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Co-production of gasification based biofuels in existing combined heat and power plants – Analysis of production capacity and integration potential

Christer Gustavsson [a,*], Christian Hulteberg [b]

[a] Department of Engineering and Chemical Sciences, Karlstad University, SE-651 88 Karlstad, Sweden
[b] Department of Chemical Engineering, Lund University, Box 124, 221 00 Lund, Sweden

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ABSTRACT

Solid fuel fired fluidized bed (FB) boilers are common in combined heat and power (CHP) plants in district heating- and process industry. In this study, utilization of such FB boilers for production of syngas in dual fluidized bed gasifiers and subsequent catalytic biofuel production to substitute natural gas (SNG), methanol (MeOH) and Fischer-Tropsch fuel (FT) has been examined. Based on the hypothesis that waste-heat and tail gas from the biofuel processes can be utilized in the CHP plant, process configurations aiming for operationally robustness and low investment cost rather than maximum stand-alone efficiency have been explored and implemented in actual industrial cases and over the full operating range of the boilers. The results of the study show that significant improvements of overall efficiency can be achieved by integration of the biofuel processes in the CHP plants and that a relatively high biofuel production capacity can be achieved. SNG showed the highest obtainable efficiency and production capacity of the studied biofuels, whereas the FT process showed largest increase in terms of efficiency when integrated in the CHP plant, compared to its stand-alone efficiency.

1. Introduction

Driven mainly by high oil prices and climate concerns, gasification of biomass with subsequent catalytic conversion to biofuels has become a research area with significant activity. Several different production routes, yielding various liquid and gaseous biofuels, have been studied [1–4]. Integration of biofuel plants with other industries have been examined and have been found to enable a higher total efficiency than obtainable with stand-alone plants, mainly due to the possibility to export heat from gas conditioning and catalytic conversion to district heating grids or other external users of low temperature energy [5–8].

In a Swedish context the district heating grids represent a large heat sink with a total heat demand of approximately 55 TWh (2013) [9]. Heat to these district heating grids is mainly supplied by combustion of different assortments of waste and forestry-based solid fuels. Another major heat sink in Sweden is steam for process industries, foremost the pulp and paper industry, where bark and different assortments of forest residues are utilized for heat production. Combustion of forestry-based fuels in district heating and forest industry combined heat and power (CHP) plants are predominantly accomplished in fluidized bed (FB) boilers, mainly of bubbling fluidized bed (BFB) type, and there are more than 80 biomass-fired FB boilers in operation in Sweden.

The importance of local feedstock and by-product distribution to the market for practical implementation of biorefineries was emphasized in a previous study [10]. Based on this, it is interesting to examine if the large number of geographically distributed CHP plants can form a platform for gasification-based biofuel production.

An FB combustion reactor can be combined with an FB gasification reactor, together forming a dual fluidized bed gasifier (DFBG). In this gasifier type, bed material is circulated between the two reactors. DFBGs can utilize dedicated combustion reactors solely used for combustion of residual char following the bed material, thereby providing heat for gasification [11]. But dual fluidized bed technology has also been applied utilizing existing solid fuel boilers [12] [13]. A steam blown DFBG operates with air as oxidizing agent in the char combustion reactor and generates a high calorific

* Corresponding author.
E-mail addresses: christer.gustavsson@kau.se, christer.gustavsson@poyry.com (C. Gustavsson).

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gas with low nitrogen content, suitable for subsequent catalytic conversion [14] [15].

Previously conducted techno-economic studies of thermo-chemical biofuel production have often found that large scale plants are required in order to achieve more competitive prices for biomass-derived automotive fuels, e.g. Ref. [16]. Such scale is not likely to be achieved by DFBG integrated with existing biomass boilers. However, recent initiatives and development in the area of small scale (<10 MW) syngas conversion to biofuels [17] [18] indicates that biofuel production based on boiler-integrated DFBG is relevant to study. A DFBG integrated with an existing biomass boiler (90 MW_{th}), has been examined in a previous study [19], where a gas production capacity of 10–30 MW (LHV) was analyzed and found technically feasible.

One cost-driving process area is the gas cleaning of the raw gas from the gasifier prior to the catalytic conversion. The approach in many techno-economic studies has been to utilize well proven concepts from the coal-based gasification business such as regenerative chemical absorption (amine wash) or physical absorption (Rectisol) for sulphur removal. Also for tar, regenerative chemical and physical absorption systems (OLGA) have been widely utilized in such analysis. Such methods for gas cleaning have proven to be efficient but result in high capital costs due to multiple columns and absorbents, making them less economical for small scale operation [20]. A fundamentally different approach is to capture contaminants in the gas stream in non-regenerative filtering and adsorption arrangements. Such an approach was examined for an experimental scale methanation plant [17], where sulphur was adsorbed in fixed beds containing ZnO and ZnO/Cu and the authors concluded that this gas cleaning approach could be a viable option for small scale methane production plants.

In addition to the scale-of-operation, the potential relevance for such low investment cost-, non-regenerative gas cleaning concepts is further accentuated by the fact that woody biomass normally has N, S, Cl concentrations that are about 1/10 of those in coal. Furthermore, the release of these components during steam gasification in DFBG is far from complete [21].

In this paper, three biofuel concepts, substitute natural gas (SNG), methanol (MeOH) and Fischer-Tropsch fuel (FT), based on DFBG and subsequent catalytic syngas conversion have been investigated, striving for operationally robust systems with low investment cost rather than maximum stand-alone efficiency. Previous research results and commercial operating parameters are used to model and evaluate biofuel production integrated with district heating- and industrial CHP production. The analysis is carried out for two actual industrial cases and over the full operating range of the boilers. The aim of the study is to evaluate the impact from such biofuel production integration on the CHP plants in terms of biofuel production capacity, electrical power generation and overall efficiency. Furthermore, we evaluate the impact of the biofuel production on the boiler operation.

2. Method and modelling

Integration of a DFBG with existing solid fuel boilers have been examined for two existing Swedish CHP plants; (i) an integrated pulp and paper mill CHP plant (PP plant) and (ii) a district heating CHP plant (DH plant). Both plants have BFB boilers with 50 kg/s maximum steam capacity. Given and assumed main data for the two plants are presented in Table 1. For the DH plant, present values for DH supply- and return water are given for February, which is the only month that is simulated for this plant. February was chosen because the CHP plant had representative heat delivery in form of warm water to the DH grid and steam to adjacent industries during this month, with average steam flow from the boiler 124 t/h.

Table 1
Main data for the CHP plants.

PP plant	
BFB boiler max. steam capacity, (t/h)	175
High Pressure (HP) steam (bar_g/°C)	100/500
Medium Pressure (MP) steam (bar_g)	9
Low pressure (LP) steam (bar_g)	3
BFB boiler flue gas temperature (°C)	170
O_2 in boiler flue gases (vol % wet)	5
Biomass dry content	50%
Steam flow from recovery boiler (t/h)	240
DH plant	
BFB boiler max. steam capacity, (t/h)	175
HP steam (bar_g/°C)	140/540
MP steam (bar_g)	7
District heating supply temperature, (°C)	90
District heating return temperature, (°C)	45
BFB boiler flue gas temperature, (°C)	160
O_2 in boiler flue gases, (vol % wet)	5
Biomass dry content, (%)	50

Schematic plant configuration for the PP plant is shown in Fig. 1 and for the DH plant in Fig. 2.

As a first step in the evaluation of the impacts of biofuel production, the "base case" was established for the two plants respectively. The two CHP plants were modelled in Chemcad 6.4.1 and the biomass consumption, the flue gas flow, heat exchanger areas and other relevant data was calculated, serving as a starting point for the comparison with the "biofuel cases". The isentropic efficiency for the steam turbines calculated from actual operating data was kept constant in the further calculations, a negligible error for the PP plant where the turbines are shared with a recovery boiler that normally accounts for some 75% of the steam flow to the turbines. As the capacity of a recovery boiler in a PP mill always is higher than the capacity of the solid fuel boiler, moderate variations of steam flow from the solid fuel boiler have a minor effect on total steam flow to the turbines. Also for the DH plant, the assumption of constant isentropic coefficient is reasonable for moderate steam flow changes given the use of a constant pressure partial arc-controlled turbine.

In the "biofuel cases", the CHP plant simulation models were altered. The new unit operations: drying, gasification, gas cleaning, gas conditioning and fuel synthesis were added as principally illustrated in Fig. 3 and integrated in the CHP plant as illustrated in Figs. 1 and 2. In accordance with a previous gasification study [19], drying of biomass to 10 wt% moisture content was assumed to be carried out in a bed dryer with air heating in two stages. For the DH plant, pre-heating of drying air was carried out utilizing DH return water whereas DH supply water was utilized for final heating of drying air. Temperature differences of 10 °C between the heat source supply temperature and the dryer supply air temperature were used. For the PP plant, pre-warming of drying air was carried out utilizing low temp. heat (65 °C) generated in the biofuel processes. Final warming of drying air to 100 °C was accomplished by low pressure steam (PP mill Alt.1). As an alternative, pre-heating of drying air by utilization of non-utilized excess heat available at the plant, enabling warming of the drying air to 55 °C before final warming by low pressure steam, was examined (PP mill alt.2). Exhaust drying air relative humidity was assumed to be 0.80 for all alternatives.

The gasification reactor was modelled as a stoichiometric reactor where raw gas composition was set manually. Based on assumed biomass composition $CH_{1.37}O_{0.61}$ (LHV 18.9 MJ/kg dry ash free basis (daf)), gasification temperature 800 °C, steam/biomass (S/B) ratio 0.6 and carbon conversion 0.75 a raw gas composition according to Table 2 has been assumed, which is in line with average