Comparative study of a combined heat and power plant retrofitted by CO$_2$ capture during the combustion of syngas from sewage sludge gasification *versus* zero-emission combustion of hydrogen produced using renewables

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HIGHLIGHTS

- Examples of possibilities to reduce CO$_2$ production in industry by hydrogen burn.
- Modernization of an existing Polish heat and power unit to capture CO$_2$.
- Cooperation of the Combined Heat and Power plant with RES producing hydrogen.
- Validation of calculations in the numerical commercial program and in-house EcoPG.

ARTICLE INFO

ABSTRACT

With ecological requirements aimed at limiting the production of CO$_2$, it is necessary to produce all, or most of the energy from RES. During the transformation process, ecological and highly efficient combustion power plants will be needed. The classic cycle of combined heat and power (CCGT) with green improvements will continue to be one of the most suitable technologies for this task. This article presents the modernization of the CCGT power plant in Zielona Góra in terms of possible solutions to reduce CO$_2$ emissions and cooperation with RES producing hydrogen. Two variants of retrofit were considered: CO$_2$ capture following the combustion of syngas obtained from gasification of sewage sludge, and emission-free hydrogen combustion in a gas turbine. Calculations were made using numerical modelling and the obtained results were validated. Avoided CO$_2$ emissions for both solutions are shown. The proposed upgrades were compared with the basic variant and other gaseous fuels.

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Nomenclature

A	Anode
AB	Absorber
B	Steam bleed from ST for MEA regeneration
BAT	Best Available Technology
C	Compressor
C_{CO2}	Compressor for compressing CO_2 for storage or transport
C_{fuel}	Fuel compressor
CC	Combustion chamber
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
COL	Cooler
DC/AC	Direct curent/alternating curent
DE	Desorber
DH	Distric heat
ECO	Economizer
EL	Electrolite
EVAP	Evaporator
F	Filter
FG	Flue Gases
G	Power generator
GT	Gas Turbine
HC	Heat consumers
HE	Heat exchanger
HP	High pressure
HRSG	Heat recovery steam generator
K	Catode
LHV	Lower Heating Value, [MJ/kg]
LP	Low pressure
$\dot{m}$	Mass flow [kg/s]
MEA	Mono-ethanol Amine
N_{el1}	Gas turbine gross electric power output [MW]
N_{el2}	Steam turbine gross electric power output [MW]
OC	Outside heat Consumers
P	Pump
p	Pressure [bar]
PEP2040	Poland's Energy Policy 2040
PEHA	Pentaethylenehexamine
SH	Superheater
SHHP I, II	High-pressure section consists of two steam superheaters
ST	Steam Turbine
$\dot{Q}_{HC}$	Net heating capacity output [MW]
q_{el,CO_2}	Electric power demand to the system [MJ/kg_{CO_2}]
q_{H,CO_2}	Heat demand to reboiler [MJ/kg_{CO_2}]
RES	Renewable Energy Sources
SHLP	Low-pressure section includes a superheater
SMR	Steam Methane Reformation
t	Temperature [°C]
TR	Transmission
WINJ	Water injection
δ_{tHP}	Evaporator high pressure pinch point [°C]
δ_{tLP}	Evaporator low pressure pinch point [°C]
$\eta_{CHP,gross}$	Combined Heat and Power plant gross efficiency [%]
$\eta_{CHP,net}$	Combined Heat and Power plant net efficiency [%]
$\eta_{el,gross}$	Gross electrical efficiency [%]
$\eta_{el,net}$	Net electric efficiency [%]
$\eta_{el,TG}$	Electrical efficiency of the gas cycle [%]
Π	Compressor pressure ratio
Δp_A	Flue gas pressure drop in absorber column $\left[Pa / \left(\frac{kg_{CO_{2,fg}}}{s} \right) \right]$
Δp_R	Pressure drop in reboiler [bar]

1. Introduction

Currently, a significant increase in demand for electricity can be observed in the world [1,2], which results, among others, from economic development [3]. Thus, power plants must operate with higher efficiencies to reduce fuel consumption [4–6]. Nevertheless, this economic development also generates some disadvantages in the form of the production of greenhouse gases, e.g. NOx, SOx, and CO_2 [7–10], and other substances generated during the combustion of coal [11,12] including hard and brown coal in conventional power plants [11,13,14]. All of the stated above leads to global climate change, an example of which is global warming. The solution to this problem might be to focus more on renewable energy sources [15], which is dictated by the rise of public awareness on environment protection, carbon footprint reduction [8,16], and political restrictions through the Best Available Technology (BAT) reference documents applied in the EU countries. The largest problem seems to be CO_2 emissions from burning fossil fuels, constantly growing at the scale of the whole world [17,18]. In 2017 it was emitted 32.5 gigatons of global CO_2

emissions related to energy production [19]. It is impeding the progress to lower the temperature worldwide at a safe level; according to the Paris Agreement [20–22] it is a limit of temperature return below 2 °C, and ideally 1.5 °C [23,24]. Since the implementation of the Paris Agreement in 2015, it has been the basis in the fight against the climate crisis [25,26]. This is where carbon capture and storage (CCS) technologies emerge as possible solutions to this problem.

According to Poland's Energy Policy 2040 (PEP2040) [27] and the current state of the Polish energy sector, it is impossible to switch to renewables and cut off conventional power plants almost immediately, as it will endanger energy safety. A lot of other countries are in a similar situation. One of the reasonable solutions in the transition process seems to be highly efficient and low-emissive combined cycle gas turbine (CCGT) plants, developed as combined heat and power (CHP) facilities, with the use of CCS technologies. Such technologies seem to be more attractive than in recent years because of the significant increase of CO_2 emission allowance prices, which recently achieved around 100 €/tCO_2.

CCGT is a favourable technology for the transition process into renewables also because of its higher flexibility [28] and

efficiency over coal-fired power plants (63% electrical efficiency with development possibilities [29] compared to a potential maximum of around 50% for supercritical technology [30]). What is more, it is a constantly developing technology resulting from the progress of material engineering, allowing the achievement of higher turbine inlet temperatures, thus higher efficiencies. The recent state of CCGT technology has been widely shown in Refs. [31,32]. The advantage of these plants also results from a variety of gas turbines (GT) and the CCGT concepts, which are still being developed e.g. CCGT cycles integrated with coal gasification [33], GT with heat regeneration [34] or steam injection to the combustion chamber (CC) [35]. In addition, CCGT systems can be integrated with energy storage to reduce energy supply interruptions into the electrical grid resulting from temporary changes in RES power output [36].

CCS technology has been used in the industry for around 80 years now, but not in the power industry. The trend seems to change as further developments of different CO_2 removal methods result in achieving economic competitiveness. This can be seen when looking at the numbers of current CCS projects, which doubled in the recent year [37]. There are several different approaches to CCS [38]: pre-combustion carbon capture [39], post-combustion carbon capture [40] and oxy-combustion CO_2 capture [9,41,42].

Chemical absorption capture processes are told to have the highest technical maturity and implementation potential. However, other methods such as physical/chemical adsorption, membrane separation, chemical looping or cryogenics are a part of the research as well [9,43]. It is necessary to mention, that CCS installations are easier to implement in coal-fired power plants where the flue gases mass flow is significantly smaller than for gas-fired power plants, and the CO_2 concentration is higher. In Ref. [44] Wu, Chen et al. presented the possibility of retrofitting a 600 MW coal-fired power plant where three different solid sorbents were used to capture CO_2, namely the solid amine Pentaethylenehexamine (PEHA), Na_2CO_3 and K_2CO_3. As a result of their research, it turns out that the solid amine sorbent (PEHA) is the best sorbent because twofold: 1) there is the smallest decrease in efficiency and 2) it is also competitive in terms of energy consumption.

There have been several types of researches done, proving the possibilities of using chemical absorption based on amines [43,45], physical adsorption using zeolites [46] or membrane separation [47] for CCGT power plants, achieving over 90% of capture efficiency. Chemical absorption separation using mono-ethanol amine (MEA) (Fig. 1 a) has been chosen for this paper, as the best examined option currently [48,49]. On the other hand, significant attention should be paid to membrane separation technology, as the membrane materials development could potentially make this method more competitive.

However, gas technologies are currently during a crisis caused by the unstable situation on the gas market. It can be seen when comparing recent energy production from gas-fired plants to previous years [50]. This results in increased research on alternative fuels for gas turbines, such as hydrogen [51] or syngas. Both of these fuels also seem to fit in the idea of energy safety and low-emission energy transformation, with grid stabilization after this process. Syngas produced from sewage sludge could help with utilizing this problematic waste to use it as a fuel in CCGT plants equipped with CCS installation, which might be a promising alternative to methane. Such power plant concepts are called negative CO_2 emission power plants as it was shown in Ref. [24] because syngas from sewage sludge is sometimes considered as a renewable source of energy. Hydrogen, however, is a prospective fuel in terms of energy storage, as using power cells to convert the electricity produced by renewables during peak hours into hydrogen [52], and then burn it as a fuel in CCGT CHP plants seems to be one of the best future energy scenarios [53]. The schematic production of hydrogen in the electrolyser is shown in Fig. 1b.

Among the variety of power cells, alkaline and polymeric ones are the most promising, where polymeric power cells have the advantage of good flexibility at quickly changing power loads [30]. There are numerous researches done on burning hydrogen in GT, as there are plenty of problems associated with burning pure hydrogen such as its explosiveness and high lower heating value (LHV) which prevent this technology to be used today. Research should be continued due to the need to reduce CO_2 emissions, and this can be achieved by burning syngas with a higher proportion of hydrogen. Scientists emphasize the possibility of co-burning hydrogen with other fuels such as biogas [9] or syngas. Such a mixture, thanks to the use of hydrogen, has better combustion properties than biogas itself, higher calorific value, low ignition delay, high flame speed, high energy density, and lower CO_2 emissions [35]. Currently, the maximum volumetric content of hydrogen in a gaseous fuel mixture which the combustion process could be controlled is about 70–95% for co-combustion with syngas [30,54]. An example is the GE 9F Syngas turbine, which achieves 40% efficiency in a simple cycle, and 57.4% in a combined cycle [54]. However, some companies and utilities carry on the research of burning 100% hydrogen in GT [30]. As a result of the combustion of fuels with an increased hydrogen content, it is necessary to develop new designs of GT blade systems in terms of both high-temperature strength and cooling systems for the first stage blades.

This paper's goal is to analyse the potential of retrofitting an existing CCGT CHP with syngas combustion coupled with CCS amine-based installation, and its influence on the energy and environmental performance of the plant. The CO_2 separation reactor has been simply modelled as well as the CO_2 compression unit. Due to the demand for low-temperature of flue gases, heat recovery for municipal heating has been considered, as well as heat recovery of the water returning from the reboiler. The results are compared to the case of zero-emissive combustion of pure hydrogen, as well as the co-combustion with CCS installation. Both cases are then compared to other, conventional gaseous fuels such as methane and the base case nitrogen-rich natural gas. The models were prepared and calculations were made using commercial and in-house numerical softwares. In addition, the topics covered in this scientific work fit into the future process of water electrolysis to generate hydrogen using renewable energy sources. RES will be treated as a source of energy for the entire process. The hydrogen obtained in this way in case of
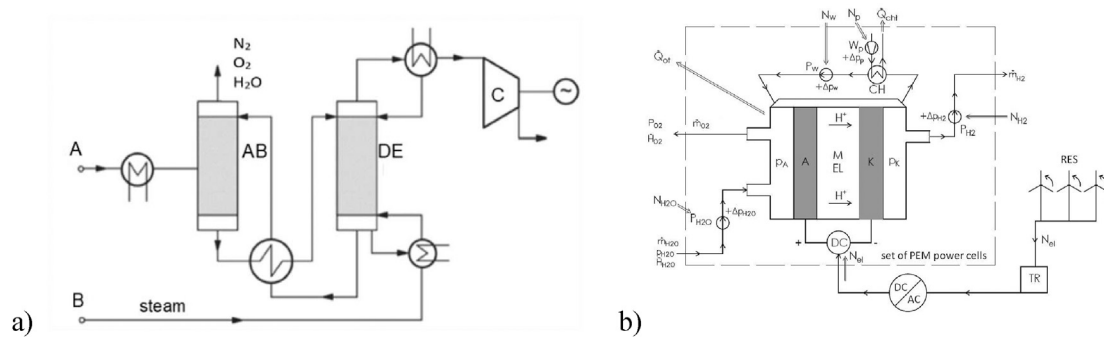
Fig. 1 — Schematic diagram of retrofits: a) CO_2 sequestration by the amine method using MEA; AB — absorber, DE — desorber, point A — flue gas inflow for sequestration, point B — steam bleed from ST for MEA regeneration, C — compressor for compressing CO_2 for storage or transport [32]; b) hydrogen generation from RES to stabilise the energy system: A — anode, K — catode, EL — electrolite, TR — transmission, DC/AC — direct curent/alternating curent, RES — renewable energy source.

RES overgeneration will act as a energy storage (chemical fuel) used in periods of energy deman on the market.

## 2.   Framework for the process simulations

In the next sections (2.1 and 2.2), the reference cycle for which the retrofit was made will be presented, as well as validation for it to check the correctness of the calculations, respectively.

2.1.   Reference plant

The considerations on the performance of a CCGT CHP plant retrofitted with a CCS installation and hydrogen combustion were made basing on an existing heat and power plant in Zielona Góra, Poland (Fig. 2). The F9E PG9171 gas turbine manufactured by General Electric was installed here. The combined heat and power plant has 190 MW of net electrical power

output and 95 MW of heat output [55], however, the calculations were conducted for ISO conditions and around 34 MW of heat output as presented in Ref. [56]. All the reference data of modelled CHP were based on three sources, namely: 1) the measurements and calculations presented at the heat and power plant's website [55], 2) an article [56] where a mathematical model of this CHP was made, and 3) the district heating part of the model was based on data presented in the research report on the steam turbine used at this plant [57].

The thermodynamic cycle of the examined CHP is presented in Fig. 2. The gas cycle consists of a gas expander (GT) coupled with air compressor (C), an air filter at compressor inlet (F), compressed air extraction for first-stage GT blades cooling, combustion chamber (CC) and electrical power generator (G). Fuel compressor (C_{fuel}) is added for the purpose of comparing electrical power input for different gaseous fuels compression. The heat recovery steam generator (HRSG) consists of two steam pressure levels. The high-pressure
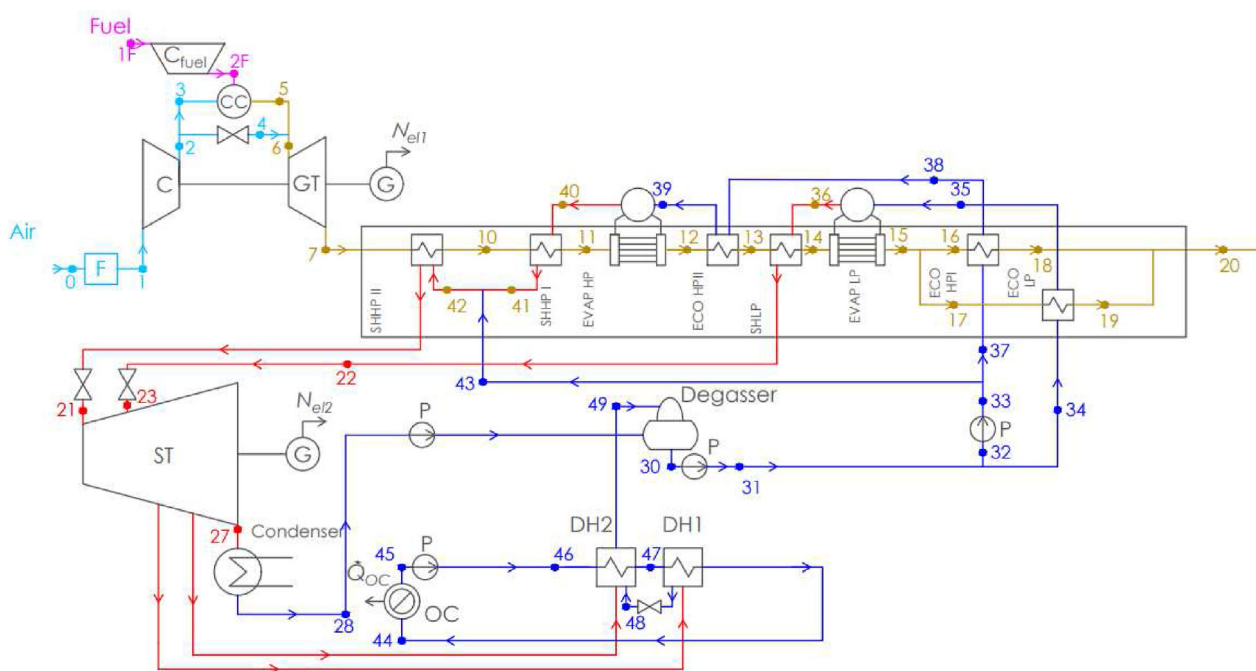
Fig. 2 — Reference cycle modelled in EBSILON®Professional [58] and EcoPG [59].

section consists of two steam superheaters (SHHP I, II), an evaporator (EVAP HP), two economizers (ECO HPI, II), and water injection for control purposes (point 43). The low-pressure section includes a superheater (SHLP), an evaporator (EVAP LP), and an economizer (ECO LP). Steam turbine (ST) is powered with steam at two different pressures. Steam extraction for heating purposes is also made at two levels of pressure, respectively to DH1 and DH2 heat exchangers, heating up the water for oudside heat consumers (OC) at temperatures $t_{44} = 58$ and $t_{45} = 78$ °C, for heating water return and supply, respectively. Condensed water then flows to the degasser. ST was modelled using four separate components to include different internal efficiencies, resulting from steam extraction and LP steam injection losses. The condensed water is pumped using pumps (P). Important technical data of the reference CHP, which was used for model validation in EBSILON®Professional and in-house code EcoPG, is shown in Table 1.

2.2. Model validation

At present, when we want to make modifications in the tested facilities as in this case, the gas and steam system installed in the Polish CHP plant located in Zielona Góra needs to be used for he EBSILON®Professional and the in-house code EcoPG validation. These modifications concern the gas part of the facility. Validation is carried out using advanced computational methods. This work uses the EBSILON®Professional software and the EcoPG program. Both codes are based on momentum and energy mass balances and allow the modelling CCGT cycles.

The data used for validation in the EBSILON®Professional and EcoPG programs are included in Table 1, and the validated

cycle diagram is shown at Fig. 2. For the purpose of verifying the correctness of the calculation model, the most important available reference values from the literature were selected (as described in section 2.1), and the relative error of the calculated values was calculated as the criterion for the correctness and accuracy of the model. The results are presented in Table 2. A satisfactory accuracy of the results was obtained, with minimal mass flow rate of steam LP and flue gas temperature at the HRSG outlet. This is due to the assumption of the pinch point at the level of 10 K, because it was not possible to determine the literature value, which also affects the level of cooling of the flue gas at the HRSG outlet. Based on these results, it can be concluded that the presented models were made correctly and can be used for further thermodynamic calculations.

2.3. Amine-based absorption process and modelling

Cycle retrofits after adding CCS installation and fuel preparation station are presented in Fig. 3. A schematic diagram of the considered amine-based absorption system is shown in Fig. 4. It was based on the model presented and calculated in the articles: first Mostafavi E. et al., second Amrollahi Z. et al. [45,60]. An optimized model with absorber intercooling and lean vapor recompression stripping has been chosen, as the most promising modification resulting in significant save of power demand for CCS system, with a relatively small cost increase [60]. 30% MEA – water solution has been chosen as the working fluid. The CSS model has been adopted as a single component consisting of inputs and outputs, regarding power inputs and fluid flows characterized at nodal points (8, 9, 25, 26, 29 in Figs. 3 and 4) adopted from the work of Amrollahi Z. et al. [45]. Processes that happen inside the model borders are modelled through performance inputs from the literature [45,60] (two items already mentioned in this subchapter). Main input parameters to the CSS installation are shown in Table 3 and correspond to all fuel cases.

The principle of work of the CCS system is as follows. The flue gas (nodal point 8 in Fig. 4) flowing at atmospheric pressure is cooled to 40 °C and blown with a fan to the absorber to overcome the pressure drop. In reality, it is the same fan as in Fig. 3, but here it was divided to cover pressure losses in the absorber independently. In the absorber column flue gas contacts the MEA (Figs. 1 and 4) solvent flowing countercurrently and reacts with it following the reaction in Eq. (1).

$$C_2H_4OHNH_2 + H_2O + CO_2 \rightarrow C_2H_4OHNH_3^+ + HCO_3^- + \Delta Q_1 \qquad (1)$$

The reaction is exothermic so absorber intercooling is used to sustain the higher driving force of the absorption process and capacity of the solvent. The rich amine mass flow rate (loaded with CO_2) leaves the absorber, is preheated in the heat exchanger (HX) and enters the stripper column. Meanwhile flue gas without CO_2 leaves the absorber to the scrubber, where some of the liquid water is recycled to the absorber, and the rest heads to the atmosphere (nodal point 9). The rich solution is heated in the stripper using the heat supplied to reboiler (R) (points 25, 26), and CO_2 is stripped out of the solution, following the reaction opposite to Eq. (1), leaving at the top of the column (point 29). The lean solution leaving the stripper decreases its pressure through

Table 1 — Technical data of the reference CCGT plant assumed for model validation.

| Parameter	Symbol	Value	Unit
GT model	—	F9E PG9171	—
GT gross electric power output	N_{el1}	126.1	MW
Flue gas flow	$\dot{m}_7$	418	kg/s
Compressor pressure ratio	Π	12.6	—
GT inlet temperature	t_6	1100	°C
GT exhaust temperature	t_7	543	°C
ST model	—	7CK-65	—
ST gross electric power output (with considered heat extraction)	N_{el2}	57.7	MW
HP turbine inlet temperature	t_{21}	505	°C
HP turbine inlet pressure	p_{21}	72	bar
EVAP HP pinch point	δ_{tHP}	8	°C
LP turbine inlet temperature	t_{23}	217.9	°C
LP turbine inlet pressure	p_{23}	6.62	bar
EVAP LP pinch point	δ_{tLP}	10	°C
Condenser pressure	p_{27}	0.051	bar
Mass flow of water injection to HP steam	$\dot{m}_{43}$	1.3	kg/s
Gross combined el. power output	$N_{el1} + N_{el2}$	183.8	MW
Net electric power output	$N_{el,net}$	177.8	MW
Net electric efficiency	$\eta_{el,net}$	47	%
Net heating capacity output	$\dot{Q}_{HC}$	34.04	MW
Combined Heat and Power plant net efficiency	$\eta_{CHP,net}$	56	%
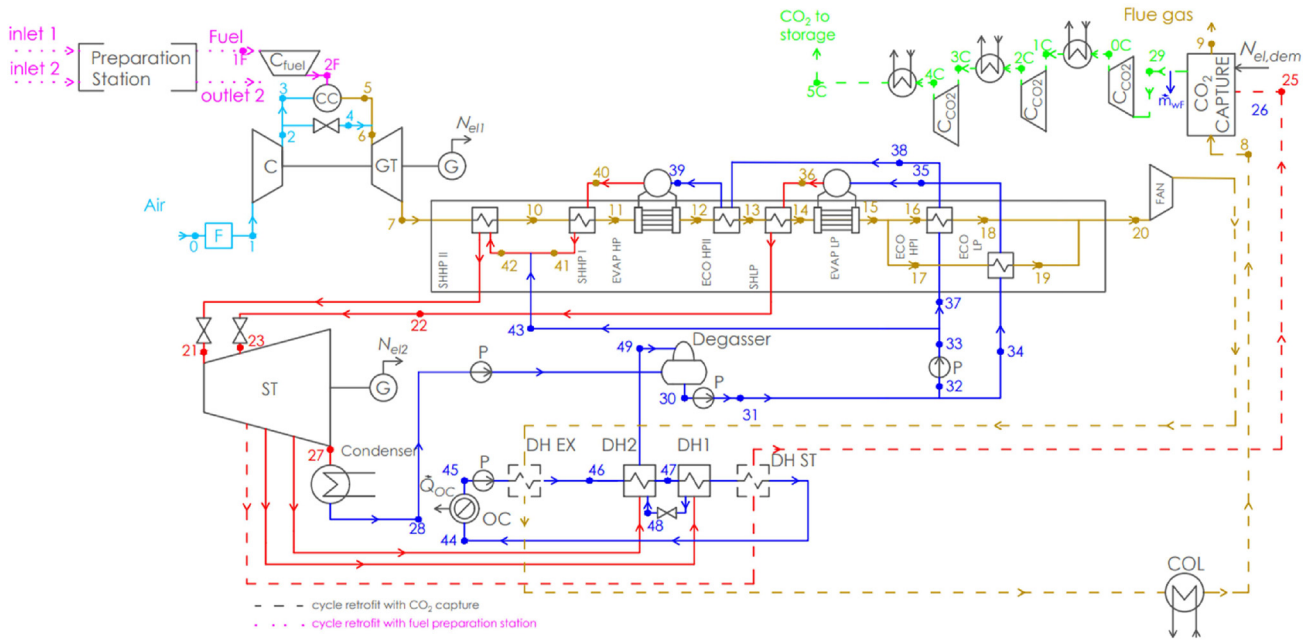
Fig. 3 — Cycle retrofits after adding CCS installation and fuel preparation station.

Table 2 — Compilation of computational results and literature values to determine the relative error and correctness of the reference computational model.

Parameter	Symbol	Reference value from operating data	Value calculated in EBSILON	Value calculated in EcoPG	Absolute error		Unit	Relative error [%]	
					EBSILON	EcoPG		EBSILON	EcoPG
GT electric power	N_{el1}	126.1	126.5	121.2	0.4	4.9	MW	0.32	3.89
Electrical efficiency of the gas cycle	$\eta_{el,TG}$	33.8	33.4	32.8	0.4	1	%	1.18	2.96
Exhaust gas mass flow	$\dot{m}_6$	418	418	418	0	0	kg/s	0	0
Exhaust gas temperature at GT inlet	t_6	1100	1098.85	1052.17	1.15	47.83	°C	0.1	4.35
Exhaust gas temperature at GT outlet	t_7	543	543.02	560.4	0.02	17.4	°C	0	3.2
LP steam mass flow	$\dot{m}_{23}$	11.14	11.91	11.91	0.77	0.77	kg/s	6.91	6.91
HP steam mass flow	$\dot{m}_{21}$	50.98	49.37	49.37	1.61	1.61	kg/s	3.16	3.16
Electrical Power ST	N_{el2}	56.33	57.6	54.24	1.27	2.09	MW	2.25	3.71

a flash valve, so a gaseous phase composed of mainly water vapor is achieved. Then it's recompressed and recycled back to the stripper where the heat of condensation can be harnessed and the heat duty of the reboiler is reduced [45]. The lean solution circles back to the absorber and the cycle is closed.

From the perspective of modelling the CCS system few assumptions have been made. The demand for electric power (pumps, fan, compressor) and heat for the installation to work is described using fixed parameters dependent on the captured CO_2 mass flow, so the energy balance looks as in Eqs. (2) and (3).

$$\dot{H}_8 + N_F + N_{P1,2} + N_C + N_{WH,i} + \dot{H}_{25} = \dot{H}_9 + \dot{H}_{26} + \dot{H}_{29}$$
$$+ \sum \dot{Q}_{WH,i} \ [MW] \tag{2}$$

$$\dot{H}_8 + \dot{m}_{29} \cdot q_{el,CO_2} + \dot{m}_{29} \cdot q_{H,CO_2} = \dot{H}_9 + \dot{H}_{29} + \sum \dot{Q}_{WH,i} \ [MW] \tag{3}$$

The influence of flue gas compositions for different fuels at sorption process has been neglected, as the content differences are rather small (no more than 1.5% difference) when compared to coal fired plants [61]. The mass fluxes of water $\dot{m}_w$ and MEA $\dot{m}_m$ that need to be replenished are also omitted. An assumption of removing water $\dot{m}_{wF}$ after the CO_2 capture was made, so the stream heading for CO_2 compression is pure CO_2, even though the real purity for this case is around 96% [45]. Temperatures and pressures at the inlet and outlet of the CO_2 capture are fixed, as the process requires, and are shown in Table 3.

CO_2 compression was modelled using three stage compressor, from 1.01 bar to storage pressure at 110 bar, proposed in different papers before [45,46]. Inter-stage cooling was implemented to reduce the power input of compressors, with water cooling to 35 °C as proposed by Kvamsdal HM, Jordal K and Bolland O [28]. The pressure ratios of all three stages were similar to achieve close to equal power inputs and temperatures of CO_2 after each stage. Pressure after first stage
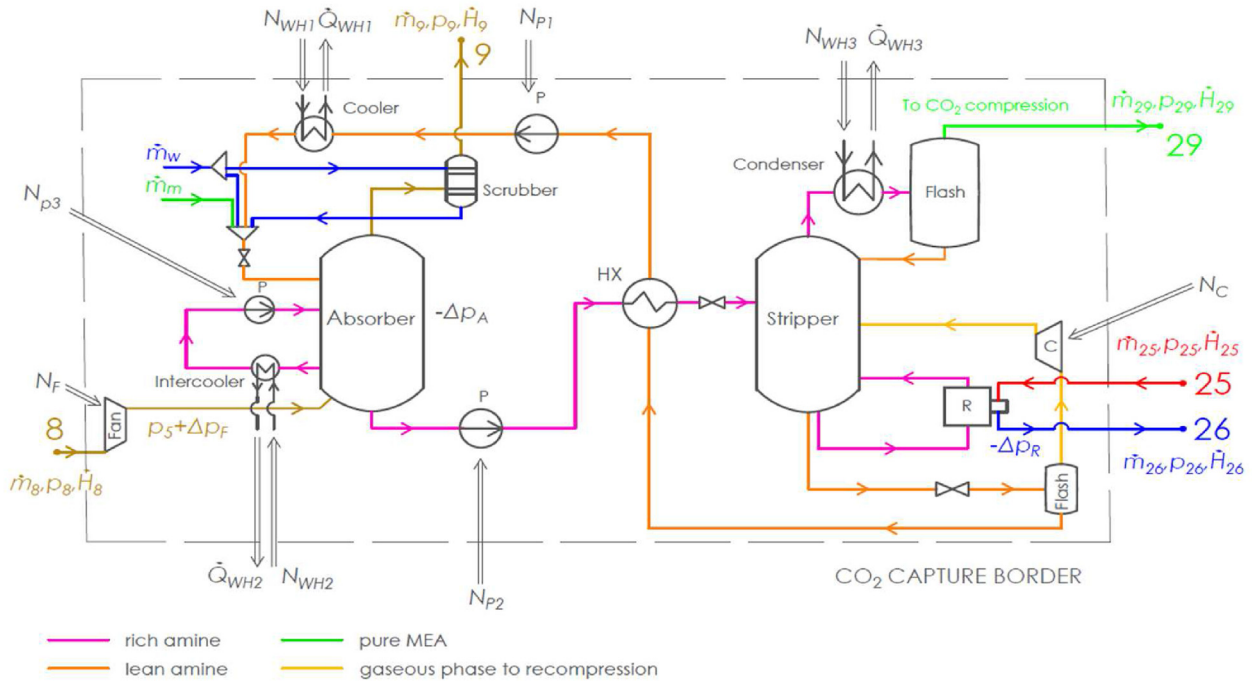
Fig. 4 – Schematic diagram of the considered amine-based absorption system.

Table 3 – Main parameters adapted for the modelled amine-based absorption system (based on [45]).			
Parameter	Symbol	Value	Unit
CO_2 capture rate	–	0.9	–
Amount of MEA solvent	–	16.27	$\left[\left(\dfrac{kg_{MEA}}{s}\right)\bigg/\left(\dfrac{kg_{CO_{2,fg}}}{s}\right)\right]$
Flue gas pressure drop in absorber column	Δp_A	128.6	$\left[Pa\bigg/\left(\dfrac{kg_{CO_{2,fg}}}{s}\right)\right]$
Flue gas inlet pressure	p_8	1.01	bar
Flue gas outlet pressure	p_9	1.01	bar
Flue gas inlet temperature	t_8	48	°C
Flue gas outlet temperature	t_9	45	°C
Flue gas mass flow	$\dot{m}_8$	418	kg/s
CO_2 outlet pressure	p_{29}	1.01	bar
CO_2 outlet temperature	t_{29}	30	°C
Steam to reboiler pressure	p_{25}	4	bar
Steam to reboiler temperature	t_{25}	145	°C
Water from reboiler temperature	t_{26}	130	°C
Pressure drop in reboiler	Δp_R	0.08	bar
Electric power demand to the system	q_{el,CO_2}	0.25	MJ/kg_{CO_2}
Heat demand to reboiler	q_{H,CO_2}	2.71	MJ/kg_{CO_2}

of the compressor is equal to 5 bar, after the second stage – 23 bar, and after the last stage, it equals 110.1 bar, just slightly more than storage pressure to overcome the pressure drop in the last cooler.

2.4. CCS model integration with CHP plant

To examine the impact of the proposed CO_2 capture system on the performance of reference power plant with different fuels considered, some modifications were implemented. The modifications are shown in Fig. 3 with a dashed line. These are mostly connected to the steam part of cycle, as there is

significant demand for steam extraction to the reboiler, to strip the CO_2 out of the solution. The steam is extracted from the turbine at a pressure of slightly over 4 bars, so it reaches the CO_2 capture reactor at exactly 4 bars. However, the steam needs to be cooled to around 145 °C [45] which is done through applying a heat exchanger at the last part of the municipal heating water cycle. The condensate leaving reboiler at 130 °C is used to heat up the municipal water and is cooled to 80 °C held constant, and then pumped back to the water cycle of power plant.

Flue gas leaving the HRSG needs to be cooled to 48 °C before entering the reactor. It is a significant amount of heat as the flue gases leaving HRSG have over 130 °C. Heat recovery from

the flue gas is proposed and applied to preheat municipal water. Flue gas cooling to 74 °C is assumed and held constant, and after-cooling is done in a second cooler. Constant temperature conditions may result in different heat outputs of the plant, however no lower than nominal, because steam extraction is then used. The concept of recovering flue gas heat is important especially when it comes to higher heat demands at winter, and fuels with more carbon content, where more CO_2 is produced which drives the demand of reboiler's heat; additionally, steam extraction to DH1 and DH2 is used to cover higher heat demands. This helps maintaining constant CO_2 capture ratio, without significant redesigning or adding an extra GT for steam production, as presented by Bartela Ł. et al. [61].

2.5. Hydrogen production and integration with the cycle

For several years, there has been a growing demand for hydrogen in the world [62,63], and according to forecasts, it will continue to grow [12,64], depending on the assumptions from the level of 73 to even 567 Mt/year [65]. Scientists see the benefit of using hydrogen in industry, e.g., heating [66] or heavy transport [66]. The use of hydrogen in the energy sector together with renewable energy sources will allow the decarbonization process to be carried out worldwide [67,68]. In addition, hydrogen may enable the storage of overgenerated electric power from renewable energy sources [69].

In the literature, it can be found works showing the interest of researchers in the use of hydrogen to drive gas turbines [20,67,70]. The technologies used in turbines allow the use of various gaseous or liquid fuels [71—73]. Among the gaseous fuels, we can mention, for example, hydrogen, methane and syngas [25] and in the group of liquid fuels: biodiesel [72] or bioethanol [74].

One of the goals presented in the European Hydrogen Strategy is to replace 10 Mt of hydrogen produced from steam-methane reforming (SMR) of natural gas with hydrogen that can be produced using renewable energy sources and electrolysis. This process will be expected to be completed by 2030 [25].

Various hydrogen production technologies and processes can be found in the literature. There are three most popular ways to produce hydrogen: steam methane reformation [23], gasification and electrolysis [65]. In addition to those mentioned to a lesser extent, bio-waste from fermentation processes [63,75] or electrolysis and biodiesel from algae [76], as well as refining bio-waste can be used to produce hydrogen.

In the industrial production of hydrogen, the SMR method is relatively inexpensive [77]. This method has disadvantages resulting from the large manufacturing of greenhouse gases. Another well-known process is water electrolysis, the importance of which is expected to grow in the hydrogen production market. This increase is due to low greenhouse gas emissions when using renewable energy sources to produce electricity. What is worth emphasizing in this technology, alkaline electrolysers used for electrolysis are cheaper and more reliable than the opposite oxide electrolysers [78].

In the literature on this subject, it is presented a paper where Schnuelle et al. [79] show that hydrogen production can be modelled using a solar thermochemical system. However,

Fazli-Khalaf et al. [80] presents the possibility of hydrogen production using the SeI nuclear thermochemical system.

Another method of hydrogen production is the gasification of coal or biomass. The advantage of gasification is the treatment of biomass as a renewable resource characterized by very low greenhouse gas emissions, which is desirable given the current trends towards their minimization. In case of coal gasification, it is one main disadvantage is releasing greenhouse gases generated during hydrogen production.

Hydrogen can be produced from biofuels and biomass [81,82], which have a number of advantages concerning the ease of obtaining renewable and environmentally friendly source [83] and also reducing the consumption of crude oil [84]. On the other hand, biofuels also have disadvantages, in particular, high costs [85]. One of the sources of biomass may be algaes [86,87] which purify water and sewage but also reduce greenhouse gas emissions [88]. One of the way to obtain biohydrogen precisely by direct photolysis of water includes using algaes, but if anaerobic algeas growth occurs in the light, then, in this case, the hydrogenises enzyme should be additionally applied [88]. In the first case, we have less hydrogen production than in the second. Still, in the second, there is a higher energy consumption due to the continuous illumination of algaes and the use of the enzyme. The cost of producing biofuel from algaes is relatively high because 77% of expenditures in breeding. However, prices of algeas can be reduced by algaes production from municipal or industrial wastewater [89,90].

The advantages of using algaes are: firstly, their ability to sequester up to 1.3 kg of CO_2 while producing 1 kg of biomass derived from them [89]; secondly, a possibility to remove nitrogen and phosphorus. Algae biomass can also generate biofuels other than biohydrogen, such as bioethanol or biobutanol. The efficiency of the hydrogen production from algeas is similar to both ways of breeding, namely: increase of algeas in sewage treatment plants and farms [91]. Microbial fuel cells could be integrated with wastewater treatment plants and enable the production of biohydrogen [92].

Futhermore, sewage-derived algae are more popular in biopolymers production [93,94] that will improve the environment by not applying polypropylene and polyvinyl from oil and replacing this substances with algeas biopolymers [95]. Biopolymers derived from algaes will be biodegradable and environmentally friendly due to the fact, bioplastic will be obtained [96]. Therefore, in algaes biomass the dominant elements are carbon and hydrogen [97].

2.6. Fuel assumptions

Fuel compositions and lower heating values (LHV) are presented in Table 4. Besides the reference case, pure methane, syngas [24], pure hydrogen and a mixture of hydrogen and methane [53] are presented. Only a case basing on pure hydrogen was modelled without CCS installation. Fuel compressors have been modelled to compare the power outputs for different fuels and mass flow rates, assuming that all the fuels are not provided under the right pressure from the gas distribution grid. Table 4 shows that the highest LHV is obtained for pure hydrogen and it is almost 3 times higher than for nitrogen-enriched natural gas, followed by a mixture of

Table 4 – Fuel compositions and LHV in [MJ/kg].

Fuel type	Symbol	Fuel compositions by volumetric shares	LHV
Nitrogen-enriched natural gas	NNG	87% CH_4, 12.3% N_2, 0.3% C_2H_6, 0.2% CO_2, 0.1% C_3H8, 0.1% C_4H_{10}	39.98
Methane	M	100% CH_4	50.015
Syngas	S	45.17% H_2, 25.61% CO_2, 13.64% CH_4, 9.09% CO, 3.39% C_3H_8, 3.1% NH_3	17.086
Hydrogen	H	100% H_2	120
Hydrogen + Methane	H + M	88.8% H_2, 11.2% CH_4	86

hydrogen and methane. It should be emphasized that the technology of electrolyzers, which is currently under development, can be used to produce this hydrogen. Besides the most developed methods such as alkaline and polymer electrolysers, other methods might be used such as SOEC (Solid Oxide Electrolyzer Cell) electrolyzers which are in the phase of research and pilot installations. SOEC technology has the potential to be used especially in large production facilities. Alkaline and polymer electrolysers are low-temperature devices where water decomposes in a liquid state, while oxide electrolysers are high-temperature electrolysers (850–950 °C) [30].

2.7. CHP with CO_2 capture performance indicators

The analysis of syngas and other fuels combustion, combined with CO_2 capture, and hydrogen combustion was performed using different indicators. Some of them, such as efficiency, emissivity or SPECCA might correspond to local changes (change between reference plant with various fuel and after retrofit) or global (change between reference plant with nitrogen-enriched fuel and after retrofit with any other fuel). Symbols not explained under the equations refer to quantities shown in Fig. 3. The indicators are as follows.

- Gross electrical efficiency (4):

$$\eta_{el,gross} = \frac{N_{el1} + N_{el2}}{\dot{m}_{1F} \cdot LHV} \cdot 100 \quad [\%] \tag{4}$$

- Net electrical efficiency (5):

$$\eta_{el,net} = \frac{N_{el1} + N_{el2} - \sum N_{el.\ demand,i}}{\dot{m}_{1F} \cdot LHV} \cdot 100 \quad [\%] \tag{5}$$

$\sum N_{el.\ demand,i}$ sum of all electric power demands such as compressors, pumps, fans, CO_2 reactor electricity demand etc.

- CHP plant gross efficiency (6):

$$\eta_{CHP,gross} = \frac{N_{el1} + N_{el2} + \dot{Q}_{HC}}{\dot{m}_{1F} \cdot LHV} \cdot 100 \quad [\%] \tag{6}$$

- CHP plant net efficiency (7):

$$\eta_{CHP,net} = \frac{N_{el1} + N_{el2} + \dot{Q}_{HC} - \sum N_{el.\ demand,i}}{\dot{m}_{1F} \cdot LHV} \cdot 100 \quad [\%] \tag{7}$$

- Electrical power penalty (8):

$$\Delta N_{el} = \left[N_{el1} + N_{el2} - \sum N_{el.\ demand,i} \right]_{wo.\ retr.}$$
$$- \left[(N_{el1} + N_{el2}) - \sum N_{el.\ demand,i} \right]_{with\ retr.} \quad [MW] \tag{8}$$

- CHP plant net efficiency penalty (9):

$$\Delta \eta_{CHP,net} = (\eta_{CHP,net})_{wo.\ retr.} - (\eta_{CHP,net})_{with\ retr.} \quad [\%] \tag{9}$$

- Specific CO_2 emissions (10) [9]:

$$e_{CO_2} = \frac{3600 \cdot X_{CO_2} \cdot \dot{m}_9}{N_{el1} + N_{el2} + \dot{Q}_{HC} - \sum N_{el.\ demand,i}} \left[\frac{kg\ CO_2}{MWh} \right] \tag{10}$$

$\dot{m}_9$ mass flow of CO_2 emitted to the atmosphere with flue gases [kg/s].

X_{CO_2} CO_2 mass fraction in flue gases [–]

- Specific CO_2 emissions avoided (11):

$$e_{CO_2,avoided} = e_{CO_2,wo.\ retr.} - e_{CO_2,with\ retr.} \left[\frac{kg\ CO_2}{MWh} \right] \tag{11}$$

- Specific primary energy consumption for CO_2 avoided (SPECCA) (12) [9]:

$$SPECCA = 360000 \cdot \frac{\frac{1}{(\eta_{CHP,net})_{with\ retr.}} - \frac{1}{(\eta_{CHP,net})_{wo.\ retr.}}}{e_{CO_2,wo.retr.} - e_{CO_2,with\ retr.}} \left[\frac{MJ}{kg_{CO_2}} \right] \tag{12}$$

3. Results and discussion

In this section, several aspects of considered retrofits were presented and discussed, focusing mostly on power plant performance and emission related indicators. As stated previously, some results refer to local changes, where considered plant before and after retrofit operates at the same fuel, and global changes, where the results are compared to reference plant without CO_2 capture.

3.1. Plant performance indicators before and after retrofit

Electrical and CHP efficiencies were calculated to compare qualitatively the considered fuels with a combination of CO_2 capture technology (except hydrogen), resulting in efficiency penalties for the entire cycle. Fig. 5 presents CHP net local and global efficiencies of the plant after the retrofit. For the reference case of fuel and methane similar results were obtained, where 6.3% efficiency penalty is observed decreasing the efficiency to 49.6%. Using syngas as fuel resulted in significantly higher efficiency penalties, especially when comparing globally, where 8.6% efficiency loss was calculated. This high loss corresponds to the electrical power penalty, as can be seen in Fig. 6 especially when including 4.8 MW of heat that was gained for the same temperature conditions. These losses result of higher fuel compressor power input (lower LHV than for reference case resulted in 2.3 times higher fuel mass flow) and higher CO_2 capture, and compression power demand, as for the same capture efficiency higher CO_2 mass flow was obtained. Also around 5 MW more of electrical power was lost, when comparing to reference plant with CCS, as an effect of higher steam extraction mass flow to cover reboiler demand.

Hydrogen and methane combustion present significantly lower CHP efficiency penalty, as the captured CO_2 stream is over three times smaller than for the reference case, so the previously mentioned power demands are lower as well, and 4 MW more of electrical power are generated at the GT, as a result of higher LHV value. The best option seems to be pure hydrogen combustion, as the lowest efficiency penalty, when

globally referring, is achieved − 1.3%, which results in the best CHP net efficiency among all the cases after retrofit. This low penalty is caused by over three times higher demand for fuel compression but compensated by gain of 5.5 MW of GT's electrical power, overall resulting in nearly 6 MW of power loss.

Electrical efficiency penalties are slightly higher than CHP efficiency penalties, except of syngas combustion, where an additional 1.3% efficiency penalty occurred, as an effect of omitting the gain of heat for municipal heating. Plants based on hydrogen combustion achieve the highest electrical efficiencies among all cases, even though before retrofit they performed noticeably worse than the reference case.

3.2. Emission indicators before and after retrofit

Besides performance results, indicators for CO_2 emission reduction need to be studied, taking into consideration energy costs for carbon capture. In Fig. 7 specific CO_2 emissions, corresponding to overall CHP power instead of just electric power, as a more representative value for this case of study, are shown. The CO_2 emissions were calculated as defined in Eq. (10), and additionally CO_2 emissions avoided are presented according to Eq. (11). The reference to local and global values is explained in the introduction to subsection CHP with CO_2 capture performance indicators. Reference case, as well as methane combustion results, are very similar, where emissivity at a level of 40 $kgCO_2$/MWh with 317 $kgCO_2$/MWh reduction is observed, comparing to plant without retrofit. CO_2 capture for syngas combustion resulted in huge emissivity reduction at the level of 460 $kgCO_2$/MWh locally. However, globally the reduction is slightly lower − 296 $kgCO_2$/MWh, as higher final emissions of 61 $kgCO_2$/MWh can be seen.

The methodology of this paper does not take into account the legal specifics, which in some countries, including Poland, allow for renewable fuels after CO_2 capture to achieve a positive environmental impact. In this case, we are talking about a power plant with negative CO_2 emissions [98]. In other words, in the case of syngas from sewage sludge gasification, negative CO_2 emissions [99] would be achieved. Thus, the emissivity in this work referred only to the amount of carbon
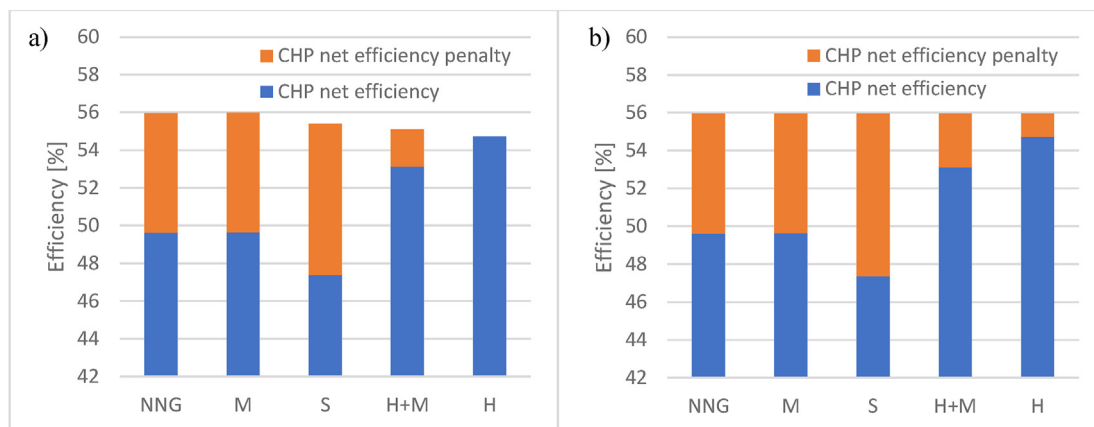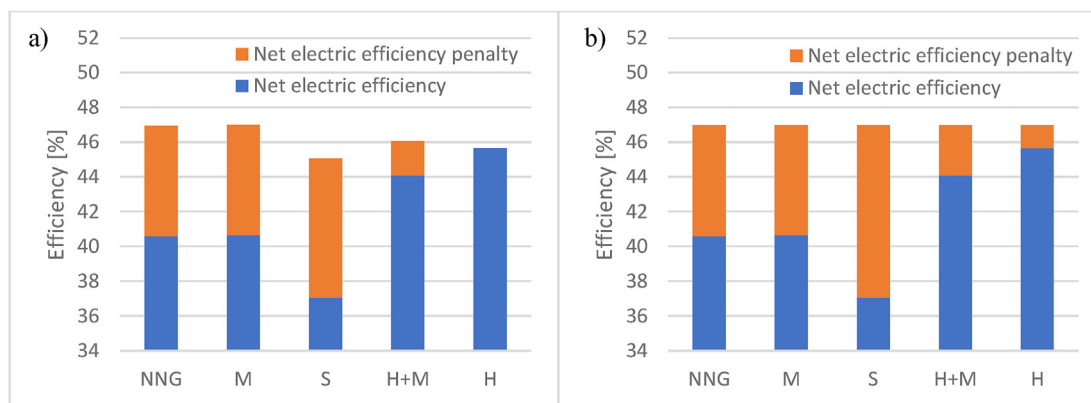

Fig. 5 − Net CHP efficiencies and efficiency penalties of CCGT plant after retrofitting with CCS system or hydrogen combustion: a) locally, b) globally. The horizontal axis refers to fuel types shown in Table 4.

Fig. 6 – Net electrical efficiencies and efficiency penalties of CCGT plant after retrofitting with CCS system or hydrogen combustion: a) locally, b) globally. The designation of names on the horizontal axis shows Table 4.
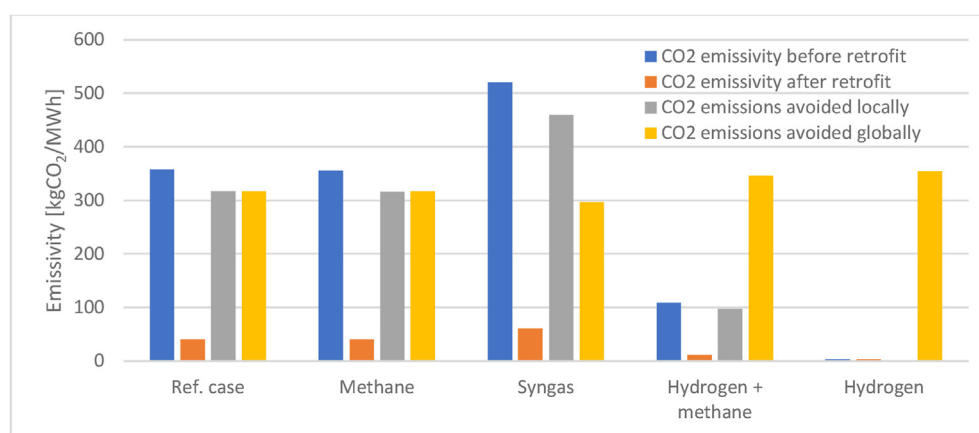
Fig. 7 – Specific CO$_2$ emissions before and after retrofit of the plant.

dioxide emitted into the environment, without taking into account the legal situation in the country.

Finally, no emissions of CO$_2$ for hydrogen combustion are achieved, followed by an emissivity of 11.3 kgCO$_2$/MWh for hydrogen + methane combustion. Obviously, the highest CO$_2$ emissions avoided globally were achieved for these two hydrogen fuels, having the most positive ecological impact on the environment. As a result of this comparison it can be seen, that it is theoretically possible to design low-emissive power sources burning fossil fuels, basing on the current technology. This is a valuable result for the purpose of energy transformation, before hydrogen technology can be used widely.

However, specific CO$_2$ emissions provide us information only about the ecological aspect of plants after retrofit, with regards to the power produced. As a measure of energy cost related to CO$_2$ capture, a SPECCA indicator is implemented, which was introduced by Campanari et al. [100]. However, authors (Campanari S. et al. and Bonalumi D. et al.) in Refs. [100,101] refer this index to electrical efficiencies, and the reference plants are considered as the state-of-the-art CCGT plants. For the purpose of this paper, referring to CHP net efficiencies seems to be more accurate, as there are some gains in heating power, and it is also a product of the power plant. Relatively low SPECCA values as comparing to other authors [100,101] show that CCS might be valuable also for CCGT and CHP plants, especially when considering additional energy-saving actions as provided in subsection: CCS model integration with CHP plant. It is also worth noting are the SPECCA values for syngas combustion which in this case might be as low as for CCGT burning methane [100,101]. This allows to burn this high-carbon content fuel with similar energy penalty and ecological impact.

Fig. 8 presents SPECCA for all the examined cases. A cost of 2.6 MJ/kgCO$_2$ was obtained for the reference case and methane combustion. What is worth noticing, a slight decrease of SPECCA locally for syngas was achieved to a value of 2.4 MJ/kgCO$_2$, as a result of heat gain. However, when referring to the reference case, the cost stands out from the others at a level of 3.9 MJ/kgCO$_2$. SPECCA indicator globally came out the best for hydrogen/hydrogen + methane combustion, 1 MJ/kgCO$_2$ and 0.4 MJ/kgCO$_2$ respectively. According to Refs. [100,101], SPECCA for CCGT with simple amine-based CO$_2$ capture considered, was equal to 3.2–4 MJ/kgCO$_2$, which is comparable to syngas combustion in this case. For methane and reference case, over 0.8 MJ/kgCO$_2$ of savings were made, and 2.2–2.8 MJ/kgCO$_2$ for hydrogen based fuels. However, it is worth noting that equally good results as for the case with hydrogen are achieved for the system considered in the work [24], namely for the negative emission carbon dioxide power plant.
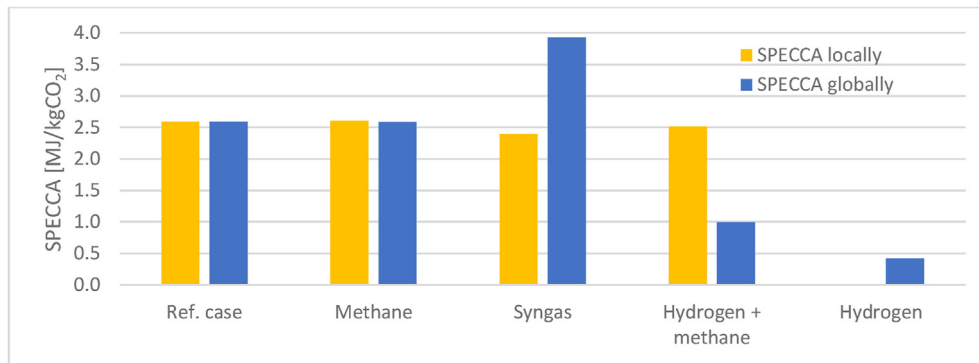
Fig. 8 – SPECCA indicators for proposed retrofits.

4.   Conclusions and future development directions

This article presents the possibilities of reducing CO_2, which is necessary to adapt to requirements imposed on countries by the EU and the internal energy policy of a given country. Currently, the policy focuses on the development and use of renewable energy sources to the greatest extent. In a country such as Poland, it is nowadays impossible to close power plants using solid fuels and produce energy only from RES. Therefore, carrying out actions aimed at reducing the production of greenhouse gases from the combustion of solid fuels is necessary. Hence, this paper presents the opportunity of retrofitting the existing CCGT CHP plant in Poland with a system based on the CCS. To achieve thermodynamic performance of modernization, numerical models and calculations were prepared in two software, namely a commercial programme Ebsilon and in-house code EcoPG. This article compares various efficiency and emission factors for several fuel cases, such as syngas coupled to an amine-based CCS. Few heat recovery systems were introduced into CHP to limit steam extraction for heating purposes, thus mitigating electrical power losses, which were a result of steam extraction to cover reboiler demand. This led to lower efficiency penalties and better SPECCA indicators for fuels like methane and nitrogen-enriched gas when compared to other authors [100]. In the case of the reference fuel and methane, similar results were obtained, e.g. a decrease in efficiency by 6.3% p. p., the efficiency reduction to 49.6%. Additionally, CO_2 emission at the level of 40 $kgCO_2$/MWh is obtained with a reduction by 317 $kgCO_2$/MWh compared to the installation without modernization.

Syngas combustion is characterized by the worst results for all the indicators examined, mostly because of its high carbon content (see Table 4) and low LHV. However, it is important to notice that this is an alternative fuel, so perhaps with an increase of prices for CO_2 emission allowances and conventional fuels, it could be a competitive technology. Thus, in Fig. 7., a local CO_2 emission reduction by 460 $kgCO_2$/MWh was achieved. In addition, syngas can be produced from a variety of unfavourable substances, e.g. sewage sludge, and it may then be useful to dispose of the resulting fuel [16]. As a result of biofuel syngas production from sewage sludge,

organic substances for energy generation are introduced to reduce the consumption of traditional energy sources.

Hydrogen combustion and co-combustion lead to the best results, both regarding low plant performance penalties and low CO_2 emissions to the atmosphere. With the development of power cells and ground-breaking progress of hydrogen combustion in GT, it may in fact be the future of the world's energetics. There is still a lot to achieve, however, the results of this paper show clearly that it makes sense to continue research on this technology.

In the next stage of the work, it is worth conducting an economic analysis of the proposed solutions to indicate the payback period for the installation of the carbon capture, electrolyzer, or gasification reactor, respectively. In turn, the main gains will deprive from avoided CO_2 emission costs. In the case of sewage sludge, there will also be a profit from the disposal of this harmful waste [98,102]. It is still reasonable to consider other types of fuel, namely biofuels produced from algaes, wood, straw, etc [103]. Forward-looking work also includes Computational Fluid Dynamics analyses, which can show a change in the emissivity of components such as CO and NO_x. In terms of durability analyses, it will be important to determine the flame length and temperature field both in the combustion chamber and in the subsequent expander stages [104,105]. Therefore, the present issues carry a whole field of perspectives for further research that contributes to increasing the share of renewable energy sources in the energy mix.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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