FOSSIL FUEL SAVINGS, CARBON EMISSION REDUCTION AND ECONOMIC ATTRACTIVENESS OF MEDIUM-SCALE INTEGRATED BIOMASS GASIFICATION COMBINED CYCLE CO-GENERATION PLANTS

by

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The paper theoretically investigates the system made up of fluidized bed gasifier, SGT-100 gas turbine and bottoming steam cycle. Different configurations of the combined cycle plant are examined. A comparison is made between systems with producer gas and natural gas fired turbine. Supplementary firing of the producer gas in a heat recovery steam generator is also taken into account. The performance of the gas turbine is investigated using in-house built Engineering Equation Solver model. Steam cycle is modeled using GateCycle^{TM} simulation software. The results are compared in terms of electric energy generation efficiency, CO_2 emission and fossil fuel energy savings. Finally there is performed an economic analysis of a sample project. The results show relatively good performance in the both alternative configurations at different rates of supplementary firing. Furthermore, positive values of economic indices were obtained.

Key words: *renewable energy, biomass gasification, combined cycles, gas turbines, co-generation*

Introduction

Using biomass for power generation is nowadays a very interesting option for CO_2 emission reduction and fossil fuel savings. Among different available biomass energy conversion technologies gasification of solid feedstock and firing a power plant with gaseous fuel is considered as one of the most effective. In comparison with traditional biomass combustion the integrated gasification plants represent higher level of power generation efficiency[1-3]. Dornburg *et al.* [3] presented that the highest relative primary energy savings, that result from using biomass, can be obtained with atmospheric and pressurized integrated biomass gasification combined cycle cogeneration plants. An amount of the non-renewable primary energy that is replaced within a regional energy system by a co-generation plant can be higher than 1.0 GJ per GJ of the biomass energy input [3, 4]. According to Walter *et al.* [5] in the middle run both co-fired and pure integrated biomass gasification plants can be a better option than capture and storage of CO_2. It has been already demonstrated in projects ARBRE

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(UK), Varnamo (Sweden), and Gussing (Austria) and other [2, 6] that a variety of technological schemes of power plants can be designed and successfully operated with medium scale reactors. There are currently many on-going research and development activities in the field [7].

On the other hand, wider commercialization and effective implementation of biomass gasification technologies into the energy market is problematic. The number of commercially running integrated gasification plants is nowadays still insignificant. This is mainly due to high initial investment costs and some technical problems of burning the low calorific value syngas in gas turbines and gas engines designed for natural gas operation. Conceptual design, optimization and feasibility studies of energy conversion plants are required to facilitate well informed decisions and promote new investments.

Technical, economic and environmental performance of the integrated biomass gasification power and co-generation plants have been so far analyzed by many authors [2, 3, 5, 6, 8-13] and other. The common conclusion is that the technology is attractive as it leads to the highest level of energy effectiveness and emission reduction. In most studies however, it is presented that profitability of investment projects is poor and significantly affected by scale of a plant. Another key problem of the successful commercialization of the technology is commercial availability of reliable and efficient gas turbines modified for hot syngas operation [5, 6, 10, 12].

There is a general opinion in the market that biomass energy conversion plants, especially the integrated gasification ones, cannot compete effectively with fossil fuel fired technologies without an effective financial support. Due to a high initial investment cost an economic attractiveness of a biomass fired power plant depends on many factors and it varies from case to case. It is however foreseen that profitability of the projects will be getting better in the near future. The reasons for this belief are increasing prices of electricity and decreasing investment cost due to technology development and scale effects.

Most of the studies available in the literature have been concentrated on electricity production only. On the other side it is the well known fact that the combined heat and power (CHP) plants represent the highest level of primary energy utilization. Marbe *et al.* [7] presented that a high level of waste heat utilization is a crucial condition for a satisfactory economic effectiveness in small to medium scale applications of biofuelled co-generation. Larson *et al.* [2] reviewed demonstration and commercial projects of integrated biomass gasification gas turbine combined cycle co-generation systems. They claim that the technology promises lower electricity costs than conventional biomass-fired steam turbine systems. It was found in previous work [4] that in the case of utility scale plant (above 60-90 MW of biomass energy input) a project of this type can be financially attractive. The relatively good economic performance of the project is the result of effective financial support and local policy promoting electricity generation from renewable resources. The profitability of an investment is highly influenced by a significant economic value of renewable electricity and CO_2 emission reduction certificates.

Several authors analyzed co-firing of natural gas (NG) and producer gas (PG) in gas turbine based plants [5, 9, 10, 12-14] and suggested the technology as a potential solution for elimination of some technical problems, reduction of initial investment costs, and faster commercialization of biomass gasification technology. It was generally concluded that the approach is effective and competitive way of production of electricity from biomass in comparison to systems using biomass only. Walter *et al.* [5] claim that the construction of 10-15 short- to medium-size gasification islands would be enough to induce important cost reductions due to learning effects. Marbe *et al.* [9], Rodrigues *et al.* [10], Walter *et al.* [5], Zwart [12], and Fiaschi *et al.* [14] analyzed co-firing of the gaseous fuels in a gas turbine and suggested that a relatively small share of the biomass derived fuel leads to favorable technical, environmental, and economic effects. It would however require modifications and adaptation of the gas turbine. Franco *et al.* [13] took into account supplementary firing of PG in turbine exhaust before heat recovery steam generator (HRSG). They showed that the solution leads to an increase of the combined plant efficiency by the optimization of HRSG and of the steam bottoming cycle. It is also attractive in the aspect of reduction of the fossil fuel consumption and reduction of CO_2 emission.

One of the most important factors influencing the economic performance of biomass energy utilization projects is availability and cost of the feedstock [1, 15]. Biomass is a low bulk density fuel that can be characterized by a significant demand for energy and costs during growing, harvesting, processing, transportation, and storage. A great care should be given to an effective use of available resources. Experience shows that organizing a biomass supply chain is not an easy task in the case of utility-scale plants. Investment projects are feasible if biomass is available within a specified distance from designed location of a plant. Depending on many different factors it is typically between 25 and 100 km [15]. Therefore the renewable fuel is suitable rather for small and medium scale local energy production facilities. Nowadays, due to emission reduction and renewable energy policies that have been adopted in many countries, there are available financial mechanisms and other forms of stimulation that significantly support new investment initiatives in the field of biomass energy conversion. Poland can be an example. According to legal regulations the share of electricity from renewable resources within the total amount of electricity sold to final consumers must be not lower than 10.4% in 2011 and rises to 12.9% in 2017 [16]. It is difficult to satisfy this obligation as there are very limited sources of wind, solar and hydro energy in the country. The co-firing of biomass in existing coal fired plants can contribute at the level of 1.6 to 4.6% [17]. Therefore other alternatives of biomass implementation into the energy market are required. Currently in Poland the financial measures that promote new projects include tradable green electricity, cogeneration and CO_2 emission reduction certificates. There are also subsidies available from the National fund for environmental protection and water management and other financing institutions. More often the projects tend to be attractive to investors. There is now a great opportunity for implementation and further development of thermodynamically effective biomass energy conversion technologies.

The aim of this work is to examine a potential for CO_2 emission reduction and savings of primary energy of fossil fuels that come with the integrated biomass gasification combined cycle co-generation technology (IBGCCC). This is being analyzed together with the current economic attractiveness of a sample investment project. A medium scale plant is taken into account. The main design criterion is to make use of existing, tested and proven equipment that has already been used in a demonstration scale application. The ARBRE project [18-20] has been selected as a source of the main input data for this study. The technological system proposed in this paper is based on atmospheric fluidized bed gasifier coupled to fluidized bed tar cracker and SGT-100 Siemens gas turbine (GT). It was found that in Polish conditions a cogeneration plant based on this machine is an excellent candidate for base load block in many municipal heating systems. It is also proposed that in order to minimize the technical risk connected with firing the turbine with biomass derived low calorific value fuel the standard NG fired machine is used. The producer gas is proposed for supplementary firing in the GT exhaust gas and steam rising in a HRSG. This idea is based on the fact that the NG supply system would be usually required as the turbines modified for PG operation mode need an auxiliary fuel for startup and shutdown purposes [21-24]. The proposed configuration of a plant is being compared with the one that assumes modifications of the SGT-100 and operation on PG only. There is no co-firing of NG and PG in GT considered as it does not eliminate all technical problems related to GT operation with biomass-derived gas. Co-firing is considered rather as a good option for an increase of use of biomass for power generation suggested for modifications of existing GT based plants [9, 12, 14].

Plant performance modelling

A schematic outline of the proposed plant is given in fig. 1. This general scheme includes all equipment that is taken into account. Different configurations of the plant are analyzed within the study basing on this superstructure.

The plant is based on the Siemens GT model SGT-100 (former Alstom TYPHOON gas turbine). There have been already supplied 3 machines of this type for operation on low calorific value fuel gases in the 3.5 to 5.0 MJ/Nm³ range [23]. The machine has been already tested in ARBRE and Varnamo demonstration plants and an extensive experience has been gained by the manufacturer [18, 22]. The machine has a proven design resulting in high availability. Rensfelt et al. [20] claim that there in the ARBRE demonstration plant were no operational problems with GT, gasifier, catalytic tar cracker, and gas filters.

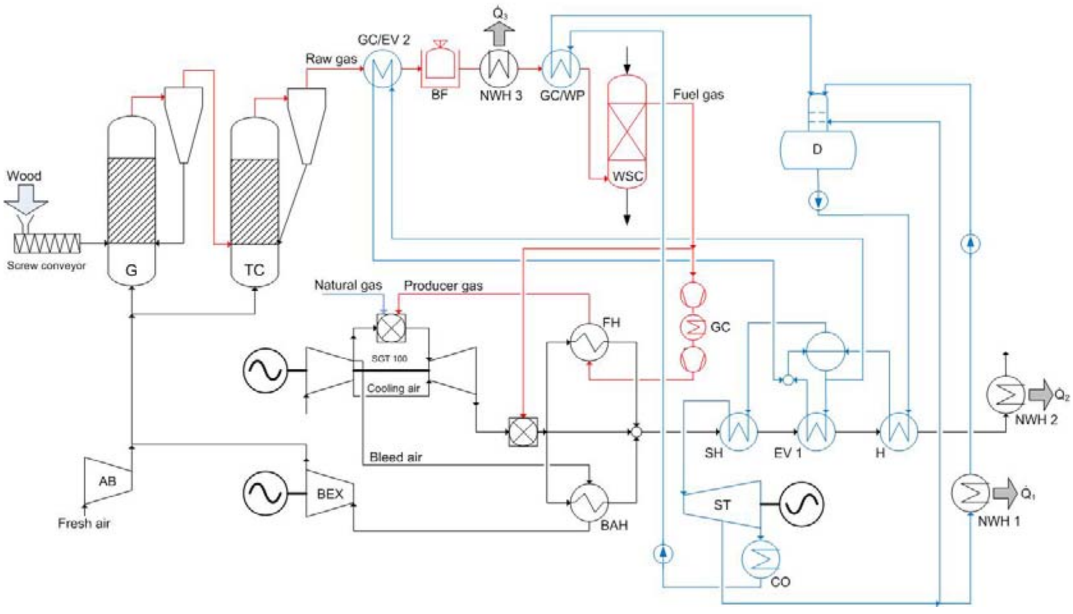

Figure 1. Schematic diagram of combined cycle co-generation plant superstructure (AB – fresh air blower, BEX – bleed air expander, BAH – bleed air heater, G – gasifier, TC – tar cracker, GC/EV 2 – raw gas cooler/waste heat recovery evaporator, BF – bag filter, GC/WP – gas cooler/condensate heater, WSC – wet scrubber, GC – producer gas compressor, FH – fuel gas heater, D – deaerator, H – boiler water heater, EV 1 – evaporator, SH – steam superheater, ST – steam turbine, CO – condenser NWH 1, NWH 2, and NWH 3 – network water heaters)

The SGT-100 single shaft turbine is available within the range of electric power ratings from 4.35 MW up to 5.4 MW. It has 10 compressor stages, 6 burners, and two expander stages. First stage nozzle and rotor blades are cooled by compressor discharge air. The compressor is equipped with variable guide vanes in order to optimize the operation of the machine. The detailed data of the SGT-100 GT were taken from the work presented by Rabovitser *et al.* [25] and it is summarized in table 1.

Table 1. SGT-100 gas turbine design data at ISO conditions [25]*

Parameter	Value
Compressor inlet flow rate, $\dot{m}_{C,in}$ [kgs^{-1}]	20.5
Compressor outlet pressure, $p_{C,out}$ [kPa]	1481.44
Compressor outlet temperature, $T_{C,out}$ [K]	677.04
Expander inlet flow rate, $\dot{m}_{Ex,in}$ [kgs^{-1}]	19.4
Expander outlet flow rate, $\dot{m}_{Ex,out}$ [kgs^{-1}]	20.9
Assumed firing temperature, T_{max} [K]	1433.15
Turbine inlet temperature**, *TIT* [K]	1387.59
Expander inlet pressure, $p_{EX,in}$ [kPa]	1454.79
Expander outlet pressure, $p_{EX2,out}$ [kPa]	102.04
Expander exhaust temperature, $T_{EX2,out}$ [K]	799.82
Nett electric power, P_{el} [kW]	5250
Speed, *N* [rpm]	17384
Assumed expander isentropic efficiency, $\eta_{i,ex}$ [%]	88.0
Assumed mechanical efficiency, η_m [%]	98.5
Assumed generator efficiency, η_g [%]	95.5
Calculated power generation efficiency**, η_{el} [%]	30.1

* Pressure 101.3529 kPa, temperature 288.15 K, relative humidity 60%.
** According to GTW Handbook the efficiency is 30.5% [26].

The simulation model of the SGT-100 machine was built using Engineering equation solver (EES) that is suitable software for this kind of problem. In-built JANAF tables were used for calculation of properties of working fluids. In the first step the model of NG fired machine was built and tuned in order to match the main technical data at ISO conditions. Some parameters had to be assumed as there was not available a detailed description of the machine. The first one is the turbine inlet temperature (TIT) that is regarded as the first rotor stage inlet temperature, *i. e.* after mixing of combustion chamber exhaust gas with the guide vane cooling air. The cooling process is modelled using a simplified approach. As the location of cooling air extraction points is not known it is being assumed that the air is taken from the compressor outlet. This assumption is quite common for simulations of gas turbines [27]. Cooling air flows to nozzle and rotor blades are among the parameters assumed for tuning purposes. The simulation model that was used for assessment of the performance of the machine is presented in fig. 2.

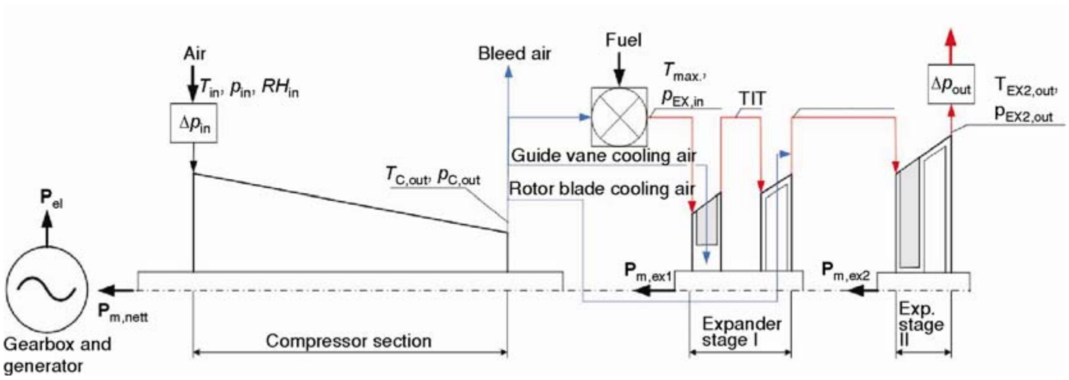

Figure 2. GT model used for simulation

The control of the machine by IGV closing does not significantly reduce the risk of compressor instability [30]. Therefore it has been decided that within this study the problem of the increased fuel mass flow rate is faced by bleeding air from the compressor. According to Palmer *et al.* [29] this strategy eliminates most of the potential surge margin problems. As the plant is integrated with the atmospheric-pressure gasifier the bleed air is used for an additional power generation in bleed air expander (BEX) (see fig. 1). It is also assumed that in selected configurations, where there is a reasonable temperature difference between GT exhaust gas after supplementary firing and compressor discharge air, a bleed air heater (BAH) is applied.

Due to the lack of a detailed compressor map of the SGT-100 GT a simplified calculation is performed. The main assumed parameter in off-design simulation is the constant value of compressor pressure ratio (PR). Furthermore it is assumed that the PR is increased by 3% when the machine is fired with PG. The increase in this range should be acceptable for the machine [28, 30, 31]. It must be stressed that this assumptions are rough and verification is required with manufacturer data before any investment decision is made. In order to estimate the performance of the machine in off-design conditions, that result from the change of fuel, the flow function in the following form is applied to expander inlet cross-section:

$$A = \frac{\dot{m}_{\mathrm{EX,in,des}}\sqrt{T_{\max}}}{FN_{\mathrm{des}}p_{\mathrm{EX,in,des}}} \tag{1}$$

In off design conditions eq. (1) is used for calculation of expander inlet pressure and it takes the form:

$$p_{\mathrm{EX,in,off}} = \frac{\dot{m}_{\mathrm{EX,in,off}}\sqrt{T_{\max}}}{FN_{\mathrm{off}}A} \tag{2}$$

The flow number (*FN*) is calculated for design and off-design operation, respectively, for chocked nozzle conditions ($p_{\mathrm{EX,in}}/p_{\mathrm{EX,out}}$>critical) from eq.:

$$FN = \sqrt{\frac{\kappa}{\mathrm{R}}\left(\frac{2}{\kappa+1}\right)^{\frac{\kappa+1}{\kappa-1}}} \tag{3}$$

where values of $\kappa$are 1.335 and 1.324 and values of R are 292.3 kJ/kgK and 283.9 kJ/kgK in design and off-design conditions, respectively. The pressure at the expander inlet can be also estimated from the relationship:

$$p_{\mathrm{EX,in,off}} = PR(p_{\mathrm{C,in}} - \Delta p_{\mathrm{C,in}}) - \Delta p_{\mathrm{CC}} \tag{4}$$

As the allowable *PR* is known from the compressor map (in this study it is assumed) eq. (2) is used to calculate the mass flow rate at the expander inlet $\dot{m}_{\mathrm{EX,in,off}}$.

Compressor inlet air volumetric flow rate is assumed to be constant and equal to that at design conditions. Then the compressor mass flow rate is calculated from the equation of state:

$$p_{\mathrm{EX,in,off}} = PR(p_{\mathrm{C,in}} - \Delta p_{\mathrm{C,in}}) - \Delta p_{\mathrm{CC}} \tag{5}$$

Compressor inlet air mass flow rate is divided into four streams:

$$\dot{m}_{\mathrm{C,in}} = \dot{m}_{\mathrm{CC,in}} + \dot{m}_{\mathrm{nozzle}} + \dot{m}_{\mathrm{rotor}} + \dot{m}_{\mathrm{bleed}} \tag{6}$$

Nozzle cooling air mass flow rate in off-design conditions is [27]:

$$\dot{m}_{\text{nozle,off}} = \dot{m}_{\text{nozzle,des}} \frac{p_{\text{EX,in,off}}}{p_{\text{EX,in,des}}} \sqrt{\frac{T_{\text{C,out,des}}}{T_{\text{C,out,off}}}} \tag{7}$$

where in design conditions $\dot{m}_{\text{nozzle,des}}$ = 1.321 kg/s. The ratio of rotor cooling air to nozzle cooling air was estimated to be 0.741 and it is kept constant in off-design simulation.

Increased mass flow rate and temperature of the biomass derived fuel gas has significant impact on the operation of the machine when PG is used instead of NG. Therefore the fuel gas heater (FH) is applied within the plant structure if the turbine is fired with PG. The additional function of this heater is to ensure that the incoming gas is above its dew point. The gas must be pre-heated to at least 250 ºC [23].

It is assumed in this study that temperature of pre-heated biomass derived gaseous fuel and compressor bleed air is within the range of 700-1000 K. It depends on the temperature of turbine exhaust gas after the supplementary firing. The temperature difference between hot inlet and cold outlet flow in a countercurrent heat exchanger is at least 100 K.

Composition of the turbine fuel gas was calculated using data from the ARBRE plant. Paterson *et al.* [19] presented the composition of the dry turbine fuel gas obtained from fluidized bed gasifier operated at the pressure of 1.5 bar. Gasification temperature is 850 °C. The temperature is elevated to 920 °C in the tar cracker. After leaving the tar cracker, the gas is cooled down to 180-200 °C in a steam generator before the bag filters. After the bag filter and before the solution scrubbing there is a secondary cooling of the gas down to 75 °C. Outlet fuel gas has 20 °C and it is saturated with water. Pressure at fuel gas compressor outlet is 19 bar[19]. The gas compressor has 5 stages with an intercooling.

In order to make the plant performance analysis possible the mass and energy balance of the gasification process was performed using EES software. It was assumed the primary fuel is wood of the following characteristics at the reactor inlet (mass, dry basis): fixed carbon –17.16%, volatile mater – 82.29%, ash – 0.55%; composition: carbon c = = 0.4732, hydrogen h = 0.07243, oxygen o = 0.4474, and nitrogen n = 0.0015. Water content of the wood at the reactor inlet is 10% [19, 20]. Lower heating value of the dry biomass is LHV_{dry} = 18.735 MJ/kg and at 10% water content is LHV_{wet} = 16.606 MJ/kg. Calculated composition of the gas from reactor and at the turbine inlet is given in tab. 2. Estimated yield of the tar free dry gas is 2.546 Nm^3/kg of dry biomass.

In the case of NG driven SGT-100 GT it assumed that the NG is delivered from medium pressure NG transmission pipeline and the available pressure is 400 kPa. Calculated NG compressor power is 102 kW and nett electricity generation efficiency of the GT system is 29.54% (ISO conditions). Performance of PG fired GT system is influenced by the effectiveness of fuel and bleed air heaters (FH and BAH).

Table 2. Producer gas characteristics

Parameter	Producer gas from tar cracker	Fuel gas to gas turbine and HRSG
H_2	9.05	10.53
CO	11.89	13.85
CH_4	3.35	3.90
C_2H_4	0.33	0.39
CO_2	12.23	14.24
H_2O	15.67	1.80
N_2	46.89	54.60
Ar	0.60	0.70
T [K]	1193	298
p, [kPa]	150	130
Yield [Nm^3(kg of dry wood)$^{-1}$]	2.967	2.546
LHV [kJkg^{-1}]	3375	3746
M [kgkmol^{-1}]	25.7	26.99

Calculated turbine exhaust gas oxygen content is 14.16%vol and 11.56%vol in design conditions and after the change of fuel, respectively. Various rates of supplementary firing are considered in order to increase electricity production from the renewable source. Supplementary firing has been already applied in ARBRE project and it is regarded as the technically feasible technology. In the case of NG fired plants supplementary firing is widely used as it increases power output of a plant and increases HRSG operation flexibility. The technology is usually applied where it is an economically attractive solution. In practice the degree of supplementary firing is limited by the HRSG inlet temperature at the level of 1000 ºC. This increases steam production by the HRSG about four times from that obtained when there is no supplementary firing. In most of the systems however, lower rates are used and the production of steam rises about two times.

In this study the degree of supplementary firing is expressed in the way of the relative oxygen content in the HRSG inlet gas. Therefore it shows how much oxygen was consumed from an initially available amount. An independent value being set for calculation is the coefficient of excess oxygen for combustion λ (defined as the actual amount of oxygen available to the amount required for total combustion). The value of λ is varied between 0 and 20, however in practice it should be limited to about λ = 3. The maximum exhaust gas temperature after supplementary firing λ = 3 is 1241 K in the case of NG fired turbine and 1197 in the case of PG fired machine. In the case of using PG as the turbine fuel a portion of the exhaust gas is used for heating of the fuel gas and bleed air. Therefore the maximum temperature at the HRSG inlet is lowered to 1052 K. The performance of PG fired SGT-100 GT system at ISO conditions with different rates of supplementary firing is presented in fig. 3. It can be observed that the nett efficiency of electricity generation within the system composed of GT, fuel compressor, and BEX increases from about 27% to about 33% when available oxygen consumption rises from 0 to 22%. This is the effect of fuel and air heating in gas-gas heat exchangers.

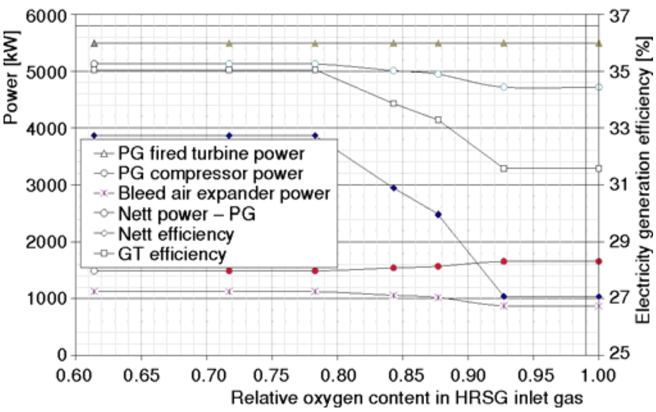

Figure 3. Performance of PG fired GT system with different rates of supplementary firing

The main driving force for using biomass as a fuel in energy sector is reduction of fossil fuels consumption and CO_2 emission. Therefore in order to assess the performance of a proposed technological solution, two main indices are used:

– Energy replacement index (ERI) that shows the amount of energy from fossil fuels that is saved within the regional energy system by using renewable energy in a co-generation plant (in GJ of non-renewable energy per GJ of biomass energy input):

$$ERI = \frac{\Delta G_{\text{coal,bio}} LHV_{\text{coal}} + (1-a)\dfrac{3.6 E_{\text{el,bio}}}{\eta_{\text{ref,system}}}}{G_{\text{wood}} LHV_{\text{wood}}} \tag{8}$$

– Global reduction of CO_2 emission:

$$\Delta G_{CO_2} = G_{CO_2,2} - G_{CO_2,1} = \Delta G_{coal} LHV_{coal} WE_{coal} + (1-a) E_{el} WE_{ref} - V_{NG} VLHV_{NG} WE_{NG} \quad (9)$$

Additionally for the sake of economic analysis the index of primary energy savings (PES) by co-generation of heat and power is calculated according to the regulation [32]:

$$PES = \left(1 - \frac{1}{\frac{\eta_q}{\eta_{q,ref}} + \frac{\eta_{el}}{\eta_{el,ref}}} \right) 100 \quad (10)$$

The reference values of efficiencies and emission indices are taken for Polish legal regulations [32, 33] (for values see Nomenclature section).

Considering benefits that result from replacing electric energy within the regional system the nett effect is taken into account. Therefore electric energy that is exported into the system is calculated as follows:

$$E_{el} = E_{el,gen}(1-\alpha) - E_{el,fss} \quad (11)$$

Within the study the value of α is set to be 0.02 and consumption of electricity by fuel supply system $E_{el,fss}$ is the sum of power consumed by gas compressors and biomass gasification system. For the biomass gasification system the consumption of electricity is assumed to be 0.075 kWh/kg of dry biomass input.

In practice it is never known what source of electricity is really replaced if a new generation facility is introduced into the regional system. The analysis is made for Polish conditions, where almost 90% of electricity is generated from hard and brown coal. Diversification of the fuel consumption structure is required and electricity from renewable and NG fired co-generation plants is supported by different legal and financial means. Consequently, it can be assumed that with a high probability the replaced electricity will be the one from the coal fired plants. Therefore, it was decided to compare fuel energy savings and emission reduction with respect to coal.

The amounts of saved coal $\Delta G_{coal,bio}$ and electricity replaced within the system $E_{el,bio}$ that are attributed to biomass consumption in a co-fired plant can be calculated twofold. For the purpose of the plant performance analysis it is assumed that these values are calculated by the difference between current and base case value, in the, *i. e.* obtained if no supplementary firing is applied:

$$\Delta G_{coal,bio} = \Delta G_{coal} - \Delta G_{coal,0} \quad (12)$$

$$E_{el,bio} = E_{el} - E_{el,0} \quad (13)$$

In the case the amount of electric energy is being calculated in order to obtain the renewable energy certificates a proportional production is assumed according to [32]:

$$E_{el,bio} = E_{el} \frac{G_{wood} LHV_{wood}}{G_{wood} LHV_{wood} + V_{NG} VLHV_{NG}} \quad (14)$$

The second method gives higher values what additionally boosts economic performance of a potential investment project. Additionally to the presented global indices the characteristics of the plant itself is being analyzed. For this purpose gross electricity generation efficiency, fuel energy utilization factor, biomass to electricity generation efficiency are introduced:

$$\eta_{\mathrm{el}} = \frac{3.6E_{\mathrm{el,gen}}}{G_{\mathrm{wood}}LHV_{\mathrm{wood}} + V_{\mathrm{NG}}VLHV_{\mathrm{NG}}} \tag{15}$$

$$EUF = \frac{3.6E_{\mathrm{el,gen}} + Q}{G_{\mathrm{wood}}LHV_{\mathrm{wood}} + V_{\mathrm{NG}}VLHV_{\mathrm{NG}}} \tag{16}$$

$$\eta_{\mathrm{el,bio}} = \frac{E_{\mathrm{el,gen,bio}}}{G_{\mathrm{wood}}LHV_{\mathrm{wood}}} = \frac{E_{\mathrm{el,gen}} - E_{\mathrm{el,gen,0}}}{G_{\mathrm{wood}}LHV_{\mathrm{wood}}} \tag{17}$$

Useful characteristic parameter of any cogeneration plant is electric power to heat ratio (or cogeneration index):

$$\sigma = \frac{3.6E_{\mathrm{el}}}{Q} = \frac{\eta_{\mathrm{el}}}{EUF - \eta_{\mathrm{el}}} \tag{18}$$

Finally it is possible to present energy and emission saving potential of biomass fired cogeneration plant as a function of main design characteristic parameters:

$$ERI = \frac{EUF - \eta_{\mathrm{el}}}{\eta_{\mathrm{b}}} + (1-a)\frac{\eta_{\mathrm{el}}}{\eta_{\mathrm{el,ref}}} \tag{19}$$

$$\Delta G_{\mathrm{CO_2}} = E_{\mathrm{el}}\left(\frac{EUF - \eta_{\mathrm{el}}}{\eta_{\mathrm{el}}\eta_b}WE_{\mathrm{coal}} + (1-a)WE_{\mathrm{ref}}\right) \tag{20}$$

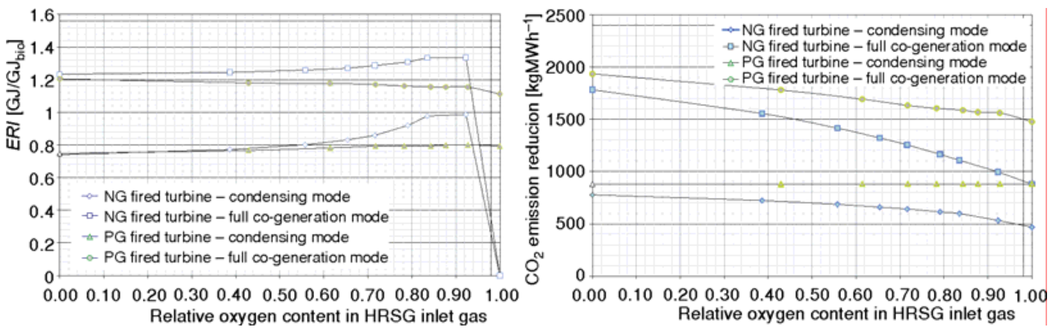

Figure 4. Energy replacement index and CO_2 emission reduction (at ISO conditions)

In general the electricity generation efficiency of a biomass fired plants is nowadays smaller than that of the fossil fuel fired ones. Therefore basing on eq. (19) it is easy to draw the conclusion that high primary fuel savings are possible only if cogeneration mode is applied. Also emission reduction is significantly boosted by cogeneration mode. Performance of the plant at ISO conditions is presented in figs. 4 to 6. Because the share of renewable energy resources in the electricity generation system *a* is taken into account in eq. (8) and (9) the benefits are slightly lower than the ones calculated with the assumption that power from renewable source reduces the load of fossil-fuel-fired plants only [33].

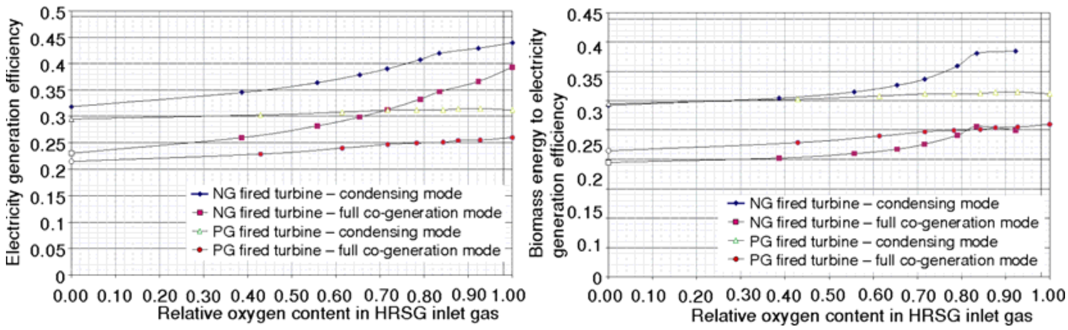

Figure 5. Gross electricity generation efficiency and biomass energy to electricity conversion efficiency

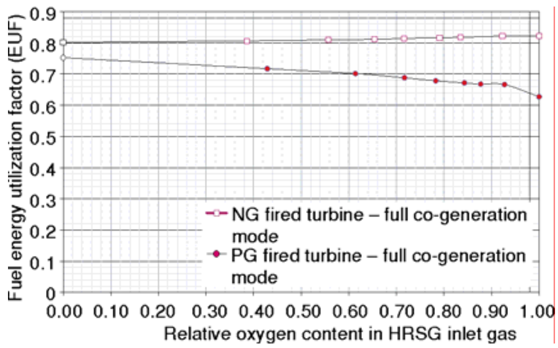

Figure 6. Fuel energy utilization factor in co-generation (EUF)

Some interesting conclusions can be drawn from the presented results. The emission reduction is always higher for biomass only fired plant as the fuel is CO_2 neutral. If however ERI, electricity generation efficiency and energy utilization factor (EUF) are taken into account the NG fired GT with supplementary firing of PG before the HRSG seems to be more attractive in several cases. This is caused by the weak performance of PG fired turbine system at small rates of supplementary firing (fig. 3). It is especially interesting that the electricity from biomass generation efficiency is high (at the level of 38%) for NG fired turbine system. This is caused by the fact that supplementary firing changes the temperature profile within the HRSG and thus lowers the outlet gas temperature. Therefore some additional energy can be recovered from the NG combustion exhaust gas.

Case study

In order to analyse the economic attractiveness of the proposed technical system a sample investment project is defined. One of the existing coal-fired municipal heating systems is being considered for modernization. The system consists of central coal fired heating plant and hot water network. The new cogeneration plant is planned to be fitted into the existing heating load thus unloading the coal fired boilers. The heating system was previously considered as a potential candidate for installation of wood fired boiler and steam turbine plant [34]. Therefore the current results can be also used for comparison of the alternative technologies of biomass energy conversion.

Climate of the country causes that the demand for heating can be divided into base load and heating season load. Average duration of the heating season is 5450 h/a. The peak heating output of the existing central heating plant is 75 MW. Out of the heating season the load varies between 10 and 6 MW. Heating network hot water temperature does not exceed 120 ºC. Measured ambient temperature varies between –20 ºC and +35 ºC. Annual heat production is 750.2 TJ. Annual consumption of coal is 39805 ton/a and current emission of CO_2 is 86695 ton/a. Annual consumption of electric energy, that is being supplied by an external grid, is 4500 MWh/a.

Currently there are in operation four coal fired water boilers of the WR25 type. All of the installed boilers have been upgraded over the last 10 years. Their current technical condition is estimated to be good or very good. Energy efficiency of each boiler is maintained at 82%. Fuel for boilers is coal with the following parameters (weighted averages): calorific value: 23.5 MJ/kg, part of ash: 15.0%, the share of sulfur: 0.6%. Emissions from the boilers are below the limit values.

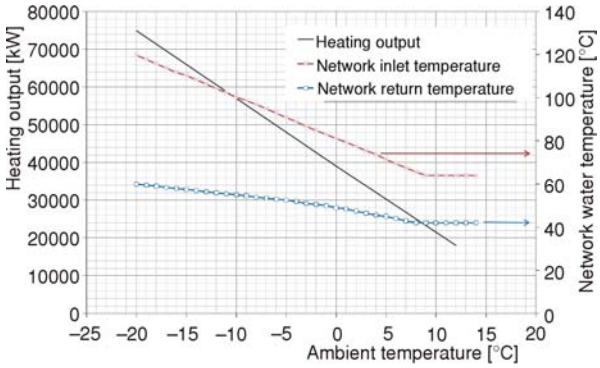

Figure 7. Heating output and network water temperature of existing heating plant

Operation of the heating system after installation of the new energy conversion facility is simulated using data from the current continuous measurements of network heating output, network water temperature, and ambient temperature. The data is presented in figs. 7 and 8.

The operation of the plant is simulated for a typical year using the time step of 1 hour. Then the annual energy balance of the plant is examined and economic analysis is performed. A hybrid calculation model was built using EES and GateCycle^{TM} (from GE Energy). The second package was used to simulate the bottoming steam cycle of the combined cycle plant. Neither steam parameters nor construction of the HRSG were optimized. The steam pressure was set to 10.0 MPa and its temperature was varied between 400 and 540 ºC depending on the HRSG inlet gas temperature. The HRSG was decided to be a single pressure one with evaporator divided into two heat exchangers EV 1 and GC/EV 2 (see fig. 1). Such configuration of the device allows favourable temperature profile in the main part of the HRSG (H + EV 1 + SH). It also leads to an effective heat recovery from the raw producer gas using a relatively small heat exchange area.

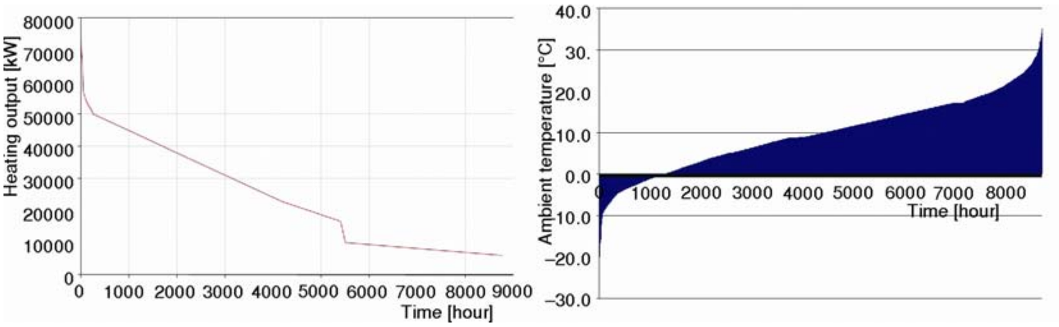

Figure 8. Heat load and ambient temperature duration curves at existing heating plant

Supplementary firing changes the temperature profile in the HRSG thus lowering final exhaust gas temperature. In this study it is being assumed that the exhaust gas is cooled down to 120 ºC. Heat required for biomass drying from assumed 35% humidity to required 10% is provided by the cogeneration plant. In the case the plant is integrated with the biomass gasifier the annual availability was set to 90% (7884 running hours). In the case of NG fired turbine the availability was set to 95% (8322 running hours). The cogeneration plant is the base load source of network heat. If there is a deficiency of heat the existing coal fired boilers WR25 enter into service with the minimal allowable load equal to 5 MW. At the time the coal boiler is started the production of heat at cogeneration plant is reduced and steam flow into the condensation section of the turbine increases. The main results are given in tables 3 and 4.

Table 3. Main results of annual mass and energy balance of the plant with NG fired turbine

Case No.	1	2	3	4	5	6	7
λ at duct burner	no firing	20	9	7	5	4	3
Relative oxygen content in HRSG	1	0.92	0.83	0.79	0.72	0.65	0.56
Electricity generated, [MWh] (generator output, PF = 0.8)	59564	64939	76197	80735	89136	96263	108796
Plant own consumption, [MWh]	2365	2913	3748	4156	4894	5536	6618
Nett electricity generated, [MWh]	57199	62026	72449	76580	84242	90727	102177
Network heat from cogeneration, GJ	195539	261789	314475	342605	389371	432125	494344
EUF, [%]	77.745	79.119	75.605	73.813	70.998	69.210	66.473
PES, [%]	16.006	19.831	21.856	22.244	22.794	23.075	23.520
Electricity from renewable source according to [16], [MWh]	0	12925	27110	33523	44435	53338	67846
Electricity from cogeneration according to [32], [MWh]	59565	63599	68718	69905	72393	75150	79720
NG consumed*, [mln Nm^3]	14.57	13.86	13.86	13.86	13.86	13.86	13.86
PG consumed, [mln Nm^3]	0	15.31	34.02	43.75	61.25	76.56	102.07
Wet biomass consumed*, [tons]	0	10238	22753	29253	40953	51193	68258
Saved coal, [tons]	10854	14734	17907	19597	22425	25001	28794
CO_2 emission reduced, [tons]	47749	62026	78643	86154	99428	111054	129964
*ERI**	0	1.397	1.255	1.197	1.133	1.101	1.064

* ERI calculated for 7844 hours of operation; Heating value of natural gas $VLHV_{NG}$ = 36.2 MJ/Nm^3; Heating value of wet biomass (as received) LHV_{wet} = 12.2 MJ/kg.

Table 4. Main results of annual mass and energy balance of the plant with PG fired turbine

Case No.	1	2	3	4	5	6	7
λ at duct burner	no firing	20	9	7	5	4	3
Relative oxygen content in HRSG	1	0.93	0.88	0.84	0.78	0.72	0.61
Electricity generated, [MWh] (generator output, PF = 0.8)	72862	79211	84885	88376	95257	102345	113010
Plant own consumption, [MWh]	17951	18461	18220	18322	18431	18986	19889
Nett electricity generated, [MWh]	54911	60750	66665	70055	76826	83359	93121
Network heat from cogeneration, GJ	257800	313441	335969	353321	382173	418163	476230
EUF, [%]	63.990	65.902	64.690	64.248	63.367	63.049	62.196
PES, [%]	34.765	34.060	33.585	33.277	32.881	32.512	31.757
Electricity from renewable source according to [16], [MWh]	72862	79211	84885	88376	95257	102345	113010
Electricity from cogeneration according to [32], [MWh]	48421	56236	58464	60286	63589	67969	73824
PG consumed, [mln Nm^3]	110.69	110.69	104.93	103.76	100.19	100.19	100.19
Wet biomass consumed, [tons]	66746	74590	81441	85825	93968	102453	116594
Saved coal, [tons]	15634	18878	20264	21315	23078	25244	28747
CO_2 emission reduced, [tons]	85235	97677	106222	111666	121825	132619	149319
ERI	1.095	1.123	1.119	1.116	1.112	1.110	1.099

Fuel availability and cost of supply

One of the major limitations for using biomass as a fuel in energy production sector comes from problems with long-term continuity and cost of supply. Each time a biomass fuelled plant is considered the available amount of the feedstock must be estimated and the optimal supply chain should be selected in the aspect of the acquisition cost.

For the purpose of this study a fuel availability survey was conducted. All potential sources of biomass within the analyzed region were identified and the potential amount of biomass was determined. Each source was characterized by geographical location, total available amount of wood of different assortments within different periods, daily supply capacity, physical properties of biomass and the specific price (loco source). Basing on the actual road route map each location was characterized by a transportation distance and real travel time. For the fixed locations of energy conversion plant and sources of fuel the logistics network was developed. The following objective function was defined:

$$C_{\mathrm{w}} = \sum_{i=1}^{i=n} \sum_{j=1}^{j=m} n_{ij} V_{ij} [(c_{\mathrm{w},ij} - c_{\mathrm{t},ij} L_i) + \rho_{ij} c_{\mathrm{ch},ij} + \rho_{ij}(w_{ij} - w_{\max}) c_{\mathrm{d},ij}] \rightarrow \min \qquad (21)$$

In details the fuel supply chain optimization problem has been discussed in [15]. The optimized cost of wood supply varies daily depending on biomass availability in particular resources. The average annual optimized cost of biomass supply as a function of the annual consumption is presented in fig. 9. These values were used as a cost of fuel within the subsequent economic analysis.

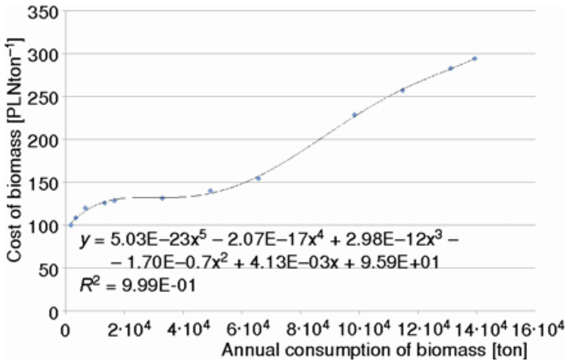

Figure 9. Cost of delivered wet biomass (loco plant)

Investment costs

Estimation of the total investment cost (TIC) is not an easy task in the case of integrated biomass gasification combined cycle cogeneration. Difficulties come from the fact that the market in this field is weak and most of the available cost data refers to a relatively small number of pilot and research plants. According to [18] the total installed costs of integrated biomass gasification combined cycle pilot plants were 5601 EUR/kW at Värnarmo (6 MW_e) and 5215 EUR/kW for ARBRE project (8 MW_e). In this study the TIC of the installation was calculated basing on particular equipment cost analysis. This is caused by the fact that the configuration of the plant is not a typical one. At first the cost of gasification island was estimated using different sources of

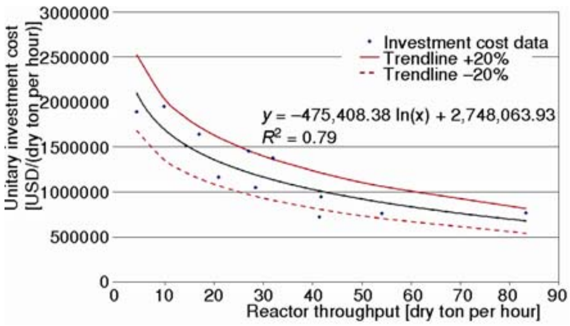

Figure 10. Investment cost of atmospheric pressure fluidized bed biomass gasification system as a function of biomass throughput

information [10, 35-37]. The costs were updated using equipment cost index CPI and results were consulted with potential suppliers. The final costing curve is presented in fig. 10 in a form of unitary cost per reactor throughput. The considered investment expenditures include the whole system from collection and processing of wet feedstock to clean gas outlet.

According to [26] the budget price of SGT-100 GT system is 2,700,000 USD. It is being assumed that the cost of the machine modified for biomass derived gas operations is 20% higher [10]. The costs of remaining equipment are calculated using the general equation:

$$EC = ECP(c_1 ECP^{c_2}) \text{ [USD]} \tag{22}$$

Equipment characteristic parameters *ECP* and coefficients c_1 and c_2 of eq. (22) are given in table 5.

Table 5. Data used for equipment costing

Equipment	*ECP*	c_1	c_2
HRSG	Q	2462.9	–0.3122
Duct burners	Q	11146.3	–0.415
Raw gas cooler / secondary evaporator	Q	2462.9	–0.3122
Gas-water heat exchangers	Q	450	–0.18
Extraction condensing turbine	P_{el}	7866.5	–0.318
Fuel gas compressors	P_{el}	207357	–0.723
Bleed air expander	P_{el}	14088	–0.502
Gas-gas heat exchangers	A	1899.2	–0.292
Condenser, cooling towers and water treatment stations	*STC*	0.175	0.0
Connection to NG distribution system	*GTC*	0.06	0.0
Turbine fuel supply system	*GTC*	0.04	0.0

Cost data presented in table 5 is used for calculation of the total equipment cost (*TEC*). Cost of building and infrastructure of the plant was 1,000,000 USD (according to an offer). Another considered Direct Cost (*DC*) components are:

– land preparation 0.05×*TEC*,
– pipelines and hydraulic integration 0.30×*TEC*, and
– automatics and control 0.10×*TEC*.

Electric interconnection (EIC) and power output (scaled from known value):

$$EIC = 500000\left(\frac{P_{\mathrm{el,gen}}}{2300}\right)^{0.6} \text{ [USD]} \tag{23}$$

Indirect cost (IDC) components are:

– project management 0.05×*DC*,
– design and documentation 0.08×*DC*,
– insurances 0.02×*DC*,
– startup and staff training 0.10×*DC*, and
– contingencies 0.10×*DC*.

The TIC estimated for the two alternative solutions and different degrees of supplementary firing is presented in fig. 11. The unitary investment cost calculated per kW of the total installed generator electric power varied from 2364 to 3299 USD/kW for NG gas fired turbine and from 3958 to 4147 USD/kW for PG fired turbine.

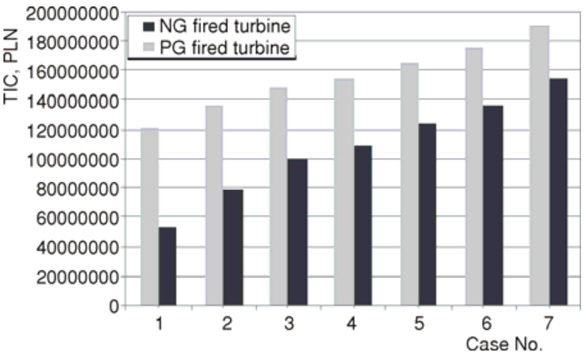

Figure 11. Total Investment Cost

Economic analysis

Biomass in Poland is considered as the main renewable source of energy. Nowadays there is a high demand for new electric power installed at the biomass fuelled production facilities. Therefore the financial support system for new investment projects has been established by the current Energy Law [38] and related regulations [16, 32]. According to the law, production of electricity using renewable energy sources and production of electricity in cogeneration facilities is being confirmed by the tradable certificates of origin. The certificates are issued for the electricity measured at the generator output. Since the year 2010 the electricity from biomass fuelled cogeneration plants is eligible for both renewable and cogeneration certificates. This significantly improves economic performance of the project.

The plant can be classified as highly efficient cogeneration if the annual value of PES is not lower than 10%. The required annual value of fuel energy *EUF* of combined cycle cogeneration plant is 80%. If a plant does not reach this value the electricity generated is divided into the electricity from cogeneration and the one generated apart from cogeneration [32].

The certificate of origin from cogeneration is being issued separately for energy produced in gaseous fuel-fired cogeneration and other types of plants. The market value of the certificate of origin from the gaseous fuel-fired cogeneration is much higher than the other one. In this study the values 127 PLN/MWh and 23 PLN/MWh are being assumed (end of 2010).

According to [38] a fuel gas obtained from processing of biomass is regarded as gaseous fuel in the meaning of cogeneration regulations. It is however not clear if the integrated gasification plant is eligible for certificate of electricity origin form gaseous fuel-fired cogeneration. As there is currently not such installation running in Poland there is a demand for legal interpretation of the regulations. Therefore in this study the lower market value of the certificates from biomass-fired cogeneration is taken into account.

The economic attractiveness of the project is expressed by means of common profitability indices of investment projects: net present value (NPV), internal rate of return (IRR) and discounted payback period (DPB):

$$NPV = \sum_{t=0}^{N} \frac{CF_t}{(1+r)^t} \tag{24}$$

$$\sum_{t=0}^{N} \frac{CF_t}{(1+IRR)^t} = 0 \tag{25}$$

$$\sum_{t=0}^{DPB} \frac{CF_t}{(1+r)^t} = 0 \tag{26}$$

General assumptions for the analysis are as follows.

- Project is located in Poland, and cash flow calculations are in local currency (PLN).
- Lifetime of the project is 15 years.
- Year of calculations is 2010.
- The project is financed in 30% by own capital and in 70% by bank credit. No subsidies are taken into account.
- Discounted cash flow rate is $r = 7.0\%$.
- Electricity selling price is 200 PLN/MWh.
- Value of certificate of electricity origin from renewable energy source is 270 PLN/MWh.
- Value of CO_2 reduction certificates is 60 PLN/MWh.
- Value of saved coal is 300 PLN/ton.
- NG price (according to tariff composed of fixed and variable part): 1.163 PLN/Nm^3.
- Ratio of EUR to PLN is 3.90 and USD to PLN is 2.88.

Results and discussion

The results of the project profitability analysis are given in fig. 12, 13, and 14. The first figure presents the structure of income generated by the systems based on NG and PG fired turbine respectively. The biggest portion of the cash inflow is represented the sales of the certificates of electricity origin and electricity itself. The income is higher in the case of PG fired turbine as the value of the green electricity certificate is high. On the other hand the increase of the income due to supplementary firing is more significant in the case of NG fired turbine. If there is no supplementary firing applied (case no. 1) the difference between the two alternative solutions is almost double. However at high degree of supplementary firing (case no. 7) the results are comparable.

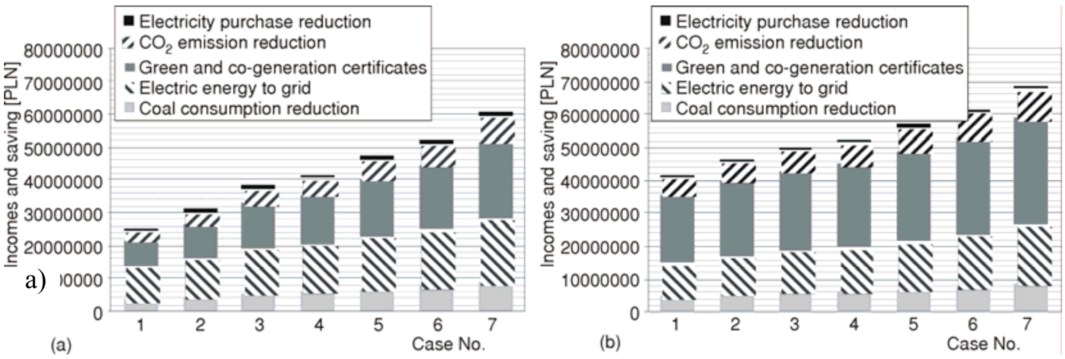

Figure 12. Structure of project income (a – NG fired turbine, b – PG fired turbine)

The main streams of cash outflows are presented in fig. 13. In the case of NG fired turbine with no supplementary firing the costs of operation are higher than in the case of PG fired turbine. This is the result of high cost of the NG. If however supplementary firing is applied the dual fuel plant represent lower costs as the share of cheap fuel (wood) increases. In the case of PG fired turbine the cost of fuel increases more significantly with the degree of supplementary firing. This is the result of higher unitary cost of wood from more distant resources (see fig. 9).

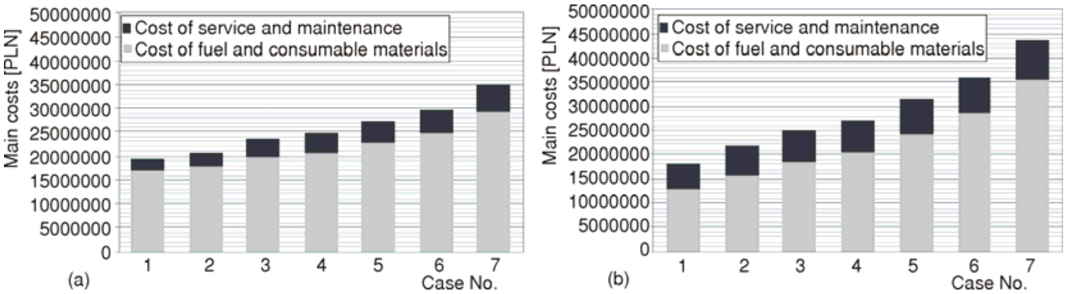

Figure 13. Selected cost items (a – NG fired turbine, b – PG fired turbine)

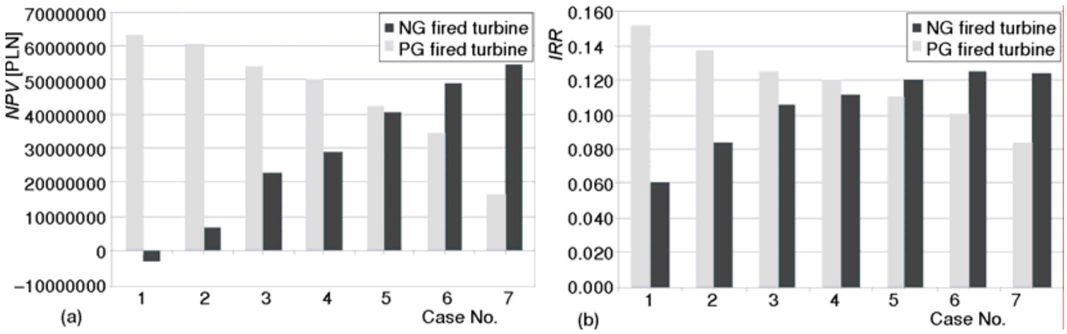

Figure 14. Project profitability indices NPV and IRR

Conclusions

Using biomass in medium scale GT based integrated gasification combined cycle cogeneration plants leads to favorable energy and environmental effects. Nowadays due the effective financial stimulation it is also an economically attractive technological option. Taking into account that such medium scale plants can be applied in many distributed locations, replacing existing coal-fired central heating plants, a great cumulative effect can be expected. This is also a good business opportunity.

In order to overcome the problems with firing gas turbine with the low calorific value biomass derived fuel a conventional NT fired turbine models can be applied. At higher rates of supplementary firing of the PG before the HRSG the profitability of a project is comparable with that obtained for PG fired turbine system without supplementary firing. Furthermore the NT fired turbine based configuration would promote a wider use of gasification technology without problems with the fueling of GT by the low calorific value fuel.

As a final concluding remark it should be said that the economic attractiveness of biomass gasification based cogeneration technology significantly depends on financial support. Considering that the discounted payback period of the investment capital is at the level of 8-12 years it should be clear that the current supporting financial mechanisms are available at least within this time span. Taking into account Polish energy market it can be concluded that the uncertainties related to legal regulations are nowadays one of most important barriers of the technology development.

Acknowledgments

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Nomenclature

A – annular cross section flow area, [m^2]
a – share of renewable energy resources in electricity generation system (a = 0.02), [–]
CF_t – annual cash flow in the year t, [PLN]
$\mathrm{c}_{\mathrm{w},ij}$ – cost of wood of a sort j from a source i, [PLN(bulk m^3)$^{-1}$]
$\mathrm{c}_{\mathrm{t},ij}$ – cost of transport of wood of a sort j from a source i, [PLN·km^{-1}(bulk m^3)$^{-1}$]
$\mathrm{c}_{\mathrm{ch},ij}$ – cost of wood chipping of wood of a sort j from a source i, [PLN(bulk m^3)$^{-1}$]
$\mathrm{c}_{\mathrm{d},ij}$ – cost of wood drying of wood of a sort j from a source i, [PLN(bulk m^3)$^{-1}$]
C_w – daily cost of wood delivery, [PLN·day^{-1}]
c_1 – first cost scaling coefficient, [–]
c_2 – second cost scaling coefficient, [–]
DC – direct investment cost, [PLN]
DPB – discounted payback period, [years]
ΔG_coal, – local reduction of coal consumption, [Mg]
$\Delta G_\mathrm{coal,bio}$ – local reduction of coal consumption attributed to use of biomass, [Mg]
$\Delta G_\mathrm{coal,0}$ – local reduction of coal consumption for base case configuration, [Mg]
ΔG_{CO_2} – global reduction of CO_2 emission, [kg]
EC – equipment purchase cost, [USD]
ECP – equipment characteristic parameter, [unit specific for the parameter]
EIC – cost of electric interconnection and power output, [USD]
ERI – energy replacement index, [GJ/GJ]
EUF – fuel energy utilization factor, [–]
E_el, – electric energy exported into grid, [MWh]
$E_\mathrm{el,bio}$ – portion of electric energy exported into grid attributed to use of biomass, [MWh]
$E_\mathrm{el,0}$ – electric energy exported into grid in base case configuration, [MWh]
$E_\mathrm{el,gen}$ – electric energy measured at generator output, [MWh]
$E_\mathrm{el,gen,0}$ – electric energy measured at generator output in base case configuration, [MWh]
$E_\mathrm{el,fss}$ – electric energy consumption within fuel supply subsystem, [MWh]
FN_des, – flow number in design conditions, [(kgKJ^{-1})$^{1/2}$]
FN_off – flow number in off design conditions, [(kgKJ^{-1})$^{1/2}$]
G_wood – mass of wood, [kg]
GTC – gas turbine cost, [USD]
IDC – indirect investment cost, [PLN]
IRR – internal rate of return, [–]
L_i – distance between i th source of wood and the power plant, [km]
LHV – lower calorific value of solid fuel, [kJkg^{-1}]
m – number of different sorts of biomass (saw dust, chips, logs, stems, branches) [–]
$\dot{m}_\mathrm{C,in}$ – air mass flow rate at compressor inlet, [kgs^{-1}]
$\dot{m}_\mathrm{blead}$ – air mass flow of bleeding
$\dot{m}_\mathrm{CC,in}$ – air mass flow rate at combustion chamber inlet, [kgs^{-1}]
$\dot{m}_\mathrm{EX,in,des}$ – combustion gas mass flow rate at expander inlet in design conditions, [kgs^{-1}]
$\dot{m}_\mathrm{EX,in,off}$ – combustion gas mass flow rate at expander inlet in off design conditions, [kgs^{-1}]
$\dot{m}_\mathrm{nozzle}$ – air mass flow rate for nozzle cooling, [kgs^{-1}]
$\dot{m}_\mathrm{rotor}$ – air mass flow rate for rotor blades cooling, [kgs^{-1}]
N – project lifetime, [years]
NPV – net present value of the project, [PLN]
n – number of sources of woody biomass, [–]
$\dot{n}_{ij}$ – daily delivery capacity of sortment j from a source i, [containers·day^{-1}]
$p_\mathrm{C,in}$ – pressure at compressor inlet, [kPa]
Δp_CC – pressure drop at combustion chamber, [kPa]
$\Delta p_\mathrm{C,in}$ – pressure drop at compressor inlet, [kPa]
$p_\mathrm{EX,in,des}$, – pressure at expander inlet in design conditions, [kPa]
$p_\mathrm{EX,in,off}$ – pressure at expander inlet in off design conditions, [kPa]
$P_\mathrm{el,gen}$ – electric power at generator output, [MWh]
PES – primary energy savings, [%]
PF – power factor, [–]
PR – compressor pressure ratio, [–]
Q – heat production, [GJ]
R, – individual gas constant of exhaust gas, [kJkg^{-1}K^{-1}]
R_a – individual gas constant air respectively, [kJkg^{-1}K^{-1}]
r – discounted cash flow rate, [–]
STC – steam turbine cost, [USD]
TEC – total equipment cost, [PLN]

TIC – total investment cost, [PLN]
$T_{C,in}$ – temperature at compressor inlet, [K]
$T_{C,out,des}$, – temperature at compressor outlet in design conditions, [K]
$T_{C,out,off}$ – temperature at compressor outlet in off design conditions, [K]
V_{ij} – bulk volume of wood of a sort *j* from a source *i*, [m^3]
VLHV – lower calorific value of gaseous fuel, [$kJN^{-1}m^{-3}$]
$\dot{V}_{C,in.des}$ – volumetric flow rate at compressor inlet in design conditions, [m^3s^{-1}]
V_{NG} – volume of natural gas used, [Nm^3]
w_{ij} – moisture content of wood of a sort *j* from a source *i*, [$kg_{H_2O}kg^{-1}$]
w_{max} – maximum allowable moisture content at the reactor inlet, [kgH_2Okg^{-1}]
WE_{coal} – CO_2 emission index for coal, [kg/GJ] (WE_{coal} = 94.85 [$kgGJ^{-1}$] [33])
WE_{NG} – CO_2 emission index for natural gas, [kg/GJ] (WE_{NG} = 55.82 [$kgGJ^{-1}$] [33])
WE_{ref} – CO_2 emission index for average system power plant, [$kgMWh^{-1}$] (WE_{ref} = 963.36 [$kgMWh^{-1}$] [33])

Greek symbols

α – power plant own needs factor, [–] (assumed value for GT base plant is 0.02)
η_b – heating system boiler efficiency
η_q, – heat production efficiency, [–]
$\eta_{q,ref}$ – reference heat production efficiency, [–] ($\eta_{q,ref}$ = 0.90 for NG and $\eta_{q,ref}$ = 0.86 for wood [32])
η_{el}, – electricity production efficiency, [–]
$\eta_{el,ref}$ – reference electricity production efficiency ($\eta_{q,ref}$ = 0.524 for NG and $\eta_{q,ref}$ = 0.327 for wood [32])
$\eta_{ref,system}$ – reference electricity generation efficiency in fossil-fuel-fired plants ($\eta_{ref,system}$=0.36)
κ – ratio of heat capacities, [–]
λ – excess oxygen coefficient (oxygen provided divided by stoichiometric oxygen requirement), [–]
ρ_{ij} – bulk density of wood of a sort j from a source *i*, [kgm^{-3}]
σ – power to heat ratio of cogeneration plant, [–]

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