 MW Class IGCC demonstration plant as shown in Table 4.

Fig. 3 depicts the results of the comparison. In the case of CO, the compositions from the simulation and industrial data at the inlet stream of the syngas cooler were 61.65 mol% and 62.45 mol%, whereas the compositions at the inlet stream of the gas turbine for the two cases were 62.93 mol% and 63.08 mol%. From this review, the relative errors were found to be 1.3% and 0.2%, which is quite acceptable not only for the confirmation of the simulation, but also for further applications, such as simulations with different grade coals.

4.2. Syngas composition

Fig. 4 shows the simulation results of the composition of syngas at each process unit in the IGCC plant for Coal #1. As shown, CO, H_2 and CO_2 were the major components of the effluent gas from the gasifier. The details of the compositions of the stream as a function of operating pressure, temperature, and mass rate at each process unit are presented in Table 4.

The compositions of the syngas from the gasifier were 61.65 mol % of CO, 30 mol% of H_2, and 3.2 mol% of CO_2 at the gasifier outlet (stream 4) shown in Fig. 4. Most of CO_2 was removed at the AGRU by an amine solvent (stream 10). The compositions of CO and H_2

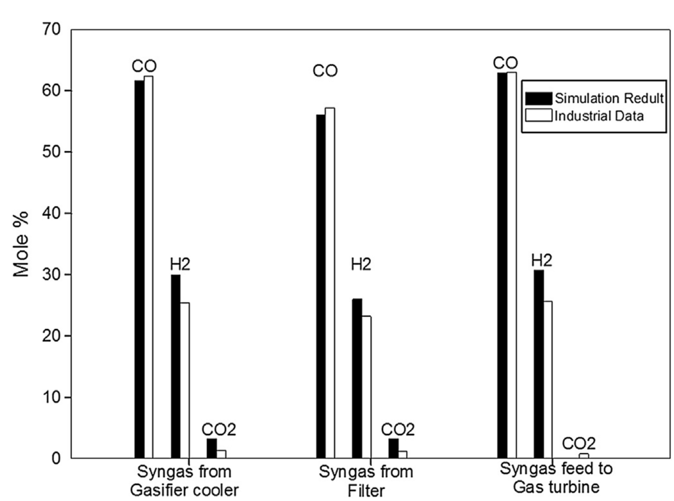

Fig. 3. Validity of the simulation results in terms of syngas composition.

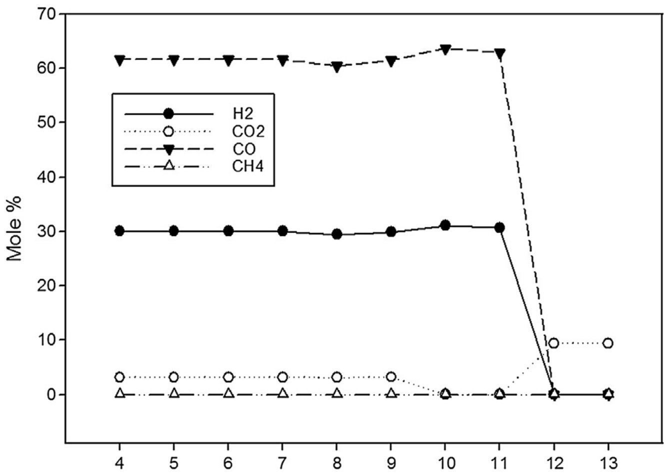

Fig. 4. Simulation results of the syngas composition for Coal #1(4: Topside of the gasifier, 5: Outlet of the syngas cooler, 6: Quench stream, 7: Outlet of the filter, 8: Inlet to the hydrolysis reactor, 9: Inlet to the AGRU, 10: Outlet of the AGRU, 11: Outlet of the saturator, 12: Outlet of the gas turbine, 13: Exhaust gas).

decreased steeply at the gas turbine (stream 11) due to the combustion reaction. During the reaction, CO and H_2 were converted into CO_2 and H_2O; therefore, the composition of CO_2 increased. The hot exhaust gas from the turbine passed the HRSG, resulting in heat transfer to the BFW for the production of steam. HP, IP and LP steam used for the steam turbines were generated from the syngas coolers and HRSG by recovering the heat from a gasifier and gas turbine exhaust gases. Moreover, syngas cooler and HRSG were modeled to calculate the quantity of the generated steam and the amount of heat recovered by utilizing the heat exchanger module in PRO/II simulator. This is furtherance, with the assumption that the approaching temperature for Economizer is 4 °C and that for Super heater is 25 °C. After the heat transfer, the exhaust gas was emitted to the atmosphere, as illustrated by stream 13 in Fig. 4.

4.3. Syngas temperature

The syngas temperature for each stream is shown in Fig. 5. The temperature at the topside of the gasifier (stream 4) in Fig. 5 was above 1400 °C due to the temperature rise by the heat of the reactions. At the quenching zone, where the main purpose was to convert fly ash into slag, the syngas temperature decreased by 900 °C because the syngas was mixed with a cold quench gas of 250 °C (stream 6). The syngas temperature at the outlet of the syngas cooler (stream 5 in Fig. 5) dropped by approximately 250 °C while steam was produced through the heat transfer between the hot syngas and the BFW. The inlet syngas temperature of the amine system should be controlled because of the low operating temperature of the amine system (stream 9 in Fig. 5). In the combustor, the temperature rose up to approximately 557 °C due to the heat of combustion. At the HRSG (stream 13 in Fig. 5), the syngas temperature decreased again by 120 °C owing to the heat transfer between the syngas and the BFW.

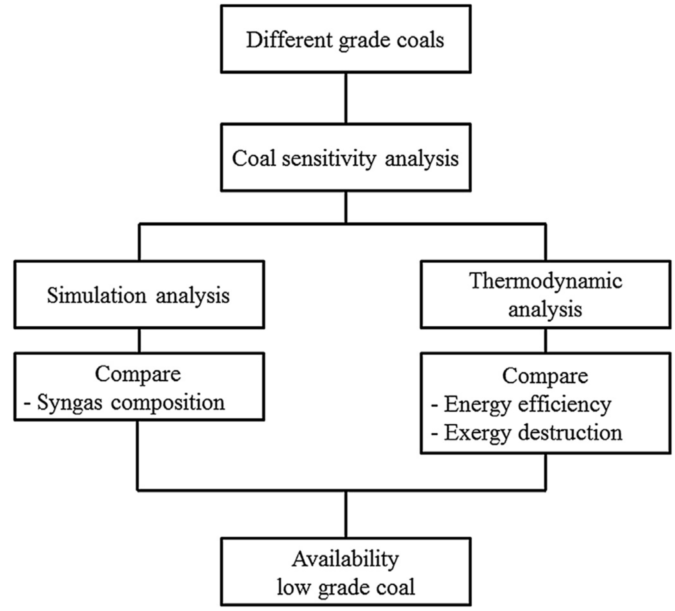

Fig. 6. Overview of coal sensitivity analysis.

4.4. Coal sensitivity analysis

In order to evaluate the possibility of using lower grade coals in commercial plants, the sensitivity analysis was carried out based on

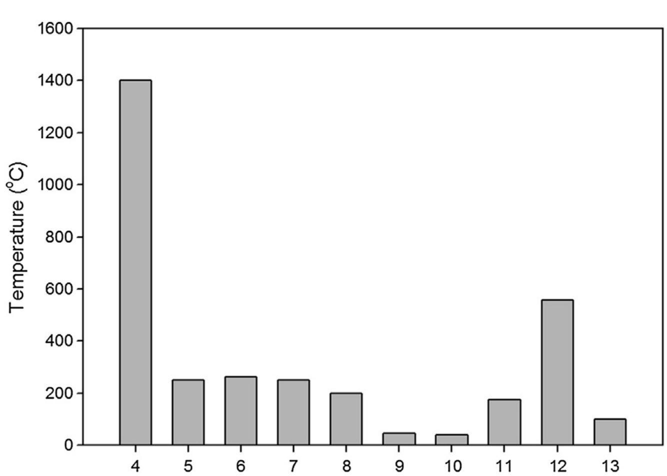

Fig. 5. Simulation results of the syngas temperature for Coal #1(4: Topside of the gasifier, 5: Outlet of the syngas cooler, 6: Quench stream, 7: Outlet of the filter, 8: Inlet to the hydrolysis reactor, 9: Inlet to the AGRU, 10: Outlet of the AGRU, 11: Outlet of the saturator, 12: Outlet of the gas turbine, 13: Exhaust gas).

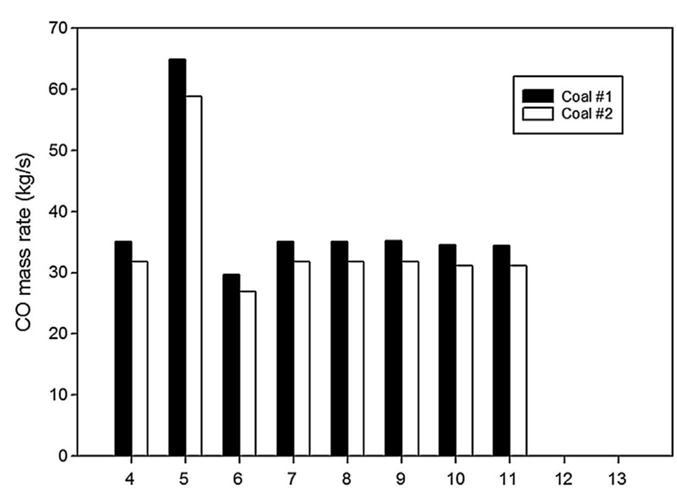

Fig. 7. Comparison of CO mass flow rates for Coal #1 and Coal #2(4: Topside of the gasifier, 5: Outlet of the syngas cooler, 6: Quench stream, 7: Outlet of the filter, 8: Inlet to the hydrolysis reactor, 9: Inlet to the AGRU, 10: Outlet of the AGRU, 11: Outlet of the saturator, 12: Outlet of the gas turbine, 13: Exhaust gas).

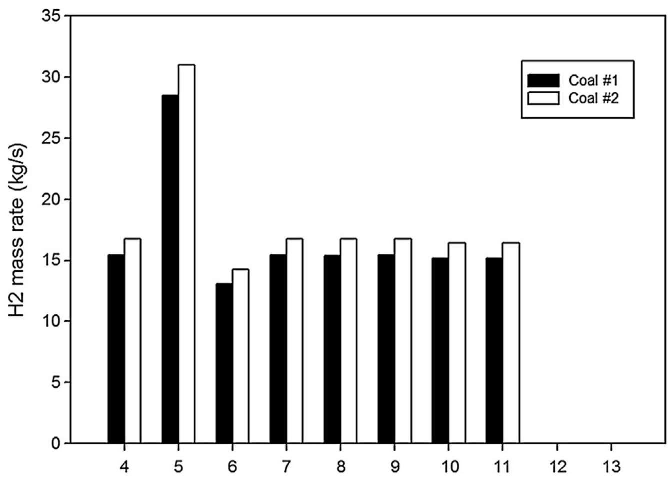

Fig. 8. Comparison of H_2 mass flow rates for Coal #1 and Coal #2(4: Topside of the gasifier, 5: Outlet of the syngas cooler, 6: Quench stream, 7: Outlet of the filter, 8: Inlet to the hydrolysis reactor, 9: Inlet to the AGRU, 10: Outlet of the AGRU, 11: Outlet of the saturator, 12: Outlet of the gas turbine, 13: Exhaust gas).

simulation results and thermodynamic analysis (Fig 6). From Table 2, the moisture content of Coal #2 was much higher (more than four times) than that of Coal #1 whereas more fixed carbon was included in Coal #1. The HHV of Coal #1 was 25,429 kJ/kg, which was 20% higher than that of Coal #2. In fact, Coal #1 is a design coal which was used for the basic design and Coal #2 is a candidate low grade coal which we seek for the possibility as a feed coal.

4.4.1. Simulation analysis

As the first step of analyzing the coal sensitivity, we attempted to quantitatively measure the influence of the grade of coals on the compositions of each syngas component and temperature by means of a case study.

Figs. 7 and 8 illustrate the molar concentration of CO and H_2 for Coal #1 and Coal #2 at different locations. Note that the concentration of CO in the Coal #1 case was higher than that in the Coal #2 case while the opposite tendency was observed for H_2 regardless of unit locations. Considering the fact that CO and H_2 are the dominant components of syngas, constituting more than 80% of the total syngas, the composition of CO and H_2 could have a considerable impact on the overall enthalpy flow of the product gas. CO and H_2 gases were used as feedstocks at the combustor for the gas turbine, which eventually provided the heat to generate power. Consequently, the concentrations of CO and H_2 significantly influence the total amount of power generation.

Tables 5 and 6 describe the material balances for Coal #1 and Coal #2 and detail the compositions and operating conditions (e.g., flow rate, temperature, and pressure).

4.4.2. Thermodynamic analysis

The enthalpy flow for Coal #1 and Coal #2 is illustrated by the Sankey diagram in Figs. 9 and 10. Total generated power and energy efficiency which serve as the criteria of performance efficiency for two coals were examined. At the same mass flow rate of feedstock, the inlet enthalpy flow to the IGCC was 803.4 MW and the net power generation was 324.4 MW in the Coal #1 (Fig. 9), whereas the inlet enthalpy flow was 673.9 MW and the net power generation was 279.1 MW in the Coal #2 (Fig. 10). The net power, power generation from the gas and turbines and power consumption for plant operation was shown in Fig. 11. As it was expected, the generated power from the lower grade coal (Coal #2) is 86% of that from the high grade coal (Coal #1) for the same inlet mass flow rate. These figures show that the IGCC process generated steams from syngas at the gasifier and the HRSG. Most of enthalpy losses took place at condensate and waste gas flows. Consequently, it is concluded that these factors are critical for minimizing the enthalpy losses in IGCC and optimizing the process configuration of the heat network for steam.

Overall efficiencies and net power for the Coal #1 and Coal #2 cases are described in Table 7. The overall efficiency for Coal #1 was 40.38%, and for Coal #2, was 41.41% under same mass flow rate of coals, turbine efficiencies as well as compressors' efficiencies. These values may tempt the conclusion that a lower grade coal is preferable for the efficient operation of the IGCC. However, one must consider the meaning of overall efficiency defined by the ratio between the net power and the total energy input based on the flow rate and HHV of the coal. In the final analysis, the denominator of the overall efficiency equation for Coal #1 was of a significantly larger value (803.4 MW) than that for Coal #2 (673.9 MW); thus a lower overall efficiency than for Coal #2.

Furthermore, when the generation of net power is more demanding, the situation becomes further complicated. To increase the net power for Coal #2 as much as that for Coal #1 (i.e., 324 MW), it was necessary to increase the mass flow rate of feedstock.

Table 5
Material balance for Coal #1.

Stream name	1	2	3	4	5	6	7	8	9	10	11	12	13
Stream description	Coal feed	Steam feed	Oxygen feed	Topside of the gasifier	Outlet of the syngas cooler	Quench stream	Outlet of the filter	Inlet to the hydrolysis reactor	Inlet to the AGRU	Outlet of the AGRU	Outlet of the saturator	Outlet of the gas turbine	Exhaust gas
Temperature [°C]	80	300	81	1400	250	263	250	200	45	40	175	557	101
Pressure [MPa]	4.90	5.25	4.35	4.35	4.08	4.35	4.08	4.00	3.80	3.53	2.90	0.00	0.00
Total mass rate [kg/s]	31.56	1.20	23.48	54.40	100.39	45.99	54.40	55.31	54.51	50.17	50.72	502.55	502.55
Total molar comp. [%]	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2	0.00	0.00	0.00	30.00	30.00	30.00	30.00	29.42	29.92	31.08	30.70	0.00	0.00
O_2	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.31	10.31
N_2	0.00	0.00	0.00	4.86	4.86	4.86	4.86	4.77	4.85	5.03	4.97	75.49	75.49
H_2O	0.00	100.00	0.00	0.00	0.00	0.00	0.00	1.93	0.25	0.18	1.40	4.80	4.80
CO_2	0.00	0.00	0.00	3.20	3.20	3.20	3.20	3.13	3.21	0.00	0.00	9.40	9.40
H_2S	0.00	0.00	0.00	0.26	0.26	0.26	0.26	0.25	0.28	0.00	0.00	0.00	0.00
COS	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00
CO	0.00	0.00	0.00	61.65	61.65	61.65	61.65	60.47	61.49	63.70	62.93	0.00	0.00
CH_4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 6
Material balance for Coal #2.

Stream name	1	2	3	4	5	6	7	8	9	10	11	12	13
Stream description	Coal feed	Steam feed	Oxygen feed	Topside of the gasifier	Outlet of the syngas cooler	Quench stream	Outlet of the filter	Inlet to the hydrolysis reactor	Inlet to the AGRU	Outlet of the AGRU	Outlet of the saturator	Outlet of the gas turbine	Exhaust gas
Temperature [°C]	80	300	81	1400	250	263	250	200	46	40	175	550	120
Pressure [MPa]	4.90	5.25	4.35	4.35	4.08	4.35	4.08	4.00	3.80	3.53	2.90	0.05	0.05
Total mass rate [kg/s]	31.56	1.20	23.48	57.13	105.88	48.75	57.13	54.96	51.35	48.06	48.64	500.46	500.46
Total molar comp. [%]													
Coal	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H_2	0.00	0.00	0.00	19.57	19.57	19.57	19.57	20.51	22.32	23.07	22.73	0.00	0.00
O_2	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.39	11.39
N_2	0.00	0.00	0.00	4.75	4.75	4.75	4.75	4.98	5.42	5.60	5.52	76.21	76.21
H_2O	0.00	100.00	0.00	12.57	12.57	12.57	12.57	8.37	0.26	0.18	1.64	3.20	3.20
CO_2	0.00	0.00	0.00	2.40	2.40	2.40	2.40	2.51	2.75	0.00	0.00	9.20	9.20
H_2S	0.00	0.00	0.00	0.13	0.13	0.13	0.13	0.13	0.17	0.00	0.00	0.00	0.00
COS	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00
CO	0.00	0.00	0.00	60.56	60.56	60.56	60.56	63.47	69.07	71.15	70.11	0.00	0.00
CH_4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

With an increase in the mass flow rate of Coal #2, the value of the inlet enthalpy flow increased proportionally. Consequently, the overall efficiency for Coal #2 decreased, corresponding to an increase of the inlet energy supplied to the coal feed. In order to illustrate this point more clearly, economic analysis based on the same operating conditions (e.g. same mass flow rate of coals) was carried out in Section 4.4.3.

Figs. 12 and 13 illustrate the exergy flow using Sankey diagrams for Coal #1 and Coal #2. The exergy destructions for Coal #1 and Coal #2 were 546.5 MW and 456.6 MW and their exergy efficiencies were correspondingly 35.1% and 35.8%. Comparing with the thermal efficiencies (40.38% for Coal #1 and 41.41% for Coal #2), the exergy efficiencies decreased by 13.1% and 13.5%. Considering that exergy is the measure of irreversibility, the differences between the thermal efficiencies and exergy efficiencies represented the energy destruction due to the energy loss to environments. The exergy losses of the main equipment in the IGCC are shown in Fig. 14. The largest exergy losses occurred at the equipment where chemical reactions—e.g., reactions for gasification and combustion for a gas turbine—took place. The exergy loss for the gasifier for Coal #1 was 12.5% and that for a GT (gas turbine) combustor was 21.7%, accounting for the destruction of about 34% of the exergy inlet flow to IGCC. The main reason for this loss was that the chemical exergy constituted a notable portion of the total exergy and the reactions caused a serious change in the chemical exergy. This analysis implies that in order to improve the practical energy savings, attention should be paid to the performance enhancement of the gasifier and the gas turbine. This actually corresponds to industry's perspectives to regard them as the key units for operation of IGCC plants.

4.4.3. Economic analysis

Even though the knowledge of a power plant's efficiency is vital in the estimation of fuel costing, it is limited in the prediction of the economic viability of the plant. To have a comprehensive comparative analysis of a power plant to know how well or poorly it does

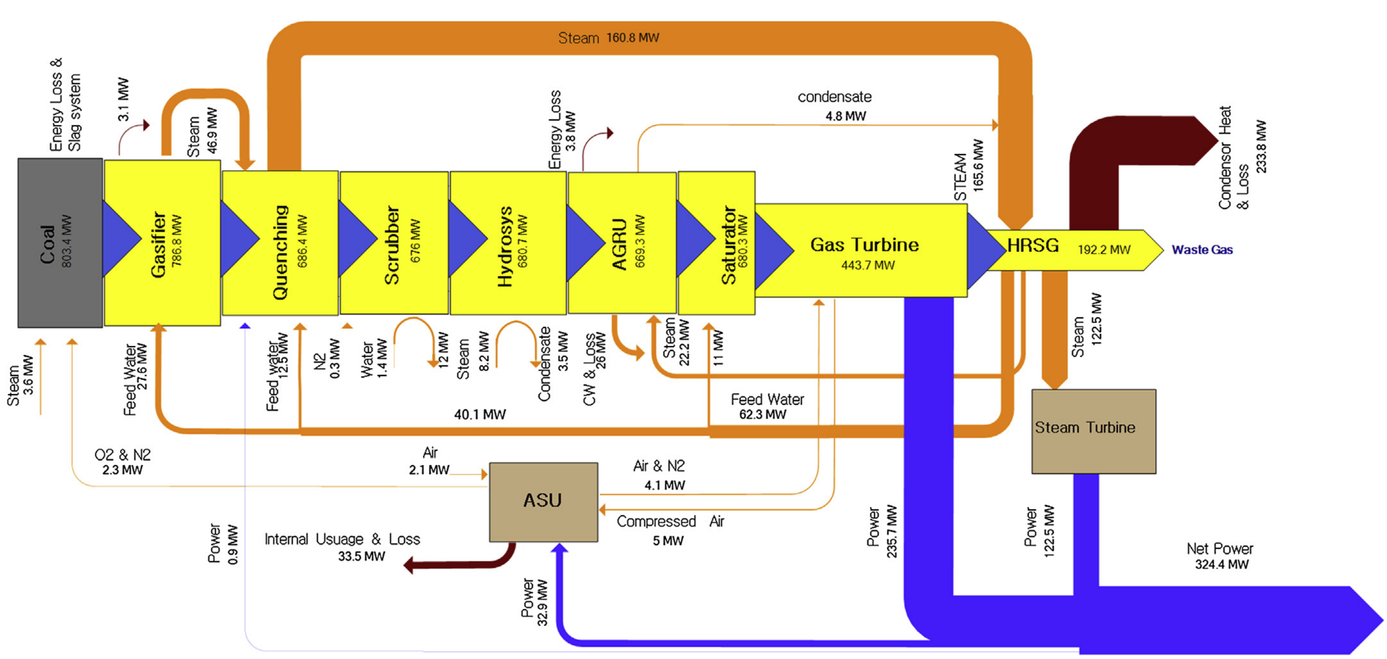

Fig. 9. Enthalpy flow diagram for Coal #1.

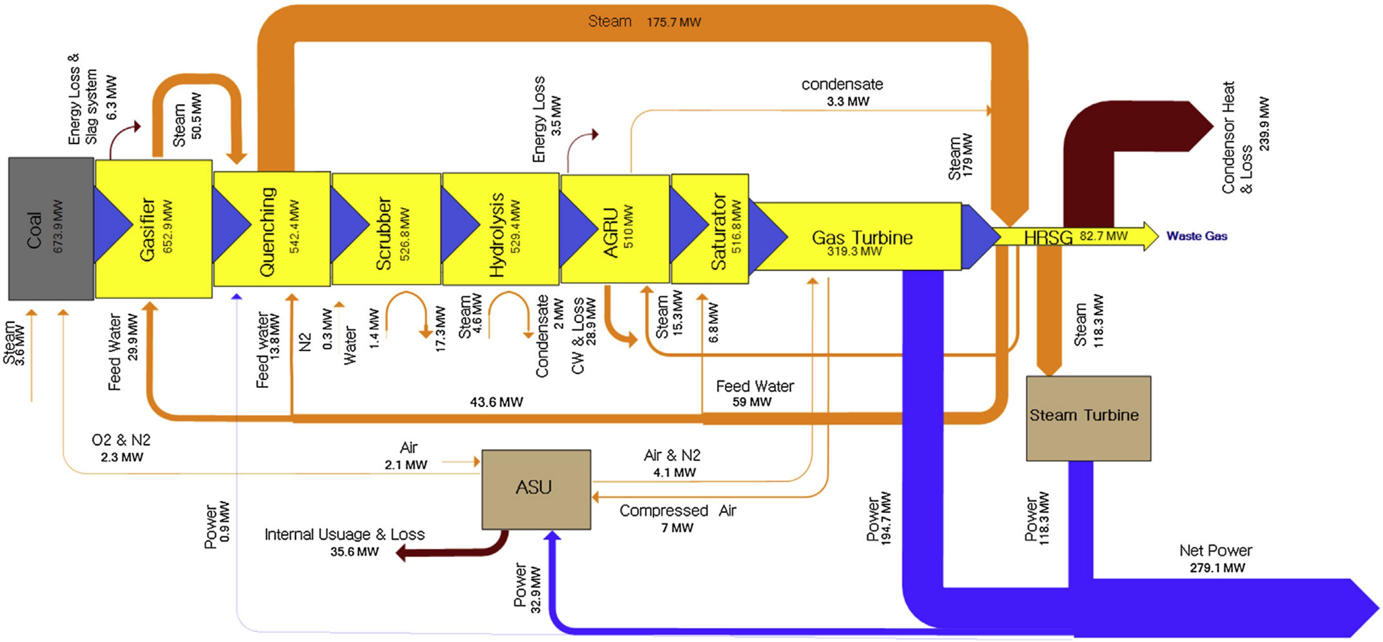

Fig. 10. Enthalpy flow diagram for Coal #2.

against other investment opportunities, a firm and detailed knowledge of the capital, fuel and labor cost are essential. This knowledge provides a figure of merit based on which informed decisions can be made regarding the plant and its operation.

For the economic aspect, this study aims to estimate the relative costs of generating electricity in an IGCC installation with two different grades of coal (Coal #1 and Coal #2). The costs used in this study were estimated using data which was generally provided by KEPCO in Korea. Estimated values could be different depending on assumptions and conditions applied in their estimation. These costs include the operating labor, material maintenance as well as administrative and support labor. There are two components of the operating costs; fixed operating cost which is generally independent of the power generation and variable operating cost, directly related to power generation.

Table 8 summarized the result of economic analysis. The costs of Coal #1 and Coal #2 were estimated at US$109.091/ton and US$85.455/ton, and the annual costs for coals based on the 85% availability of plant operation were US$78,445,455 and US$61,450,909. In order to compare the cost of electricity, the same condition for the maintenance/operation, depreciation and labor costs were employed. The total cost to generate the net power of 320 MW using Coal #1 was estimated at US$163,687,273 whereas US$ 146,692,727 was spent to produce the net power of 262 MW using Coal #2. The cost of electricity for this study was calculated to be US$0.07/kWh for Coal #1 as the base year cost of electricity whilst Coal #2 yielded a cost of electricity value of US$ 0.08/kWh. Usage of Coal #1 as a fuel in the power plant yielded a net power of 2,382,720 MWh/y whilst Coal #2 generated a net power of 1,950,852 MWh/y.

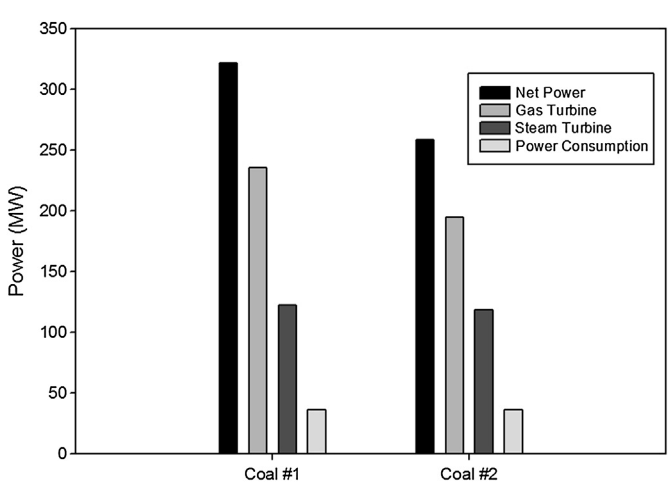

Fig. 11. Generated power & power consumption for Coal #1 and Coal #2.

5. Conclusions

Process modeling and simulation was performed for a 300 MW Class IGCC plant using the PRO/II simulation package. Through the simulation, both the ability to predict the syngas composition and the coal sensitivity were evaluated. The simulated results of the syngas composition were compared with the industrial data for a 300 MW Class IGCC demonstration plant and showed a good agreement with less than 2% marginal error.

To analyze the effects of different feedstocks, a simulation case study was performed for two different grade coals with the same

Table 7
Generated power & power consumption for Coal #1 and Coal #2.

		Coal #1	Coal #2
Power generation	MW	358.2	313.0
Gas turbine & compressor	MW	235.7	194.7
Steam turbine	MW	122.5	118.3
Power consumption	MW	33.8	33.9
Syngas recycle compressor	MW	3.3	3.3
Air separation unit	MW	28.1	28.2
HP, IP, LP BFW pumps	MW	1.6	1.7
Others	MW	0.8	0.8
Net power	MW	324.4	279.1
HHV of coal	MW	803.4	673.9
Overall efficiency	%	40.38	41.42

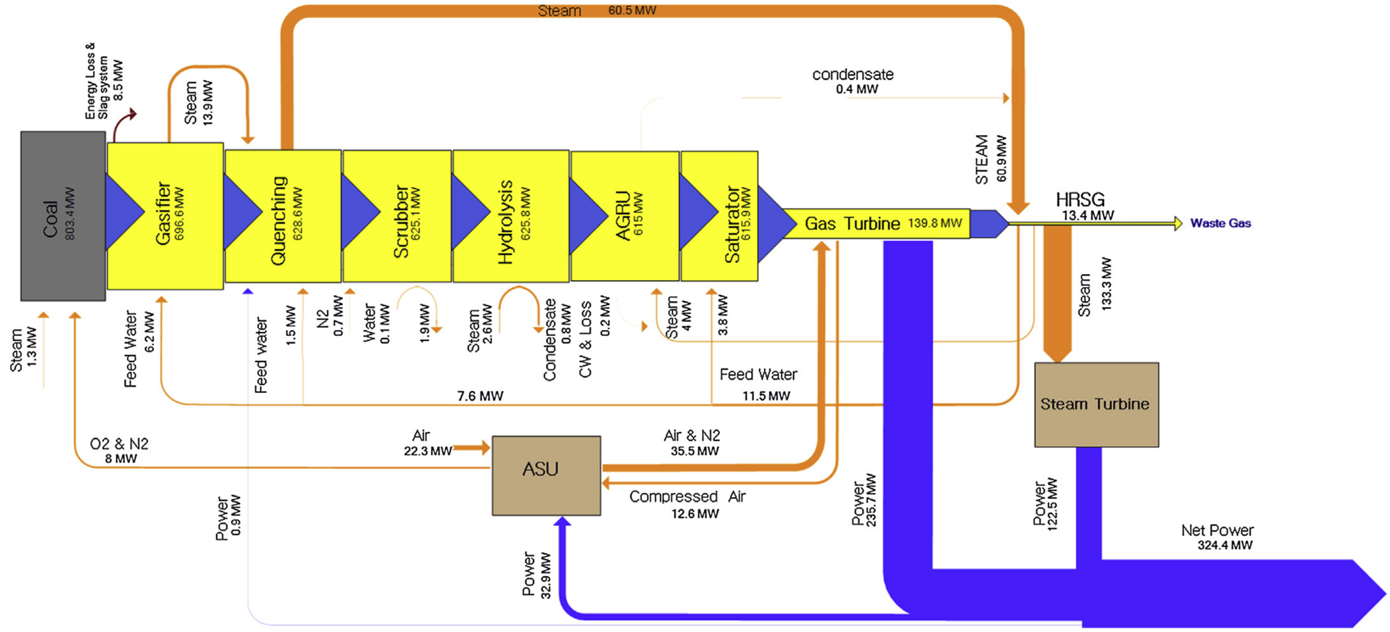

Fig. 12. Sankey diagram for exergy flow (Coal #1).

operating conditions. In order to investigate the quality of syngas produced, mass flow rate of CO and H_2 for Coal #1 and Coal #2 were compared at each stream. For the thermal efficiency evaluation, an attempt was made by means of first and second law of thermodynamics. Moreover, a careful overview of the enthalpy flow was depicted using Sankey diagrams which also elucidated the power generation, net power as well as energy losses at each of equipment. Taking into consideration, the same operating and design conditions, (i.e. feed rate, turbine efficiencies, etc.) the thermal efficiencies for two different grades of coal were 40.38% and 41.41% with a corresponding net power generation of 324.4 MW and 279.1 MW. Performing exergy analysis for the plant and individual units, the amount of irreversibility could be estimated, which played an important role in reducing the available work in the IGCC. The main exergy destruction took place at the gasification unit and the GT combustor; the percent of exergy losses at these locations was 12% and 21.7%. From the analysis, we concluded that chemical reactions were the main reason for exergy destruction and that efforts should be made on these units to improve the overall thermal efficiency.

All in all, an economic analysis using commercial data was carried out to calculate the production cost of electricity for both cases. The main entries considered in the calculation include the price of coals, operating and maintenance cost, labor cost and depreciation. It was concluded that the cost of electricity for Coal #1 and Coal #2 were evaluated as 0.0678 US$/kWh and 0.0752 US$/kWh.

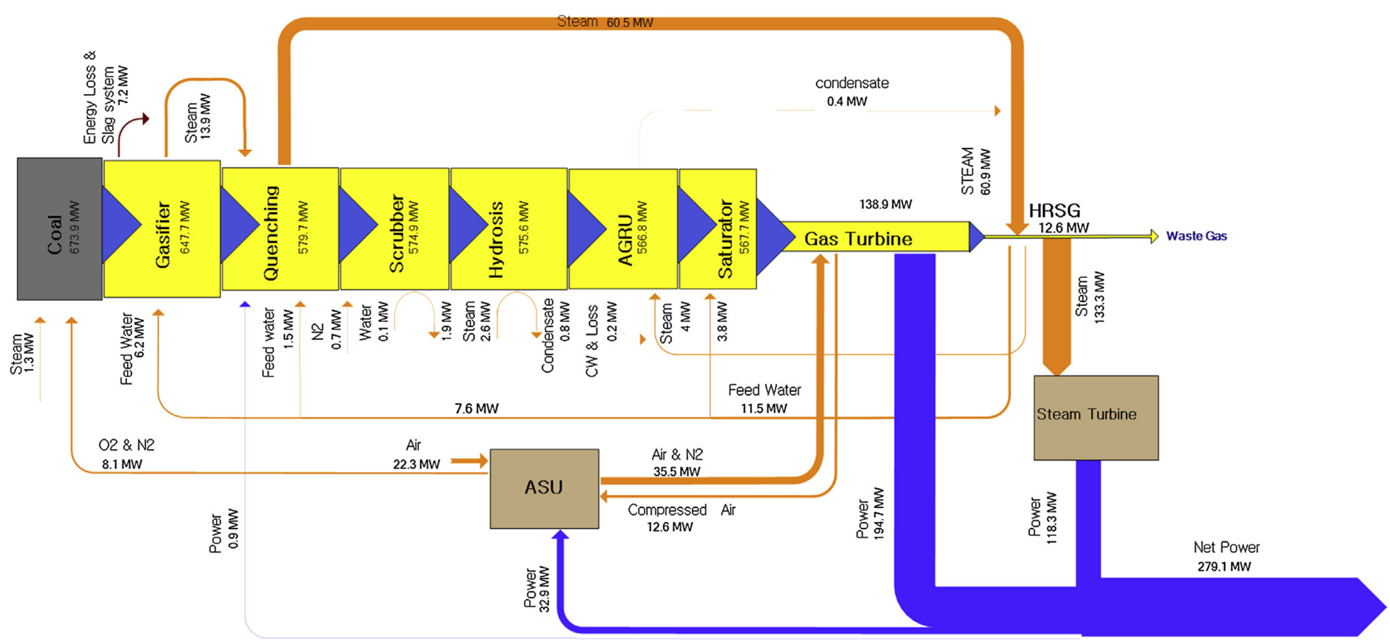

Fig. 13. Sankey diagram for exergy flow (Coal #2).

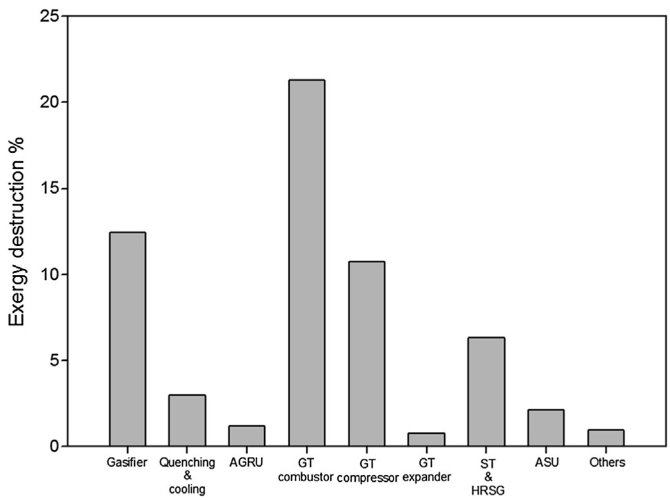

Fig. 14. Exergy losses of main equipments.

Table 8
Cost of electricity for Coal #1 and Coal #2.

	Coal #1		Coal #2	
Cost				
Coal price	109.09	US$/ton	85.46	US$/ton
Annual coal price	78,445,455	US$	61,450,909	US$
Operation and maintenance for CC and gasification	34,982,727	US$/y	34.982,727	US$/y
Operation and maintenance for ASU and commissioning	1,845,455	US$/y	1,845,455	US$/y
Depreciation	41,430,000	US$/y	41,430,000	US$/y
Labor cost	6,983,636	US$/y	6,983,636	US$/y
Total cost	163,687,273	US$/y	146,692,727	US$/y
Power				
Net power	320	MW	262	MW
Availability of plant operation	85	%	85	%
Available net power per year	2,382,720	MWh/y	1,950,852	MWh/y
Cost of electricity	0.07	US$/kWh	0.08	US$/kWh

Acknowledgment

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