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The techno-economic potential of integrated gasification co-generation facilities with CCS *Going from coal to biomass*

J.C. Meerman*, M. Knoope, A. Ramírez, W.C. Turkenburg, A.P.C. Faaij

Energy & Resources, Copernicus Institute, Faculty of Geosciences, Utrecht University, Budapestlaan 6, 3584 CD Utrecht, The Netherlands

Abstract

This study analyses the impact of technological improvements and increased operating experience on the techno-economic performance of integrated gasification facilities producing electricity and/or transportation fuels. Also, the impact of using torrefied biomass instead of coal and/or applying CCS is examined. Results indicate that current production costs of electricity and/or transportation fuels are above market prices. Future improvements, however, could reduce production costs sufficiently to make gasification facilities economical. Furthermore, although CCS can be used to reduce CO_2 emissions at relative low CO_2 avoidance costs, only the use of biomass allows the production of carbon neutral electricity and/or transportation fuels and in combination with CCS can even result in negative CO_2 emissions.

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Future; Economic; Technical; Gasification; FT-liquids; Biomass; CCS

1. Introduction

To significantly reduce global CO_2 emissions requires the decarbonisation of both the transport and power sector [1]. Integrated gasification (IG) facilities producing electricity or Fischer-Tropsch liquids (FT-liquids) can potentially decarbonise both sectors by applying carbon capture and storage (CCS) and/or using biomass as feedstock. Being able to use biomass as well as coal means that these facilities can play a role in the transition towards a renewables based energy infrastructure.

In previous research we examined the technical and economic potential of state-of-the-art (SOTA) integrated gasification poly-generation (IG-PG) facilities [2,3]. Our results show that coal and biomass

* Corresponding author. Tel.: +31-30 253 2590; fax: +31-30 253 7601. *E-mail address:* J.C.Meerman@uu.nl.

can be converted into electricity at 38-40% efficiency[†] and FT-liquids at 55-60% efficiency. Using torrefied wood pellets (TOPS) results in improved technical and economic performance compared to conventional wood pellets. Also, it was shown that with SOTA technology neither electricity nor FT-liquids can be produced competitively. Advanced technologies and technological learning can, however, bring production costs down. This may make integrated gasification facilities profitable in the longer term. Therefore, in this study the impact of potential technological and operational improvements on the technical and economic performance of integrated gasification facilities is assessed.

Nomenclature

AGR	Acid gas removal
ASU	Air separation unit
CCS	Carbon dioxide capture and storage
EF	Entrained flow
FT	Fischer-Tropsch
IG	Integrated gasification
IGCC	Integrated gasification combined cycle
IG-FT	Integrated gasification Fischer-Tropsch
NPV	Net present value
SEWGS	Sorption enhanced water-gas shift
SOTA	State-of-the-art
TOPS	Torrefied wood pellets
WGS	Water-gas shift

1.1. Integrated gasification facilities

In an IG facility (Figure 1), a solid carbon-containing feedstock is fed into an entrained flow (EF) gasifier. The high operating temperatures (>1500ºC) result in a syngas consisting mainly of CO, CO_2, H_2 and H_2O. The required heat is supplied by combusting part of the feedstock by adding a sub-stoichiometric amount of oxygen, supplied by an air separation unit (ASU). Pure oxygen instead of air is used to obtain the required high temperatures, to increase overall efficiency and to reduce the size of downstream equipment [4,5]. The syngas is cooled and cleaned of contaminates. Depending on the desired product, the H_2:CO ratio of the syngas is adjusted in a water-gas shift (WGS) reactor. This can be done before or after the acid gas removal (AGR). When producing electricity, the syngas is fed into a gas turbine and combusted. When producing FT-liquids, the syngas is fed into a FT-reactor. The FT-liquids are purified and any off-gas is fed into a gas turbine and combusted. To increase the overall economics of an IG facility, steam is generated at various locations and used for electricity production in steam

† All energy values and efficiencies given in this study are higher heating values, unless stated otherwise.

turbines. To lower the CO_2 emissions of the facility, CO_2 can be captured at the AGR, compressed and subsequently stored in underground geological reservoirs. Detailed information of the individual components, i.e., ASU, gas cleanup, gas and steam turbines, can be found in Meerman et al., [6].

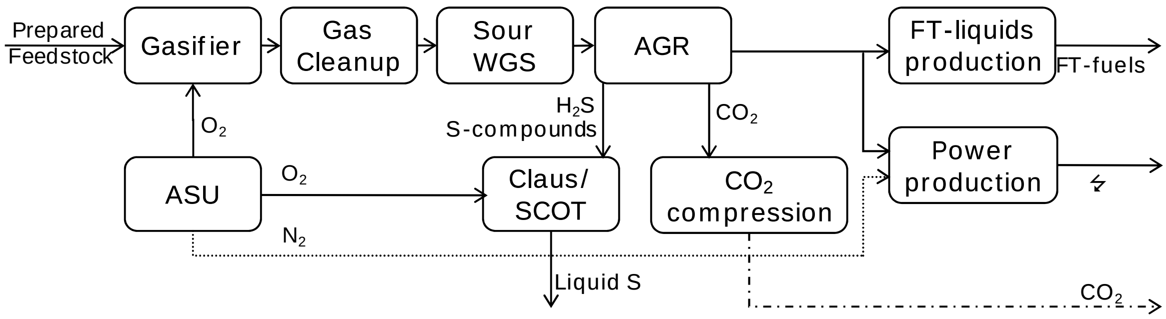

Figure 1 Simplified process layout of an integrated gasification facility using SOTA technology.
Waste, heat and recycle streams are not displayed [2].

2. Methodology

Based on commercially available technologies, plant configurations for SOTA IGCC and IG-FT facilities, both with CO_2 capture and storage (CCS) and without (Vent), were selected [6]. The time period in which new technologies are expected to become commercially available was selected based on the following criteria:

- Short term (2015-2020): technologies that are currently being tested in large-scale pilot projects;
- Mid term (2020-2035): technologies that have been successfully tested in laboratories and/or that are being tested in small scale pilot projects;
- Long term (2035-2050): technologies that are currently under development at lab scale or are at proof-of-concept stage.

When multiple technologies are available for the same process, the technology with the lowest production costs of the main product was selected. The resulting configurations were modelled in a component-based chemical AspenPlus simulation model [2]. This model calculates the relevant mass- and energy balances and, combined with an Excel-based economic model, allows the calculation of the production costs [2,3,6].

Production costs of the main product were calculated using the net present value (NPV) method, see equation (1) [7]. Note that temporary stored carbon in the chemical products still counts as emitted CO_2. To include transport and storage of CO_2, a fixed price per t CO_2 was taken. CO_2 avoidance costs were calculated according to equation (2). All cost data are given in €$_{2008}$. Common technical and economic parameters are presented in Table 1.

$$P_{MP}\ (€/GJ) = \frac{\alpha * I + O\&M + Feedstock - \sum\left(F_{SPx} * P_{SPx}\right)}{F_{MP}} \tag{1}$$

$$CO_2\ \text{avoidance costs}\ (€/t\ CO_2) = \frac{P_{MP} - P_{MP\ ref}}{\left(E_{ref}/F_{MP\ ref}\right) - \left(E/F_{MP}\right)} \tag{2}$$

Where α is capital recovery factor (yr^{-1}), calculated by $r/(1-(1+r)^{-L})$; ris discount rate; L is economic lifetime (yr); I is total capital investments of the facility (M€); O&M is operating and maintenance costs (M€/yr); Feedstock is coal or TOPS cost (M€/yr); F_{SPx} is annual flow side-product x (GJ/yr or kt/yr); P_{SPx} is market price of side-product x (€/GJ or €/kt); F_{MP} is annual flow of main product (GJ/yr); P_{MP} is production costs of main product (€/GJ); E is net CO_2 emission, including carbon in chemical products (t CO_2/yr); Ref is the reference system, namely a coal-fired integrated gasification facility without CCS.

Table 1 Technical and economic assumptions integrated gasification facilities.

Parameter	Unit	Value
Location	-	NW-Europe
Construction time 1)	Year	3
Plant economic lifetime	Year	20
Discount rate	%	10
Plant size	MW_{HHV} coal eq.	1000
O&M costs 2)	% of cap. cost	4
TOPS costs 3)	€/GJ	3.0-6.3
Coal costs 3)	€/GJ	2.25
CO_2 trans. & storage costs 4)	€/t CO_2	10
Ref. electricity price 5)	€/GJ	15.7
Sulphur price	€/t S	100
Slag price	€/t slag	0
CO_2 credits 6)	€/t CO_2	0

1) Based on literature, a construction time of three years was assumed and capital costs were evenly divided over these years [5,8,9,10].
2) The O&M costs are assumed to be 4% for all components except if stated differently in literature.
3) Feedstock costs were 2.25 €/GJ for coal and 6.3 €/GJ for biomass pellets beginning 2010. Although TOPS are not produced commercially today, it was assumed that they have the same price as biomass pellets as the increase in production costs is compensated by reduction in transportation costs. Literature studies show that TOPS prices could drop to 3 €/GJ TOPS [11,12,13,14,15]. See Meerman et al., for more information [3].
4) According to the Zero Emission Platform, transport to and storage in depleted gas or oil fields of CO_2 will cost between 2-15.7 €/t CO_2. When storing offshore, the CO_2 transport and storage costs increase to 5.5-20 €/t CO_2 for depleted gas or oil fields [16]. Based on expert interview, the CO_2 transport and storage costs were set at 10 €/t CO_2 [17].
5) The reference electricity price is based on the average Dutch day-hourly market price between 2004-2008. The observed trends were considered representative for NW-Europe. During that period the electricity price varied between 0-1050 €/MWh (0-290 €/GJ), with an average price of 57 €/MWh (15.7 €/GJ) [18].
6) In this study CO_2 avoidance costs are calculated. Therefore, no CO_2 credit price was used.

3. Results

3.1. Configurations

Based on commercial technologies and expected technological development, the following configurations for the IGCC and IG-FT facilities were made (see Table 2).

Table 2 Processes used for the different time periods.

		Current	Short term	Mid term	Long term - GT	Long term - SOFC
Feeding		Lock hopper	Lock hopper	Solid feed pump	Solid feed pump	Solid feed pump
Oxygen production		Cryogenic ASU	Cryogenic ASU +	ITM	ITM	ITM
Quench	IGCC-Vent	Syngas	Syngas	Syngas	Syngas	Water
	IGCC-CCS IG-FT	Water	Water	Water	Water	Water
WGS AGR SRT	IGCC-Vent	Selexol Claus	Selexol + Claus	TDS & DSRP	TDS & DSRP	TDS & DSRP
	IGCC-CCS	WGS Selexol Claus	WGS Selexol + Claus	SEWGS TDS & DSRP	SEWGS TDS & DSRP	TDS & DSRP
	IG-FT	WGS Rectisol Claus	WGS Rectisol + Claus	Adv. WGS Rectisol ++ Claus	Adv. WGS Rectisol ++ Claus	N.A.
CO_2 compression		Conventional	Conventional	Shock wave	Shock wave	Shock wave
(Syn)gas combustion		GT	GT +	GT ++	GT +++	SOFC & GT +++
HRSG gasifier		IP steam	IP steam	IP steam	HP steam	HP steam
FT-liquids synthesis		Cobalt-based catalyst	Cobalt-based catalyst	Cobalt-based catalyst	Diesel selective catalyst	N.A.

ASU: air separating unit; ITM: ion transfer membrane; TDS: transport desulphurisation; DSRP: direct sulphur recovery plant; WGS: water-gas shift; SEWGS: sorption enhanced water-gas shift; GT: gas turbine; SOFC: solid oxide fuel cell; HRSG: heat recovery steam generation; IP: intermediate pressure; HP: high pressure; N.A: not applicable.

The current configurations consist of cryogenic ASU, lock-hopper feeding system, dry-fed Shell EF gasifier, candle filter, wet scrubber, WGS reactor (for CO_2 capture or FT-liquids production), solvent based AGR (Selexol for IGCC or Rectisol for IG-FT), Claus/SCOT, FT-reactor with conventional FT-catalysts (only for IG-FT) and SOTA gas and three pressure steam turbines. If CO_2 is captured, the integrated gasification facilities also contain a conventional CO_2 compressor.

In the short term, only gradual improvements to already existing technologies are expected. The improved technologies are cryogenic ASU, solvent-based AGR and the gas turbine.

In the mid term several new technologies can be introduced which require alterations in the overall process configurations compared to SOTA. Common to both facilities is the replacement of the cryogenic ASU with an ion transfer membrane ASU. The lock-hopper is replaced by a solid feed pump and the gas turbine is upgraded to a high efficiency design. If CO_2 is compressed, the CO_2 compressor is replaced by a RamGen compressor. IGCC facilities can be equipped with hot gas cleaning and transport desulphurisation. The sulphur compounds are converted into elemental sulphur using the direct sulphur removal process, thereby eliminating the need for the Claus and SCOT installations. In the case of IGCC-CCS, the syngas is shifted using SEWGS after the sulphur compounds are removed. SEWGS also removes CO_2 from the syngas. A problem is that the H_2:CO ratio cannot be manipulated while still obtaining a low CO_2 concentration in the syngas. As the FT-reactor requires a certain H_2:CO ratio as well as a low CO_2 concentration, SEWGS cannot be used. Therefore, the IG-FT facilities will still rely on a separate WGS and CO_2 removal units. The WGS is upgraded to reduce the steam consumption and the Rectisol AGR is improved, resulting in reduced energy consumption.

In the long term, the operation conditions of the steam cycle could change from subcritical to supercritical. Also, the syngas cooler is expected to be upgraded to produce high pressure steam instead of intermediate pressure steam. The Rectisol based AGR in the IG-FT facilities is improved even further. The catalyst in the FT-reactors is replaced by a diesel selective catalyst with a different chain growth probability (α) depending on the length of the hydrocarbon. It is assumed that this has no effect on the reactor size and costs. The gas turbine is improved even further.

3.2. Integrated gasification facility performance

Currently, both the IGCC and IG-FT facilities have production costs above the market price of the main product (see Figure 2). Advancement in technologies, however, can make them profitable. In the long term, the efficiency of a coal-fired IGCC without CCS could increase from 44% to 52%, while production costs drop from 17 €/GJ (60 €/MWh) to 11 €/GJ (40 €/MWh). The increase in efficiency is mainly due to a higher output of the gas turbine. Production costs are affected by an increase in efficiency (-2.4 €/GJ) and availability (-1.7 €/GJ) and reduction in capital and O&M costs (-1.4 €/GJ). If SOFCs are used, the efficiency could increases to 59%, but the high capital and O&M costs of the SOFC increase production costs to 13 €/GJ (45 €/MWh). Applying CCS in the long term could result in an efficiency of 43% and production costs of 16 €/GJ. Compared to SOTA facilities, the energy consumption of the CO_2-capture equipment decreases, but energy demand of the CO_2 compressor increases as the CO_2 exiting the SEWGS is at a low pressure. Despite the higher energy penalty, this system was selected as the capital costs of a facility using SEWGS is much lower than if a solvent-based CO_2 capture system is used, resulting in lowest production costs for the SEWGS system. An IGCC equipped with CCS could have lower production costs if SOFCs become available. Although capital costs increase by 13%, overall energetic efficiency increase by 13%$_{pt}$, resulting in production costs of 14 €/GJ.

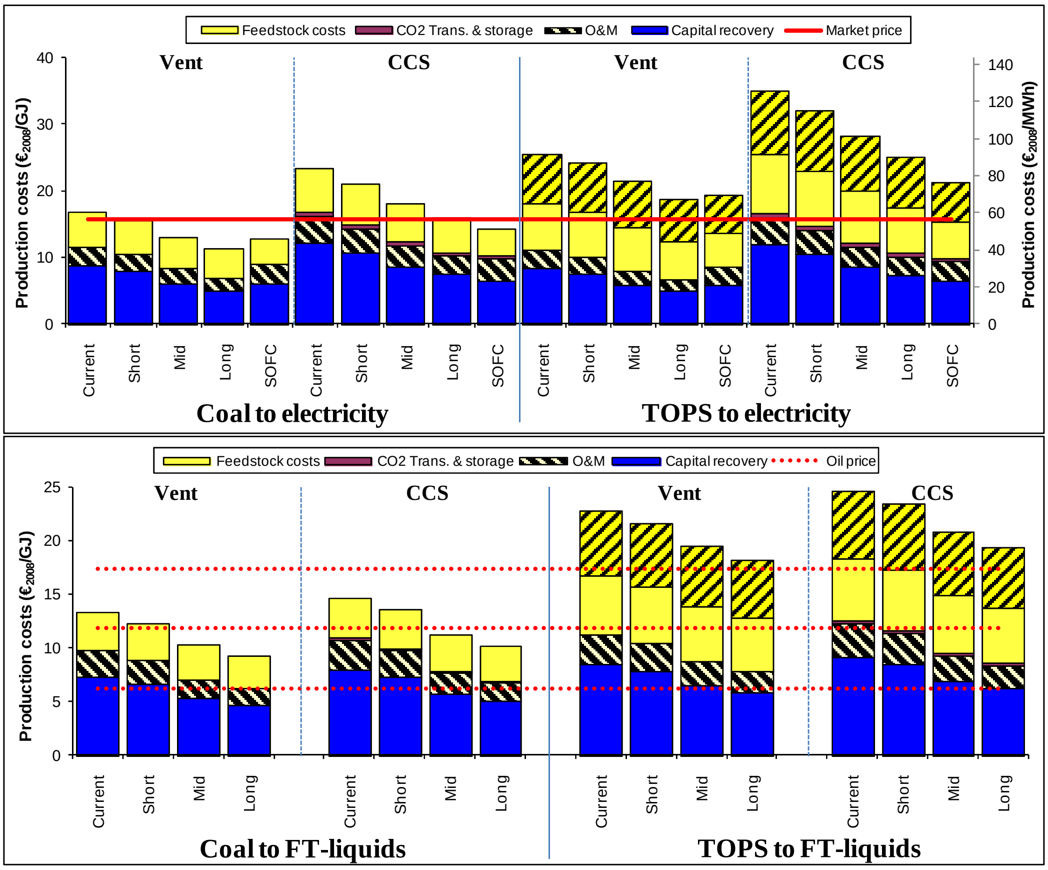

Figure 2 Production costs of electricity (above) and FT-liquids (below). The lighter upper part of the feedstock bar is the addition in production costs when using the high value for the TOPS price.

FT-liquids can currently be produced from coal for 13 €/GJ, which is competitive with crude oil derived fuels at an oil price of 113 \$/bbl. In the long term, overall energetic efficiency could increase from 61% to 65%. The higher efficiency, lower capital costs and increased availability could reduce produce costs to 9 €/GJ. Applying CCS at a SOTA coal-fired IG-FT would results in an efficiency of 58% and production costs of 15 €/GJ. In the long term, the efficiency could increase to 63% and production costs could drop to 10 €/GJ.

3.3. CO_2 emissions

The CO_2 emissions of the SOTA coal-fired IG facilities are around 2,000 kt CO_2/yr, which could increase to 2,400 kt CO_2/yr due to a higher availability. For electricity this means specific emissions of 0.7 kg CO_2/kWh. As overall energetic efficiency is expected to increases over time, this value could drop to 0.5 kg CO_2/kWh in the long term. For FT-liquids, the specific emissions are around 0.2 t $CO_2/GJ_{FT\text{-}liquids}$, both now and in the long term. If CCS is applied, specific emission of the IGCC facility are currently 0.03 kg CO_2/kWh and could drop to 0.01 kg CO_2/kWh in the long term. The production of FT-liquids while applying CCS shows a different picture. As a significant fraction of the carbon is embedded in the end product, specific emissions are 0.1 t CO_2/GJ, both now and in the long term.

In order to produce carbon-neutral electricity or transportation fuels, the use of biomass is mandatory. If only TOPS is used and CCS is not applied, specific CO_2 emissions are zero, regardless of production. If, however, TOPS and CCS are combined, specific emissions of electricity production are -0.9 kg CO_2/kWh for SOTA installations and could change to -0.6 kg CO_2/kWh in the long term. The increase in specific emissions is due to the higher efficiency, meaning that for the same amount of electricity, less biomass is needed and less CO_2 can be stored. The specific emissions of TOPS-based FT-liquids while applying CCS are around -0.1 t CO_2/GJ.

3.4. Effect of a CO_2 price

The effect of a CO_2 price on the production costs of SOTA IGCC and IG-FT facilities is given in Figure 3. The impact of the biomass price on the production costs is clearly visible. The main difference between the IGCC and IG-FT facilities is the penalty of applying CCS. For the IGCC facilities, CCS becomes attractive only at higher biomass (>6 €/GJ) and/or CO_2 prices (>25 €/t CO_2). For IG-FT facilities CCS is already attractive at low CO_2 prices (>10 €/t CO_2), even if biomass prices are low (>3 €/GJ). The results also indicate that at moderate CO_2 prices (>30-40 €/t CO_2, depending on the biomass price) the combination biomass and TOPS results in the lowest production costs.

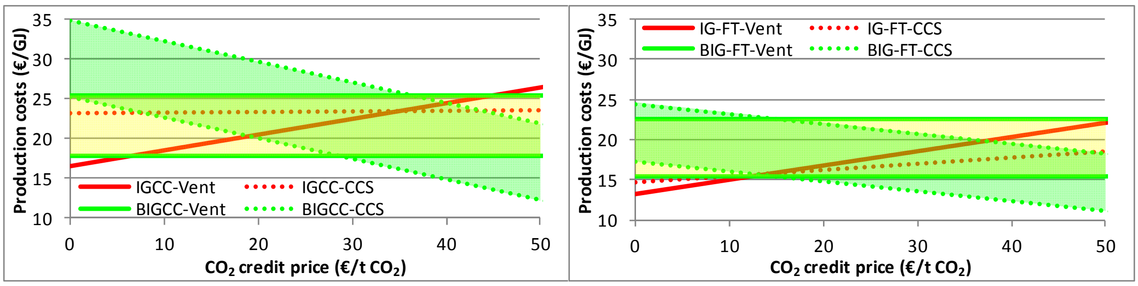

Figure 3 Effect CO_2 credit price on production costs of SOTA integrated gasification facilities. The shaded area is the range due to low and high TOPS prices.

4. Conclusion

Advanced technologies may reduce production costs of a coal-fired IGCC without CO_2 capture from 17 €/GJ to 11 €/GJ. When CO_2 is captured, it is found that production costs are lowered from 23 €/GJ to 14 €/GJ using SOFC. This would result in IGCC becoming profitable in the short term if CCS is not applied and in the long term if CCS is applied. When TOPS are used as feedstock, production costs are currently calculated at 25 €/GJ without CCS and 35 €/GJ with CCS, dropping to respectively 19 €/GJ and 21 €/GJ in the long term. New technologies alone do not lower production costs of TOPS-fired IGCC under the current average electricity market value of 16 €/GJ. If, as several studies indicate, TOPS prices drop to 3 €/GJ, production costs would decrease to 12 €/GJ without CCS and 15 €/GJ with CCS in the long term. In this case, production costs would drop under the current market price.

New technologies in IG-FT facilities are found to have a slightly smaller impact on the production costs. When using coal, production costs decrease from 13 €/GJ to 9.1 €/GJ if CO_2 is vented and from 15 €/GJ to 10 €/GJ if CO_2 is captured and stored. The use of TOPS would result in 23 €/GJ and 18 €/GJ without CCS and 24 €/GJ and 19 €/GJ with CCS for respectively now and in the long term. Here, lower biomass feedstock costs of 3 €/GJ results in production costs of 11 €/GJ without CCS and 12 €/GJ with CCS.

Specific CO_2 emissions can be reduced by capturing CO_2 or by substituting coal by TOPS. If both options are applied, net negative emissions can be obtained. This option becomes attractive both for IGCC and IG-FT facilities at moderate CO_2 prices (>30-40 €/t CO_2).

It is concluded that gasification can be an attractive technology to produce carbon neutral electricity and/or transportation fuels. Although production costs are currently above market prices, future improvements can lower the production costs and make gasification facilities profitable. Furthermore, both biomass and CCS can be used to reduce CO_2 emissions at relative low CO_2 avoidance costs.

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