Research and development of high efficiency low emission combined cycle power plant arrangements

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Abstract. Coal-fired steam turbine thermal power plants produce a large part of electricity. These power plants usually have low efficiency and high carbon dioxide emission. An application of combined cycle power plants with coal gasification equipped with carbon capture and storage systems may increase the efficiency and decrease the harmful emission. This paper describes investigation of the oxidizer type in the integrated gasification combined cycle combustion chamber and its influence upon the energy and environmental performance. The integrated gasification combined cycle and oxy-fuel combustion technology allow the carbon dioxide capture and storage losses 58% smaller than the traditional air combustion one. The IGCC with air combustion without and with carbon dioxide capture and storage has 53.54 and 46.61% and with oxy-fuel combustion has 34.94 and 32.67% net efficiency. Together with this the CO2 emission drops down from 89.9 to 10.6 gm/kWh. The integrated coal gasification combined cycle with air oxidizer has the best net efficiency.

1. Introduction

Nowadays coal-fired steam turbine thermal power plants with efficiency below 38% produce almost 10 000 TWh of the world electricity. For the last two decades the carbon dioxide atmospheric content grows for 2 ppm per year which surely contributes to the global warming [1, 2]. Moreover, the large coal resources and its low price make it an attractive energy source for the electricity production. This defines the importance of coal technology with minimal carbon dioxide emissions.

The carbon dioxide emission may be decreased by application of carbon capture and storage (CCS) systems and by the thermal power plant (TPP) efficiency improvement [3, 4]. The efficiency of electricity production from coal may be increased by transition to the integrated coal gasification combined cycle (IGCC) [5–9].

Integrated coal gasification combined cycles usually include steam-oxygen and steam-air gasification because in the combined cycle all gasification components are available. The syngas produced with the steam-oxygen technology has higher heating value than syngas produced with other methods [10, 11]. It is worth mentioning that the integrated coal gasification combined cycle has rather low efficiency below 45% which is mostly caused by the coal gasification losses. Moreover, the coal-fired combined cycle power plants have relatively low initial parameters which also determines their lower efficiency compared to the advanced power plants [12–15].

Reduction of carbon dioxide emissions at combined-cycle TPPs using syngas in the gas turbine combustion chamber is traditionally ensured by equipping of a carbon capture and storage system, which
consumes from 8 to 12% of the generated power plant electric power [16]. The CO₂ may be separated from other gases before or after fuel combustion. Also known is the oxy-fuel combustion technology where fuel burns in the almost pure oxygen without the nitrogen dilution, so the carbon dioxide capture consumes less power. The oxy-fuel combustion allows capture of 99% of carbon dioxide which means the practically zero emission as compared with the carbon dioxide capture before or after combustion in air with the capturing degree below 89% [17–21]. Therefore, the investigation of oxy-fuel combustion integrated gasification combined cycle with CCS is of great interest [22, 23].

This paper reviews possible transition to the coal-fired combined cycle technology with high turbine inlet parameters and the CO₂ emission decrease by oxygen fuel combustion. The analysis compares thermal and environmental performance of IGCC with high working fluid parameters and syngas firing in air or almost pure oxygen.

2. Air and oxy-fuel combustion integrated coal gasification combined cycle

This investigation is devoted to the combined cycle power plant with steam-oxygen coal gasification, carbon capture and storage systems. These power plants specific feature is the oxidizer type supplied to the combustion chamber for the syngas combustion. In the first case the oxidizer is air, in the second case—oxygen.

Figure 1 presents a cycle arrangement of the integrated coal gasification combined cycle with air fuel combustion. The gasification block 3 produces syngas by the steam-oxygen blow method and includes gasifier and ash handling. The air separation unit (ASU) 1 produces oxygen for gasification by air separation into oxygen and nitrogen. It compresses the oxygen up to the gasification pressure in the inter-cooled compressor 2. Steam is taken from the steam turbine 14. Then the gas is supplied to the gas turbine combustion chamber 5. The air compressor 4, gas turbine 6 and power generator 7 are mounted on the common shaft. Compressor 4 raises the air pressure up to the combustion chamber 5 pressure. Some air is supplied to the gas turbine 6 cooling.

After the combustion products have expanded in the turbine 6 the exhaust gas is directed to the double-pressure drum type heat recovery steam generator (HRSG). In HRSG the heating gas transfers heat to water medium by heat exchanger surfaces from the high-pressure steam superheater 8 to the condensate gas heater 13. The steam turbine exit steam is condensed in the condenser 16. Then the condensate pump 19 supplies water to the condensate gas heater 13. The condenser 16 outlet water temperature is lower than the acceptable inlet temperature of the heater 13, therefore, a part of heated condensate is supplied to re-circulation by the pump 20. After heater 13 the water passes the deaerator 15 that is fed with the superheated low-pressure steam. Then the feed water pumps 17 and 18 split the water into two flows with high and low pressures.

After the feed water pump 17 water subsequently passes the vaporizer 12 and low-pressure superheater 11 and enters the steam turbine mixer where it meets the high-pressure steam and expands. Downstream the high-pressure feed water pump 18 water enters the economizer 10 and then, similar to the low-pressure circuit, enters the high-pressure vaporizer 9 and superheater 8. The high-pressure steam enters the steam turbine 14 where it expands. The turbine is mounted on the generator 7 shaft.

Figure 2 shows the second cycle arrangement which differs from the first one by the fuel combustion in the combustion chamber 5 with the oxygen produced by the ASU 1. The oxygen is compressed in the inter-cooled compressor 2. The turbine 6 inlet temperature is reduced by the water injection into the syngas and combustion products. The water is supplied by the pump 21. The high temperature turbine 6 is cooled with the air compressed by the air compressor 4. The compressor 4, gas turbine 6 and power generator 7 are mounted on a single shaft. Other cycle arrangement elements of the figure 2 are equal to the ones of figure 1.

Table 1 presents the main integrated coal gasification combined cycle computer simulation parameters. The coal composition is assumed according to the data [10]: moisture (a.r.) 8.10%, ash 14.19%, carbon 74.04%, hydrogen 4.08%, nitrogen 1.67%, oxygen 7.36%, sulphur 0.65%, volatile matter (dry) 28.51%, chlorine 0.01 %. The 1700°C gas turbine inlet temperature corresponds to the latest developments [9].
Figure 1. Flow chart of the IGCC with syngas combustion in air.

Figure 2. Flow chart of the IGCC with syngas combustion in oxygen.

Table 1. Input data for the integrated coal gasification combined cycle arrangements analysis.

| Parameter                                         | Air combustion | Oxygen combustion |
|---------------------------------------------------|----------------|-------------------|
| Oxygen purity, %                                   | 95.6           |                   |
| Gasifier pressure, MPa                            | 3.5            |                   |
| Gas turbine inlet temperature, °C                 | 1700           |                   |
| Coolant specific flow, %                          | 13.6           |                   |
| Gas turbine inlet pressure, MPa                   | 3              | 3.5               |
| Turbine internal efficiency, %                    | 89             |                   |
| Pumps internal efficiency, %                      | 85             |                   |
| Compressors internal efficiency, %                | 88             |                   |
| Mechanical, electric motor, power generator, heat transport efficiency, % | 99             |                   |
| High-/low-pressure steam, MPa                     | 8.55/0.70      | 12.35/0.70        |
| High-/low-pressure superheater minimal temperature difference, °C | 20/20          | 120/20            |
| High-/low-pressure vaporizer minimal temperature difference, °C | 50/10          | 150/30            |
| Condenser pressure, kPa                            | 4              |                   |
| High-/low-pressure feed water pump outlet MPa     | 13.0/0.9       |                   |
| Condenser pump outlet pressure, MPa               | 0.6            |                   |
| Condensate temperature at the condensate gas heater inlet, °C | 60             |                   |
| Deaerator pressure, MPa                           | 0.45           |                   |

The integrated coal gasification combined cycle arrangement computer simulation involved a set of simulation models with following purposes:

- Air separation unit produces oxygen [24].
- Steam-oxygen blown gasifier transforms coal to syngas [10].
- Combined cycle gas turbine produces electrical power.

Figure 3 presents connections of the mass and energy flow models for the air syngas combustion power plant, gasification and air separation units. The gasification block inputs are the coal composition, humidity and ash. Moreover, at the gasifier inlet the flow of oxygen compressed up to the gasifier pressure and the steam flow taken from the steam turbine bleeding are assumed. The syngas flow with the gasifier outlet composition, temperature, pressure and mass flow enters the combustion chamber of integrated coal gasification combined cycle model. The integrated coal gasification combined cycle power is spent for the internal consumption including the air separation unit compressors drive and the
rest is supplied to consumers. In the case of oxygen syngas combustion (figure 3b) the air separation unit outlet oxygen enters the integrated coal gasification combined cycle oxygen compressor.

(a) with air syngas combustion

(b) with oxygen syngas combustion

**Figure 3.** Connections between mass and energy flow simulation models of IGCC.

The ASU and gasifier block models are simulated using MS Excel. The air separation unit simulation assumed air as a two-component mixture of nitrogen (79%) and oxygen (21%). The gasifier simulation involved the following assumption:

- The gasifier internal pressure is kept constant.
- Hydrogen, nitrogen and oxygen completely take part in the syngas formation process.
- Ash and syngas leave the gasifier with equal temperature.

The combined cycle gas turbine simulation was carried out using Aspen Plus (figure 4). The computer simulation model of the combined cycle power plant with syngas air combustion includes the following elements (figure 4a): air compressor with air bleeding for cooling, cooled gas turbine, double-pressure heat recovery steam generator with six surface heat exchangers, steam turbine with steam bleeding for gasification, condenser, deaerator, auxiliary equipment with condensate, feed water, recirculation and circulation pumps.

The oxygen syngas combustion combined cycle model (figure 4b) differs from the model in figure 4a by the oxygen compressor that increases the oxygen pressure before the combustion chamber and the additional water pump which supplies water to the combustion chamber.
The combined cycle gas turbine computer model involves a few assumptions as the following:

- Compressor bleeding mass flow is not dependent on the cooling system efficiency.
- The model does not consider the cooling air injection after each vane or blade row.
- The syngas combustion is stoichiometric.
- Specific internal efficiencies of compressor and gas turbine and the combustor losses are constant.

3. Results
Table 2 summarizes the integrated coal gasification combined cycle main energy and environmental performance obtained from the cycle arrangement analysis. The transition from air to oxygen combustion without the carbon dioxide capture and storage losses reduces the thermal power plant efficiency from 53.54 to 34.94%. This transition combined with the carbon dioxide capture and storage losses reduces the TPP efficiency from 46.61 to 32.67%. The efficiency of simulated air blown IGCC with CCS and gas turbine inlet temperature of 1700°C at 46.61% is in line with currently working Nakoso IGCC LHV efficiency of 42.9% with gas turbine inlet temperature of 1200°C [25].

The transition from air to oxygen combustion in combined cycle power plant with coal gasification leads to a remarkable reduction of the thermal efficiency which is mostly caused by higher heat losses with the HRSG exhaust gas (figure 5). In the case of oxy-fuel combustion this is caused by the turbine inlet temperature reduction by the water injection. Therefore, the gas turbine and heat recovery steam generator exhaust gas for 57% consists of water vapour and its heat content includes the evaporation heat. Thus, the HRSG exhaust with its high heat content is at the lowest temperature acceptable for the heat recovery steam generator because the water condensing on the condensate gas heater surface is not acceptable.
Table 2. Integrated coal gasification combined cycle arrangement analysis.

| Parameter                          | Air combustion | Oxygen combustion |
|-----------------------------------|----------------|-------------------|
|                                  | Without CCS    | With CCS          |
|                                  | With CCS       | Without CCS       | With CCS       |
| Gross power, MW                  | 226.0          | 231.5             | 160.6          |
| Net power, MW                    | 207.3          | 180.5             | 171.7          | 70.9           |
| Auxiliary electricity requirements, MW | 18.7          | 45.5              | 34.94          | 32.67          |
| Net efficiency, %                | 53.54          | 46.61             | 32.67          |
| CO₂ emissions, gm/kWh            | 89.90          | 10.63             |

Another important factor influencing the efficiency is the auxiliary electricity requirements. In the oxygen syngas combustion case the auxiliary electricity requirements are 1.56 times higher than in the air combustion one (figure 6) in spite of the two times lower CO₂ capture and storage consumption (figure 7). The 3.4 times higher auxiliary consumption share in gross power is mostly because of the ASU and oxygen compressor consumption. Unlike in the IGCC with air combustion, in the integrated coal gasification combined cycle with oxygen combustion oxygen is produced and compressed not only for the gasification process but also for the syngas combustion.

The oxy-fuel combustion technology undoubtedly has advantages in terms of the high environmental safety. The degrees of carbon dioxide capture with air and oxygen combustion are 89 and 99%. In other words, the integrated coal gasification combined cycle carbon dioxide emission drops down because of the transition from air to oxygen combustion from 89.90 to 10.63 gm/kWh.

The oxy-fuel combustion technology allows for the lowest emissions, so it is of great interest to improve its efficiency. The heat recovery steam generator exhaust gas consists of 57% water vapour which makes it the first target for the thermal efficiency improvement. The exhaust related losses may be reduced by adding surface type condensing heat exchanger in the exhaust gas flow path (figure 8). The heat exchanger condenses water vapour from the exhaust gas and the obtained thermal energy may be transferred to the supply, or district water. In the case of the direct and reverse supply water temperatures assumed at 70 and 40°C the exhaust gas heat recovery degree is 80% and up to 97% of the water vapour will be condensed.

This cycle arrangement allows for additional recovery of 150 MW heat power in the integrated coal gasification combined cycle with carbon capture and storage system but this technical solution is related to a few problems. Specifically, a problem is the stability of oxy-fuel combustor with large water
injection and the condensing heat exchanger that would combine the high heat transfer efficiency and high carbonic acid resistance.

Figure 6. IGCC gross power and auxiliaries electricity requirements with different oxidizers.

Figure 7. Gross power distribution of IGCC with different oxidizers.

Figure 8. Modification of the IGCC heat recovery steam generator exhaust and oxy-fuel combustion.

4. Conclusions

Cycle arrangements of the combined cycle power plant with steam-oxygen coal gasification and carbon capture and storage systems and their computer simulation models are developed. The integrated coal gasification combined cycle versions use air or oxygen oxidizers. The integrated coal gasification combined cycle with air combustion is traditional and the integrated coal gasification combined cycle with oxygen syngas combustion involves the turbine inlet temperature reduction down to 1700°C by water recirculation and injection into combustion chamber.

Based on the results of thermodynamic analysis of the integrated coal gasification combined cycle arrangements, it was established that:

- The integrated coal gasification combined cycle with air combustion without and with carbon dioxide capture and storage has 53.54 and 46.61% net efficiency and the carbon dioxide emission of 89.90 gm/kWh using carbon capture and storage.
The integrated coal gasification combined cycle with oxy-fuel combustion without and with carbon dioxide capture and storage has 34.94 and 32.67% net efficiency and the carbon dioxide emission of 10.63 gm/kWh using carbon capture and storage.

In the case of oxygen syngas combustion, the heat losses with the heat recovery steam generator exhaust gas are about 35% which is 4.5 times higher than in the case of air combustion. This effect is caused by the remarkably high water vapour content in the exhaust gas of about 57%. The transition from air to oxygen combustion requires power consumption increase of air separation unit and oxygen compressor from 8 to 21% of the plant power gross power.

The efficiency of the oxy-fuel combustion integrated coal gasification combined cycle may be improved by a condensing heat exchanger that transfers the exhaust gas vapour condensing heat to the delivery water. It allows for additional recovery of 150 MW heat power.

The main problems of the oxy-fuel combustion integrated coal gasification combined cycle design is the combustion stability in oxygen-syngas combustion chamber with water injection and design of a corrosion resistant condensing heat exchanger.

5. References
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