

INFLUENCE OF THE SELECTED PARAMETERS ON THE EFFECTIVENESS OF IGCC SYSTEM INTEGRATED WITH CCS INSTALLATION

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The paper presents the basic input data and modelling results of IGCC system with membrane CO₂ capture installation and without capture. The models were built using commercial software (Aspen and GateCycle) and with the use of authors' own computational codes. The main parameters of the systems were calculated, such as gross and net power, auxiliary power of individual installations and efficiencies. The models were used for the economic and ecological analysis of the systems. The Break Even Point method of analysis was used. The calculations took into account the EU emissions trading scheme. Sensitivity analysis on the influence of selected quantities on break-even price of electricity was performed.

Keywords: IGCC, modelling, CO₂ capture, membranes, economic analysis

1. INTRODUCTION

Despite numerous efforts aiming to increase energy production from renewable sources, coal for a long will remain the main fuel in electricity generation systems. Currently, nearly 40% of global electricity is produced from coal. The main reason for that is the price and availability of coal resources. On the other hand, mandatory for members of the European Union the Emissions Trading Scheme (ETS) and other international commitments (e.g., energy-climate package), should lead to significant reductions of greenhouse gas emissions to the atmosphere. This challenge is difficult to achieve, especially in energy systems based on combustion of coal. Therefore, the technologies are developed, which in the future should allow for nearly emission-free electricity production from fossil fuels, including pre-combustion, post-combustion and oxy-combustion, described and evaluated e.g. in (Bartela et al., 2014a; Bartela et al., 2014b; Desideri and Paolucci 1999; Feron, 2009; Skorek-Osikowska et al., 2013, Toftgaard et al., 2010; Zheng, 2011). The IGCC (Integrated Gasification Combined Cycle) is a pre-combustion system. In this kind of system fuel is gasified in a gas generator, forming a combustible synthesis gas, whose composition depends primarily on the type of generator and the parameters of the gasification process. Gas is then cleaned and combusted in a gas turbine, which generates most of electric power produced in the system. The rest of power is produced from the expansion work of steam in a steam turbine installation.

The main advantage of IGCC systems is higher, compared to the conventional coal-fuelled power plants, efficiency of electricity generation (Badyda et al., 2010; Cormos, 2012; Maustrad, 2005). However, if the systems should be treated as zero-emission, they must be integrated with carbon

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capture and storage (CCS) installation. Due to the fact that the CO₂ capture is realised from the process gas with a relatively high content of carbon dioxide before the combustion process, and not, as in conventional systems, from flue gases with low CO₂ content, less energy-intensive separation methods, including physical absorption process or membrane separation are used here. Thus, even though current IGCC systems are not competitive with conventional electricity generation from coal, they are considered prospective in the face of the necessity to significantly reduce carbon dioxide emissions and, therefore, when the emissions trading scheme will be valid in the final form. It results mainly from the better ecological characteristics of these systems (due to the higher efficiency) and less energy-intensive methods of separating carbon dioxide from the synthesis gas (due to the greater proportion of CO₂ in the gas and implementation of the capture process before the combustion).

The main objective of the work presented in this paper is the economic and ecological evaluation of an IGCC system integrated with a membrane installation for carbon dioxide capture and comparison of the systems with and without the CO₂ capture installation in the context of the EU emissions trading scheme.

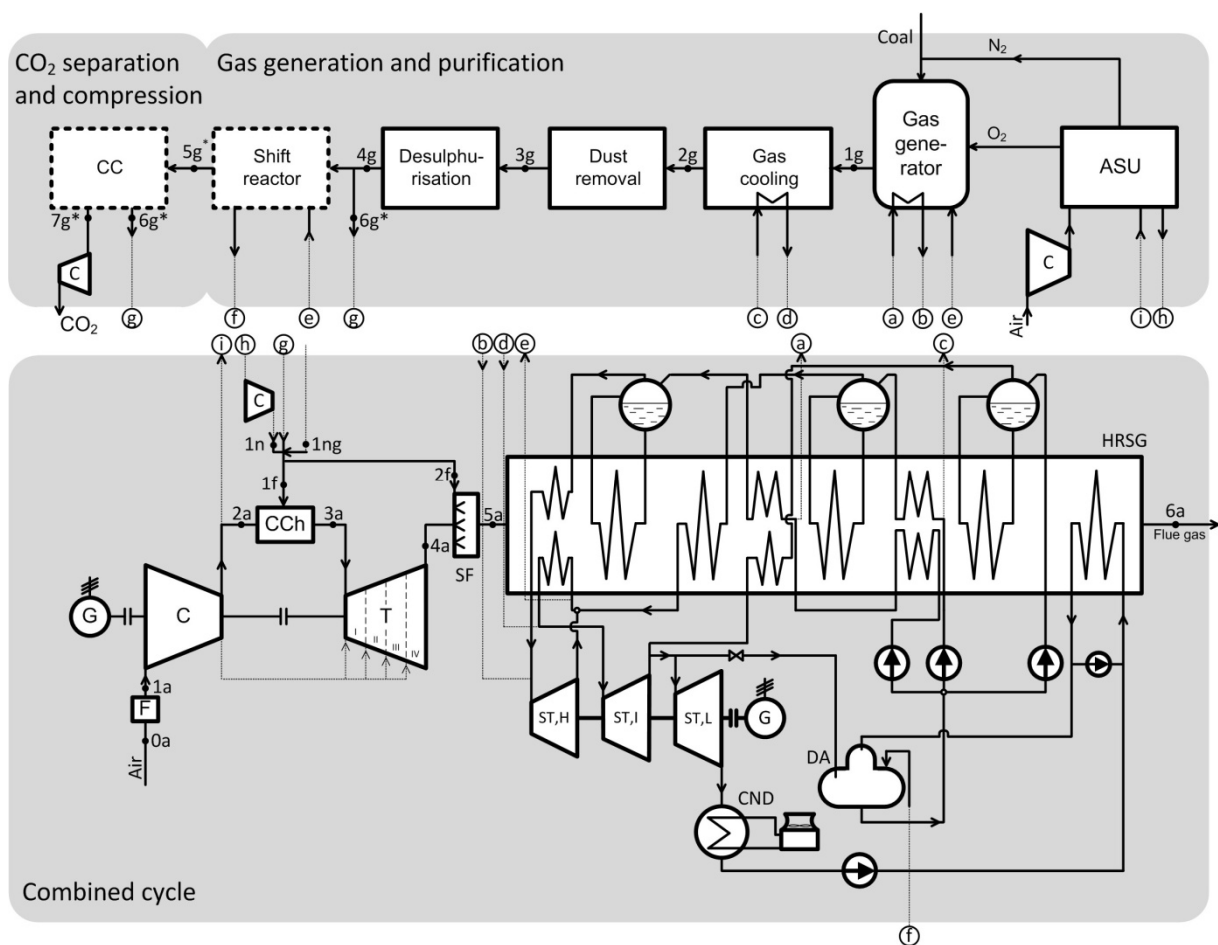


Fig. 1. Scheme of IGCC system without and with CO₂ capture; with a dashed line installations required in the case of CO₂ capture are marked;

ASU – Air Separation Unit, C – Compressor, G – Generator, ST – Steam turbine, CND – condenser, DA – deaerator, CCh – combustion chamber, HRSG – Heat recovery steam generator, F – filter

2. DESCRIPTION OF IGCC SYSTEM

In order to achieve the main objectives of the work, a model of an integrated gasification combined cycle was built. This system consists of an air separation unit (ASU) producing technical oxygen, gas

generator, a path of gas cleaning and cooling before supplying it to the gas turbine system, a gas turbine installation and a steam-water cycle with a steam turbine.

Carbon dioxide capture requires additional installations within the plant, including mainly the shift reactor (conversion of CO to CO₂ with the use of steam), the installation of CO₂ separation (e.g., absorption or membrane) and the compression installation of captured carbon dioxide before its transport to the storage place. It is also necessary to adapt the gas turbine to the combustion of gas with high hydrogen content. Diagram of IGCC plant with and without carbon capture installation is shown in Fig. 1.

For the calculation a pressurised, oxygen-fed, entrained flow gasifier (based on Shell technology, (Cormos, 2012; Maustrad, 2005; Smitha et al., 2008; Sun et al., 2011; Zheng and Furinsky, 2005)), powered with coal with the composition shown in Table 1 was chosen.

Coal is transported to the gas generator using nitrogen from ASU. Gasifying medium is oxygen with a purity of 95%, supplied from the cryogenic oxygen plant, and water vapour. The amount of oxygen is determined on the basis of stoichiometric calculations of the process for the excess air ratio $\lambda = 0.42$. The oxidant is fed to the generator at a pressure equal to the gasification pressure (4 MPa).

Table 1. Composition and main parameters of coal

Parameter	Value
Ultimate analysis [%]	
carbon	72.04
hydrogen	4.08
nitrogen	1.67
oxygen	7.36
sulphur	0.65
chlorine	0.01
Proximate analysis [%]	
moisture	8.10
ash	14.19
volatile matter	28.51
lower heating value, MJ/kg	27.80

Gas from generator is cooled and cleaned (primarily particulates and sulphur compounds are removed) and then goes to the gas turbine combustion chamber. Enthalpy of the flue gas from a gas turbine is used for production of steam in the three-pressure heat recovery steam generator (HRSG). The model assumes that the gas turbine is not integrated with the compressor in the air separation unit. It was also assumed that, regardless the variant (with or without CO₂ capture) the gas turbine does not change, while the other components of the systems are the results of modelling of this machine. This means that the stream of coal at the inlet to the gas generation system is calculated in such a way to produce the stream of gas that is necessary to obtain a determined maximum power of the gas turbine. This causes differences in the auxiliary power of the individual installations within both systems. The most important parameters of the systems without (IGCC) and with CO₂ capture (IGCC+CCS) are summarised in Table 2.

In the case of carbon dioxide capture it is necessary to implement an additional reactor of the conversion of carbon monoxide to carbon dioxide (Shift) and the installation of CO₂ separation from a process gas. To the Shift reactor steam at parameters 54.67 bar and 369 °C is supplied from the steam

cycle. As a result, carbon monoxide is converted to carbon dioxide and the process gas is enriched in hydrogen, according to the reaction:



Table 2. Main input data for a model of an IGCC system

Quantity	Unit	IGCC	IGCC+CCS
ASU			
Air stream	kg/s	125.30	166.16
Air composition: oxygen/nitrogen share	-	0.21/0.79	0.21/0.79
Technical oxygen purity	-	0.95	0.95
Technical oxygen stream	kg/s	30.54	38.48
Energy intensity of ASU	kWh/kgO ₂	0.22	0.22
Auxiliary power of ASU	MW	23.12	29.13
Power of oxidant compressor	MW	11.79	14.85
Gasifier			
Gasification pressure	bar	40.0	40.0
Coal stream	kg/s	34.69	43.71
Oxygen/coal stream ratio	kg/kg	0.89	0.89
Steam/coal stream ratio	kg/kg	0.13	0.13
Nitrogen used for coal transport/coal stream ratio	kg/kg	0.09	0.09
Gas purification system			
Efficiency of dust removal	%	99.0	99.0
Stream of water vapour directed to Shift reactor	kg/s	-	57.62
Temperature of steam directed to Shift reactor	°C	-	369
Pressure of steam directed to Shift reactor	bar	-	54.67
Carbon dioxide capture and compression			
Permeation coefficients of the membranes			
CO ₂	m ³ _w /(m ² hbar)	-	0.05
H ₂ O	m ³ _w /(m ² hbar)	-	0.00025
N ₂	m ³ _w /(m ² hbar)	-	0.00017
H ₂	m ³ _w /(m ² hbar)	-	0.0005
CO	m ³ _w /(m ² hbar)	-	0.0013
Feed pressure	bar	-	34.0
Feed temperature	°C		40
Permeate pressure	bar		1.0
Carbon dioxide recovery rate	%		91.34
Final pressure in the CO ₂ compression installation	bar		150
Energy intensity of the compression installation	kWh/kgCO ₂		0.108
Auxiliary power of the capture process	MW		0.00
Auxiliary power of the compression installation	MW		35.22

It was assumed in the analysis that one gas turbine operates in the system. However, no specific model was chosen but only a set of turbine parameters with specified power was adopted, provided by the manufacturers to work also in IGCC systems. Gas turbine installation powered by a fuel other than

designed, needs to be adapted to the new working conditions. This is particularly problematic in the case of gas turbines fuelled with high-hydrogen content fuel, and therefore for the system with carbon dioxide capture. Detailed analyses of the methods to counteract the negative effects of burning such fuel are presented elsewhere (Bartela and Kotowicz, 2011). The analysis assumed that the process gas before being burned in a gas turbine combustion chamber is diluted with nitrogen derived from the air separation unit. This requires the use of a compressor that compresses nitrogen to a pressure required in the gas turbine combustion chamber. It was assumed that in the process without CO₂ capture, the gas is diluted to such a degree to obtain the same flame temperature as that when the designed fuel (natural gas) is supplied to the turbine. In the system with CO₂ capture installation the amount of nitrogen supplied to the combustion chamber together with the process gas may result from a maximum specified by the turbine manufacturer for the proportion of hydrogen (General Electric, 2009). In the analysis the fraction of hydrogen in the gas mixture at 60% was assumed.

In the calculations it was assumed that the carbon dioxide capture in IGCC system is realised with membranes for gas separation. Although this is a technology that cannot be regarded as commercially fully mature, according to the literature, it is possible to reduce energy consumption in the CO₂ capture process in comparison to other methods of separation. For the analysis it was assumed that the capture system is composed of a membrane installation consisting of polymer membranes with polivinylloaminy FSC (fixed site carrier polyvinyleamine) selective for carbon dioxide (carbon dioxide passes through the membrane). These membranes were selected for the analysis based on the authors' previous studies (Kotowicz et al., 2010a; Kotowicz et al., 2010b; Kotowicz and Bartela, 2012; Kotowicz and Janusz-Szymańska, 2010; Skorek-Osikowska et al., 2012a; Skorek-Osikowska et al., 2012b). The main target of the selection was the possibility of obtaining assumed CO₂ purity and recovery rate (at least 90%). They are characterised by the H₂ permeability coefficient equal to 0.0005 m³_u/(m²·h·bar), the CO₂ permeability equal to 0.05 m³_u/(m²·h·bar), and selectivity to carbon dioxide $\alpha^* = 100$ (Grainger and Hagg, 2008). A scheme of the membrane module is shown in Fig. 2.

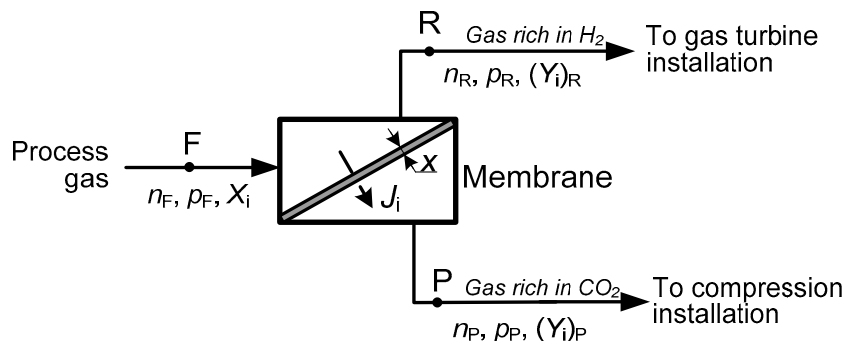


Fig. 2. Scheme of a membrane selective for carbon dioxide

Due to the fact that according to the relation used for determining the stream permeating through the membrane dJ_i (denotations in accordance with Fig. 2):

$$dJ_i = \frac{P_i}{\delta} (p_F X_i - p_P Y_i) dA_m \quad (2)$$

the main parameter deciding about the quality of the separation process is, in addition to the parameters characterising the properties of the membrane, the partial pressure difference on both sides of the membrane, membrane systems are particularly predisposed for CO₂ capture in IGCC systems. The gas resulting from coal gasification in pressurised gasifiers has usually such a high pressure that the use of additional machines (compressors or vacuum pumps) is not needed. This allows for significant reduction of the energy demand of the carbon dioxide capture process.

The last element indispensable in the case of carbon dioxide capture is an installation of its compression before its transport to a storage place. In the literature there are no precise requirements for the parameters of a stream of captured carbon dioxide and the available data are based mainly on the American experience in the mining industry (Zheng, 2011). Therefore, the calculation assumes that carbon dioxide will be transported as a supercritical fluid and the final pressure in the compression installation will amount to 150 bar. The purity of the captured CO₂-rich stream results from the properties of the separation plant but it was assumed that it cannot be less than 0.9. The installation consists of a four-section compressor with interstage cooling to 30 °C. The heat from cooling sections of the compressor is not used in the cycle.

3. RESULTS OF MODELING OF THE SYSTEMS

For building models of the integrated gasification combined cycle with CO₂ capture installation, commercial programs were used, including Aspen Plus (model of gas generation and purification, oxygen production and compression of carbon dioxide before transport), GateCycle™ (gas turbine installation, heat recovery steam generator and steam-water cycle) and Aspen Custom Modeler (membrane for CO₂ separation from the process gas). During the process of building the models the authors took advantage of the experience gained in previous works related to the modelling of energy systems, e.g. (Desideri and Paolucci, 1999; Kotowicz et al., 2010; Kotowicz et al., 2011). Models of individual installations and the model of the whole installation were validated on the basis of the literature data e.g. (Cormos, 2012; Desideri and Paolucci, 1999; Feron, 2009). The models can be used to define the most important thermodynamic parameters of streams at different points, and the power of machines and equipment in the plants, used for ecological and economic analyses. Selected data concerning stream parameters in the system are shown in Tables 3 and 4. They concern the systems without and with CO₂ capture.

For a selected gas turbine gross and net power of the whole system as well as auxiliary power of the system with and without CO₂ capture were calculated. Power in IGCC plants is generated both in the gas turbine and steam turbine installation. The auxiliary power is affected mainly by the power of the air separation unit, system for coal preparation and transport, generation and purification of the process gas, steam-turbine installation, gas turbine installation and, in the case of the systems integrated with CO₂ capture, the power needed to capture and compress carbon dioxide prior to transport.

Table 3. Main parameters of the gas and gas composition in the selected points of IGCC system without CO₂ capture; denotations according to the Fig. 1

Parameter	Raw gas (1g)	Purified gas (4g)	Gas to gas turbine (1f)	Flue gas (5a)
Temperature, °C	1600	40	15	85
Pressure, bar	38.5	36.61	27.8	1.02
Flow rate, kg/s	72.87	67.17	92.21	717.11
H ₂ , % vol	26.23	28.40	22.14	0.00
CO ₂ , % vol	4.18	4.55	3.55	8.53
CO, % vol	56.46	61.11	47.64	0.00
N ₂ , % vol	4.61	5.07	25.99	74.80
H ₂ O, % vol	4.68	0.01	0.01	3.78
other, % vol	3.84	0.86	0.67	12.89
LHV, MJ/kg	11453	11840	8238	-

Table 4. Main parameters of the gas and gas composition in the selected points of IGCC system with CO₂ capture; denotations according to the Fig. 1

Parameter	Raw gas (1g)	Purified gas (4g)	Gas before membrane (5g*)	Retentate (6g*)	Permeate (7g*)	Gas to gas turbine (1f)	Flue gas (5a)
Temperature, °C	1600	40	40	40	40	15	85
Pressure, bar	38.5	36.61	34.00	34.00	1.00	26.92	1.05
Flow rate, kg/s	91.80	84.62	114.01	23.69	90.32	64.98	692.56
H ₂ , % vol	26.23	28.40	54.50	85.05	4.43	60.00	0.00
CO ₂ , % vol	4.18	4.55	39.51	5.51	95.23	3.89	1.09
CO, % vol	56.46	61.11	3.27	5.23	0.00	3.69	0.00
N ₂ , % vol	4.61	5.07	2.44	3.76	0.28	32.10	74.72
H ₂ O, % vol	4.68	0.01	0.28	0.45	0.01	0.32	12.64
other, % vol	3.84	0.86	0.00	0.00	0.00	0.00	11.54
LHV, kJ/kg	11.45	11.84	7.01	32.79	-	11.92	-

These quantities were determined based on the results of modelling of the individual installations. The main data concerning thermodynamic parameters and environmental indicators of particular installations are presented in Table 5.

Table 5. Selected characteristic environmental and thermodynamic parameters of the analysed technologies

Quantity		IGCC	IGCC+CCS
Gross power	MW	508.03	484.67
Total auxiliary power of the system	MW	66.71	120.80
Net power	MW	441.31	363.87
Power of the gas turbine	MW	289.05	305.87
Power of the steam turbine	MW	218.98	178.80
Process gas chemical energy flux	MJ/s	834.55	1051.36
Coal energy flux	MJ/s	946.43	1192.33
CO ₂ emission	kg/s	91.19	16.68
CO ₂ emission incriminating a unit of gas/coal chemical energy	kgCO ₂ /GJ	96.35	13.99
CO ₂ emission incriminating unit of electricity produced	kgCO ₂ /MWh	646.19	123.89
Gross efficiency	%	53.68	40.65
Net efficiency	%	46.63	30.52

4. MAIN ASSUMPTIONS FOR ECONOMIC AND ECOLOGICAL ANALYSIS

Economic analysis was carried out for the IGCC systems, using the authors' own computational algorithm built in the Excel environment. For the model of the system with and without the capture installation, key economic indicators were adopted, such as unit investment costs, operating costs or cost of financial services. To assess the economic efficiency of the analysed solutions the *NPV* (Net Present Value) indicator was mainly used. The net present value results from adding (cumulating) the discounted cash flow (*CF_t*) in all the years of operation, at a known level of the discount rate *r*. The condition for the profitability of the project is a positive *NPV* value. A situation where *NPV* = 0 means, that the project did not bring a profit, but the invested capital has been returned. The *NPV* is calculated from the formula:

$$NPV = \sum_{t=0}^{t=N} \frac{CF_t}{(1+r)^t} \quad (3)$$

From the condition of setting to zero the net present value ($NPV = 0$) the break-even price of electricity was determined c_{el}^{b-e} , which is in fact the minimum sale price of the produced electricity, that ensures profitability of the investment. Taking into account all the components of cash flow, the formula for determining the break-even price has the following form:

$$C_{el}^{b-e} = \frac{\sum_{t=0}^{t=N} \frac{[J + (K_{PR} + P_d + K_{obr}) - A - F - L]}{(1+r)^t}}{\sum_{t=0}^{t=N} \frac{(E_{el} - E_{el,pw})_t}{(1+r)^t}} \quad (4)$$

Values of the individual components of the cash flows were determined according to the methodology presented e.g. in (Kotowicz, 2009; Skorek and Kalina, 2005) and another paper of the authors (Kotowicz et al., 2011, Skorek-Osikowska et al., 2014). The calculations took into account the size of the investment in fixed assets, cost of fuel, non-fuel costs (e.g. costs of operation, maintenance and repairs, cost of salaries) and the costs of carbon dioxide emission. Data for the economic calculations were taken from the available literature, e.g. (Cormos, 2012; Descamps et al., 2008; Grainger and Hagg, 2008; Huang et al., 2008; Kotowicz and Janusz-Szymańska, 2010; Malko, 2011; Melchior and Madlener, 2012; Ściążko et al., 2006; Zhao et al., 2009), especially in the form of indicators of the unit or absolute values. The most important ones are presented in Table 6.

Determination of the unit investment costs for the purchase of machinery and equipment is often based on published literature data from existing systems (most reliable) or on estimating of the cost based on approximation curves. These indicators are often determined with the exponential equation (Skorek and Kalina, 2005):

$$C_U = C_R \left(\frac{X_U}{X_R} \right) \quad (5)$$

The value of the α exponent is for the energy systems typically assumed in the range between 0.6 and 0.7.

The investment costs were estimated for such installations as: gas generator island, installation of the cryogenic air separation unit, gas purification system, gas-turbine installation and steam-water cycle. Additionally, in the case of a system with CO₂ capture, unit investments for Shift reactor, membrane CO₂ capture and compression installation as well as for transport and injection of captured carbon dioxide were determined. In this paper, the investments in individual plants were determined based on the specific investment costs indicators j or with approximation formulas. Unit cost indicators are expressed in monetary units (e.g., PLN, €) related to the typical parameters of the systems, machinery or equipment, e.g. nominal power. As an example, specific investments in a gas turbine, expressed in €/kW_{e,b}, was determined from the relation (Skorek and Kalina, 2005):

$$j_{TG} = 5082.4(N_{elTG,nom})^{-0.271} \quad (6)$$

the total investment cost for the compressor in the carbon dioxide compression installation before transport from the formula (Kotowicz and Janusz-Szymańska, 2010):

$$j_{C,CCS} = 1.051 \frac{(39.5\dot{m}_{CO_2})}{0.9 - \eta_C} \eta_C \ln \beta \quad (7)$$

The investment cost on the membrane module was estimated according to (Kotowicz and Janusz-Szymańska, 2010), assuming the price of one square meter of membrane equal to 16 €.

Determined from the relation (5) to (7) and the available literature data (mainly (Cormos, 2012; Descamps et al., 2008; Grainger and Hagg, 2008; Huang et al., 2008; Kotowicz and Janusz-Szymańska, 2010; Melchior and Madlener, 2012; Ściążko, 2008; Ściążko et al., 2006; Zhao et al., 2009)) specific investment costs for particular installations in IGCC system with and without carbon dioxide capture are shown in Table 7.

Main data assumed for the economic analysis are gathered in Table 6. The analysis included the functioning of the emissions trading scheme and therefore charge for CO₂ emissions. The allocation of free emission allowances was not taken into account.

Table 6. Specific investment cost on particular installations, expressed in €/kW_{e,b}

Installation	IGCC	IGCC+CCS
Coal preparation installation	71	79
Gas generator	283	317
ASU	172	190
Gas purification installation	99	111
Gas turbine installation	174	174
Power generation system	460	463
Other (site, utilities, permissions, prime costs, etc.)	423	523
Shift reactor	-	40
Membrane CO ₂ capture installation	-	75
CO ₂ compression installation	-	51
Total	1682	2024

5. RESULTS OF THE ECONOMIC AND ECOLOGICAL ANALYSIS

Basing on the assumptions made and the condition of setting the net present value to zero, the break-even price of electricity was first of all determined. The value of this indicator in the system without capture was 368.5 PLN/MWh (87.7 €/MWh), while for the system with capture it was equal to 377.8 PLN/MWh (90.0 €/MWh). This means that for the assumptions made, the system with carbon dioxide capture is less profitable than the system without capture. Break-even price of electricity significantly exceeds the value of the price in conventional coal-fired system with CO₂ capture (Kotowicz et al., 2011; Wójcik and Chmielniak, 2010).

According to the current EU emissions trading scheme (ETS), it is important to know the impact of the price for emission allowances on the break-even price of electricity, especially given the fluctuations and growth forecasts of allowances price. The calculations were made in the range of prices from 0 to 80 €/tonne of CO₂. This analysis did not include the allocation of free emission allowances. In Table 8 break-even price of electricity for the system with and without capture and for two levels of allowance prices, i.e. 6.6 €/tCO₂ (assumed on the basis of the average price of allowances from the European market in the first half of June 2012) and 40 €/tCO₂ is presented.

As a reference, values for a case in which the emissions trading scheme does not exist (the price of allowances is equal to zero) is also shown. Fig. 3 shows the change of the value of the break-even price of electricity when changing price of allowances in the range from 0 to 80 €/tCO₂.

Table 7. Main input data for the economic analysis

Specification	Unit	IGCC	IGCC+CCS
Gross power of the system	MW	508.03	484.07
Gas turbine power	MW	289.05	305.97
Auxiliary power rate	%	13.1	24.92
Annual working time	h/a	7000	
Unit investment costs	€/kW _{installed power}	1682	2024
Construction time	years	3	
Distribution of the investment costs in subsequent years of construction	%	15/30/55	
Share of investor's own means	%	25	
Share of commercial credit	%	75	
Interest of the commercial credit	%	6	
Payback time of the commercial credit	years	10	
Exploitation time	years	20	
Discount rate	%	6.2	
The cost of repairs with the division in consecutive years of operation related to the investment cost	%		
	Year 1	1.0	1.1
	Years 2÷3	1.5	1.7
	Years 4÷7	2.0	2.2
	Years 8÷11	2.5	2.75
	Years 12÷15	3.0	3.3
	Years 16÷20	3.5	3.85
Coal price	€/GJ	2.38	
CO ₂ emission allowances price	€/Mg	40	
Employment	pers./MW _{e,b}	2.5	2.8
Monthly salary including related costs	€/post/month	1190	
Average depreciation rate	%	6.67	
Income tax rate	%	19.0	
Liquidation value related to the investment	%	0.2	
Rate of exchange	PLN/Euro	4.2	

Table 8. Results of the economic analysis

Emission allowances price, €/tCO ₂	Break-even price of electricity, PLN/MWh (€/MWh)	
	IGCC	IGCC+CCS
0	242.5 (57.7)	356.6 (84.9)
6.6	263.3 (62.7)	360.2 (85.8)
40	368.5 (87.7)	377.8 (90.0)

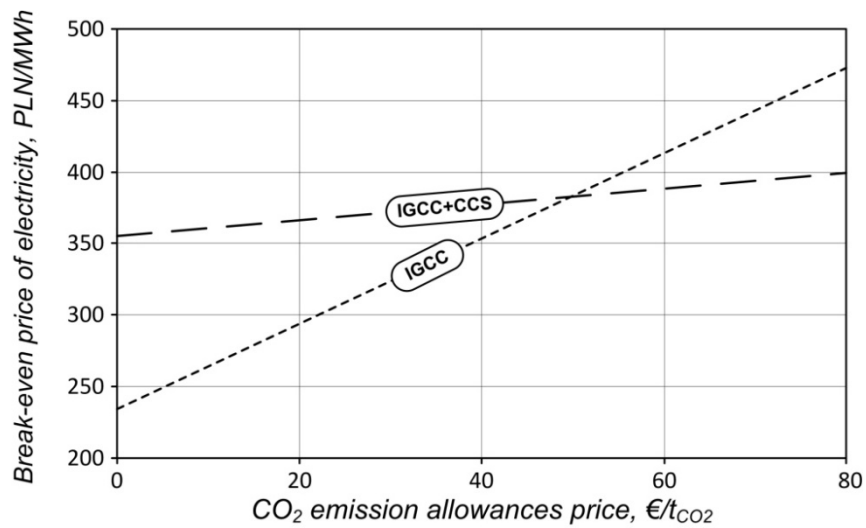


Fig. 3. Break-even price of electricity as a function of a change in the CO₂ emission allowances price within the range $\pm 20\%$

The results of analysis show significance of the emission allowance prices for supporting the system with CO₂ capture. In the system with carbon dioxide capture the influence of a change of price of allowances on a change of the cost of generating electricity is much smaller than in the system without capture. Thus, this type of systems is not very sensitive to a change of the price of emission allowances, which is particularly advantageous in the face of growth forecasts of allowance prices. However, at current rates the system integrated with carbon dioxide capture installation is an investment less profitable than the corresponding system without capture.

In the economic analysis of energy systems a proper adoption of unit investment costs is essential. It is not easy in the case of technologies that are still being developed, due to the lack or small number of existing systems that could serve as a reference. Moreover, it can be assumed that with the commercialisation of the developed technology the unit investment cost will relatively decrease. The difference in capital cost between technologies with and without capture will also decrease. Change of the break-even price of electricity in the case of a change of relative investment cost in the range $-0.2 \div 0.2$ is shown in Fig. 4 and Fig. 5. The analysis of the change of the price of coal (as one of the major components of the fixed costs) and annual operation time in the same ranges of variation are also presented.

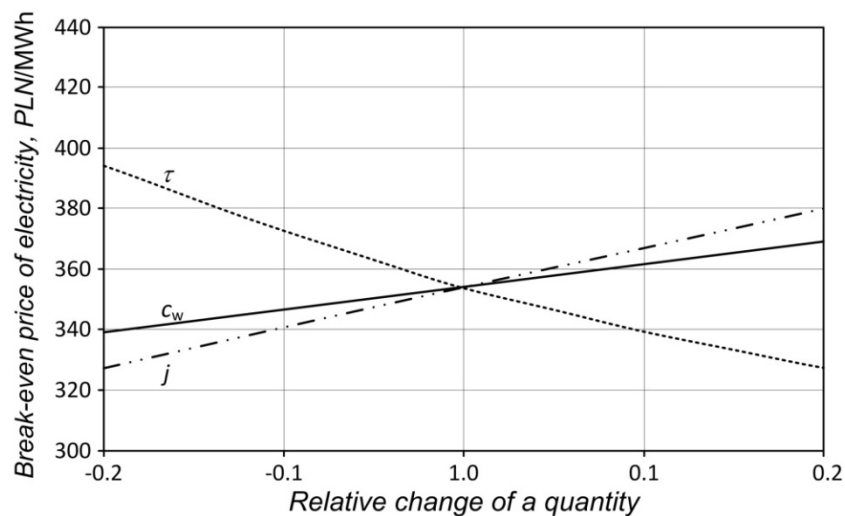


Fig. 4. Break-even price of electricity in IGCC system without CO₂ capture as a function of a change of the unit investment cost (*j*), coal price (*c_w*) and annual operation time (*τ*) in the range $\pm 20\%$

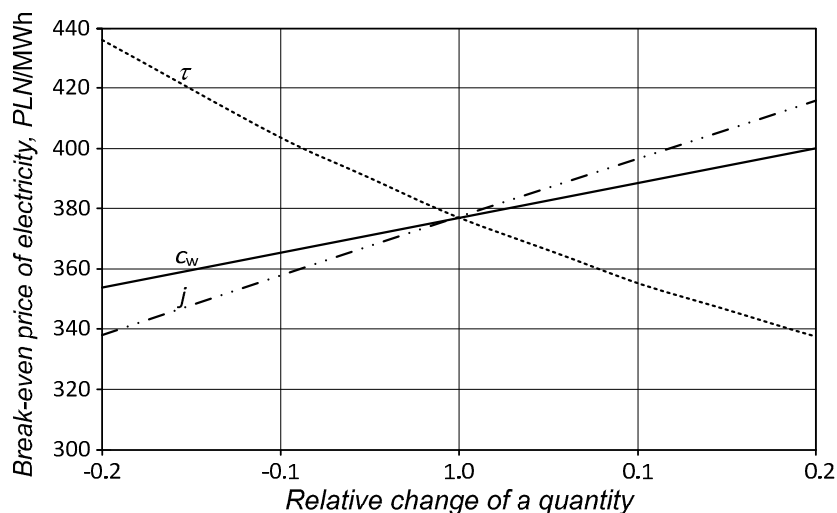


Fig. 5. Break-even price of electricity in IGCC system with membrane CO₂ capture as a function of a change in the unit investment cost (*j*), coal price (*c_w*) and annual operation time (*τ*) within the range ±20%

The slope of the curve in relation to the x-axis determines the importance of the impact of a certain quantity on the value of break-even price of electricity. Thus, it results from the analysis, that the greatest influence has the annual operation time, then the unit investment cost and the lowest impact has the price of coal. However, in practice, changes of these values can occur in different ranges. While investment in new technologies, which could include coal gasification systems, may decrease with the development of these systems, the coal price is unlikely to significantly decrease in the future. The relatively significant decrease in break-even price of electricity can be achieved by increasing the availability of the IGCC systems. Increasing time from 7000 h/a to 8000 h/a results in a change by about 20 PLN/MWh in the case of the system without capture and by about 30 PLN/MWh in the case of the system with CO₂ capture.

An interesting indicator in terms of assessing the integration of energy systems with CCS installations is cost of CO₂ avoided emission. Determination of the cost of avoided emissions requires a comparison of the system integrated with the carbon capture installation with a so-called a reference system thus, the unit without integration (in which the CO₂ capture is not realized). This indicator shows the cost of carbon dioxide removal, taking into account a decrease of efficiency of the system resulting from the implementation of the CCS installation. The cost of CO₂ avoided emissions is described by the relationship:

$$CAE = \frac{(C_{el}^{b-e})_{REF+CCS} - (C_{el}^{b-e})_{REF}}{(e_{CO_2})_{REF} - (e_{CO_2})_{REF+CCS}} \quad (8)$$

The cost of avoided emissions (CAE) for IGCC system integrated with CO₂ capture was determined in relation to the corresponding system without integration, assuming that market mechanisms in the form of emissions trading scheme do not exist. Determined in such a way cost of avoided emissions gives the information about the limit price of emission allowances at which the two compared solutions have approximately the same economic effectiveness. The most important results of ecological analysis are summarised in Table 8.

Adaptation of the CCS installation in the examined coal-fired systems causes an increase in the auxiliary power and, consequently, decrease of efficiency. Calculated cost of CO₂ avoided emission is 193.5 PLN/tCO₂. It is also the minimum price of CO₂ emission allowances for which the break-even price of electricity would be the same in the system with and without carbon dioxide capture.

Table 9. Cost of avoided emission in the analysed IGCC system

Evaluation index	Unit	Technology	
		IGCC	IGCC+CCS
e_{CO_2}	kg/MWh	743.9	154.1
CAE	PLN/tCO ₂ (€/tCO ₂)	-	193.5 (46.1)

6. CONCLUSIONS

The main purpose of the analyses presented in this paper was the economic and ecological evaluation of the integrated gasification combined cycle with and without the carbon dioxide capture installation. Carbon dioxide capture is one of the methods that should contribute to the reduction of greenhouse gas emissions to the atmosphere (Chmielniak, 2011). IGCC systems offer many advantages, including in particular the high efficiency of electricity production. When using an external source of heat in order to supply heat for endothermic reactions in gas generator, the efficiency of IGCC systems can even be higher than that of systems currently used (Kawabata et al., 2012). However, investment costs of IGCC system significantly outweigh the costs of conventional systems, so their development is connected mainly with the possibility of implementation of less energy intensive carbon dioxide capture methods than in the case of the methods used for CO₂ capture from flue gases after combustion process in conventional systems.

Membrane separation method used in the analyses presented in this paper allows realization of the capture process practically without any energy input, based only on high pressure of the process gas. However, it does not change the fact that it is necessary to implement the shift conversion reactor, to which significant amounts of steam are needed (thereby reducing stream of steam expanded in the turbine), and the carbon dioxide compression installation before its transport to the storage area, which is associated with a significant power needed to drive the compressors. The results of analysis show that the auxiliary power of the system with capture makes the break-even price of electricity, even with the emission allowances prices equal to 40 €/tCO₂, higher by more than 4.5 €/tCO₂ than that in the case of the system without capture, and thus, makes this system unprofitable. It should be assumed that in the future, in connection with bringing to operation consecutive commercial or demonstration systems, the profitability of IGCC systems can be increased, especially in the case of an increase in the emission allowances price with simultaneous lowering of the unit investment cost and increasing availability of the systems. To reduce the investment costs associated with the capture process it may be advisable to use membranes selective for CO, which would allow for carbon dioxide capture with omitting the shift reactor. However, further development of the membrane technology is needed.

SYMBOLS

A	amortization
C	cost
CAE	cost of avoided emission
c_{el}	price of electricity, PLN/MWh (€/MWh)
CF	Cash Flow
e_{CO_2}	unit CO ₂ emission
E_{el}	gross electricity production,
E_{el_pw}	auxiliary power of the system
F	interest on loans

j	unit investment cost
J	investment cost
J_i	stream permeating through the membrane
K_{obr}	change of the working capital
K_{PR}	production costs
\dot{m}	mass flow rate, kg/s
N_{el}	electric power, MW
\dot{n}	molar stream
NPV	Net Present Value
p	pressure, bar
P_d	income tax
r	the discount rate
t	consecutive year of consideration from the beginning of the construction of the system
X	molar share of a component before membrane
Y	molar share of a component after membrane
X_U, X_R	characteristic discriminant of the system in Equation (5)

Greek symbols

α	scaling factor in Equation (4)
β	pressure ratio
δ	membrane thickness, m
η	efficiency

Subscripts

C, CCS	compressor in the CCS installation
F	feed
nom	nominal
P	permeate
R	retentate
REF	concerns reference system
pw	auxilliary power
TG	gas turbine
U	concerns estimated system

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