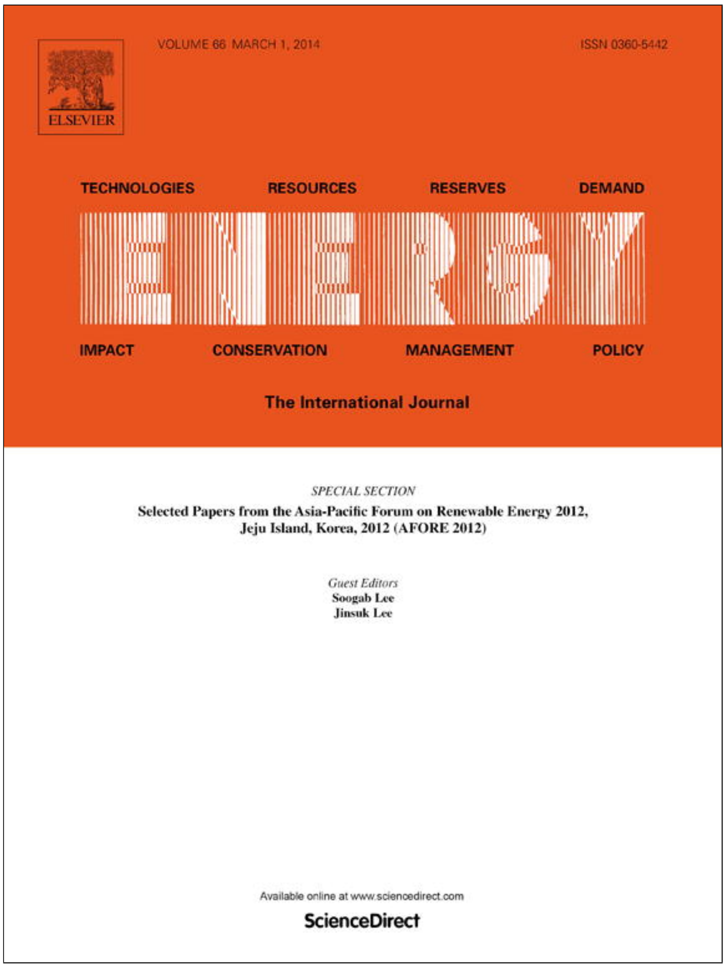


VOLUME 66 MARCH 1, 2014
ISSN 0360-5442

ELSEVIER

TECHNOLOGIES RESOURCES RESERVES DEMAND

ENERGY

IMPACT CONSERVATION MANAGEMENT POLICY

The International Journal

SPECIAL SECTION

Selected Papers from the Asia-Pacific Forum on Renewable Energy 2012,
Jeju Island, Korea, 2012 (AFORE 2012)

Guest Editors
Soogab Lee
Jinsuk Lee

Available online at www.sciencedirect.com

ScienceDirect

Energy 66 (2014) 667–676

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Investment and production costs of synthetic fuels – A literature survey

Geert Haarlemmer [a,*], Guillaume Boissonnet [a], Emanuela Peduzzi [a,b], Pierre-Alexandre Setier [a]

[a] *Commissariat à l'énergie atomique et aux énergies alternative, CEA, LITEN, Biomass and Thermal Networks Service, Biomass Technologies Laboratory, 38054 Grenoble (Cedex 9), France*
[b] *Ecole Polytechnique Fédérale de Lausanne, Laboratoire d'énergétique industrielle, Station postale 9, 1015 Lausanne, Switzerland*

ARTICLE INFO

Article history:
Received 23 June 2013
Received in revised form
13 January 2014
Accepted 24 January 2014
Available online 22 February 2014

Keywords:
Biofuels
BtL
CtL
GtL
Gasification
Fischer–Tropsch

ABSTRACT

Synthetic fuels, or synfuels, can be produced from gas, coal and biomass. The conversion of gas and coal is well established but lignocellulosic biomass conversion is slow to develop. This paper addresses the issue of the production cost of second generation biofuels via the thermo-chemical route, biomass to liquids (BtL). Techno-economic studies help identify promising conversion processes, but also introduce a false confidence in the technology that may lead to ill fated decisions. A large number of techno-economic studies have been published since the year 2000 showing a large variability in the results. This paper analyses the published data and presents causes of the observed variability, including a comparison with coal and gas to liquids.

Large uncertainties remain however with regard to the precision of the economic predictions. It will be shown that the spread in the economic source data accounts for much of the spread in the predictions. These uncertainties affect both CtL and BtL cost predictions. It will be shown however that the results are relatively coherent and that most of the differences between the costs of synthetic fuels can be traced back to economies of scale considering mature technology.

1. Introduction

Synthetic fuel plants, and in particular Biomass to Liquids (BtL) plants, have been described in a large number of publications together with estimations for investment and fuel production costs. As no commercial BtL plants exist, all studies presenting production economics should be considered prospective. The BtL plants that are currently being designed are mostly demonstration projects to test and validate the technology chain. BtL plants are largely inspired by Coal to Liquids (CtL) and to a lesser extent Gas to Liquids (GtL) plants, in operation for many years now but regaining interest due to the rising oil prices.

When looking at the gasification section for BtL plants, the published literature is equally distributed between fluidised bed and entrained flow gasifiers. CtL and GtL plants are usually proposed for very high capacities and CtL plants use often, but not always, entrained flow gasifiers. The process schemes of the BtL and CtL plants are described in Refs. [1] and [2] amongst others. Techno-economic studies require accurate source data. In absence of a reliable industrial data, it is interesting to perform a benchmark study to allow researchers to maybe validate but at least to compare studies.

Haarlemmer et al. [1] evaluated a large number of publications presenting BtL plants with investment levels and production costs. Given the large period in which the data was published, and the wide variety of capacities, a normalisation of the data was applied to obtain an objective comparison of the data. The data was normalised to €2011 and a reference capacity, 400 MWth. It became obvious that no reliable conclusions can be drawn when evaluating one single study. The objective of this paper is to better understand the reasons for the spread in the data by studying the source data. A comparison with fossil synfuel plants is made to validate the overall cost level and to gain an insight in the effect of the economies of scale. Investors and policy makers will not be able to engage large

---

* Corresponding author.
E-mail address: Geert.Haarlemmer@cea.fr (G. Haarlemmer).

http://dx.doi.org/10.1016/j.energy.2014.01.093

Acronyms

ATR	Auto Thermal Reformer
BEOP	Break-Even Oil Price
C^{unit}	Capacity unit
C^{Ref}	Reference capacity
CAPEX	CAPital EXpenditure
CtL	Coal to Liquids
GtL	Gas to Liquids
FT	Fischer–Tropsch
HDT	Hydrotreatment/hydrocracking (upgrader)
IRR	Internal Rate of Return
ISBL	InSide Battery Limits
LNG	Liquefied Natural Gas
NPV	Net Present Value
POX	Partial OXidation
P^{unit}	Price process unit
P^{unit}_{Ref}	Reference price process unit
R^2	Coefficient of determination
SMR	Steam Methane Reformer
Synfuel	Synthetic fuel

Units

MMSCFD	Million Standard Cubic Feet per Day
BtL	Biomass to Liquids
MWth	Megawatt thermal power
t/h	ton per hour

capital investments before the financial risks are better understood. Investors and policy makers can build on this paper to perform more accurate risk assessments.

2. BtL, CtL and GtL processes

The process chain of synthetic fuel plants has been published widely. As written earlier, BtL plants are generally presented as modified CtL and GtL plants. Biomass and coal are both solid fuels. Unfortunately some subtle differences between coal and biomass make that this modification is harder than it seemed a decade or so ago. The main differences between coal and biomass are energy density, ash content and quality and different trace elements. Ash fusion temperatures may cause operating difficulties in fluidised gasifiers (bed agglomeration) but also modify the flow behaviour of molten slag in high temperature entrained flow reactors. The prediction of ash melting behaviour and slag properties remains difficult [3]. Downstream of the gasifier and after the initial purification steps, the differences between GtL, CtL and GtL plants are small. The promises of a rapid deployment of BtL technology have not been fulfilled [4]. At the same time, world scale GtL and CtL plants are now operating and more plants are seriously considered.

BtL plants are generally proposed in the 50–200 t/h range, this is often a compromise between harvesting and transport on one hand and economies of scale on the other. Coal has a high energy density and is mined in large quantities and transported all over the world. CtL plants are therefore typically proposed as 500–2000 t/h capacities (30,000–100,000 barrels per day), even though some explorations have been performed for small scale units [5]. GtL plants are currently operating at 10,000–150,000 barrels per day. Wood resources are organised differently from coal resources, even though the paper industry mobilises large amounts of wood, there is no large public trading of biomass. GtL plants are often proposed where gas cannot be sold (stranded natural gas). The gas is sometimes co-produced with the oil and must be flared, liquefied (LNG) or transformed to synfuels. For this reason the value of the gas consumed in GtL plants is much lower than the trade price in densely populated regions.

Synfuel plants consist of gasification, purification and the fuel synthesis units, the general scheme has been described in many scientific papers [6,7], patents [8,9] and technical reports [10,11]. Biomass should be dried when it is too humid (humidity higher than 10–20%), typically the case for biomass. Evaporating water in the gasifier reduces the efficiency of the gasifier. Coal can be used dry (example Shell Coal Gasification Process) or in a slurry (example General Electric Gasifier) [12]. The efficiency of the gasification decreases with increasing humidity of the feed [13]. The heating value of coal is sufficiently high to allow some losses due to the humidity of the feed.

The feed preparation further consists of grinding (coal and biomass) and a thermal treatment (such as torrefaction or pyrolysis for biomass) when necessary. Coal can be milled to a fine powder at reasonable cost without any further treatment. In the case of biomass gasification, the choice of the gasifier may impose some constraints on the pre-treatment. Entrained flow reactors require finely ground biomass that is not obvious to obtain with raw material. In this case a pre-treatment such as torrefaction or pyrolysis is required. Fluidised bed reactors accept dried woodchips. The coal or biomass gasification section consists of a fluidised bed or an entrained flow gasifier. Other gasification technologies (fixed bed, rotating drums or others) are not usually proposed for large scale plants. Natural gas is typically transformed in a steam methane reformer (SMR), autothermal reformer (ATR) or a partial oxidation reactor (POX) [14].

Gasifiers have been described in many papers and textbooks. For this paper we retain that circulating fluidised bed gasifiers operate at low pressures and temperatures around 850 °C (model used FICFB [15]). The gasification is performed with steam; the heat required is supplied by the combustor where part of the char is burned with air. Heat is transferred from the combustor to the gasifier by a circulating fluidisation material (olivine, sand or others). The produced gas is rich in hydrogen, methane and tars. Bubbling fluidised bed reactors gasify with a steam and air or oxygen mixture in a single reaction chamber, the fluidisation of the bed material and the biomass is done with the gasification agent. Entrained flow reactors operate at high pressures and high temperatures [13]. Ash is melted and is recovered as liquid slag. Methane and tars are reformed and the gas is rich in carbon monoxide.

The syngas must be purified and converted into a gas suitable for use in the Fischer–Tropsch unit. The purification of the syngas removes pollutants as sulphur and nitrogen containing compounds, carbon dioxide and many other trace pollutants. Many other fuels can be synthesised but this paper analyses only Fischer–Tropsch plants producing a diesel substitute. The ratio between carbon monoxide and hydrogen should be adjusted to around 1:2. The Fischer–Tropsch unit produces wax that is upgraded to diesel fuel and naphtha in the upgrader.

3. Economic data

Very few reliable industrial and commercial data is freely available. BtL plants do not exist in significant capacities and in any case this type of data is rarely available in sufficient detail. Most authors perform simulations and calculate the cost of the plants by adapting earlier published data to their projected plant. When cost estimation software is used, the same approach is used but at a lower level. Care should then be taken to include the full plant or unit in the simulations. The data in this paper is, most of the time, directly taken from the cited studies. All of these studies consider mature technology. None of the data was explicitly based on pilot plant data.

3.1. Updating economic data

The cost of process equipment, units or plants, can be estimated from sizing and reference data by Eq. (1). Estimations of the investment costs P^{unit} as a function of the capacity C^{unit} of the units are estimated with a relationship comparing the unit with a reference unit. The reference unit has an investment cost $P^{\text{unit}}_{\text{Ref}}$ for a reference capacity of C^{Ref}:

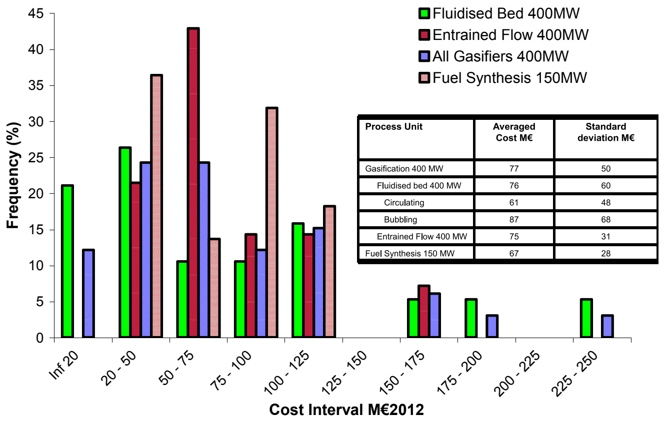
$$P^{\text{unit}} = P^{\text{unit}}_{\text{Ref}} * \left(\frac{C^{\text{unit}}}{C^{\text{Ref}}}\right)^{\text{Factor}} \tag{1}$$

Eq. (1) represents the increase in capital cost of a unit or a plant by increasing its capacity at constant technology. For a mature technology (*n*th process plant) this equation is assumed to describe the evolution of the cost of a plant with changing capacities [16]. The cost generally increases less than the capacity (factor <1) leading to an economy of scale. In practice for new technologies, learning curves and economies of scale are initially inseparable. The pioneering plants are generally smaller than mature designs, and the economies that are made between pioneering plants and mature world scale production facilities include both learning and scale effects [17]. Most published data considered for this paper are based on mature technology, learning effects are therefore not considered. The sum of the estimated unit investments leads to the ISBL (Inside Battery Limits) investment cost. It is generally accepted that cost estimations based on equivalent constructed units (Capacity factored methods or Class 5 estimations as defined by the American Association of Cost Engineers, AACE) have an uncertainty up to ±50% (or even 100%) [16], while detailed cost estimations based on equipment data (Class 3 or 4 estimations) improve the estimations; up to ±30% (the uncertainty remains high). More precise estimations are only possible at an advanced stage of the design and construction process after safety studies [18]. For each of the process units, the most relevant available data is used from the literature. The extrapolation factor 0.7 is a typical value for extrapolations of this kind for overall process plants, used in this study. Each unit or equipment has however its own factor depending on the scalability of the unit or the equipment.

Fuel production costs are updated taking into account the evolution of the investment [19], the coal price evolution [20] and inflation. Figs. 1 and 2 present the results of this work updated to 2012 with the CERA index [19]. It is obvious that no straightforward conclusion can be drawn when evaluating one single study. Production cost data is more difficult to compare than investment data due to the sensibility to the business model and its parameters [21]. These results are however the data that receives the most attention from the public. By comparing a large amount of results it is possible to foresee costs and their uncertainty. Investors and policy makers will not be able to engage large capital investments before the financial risks are better understood.

3.2. Source data for process units

Some of the spread in the data is due to differences in source data. This section presents some of the source data presented and used in the studies. Reliable cost data is highly priced information and is difficult to obtain. Few authors dispose of reliable data for the complete plant and use published data to complete the data set. The reliability is difficult to assess objectively. Several authors present costs of different process units that can easily be used, once updated to the desired year and scale. Some units are well known such as the air separation unit, others such as the gasifiers present large uncertainties. The following tables give the costs for some main process units.



Process Unit	Averaged Cost M€	Standard deviation M€
Gasification 400 MW	77	50
Fluidised bed 400 MW	76	60
Circulating	61	48
Bubbling	87	68
Entrained Flow 400 MW	75	31
Fuel Synthesis 150 MW	67	28

Fig. 1. Distribution of investment for different gasifiers and FT fuel synthesis.

Table 1 presents the gasifier investment costs found in a large number of publications. The original data is presented together with the updated data to €2012 and a capacity of 400 MWth. It is likely that (especially circulating) fluidised bed gasifiers cannot be built with a 400 MWth capacity and in practice multiple smaller trains will be used. The sole purpose of the extrapolation is to be able to compare the technologies and the data. The extrapolation factor will be close to 1 in the case where a large number of reactors will be required, increasing therefore the costs of a 400 MWth capacity. Whenever the extrapolation factor was not specified, the classic value of 0.7 was used. Whenever the number of gasifiers was announced in the studies, the unitary capacity and cost were used. The maximum capacity of entrained flow reactors seems to be 1 GWth, the maximum capacity of fluidised bed reactors is not clear and not always treated in different studies.

The data for the FT units in Table 2 presents a large spread. There are many different Fischer–Tropsch technologies, mostly based on fixed bed or slurry reactors. It is unclear how these

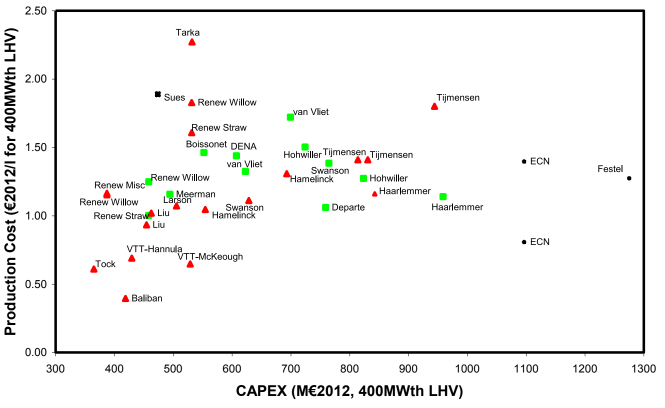


Fig. 2. Normalised investment and levelised production costs for BtL plants with 🟩 entrained flow reactors ▲ fluidised bed reactors ■ unknown technology.

Table 1
Literature overview gasifiers with economic data.

Author	Ref.	Gasifiers	Cost	Reported capacity(MWth)	Scale factor	Year data	Cost €2012 (400 MWth)
Chrisgas	[22]	BFB[a] Biomass	8.7 M€	207		2009	16
Kreutz	[23]	EF[b] Coal	199 M$	815	0.67	2007	115
Kreutz	[23]	BFB[a] IGT[c] Biomass	87 M$	815	0.67	2007	50
Larson	[24]	BFB[a] Biomass	113 M$	893		2003	91
Liu	[25]	CFB[d] Biomass	336 M$	828		2007	227
Liu	[25]	EF[b] Coal	184 M$	917		2007	95
Lu	[26]	CFB[d] Biomass	118 M$	79		2008	152
Lu	[26]	CFB[d] Biomass	1176 M$	283		2008	108
Martelli	[27]	SCG[e] Quench Coal	140 M$	771	0.67	2008	73
Martelli	[27]	SCG[e] SG[f] Coal	178 M$	737	0.67	2008	96
NETL Power	[12]	SCG[e] SG[f] Coal	140 M$	757		2007	84
NETL CtL	[28]	EF[b] Coal	102 M$	999		2006	55
NETL CtL	[5]	EF[b] Coal	66 M$	640		2006	49
NETL CtL	[5]	EF[b] Coal	102 M$	670		2006	73
Ng	[29]	EF[b] Biomass	26 M€	380	0.7	1999	55
RENEW	[30]	EF[b] Biomass	26 M€	250	0.7	2006	48
RENEW	[30]	CFB[d] Biomass	7 M€	100	0.7	2006	24
RENEW	[30]	FICFB[g] Biomass	5 M€	17	0.7	2006	63
Sarkar	[31]	CFB[d] SilvaGas	49 M$	417		2008	38
Sarkar	[31]	BFB[a] RenuGas	104 M$[l]	417		2008	82
Swanson	[32]	EF[b] Biomass	68 M$	389		2007	64
Swanson	[32]	BFB[a] Biomass	28 M$	389		2007	27
Tijmensen	[33]	CFB[d] BCL[h] Biomass	13 M$	400[j]	0.7	2000	19
Tijmensen	[33]	BFB[a] TPS[i] Biomass	3 M$	70	0.7	2000	16
Tijmensen	[33]	BFB[a] IGT[c] Biomass	30 M$	400	0.7	2000	45
Tock	[34]	FICFB[g] Biomass	6.7 M€	20		2007	65
Tremel	[35]	General biomass	140 M$	500	0.65	2012	91
Van Vliet	[36]	BFB[a] IGT[c] Biomass	38 M€	400	0.7	2007	47
Van Vliet	[36]	SCG[e] SG[f] Coal	75 M€	400	0.7	2007	100
Van Vliet	[36]	SCG[e] SG[f] Biomass	120 M€	400	0.7	2007	160
VTT-Hannula	[11]	BFB[a] UCGP[k]	151 M€	370	0.75	2010	176
Williams	[37]	EF[b] Coal	49 M$	600	0.67	2003	52
Williams	[37]	BFB[a] Biomass	32 M$	111	0.7	2003	111

[a] BFB: Bubbling Fluidised Bed.
[b] EF: Entrained Flow.
[c] IGT: Institute for Gas Technology.
[d] CFB: Circulating Fluidised Bed.
[e] SCG: Shell Coal Gasification.
[f] SG: Steam Generation.
[g] FICFB: Fast Internal Circulating Fluidised Bed.
[h] BCL: Battelle Columbus Laboratory.
[i] TPS: Thermal Processes Sweden.
[j] Above reported maximum capacity.
[k] UCGP: Ultra Clean Gas Process.
[l] Original data included oxygen plant estimated at 60 M$ and deducted in the table.

different technologies are reflected in the unit costs. Downstream of the Fischer–Tropsch unit an upgrading unit converts the wax to diesel fuel and naphtha. When both units are presented separately in the relevant publication, the sum of both units is reported in Table 4. Sometimes only the fuel synthesis unit is presented, in this case it is supposed that the Fisher–Tropsch unit is followed by an upgrader.

The results in Tables 1 and 2 are presented in Fig. 1. A typical 400 MW gasification facility is equipped with a 150 MW fuel synthesis unit (corresponds to a 15% mass yield and 38% energy for a 400 MWth BtL plant, a commonly found fuel yield). The investment costs of these units are equivalent with a similar uncertainty. RENEW [30] did not use a multiplier to pass from ISBL to the overall investment, with only minor utility units included in the unit list. This probably means that the reported ISBL costs include provisions for infrastructure, utilities and engineering. The updated cost was reduced by 33% to be able to include utilities and infrastructures in the final plant (estimated at 50% of ISBL costs). The published costs of fluidised bed gasifiers are similar to entrained flow gasifiers; the difference is in the variation. This may partly be due to the variety in the technology, but the spread cannot be explained solely by the difference between bubbling and circulating fluidized beds. Both gasification and FT data show that cost data in the earlier years of this review are relatively low. More recently the spread in the data increases, with more and more high values.

Fig. 1 presents the frequency with which the different cost levels occur for the normalised data. The number of data points is too low to draw firm conclusions but the graph does give an insight in the underlying trend. On average fluidised bed gasifiers are on the same price level as entrained flow reactors. This observation is confirmed by Tremel et al. [35], stating that the prices are expected to be similar. The spread in the data is large however. In practice fluidised bed will probably be proposed in multiple smaller units, increasing the price per MWth. The Fischer–Tropsch fuel synthesis units display much lower spread for the given capacity.

The presented process units, gasifiers and fuel synthesis, are selected between the most costly in the process chain. Similar spreads can be expected for torrefaction units, very few economic data is available however. Air separation and gas purification are classic process units and the costs are fairly well known.

Table 2
Literature overview FT fuel synthesis and upgrading.

Author	Ref.	Reported cost	Reported capacity (bbl/d)	Reported capacity (MWth fuel)	Scale factor	Year data	Cost €2012 (150 MW unit)
Choi	[38]	54 M$	8820	547		1996	40
Haarlemmer	[1]	125 M€	3178	197	0.7	2011	104
Liu	[25]	158 M$	4521	286		2007	93
Liu	[25]	968 M$	50,000	3159		2007	106
Lu	[26]	11 M$	679	42		2008	22
Lu	[26]	91 M$	7143	442		2008	35
Meerman	[39]	38 M€	2113	131	0.72 (FT) 0.7 HDT	2008	46
NETL	[28]	418 M$	50,000	3100		2006	80
NETL	[5]	69 M$	8320	516		2006	30
NETL	[5]	78 M$	9609	596		2006	30
Ng	[29]	14 M€	1613	100		1999	44
RENEW Slurry	[30]	183 M€	5253	290	0.72 (FT) 0.7 HDT	2006	75
RENEW Fixed Bed	[30]	186 M€	3731	206	1 (FT) 0.7 HDT	2006	94
Sues	[40]	99 M$	3113	131	0.7	1997	86
Swanson	[32]	49 M$	3496	193		2007	38
Swanson	[32]	59 M$	2717	150		2007	54
Tijmensen	[33]	17 M$	1811	100	1	2000	37
Tock	[34]	71 M€	3877	240		2007	63
VTT-Hannula	[11]	77 M€	2532	157	0.7	2010	82
Williams	[37]	198 M$	16,700	1035		2003	109

3.3. *Overall plant cost*

Some of the differences between studies and probably also in the use of the data is in the conversion from unit costs to the cost of a plant. Typically the different ISBL costs are estimated. With various scaling factors, the cost of engineering, infrastructures and utilities are estimated. To be able to start the plant, initial charges and a working capital is required. The methods to estimate these factors vary greatly producing a wide spread in the final investment levels. Table 3 presents for a number of studies the ISBL and final costs.

The average factor is 1.56 with a standard deviation of 0.3. It is clear that the actual value to use must depend on the local situation. Bauman [41] presents a table of the contributions of process equipment and other items in the overall cost structure of a plant at a variety of locations. The contribution of the process equipment varies from 20 to 28%. The computation of the ISBL cost from the main equipment typically depends on the equipment, the factor varies from 2.4 to 4 times the cost of the equipment [47]. A factor 3, or less, is valid for most common equipment. When using this factor, for every 100 dollars spent on a plant, 20–28 dollars is spent on main equipment, leading to an overall ISBL unit cost of 60–84 dollars per 100 dollars spent on a plant. The resulting multiplication factor is 1.2–1.7, largely depending on the plant type, the location and the year and duration of the construction. The factors show no dependency on their publication year.

3.4. *Costs of resources*

Biomass is not traded on a global basis and the actual cost of biomass is difficult to assess. The cost of coal is however well documented. Both biomass and coal costs depend on the quality, origin and transport of the resources. The published literature data is presented in Tables 4 (biomass) and 5 (coal). Biomass data is updated with an average yearly inflation of 3%.

Coal prices are often presented in $ per ton. Heating value and ash content is obviously quite variable. The evolution of the coal prices to 2012 was performed with the averaged evolution found in the BP Statistical Review [20]. Coal is traded in US$ and most CtL studies are done in this currency. To stay as close as possible to the original data this currency is presented in Table 5.

The BP Statistical Review [20] presents the cost of coal in Japan, Europe and the United States. The average value for these locations is currently 115 $ per ton, or around 86 €/ton. With an averaged lower heating value of 28 MJ/kg (anthracite and bituminous coal) this would amount to 3.1 €/GJ, just over half of the energy cost for biomass. This comparison also shows that the cost for coal considered in most studies is below its market value and especially much below the cost of biomass. This order of magnitude comparison shows that the likely energy costs for a biomass resource will roughly be double that of a coal resource.

4. Comparison and evaluation of literature data

Synfuel plants have been described in a large number of studies. These include BtL, CtL and GtL plants. The published results are for different technologies, capacities, years and currencies. This paper attempts to compare the different published data by updating the data to 2012 and by mapping the projected plants on a reference capacity. The data is updated by applying the averaged biomass and coal prices, normalisation of the plant size to the reference capacity

Table 3
Relation between plant and ISBL investment costs.

Author	Ref.	Plant type	ISBL cost (M€)	Total capital investment (M€)	Factor
Bauman	[41]	General			1.2–1.7
DENA	[42]	BtL	330	530	1.61
Heinrich	[43]	BtL	300	425	1.42
Lu	[26]	CtL	250.9	323	1.29
Lu	[26]	CtL	1026	1451	1.39
Mantripragada	[44]	CtL			1.75
Martelli	[27]	IGCC	1276	1539	1.21
Martelli	[27]	IGCC	1344	1590	1.18
NETL	[12]	IGCC	910	1948	1.53
NETL	[28]	CtL	2351	3650	1.55
NETL	[5]	CtL	384	598	1.56
NETL	[5]	CtL	519	797	1.54
Ng	[29]	BtL			2.45
Philips	[45]	BtL			1.39
Seltzer	[46]	IGCC	501	633	1.26
Swanson	[32]	BtL	309	606	1.96
Swanson	[32]	BtL	254	498	1.96
Tijmensen	[33]	BtL			1.53

Table 4
Biomass costs in different studies.

Author	Ref.	Year data	Type	Published cost (€/GJ LHV)	Updated cost (€ 2012/ GJ LHV)
Baliban	[48]	2011	Hardwood residues	4.0	4.1
Departe	[49]	2006	Not specified	5.5	6.6
ECN	[10]	2006	Not specified	4.0	4.8
Haarlemmer	[1]	2011	Wood chips	5.1	5.3
Hohwiller	[50]	2006	Not specified	5.6	6.6
Hamelinck	[51]	2000	Not specified	2.1	3.1
Liu	[25]	2007	Switchgrass	3.6	4.2
Meerman	[39]	2009	TOPS[a]	6.3	6.9
RENEW	[30]	2007	Willow	7.8	9.0
RENEW	[30]	2007	Straw	4.5	5.2
RENEW	[30]	2007	Miscanthus	7.0	8.1
Tarka	[52]	2009	Not specified	3.4	3.7
Tijmensen	[33]	2000	Poplar wood	2.1	3.1
Tock	[34]	2007	Not specified	9.2	10.6
Sues	[40]	2011	Forest residues	2.0	2.1
Swanson	[32]	2005	Corn stover	3.0	3.9
van Vliet	[36]	2005	Salix pellets	4.6	5.7
VTT-McKeough	[53]	2005	Forest residues	4.2	5.1
Averaged					5.4 €/GJ or 96 €/t[b]

[a] Torrefied biomass.
[b] Averaged value calculated with a lower heating value 18 MJ/kg.

and expressed in €2012. In the following section CAPEX is supposed to be the total plant cost. Production costs are supposed to be the cost of the fuel as produced; including variable operating costs and fixed charges (investment and taxes). The uncertainty due to the large spread in resource costs observed in Section 3.4 is therefore reduced. This allows an objective comparison of the data. Going much further in the normalisation will reduce the results to a local sensitivity study.

4.1. BtL data

The authors [1] previously evaluated a large number of publications presenting BtL plants with investment levels and production costs. Given the large period in which the data was published, and the wide variety of capacities an update of the data was performed to obtain an objective comparison of the data, the capacity is normalised to a reference capacity (400 MWth LHV) using formula (1) and the capital and levelised production costs are updated to €2012 with the CERA index [19].

As was shown by Haarlemmer et al. [1], the biomass studies are performed with different economic calculation methods, different time frames (from 10 to 30 years) and a large variety of technologies and process schemes. The economic results of most BtL studies are limited to simple cost calculations, the sum of the financial and the operating costs divided by the volume of the production. There appears to be a rising trend following a moderate decline with increasing investments. One could be tempted to interpret this as an increase in production costs due to the increase in the plant cost (CAPEX) followed by an increased efficiency by the more expensive plants leading to lower production costs. It is hazardous to interpret the data this way as all studies are completely independent.

The names along the points in Fig. 2 refer to publications listed in Table 6. A detailed analysis of the different data points with the procedure followed is presented in Haarlemmer et al. [1].

The data in Table 6 confirms the variation found in Fig. 2. The source data for capital plant cost calculations is ISBL and equipment costs as well as factors to account for engineering, infrastructure and start-up. Source data is rare and is often reused. An initial data set was published by Faaij and Meuleman in 1998 [61] containing estimates for biomass gasification for electricity generation. A significant section of this data was used by Tijmensen et al. [33] and Hamelick et al. [51] extended with process data from a variety of sources. This data set formed the basis of many studies with most studies using additional data sources. Many studies use cost estimation packages linked to simulation software. This approach is valid but as only a small fraction of the process equipment of a final plant is simulated, the estimation of a total plant cost from a small selection of main equipment remains delicate.

Most studies assume the estimate is valid for the *n*th plant, although this is mentioned explicitly only in some cases. The justification for this assumption is that all separate process units are validated and known technologies. This would be valid if a BtL plant is merely a modified CtL plant. In practice, torrefaction and biomass gasification are far from being a validated technology. Emerging technologies typically go different phases before the technology is mature. Typically the initial cost estimates are quite low, inciting a rapid development of the technology. Costs tend to rise during the conception and projected deployment of the technology, until the costs reach a maximum for the first demonstration or commercial plant. Costs will fall before stabilising around the *n*th plant. This observation is typically true for both capital investment as well as production costs, and is called the “mountain of death”, indicating that some new technologies may never emerge in absence of rich sponsors [61]. One would expect that this phenomenon can be observed for the data presented in Table 7. The updated levelised production costs and the plant costs are plotted as a function of the publication year in Fig. 3.

From Fig. 3 it can be observed that there is a trend towards lower CAPEX cost estimates as time goes on, estimates have dropped by 25%. The coefficient of determination ($R^2 = 0.46$) is low. This seems to be opposite to the phenomenon described earlier that suggests an increase in cost before the first commercial unit. The down going trend is not very clear but it suggests that estimates are more optimistic as time goes on without a real return of experience. Levelised fuel production costs follow a similar trend.

4.2. CtL data

The presented CtL studies in Fig. 4 are all performed with a technical lifetime of the plant of 30 years. All presented studies are based on a discounted net present value (NPV) method. Most CtL

Table 5
Coal costs in different studies.

Author	Ref.	Year data	Type	Published cost ($/ton)	Updated cost ($2012/ton)	Updated cost (€2012/ GJ LHV)
Alvarez	[54]	2010	Illinois	42	58	1.46
Liu	[25]	2007	Bit. Illinois	56	109	2.41
Lu	[26]	2008	Bit. Utah	42	43	1.04
Jaramillo	[55]	2007	Coal	42	87	Not spec.
Kreutz	[23]	2008	Coal	47	92	2.11
Mantripragada	[44]	2007	Illinois 6	60	111	2.77
Mantripragada	[56]	2010	Sub-bit. lignite	46	71	2.22
Mantripragada	[56]	2010	Lignite	46	71	2.87
Meerman	[39]	2008	Coal	61	62	Not spec.
RAND	[57]	2005	Coal	30	61	Not spec.
van Bibber	[5]	2006	Bit. Pittsburgh 8	55	112	2.68
van Bibber	[28]		Illinois 6	37	75	1.80
Zhou	[58]	2011	Coal	91	93	2.71
Averaged					75 $/ton or 57 €/ton	1.95 €/GJ

Table 6
Authors and references of the BtL data presented in Fig. 2.

Table	Ref.	Year data	Capacity (MWth)	Plant cost (M€)	Plant cost (M€ 2012)	Plant cost (400 MW M€ 2012)	Diesel (€/l	Diesel 400 MW (€2012/l)
Baliban	[48]	2011	247	296	299	419	0.39	0.40
Boissonnet	[59]	2010	400	502	552	552	1.30	1.46
DENA	[42]	2006	500	520	710	607	1.03	1.44
Departe	[49]	2006	500	650	888	759	1.30	1.06
ECN	[10]	2006	250	578	789	1096	0.68	0.81
ECN	[10]	2006	1800	2301	3142	1096	0.53	1.40
Festel	[60]	2007	750	1600	1980	1275	0.82	1.27
Haarlemmer	[1]	2011	400	949	959	959	1.15	1.14
Haarlemmer	[1]	2011	400	834	843	843	1.23	1.16
Hamelinck	[51]	2000	400	280	554	554	0.42	1.05
Hamelinck	[51]	2000	400	350	693	693	0.53	1.31
Hohwiller	[50]	2006	500	620	847	724	1.11	1.50
Hohwiller	[50]	2006	500	705	963	823	0.94	1.27
Liu	[25]	2007	660	521	645	455	0.57	0.93
Liu	[25]	2007	660	531	657	463	0.62	1.02
Meerman	[39]	2009	848	727	827	494	0.75	1.16
Renew Willow	[30]	2007	500	433	536	458	1.07	1.25
Renew Willow	[30]	2007	500	502	621	531	1.57	1.83
Renew Willow	[30]	2007	50	73	90	387	1.88	1.15
Renew Straw	[30]	2007	500	433	536	458	0.74	1.00
Renew Straw	[30]	2007	500	502	621	531	1.18	1.61
Renew Misc	[30]	2007	50	73	90	387	1.89	1.17
Tarka	[52]	2009	851	784	902	532	1.24	2.27
Sues	[40]	2011	285	370	374	474	1.20	1.89
Swanson	[32]	2007	389	498	616	628	0.98	1.11
Swanson	[32]	2007	389	606	750	765	0.79	1.39
Tijmensen	[33]	2000	367	424	839	891	0.58	1.41
Tijmensen	[33]	2000	367	415	822	873	0.58	1.41
Tijmensen	[33]	2000	367	482	954	1013	0.74	1.80
Tock	[34]	2007	400	295	365	365	0.60	0.61
van Vliet	[36]	2005	400	390	623	623	0.87	1.32
van Vliet	[36]	2005	2000	1351	2157	699	0.54	1.72
VTT-Hannula	[11]	2010	370	370	407	429	0.62	0.69
VTT-McKeough	[53]	2005	260	245	391	529	0.48	0.65

studies present the equivalent oil price, or break-even oil price (BEOP) at which the unit is competitive against crude oil with a certain internal rate of return (IRR), for the comparison the cases with an IRR of 20% are presented where possible (some of the cases presented for Lu [26] are with an IRR of 12%).

For comparison, the Brent oil price in February 2013 fluctuated from 110 to 118 $ (82–89 €) per barrel. The results from van Bibber are taken from two difference publications. The two points on the left are based on small scale units, one of which using a co-generation option. The global trend is increasing production costs with rising capital expenditure, which seems to be logical. The third central point of van Bibber concerns large scale units. The data is summarised in Table 7.

The fuel prices in Fig. 3 and Table 6 were updated to 2012 with a uniform coal price of 75 $/ton or 57 €/ton, the average in all studies. Many studies use a coal price much below the value in the BP statistical review [20].

4.3. GtL data

GtL plants have a different economic basis. Gas is available in a variety of locations, often co-produced with crude oil. This basically means that for GtL studies the gas feedstock is typically taken at very low values, 0.5 to 2 $ per MMSCFD. The BP Statistical Review [20] reports traded gas prices for Europe are 4 $ per MMSCFD in the year 2000 rising to 10 $ per MMSCFD in the year 2011. The cost of the natural gas feedstock is essentially the extraction and treatment costs. Little public data is available for GtL, and even less published production costs. The Shell Pearl project [63] reports revenues of 4500 M$ per year for a 19,000 M$ investment based on an oil price of 70 $ per barrel [64]. This suggests that the feedstock plays a limited role in the product cost structure. The reported feed gas costs are essentially production costs of 6 $ per barrel of oil equivalent [63]. The results of the survey are presented in Table 8.

Natural gas is often co-produced with condensate and crude oil. When exporting by pipeline is not possible and flaring becomes undesired, liquefaction (LNG) and GtL become interesting options. The low costs of the stranded gas encouraged oil companies to invest in very large plants; examples are modern plants such as the Pearl and Oryx plants in Qatar.

4.4. Comparison BtL, CtL and GtL data

The spread in the investment data is very large, even though the spread in the CtL data is much lower at first site. To compare the two data sets, the coal data set is normalised to 400 MWth (assumed lower heating value 32 MJ/kg leading to 45 t/h for each of the cases). It will be needless to say that this extrapolation is quite large and induces major uncertainties in the data.

Fig. 5 presents the results of this comparison, all the data is normalised to 400 MWth plants. The spread of the original data has certainly been amplified by the data manipulations. We observe that the fuel production costs of the CtL and BtL are more or less equivalent (some outliers). The investment costs for CtL plants are however significantly lower, 512 M€ against 670 M€ for the BtL case. The spread is much lower, as observed earlier, for the CtL cases (standard deviation 82 M€ against 237 M€ for the BtL case). As seen in Section 3.2, the averaged ISBL costs of the gasification and

Table 7
Authors and references of the CtL data presented in Fig. 3.

Table	Ref.	Year data	Capacity (MWth)	Plant cost (M$)	Plant cost (M$ 2012)	Plant cost (1000 t/h M€ 2012)	BEOP ($/barrel)	BEOP (€2012/barrel averaged coal price)	Diesel (€2012/l)
Alvarez	[54]	2010	8337	5500	5963	4472	97	91	0.62
Alvarez	[54]	2010	8337	5500	5963	4472	90	85	0.57
Jaramillo	[55]	2007	5742	2537	4017	3013	63	49	0.34
Liu	[25]	2007	7408	4852	5989	4492	58	48	0.33
Liu	[25]	2007	7408	4919	6072	4554	65	54	0.37
Lu	[26]	2008	123	251	6607	4955	233	121	0.81
Lu	[26]	2008	1235	1026	5840	4380	71	43	0.29
Lu	[26]	2008	1235	1082	6248	4686	82	49	0.34
Lu	[26]	2008	1235	1026	5840	4380	100	60	0.41
Lu	[26]	2008	1235	1082	6248	4686	115	69	0.47
Mantripragada	[44]	2007	6482	4595	6684	5013	74	57	0.39
Mantripragada	[44]	2007	6482	4655	6772	5079	82	63	0.43
Mantripragada	[56]	2010	8643	5615	5936	4452	75	69	0.47
Mantripragada	[56]	2010	12,080	6870	5746	4309	92	63	0.63
Meerman	[39]	2009	980	1201	1307	4029	84	49	0.34
Kreutz	[23]	2007	7272	4407	4407	3559	40	38	0.26
Kreutz	[23]	2007	7272	4878	4878	3939	56	53	0.36
RAND	[57]	2005	6083	3300	5809	4357	55	55	0.38
RAND	[57]	2005	6083	4050	7261	5446	65	65	0.44
RAND	[57]	2005	6083	3300	5809	4357	62	62	0.42
RAND	[57]	2005	6083	4050	7261	5446	75	75	0.51
Tarka	[52]	2009	7458	5125	6287	4715	84	81	0.55
Vallentin-Williams	[62]	2006	2357	2072	6753	5065	58	49	0.34
Vallentin-SSEB	[62]	2006	6121	2224	3716	2787	55	58	0.40
van Bibber	[5]	2006	1253	384	3033	2274	80	52	0.36
van Bibber	[5]	2006	1315	519	3911	2933	80	52	0.36
van Bibber	[28]	2006	7830	3650	6094	4571	65	65	0.44
Zhou	[58]	2011	14,700	5394	6542	4907	68	58	0.40

fuel synthesis units are 77 M€ and 67 M€ respectively for this capacity, accounting for around 25% of the average total plant cost. The sum of the standard deviation of the ISBL costs of the gasification and fuel synthesis sections (Table 3) multiplied with the factor to account of the overall plant cost (section 3.3) gives 120 M€. The CtL case is largely within these limits. The spread in BtL cases cannot be completely accounted with the uncertainty of only these two units, but around 50% of the uncertainty can accounted for by only these two units.

The data in Fig. 5 suggests that the approach of normalising the different studies to compare them is valid, but inevitably introduces an additional uncertainty. What is striking is that spread in investment costs for CtL is much lower than that for BtL. Very large extrapolations such as performed here for the coal case introduce additional uncertainties to the data. Differences in the quality and price of the feedstock were corrected for but remain a source of uncertainty. The prices of the coal feedstock were compared with the BP statistical review [20] and it was found that most publications underestimate the coal price. This discrepancy has not been corrected for. Biomass is not publicly traded so the feedstock price remains uncertain.

As mentioned earlier, BtL plants levelised production costs are often calculated (but not exclusively) by dividing the operating costs, combined with the installments of the construction loan, by the volume of fuel. All CtL cases examined use more complex discounted methods, taking in account the reality of company financing. In this case, variable costs and revenues are escalated with a factor for inflation (1–5%) but also discounted with a discount rate (10–20%). Future earnings and costs are discounted to today's money making future revenues less interesting then

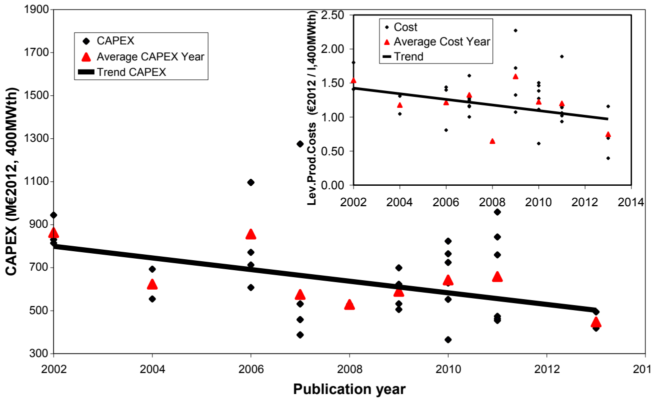


Fig. 3. Evolution over the years of the CAPEX and levelised production costs (in subfigure), averaged yearly data and trend line.

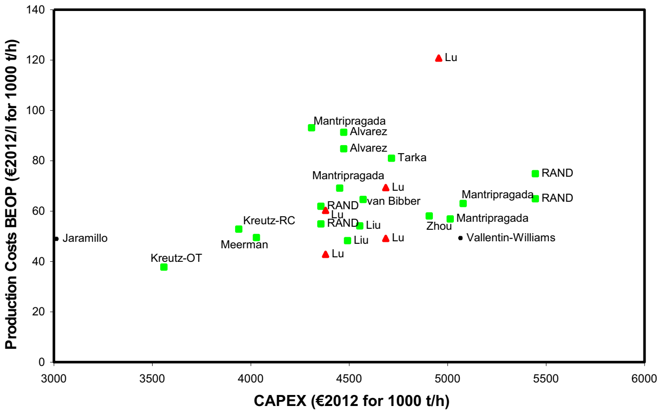


Fig. 4. Normalised investment and levelised production costs for CtL plants with 🟩 entrained flow reactors, ▲ fluidised bed reactors and ■ unknown technology.

Table 8
GtL investment data.

Data	Ref.	Year data	Capacity feed (MW)	Capacity (barrels/d	Plant Cost (M$)	Plant Cost (M$2012)
Chevron Nigeria	[10]	2005	4773	34,000	2000	3194
Choi	[38]	1996	1228	8820	415	1009
Economides	[65]	2005	9212	65,000	1625	2595
Sasol Oryx	[66]	2010	4773	34,000	1500	1650
Shell Pearl	[63]	2012	19,650	140,000	19,000	19,000
Udaeta	[67]	2006	5007	50,000	1423	1943
Wood	[68]	2011	123	1000	100	101

today's. Even though in absolute terms earnings are higher in the future due to inflation, they are perceived as lower by today's decision makers. The resulting fuel cost is generally higher when using discounted methods as money earned in the future is less valued than money made in earlier years, the difference can be 10% [1]. Differences in calculation methods and business models will account for much of the spread in the production cost data. Comparing the large volume of data allows us to forecast a cost and its associated uncertainty. Using CAPEX data in one single production cost model will certainly reduce the spread but not necessarily represent economic reality more accurately.

In the absence of published production cost data for GtL, the comparison between GtL, CtL and BtL is exclusively done on capital cost basis. Fig. 6 presents the investment costs per MWth. The investment data is actualised to €2012 at the original capacity. The number of BtL points (35 points) is much larger than the CtL (26 points) and GtL (7 points) points. The individual fitted curves for each of the cases CtL and GtL are represented in Fig. 6 with a scale factor of 0.7 and a reference capacity of 1000 MWth. It appears clearly that the CtL and GtL data is well adapted to be represented by equation (1) and that the investment data is coherent. The BtL points are too diffuse (coefficient of determination, $R^2 = 0.04$) to be reasonably represented by this type of equation and the trend line is therefore not shown.

From fitted curves in Fig. 6 we can conclude that CtL points are somewhat below the BtL points. GtL points are significantly lower. The BtL points are situated slightly above the fitted curve. These results confirm that even that GtL plants are essentially similar to BtL and CtL plants, the gasification section is much simpler resulting in a lower capital investment.

5. Conclusions

This paper summarises a large part of the global open technical and scientific literature considering synthesis fuel production. The problem with techno-economic studies in the open literature is that they are performed on different feedstocks, with different technologies, using different economic models in a constantly evolving global environment.

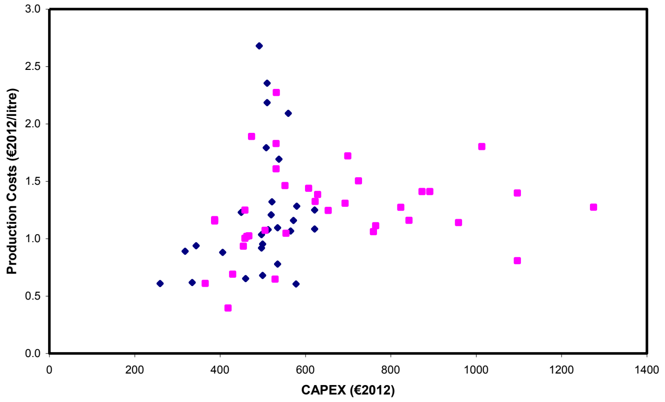


Fig. 5. Normalised investment and levelised production costs for ■ BtL and ◆ CtL both for 400 MWth.

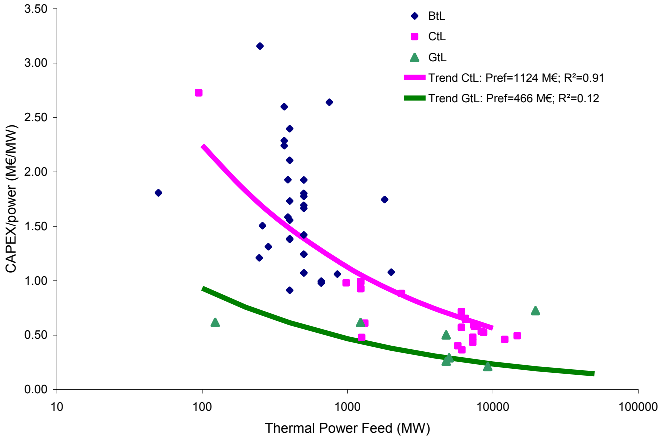


Fig. 6. Investment costs for GtL ▲, ■ CtL and ◆ BtL with trend lines according to equation (1) with the Pearson coefficient of determination.

The uncertainties are present on all levels, primary fuel costs, technology, investment levels and yield. The spread in the economic source data, mainly the cost of units, can account for a large part of the uncertainties. The message of this paper is that interpreting one single publication of data source can easily lead to false conclusions. Demonstration plants and pre-commercial units will be needed to obtain a clearer picture. BtL plants are situated at the beginning of the learning curve.

The fact that coal results can easily be mapped on the results for biomass, allows us to have some confidence in the estimated fuel prices and investment levels. The results clearly show that the expected construction costs of biomass to liquid plants are higher than those for coal to liquid plants with much higher uncertainties. Coal and gas to liquids investment estimates appear to evolve according to the classical cost estimation formula (equation (1)), this cannot be said for BtL. Technology improvements, experience and economies of scale will be required to reduce biomass to liquid costs.

This study shows that the production costs of synthetic fuel plants are high but the coal and gas cases confirm that very large capacity plants can be competitive at current coal and oil prices. With current crude oil prices synthetic fuel plants (GtL and CtL) are economically viable on the condition that economies of scale can be applied. Economies of scale are more difficult to apply to BtL plants and competitively will have to come from technology improvements, lower resource costs (waste biomass) and integration with existing plants. The difficulties with the economies of scale for BtL plants reside in the fact that the technology is not mature but also due to difficulties in feedstock logistics. The cost of the coal resources is generally underestimated in CtL economic studies but there appears to be sufficient margins in the projected levelised production costs. The actual production costs may be somewhat higher than predicted. Biomass will probably be more expensive than coal on the short term. Predictions on the cost of biomass in the future remain delicate.

References

[1] Haarlemmer G, Boissonnet G, Imbach J, Setier P-A, Peduzzi E. Second generation BtL type biofuels – a production cost analysis. Energy Environ Sci 2012;5:8445–56.

[2] Anantharaman B, Chatterjee D, Ariyapadi S, Gualy R. Consider coal gasification for liquid fuels production. Hydrocarbon Process 2012;91(12):47–53.

[3] Froment K, Seiler J-M, Defoort F, Ravel S. Inorganic species behaviour in thermochemical processes for energy biomass valorisation. Oil Gas Sci Technol – Rev 2003;38(4):725–39.

[4] Hayes DJM. Second-generation biofuels: why they are taking so long. Wiley Interdiscip Rev Energy Environ; 2012.

[5] Bibber LV, Shuster E, Haslbeck J, Rutkowski M, Olson S, Kramer S. Technical and economic assessment of small-scale Fischer–Tropsch liquids facilities. NETL; 2007.

[6] Seiler JM, Hohwiller C, Imbach J, Luciani JF. Technical and economical evaluation of enhanced biomass to liquid fuel processes. Energy 2010;35:3587–92.

[7] Sues A, Juraščík M, Ptasinski K. Exergetic evaluation of 5 biowastes-to-biofuels routes via gasification. Energy 2008;35(2):996–1007.

[8] Bayle J, Boissonnet G, Marty E, Seiler J-M. Production of liquid fuels by a concatenation of processes for treatment of a hydrocarbon feedstock. US7214720B2; 2007.

[9] Diebold JP, Sherwood S, Lilley AW, Walt RR. Conversion of biomass feedstocks into hydrocarbon liquid transportation fuels. US2010/0036181A1; 2010.

[10] Boerrigter H. Economy of biomass-to-liquids (BTL) plants – an engineering assessment. ECN; 2006. http://www.ecn.nl/docs/library/report/2006/c06019.pdf.

[11] Hannula I, Kurkela E. Liquid transportation fuels via large-scale fluidised bed gasification of lignocellulosic biomass. Espoo, Finland: VTT; 2013. http://www.vtt.fi/inf/pdf/technology/2013/T91.pdf.

[12] Black J. Cost and performance baseline for fossil energy plants. Volume 1: bituminous coal and natural gas to electricity. NETL; 2010.

[13] Higman C, Burgt Mvd. Gasification. Burlington, MA, USA: Gulf Professional Publishing; 2003.

[14] Wilhelm DJ, Simbeck DR, Karp AD, Dickenson RL. Syngas production for gas-to-liquids applications: technologies, issues and outlook. Fuel Process Technol 2001;71(1–3):139–48.

[15] Pfeifer C, Puchner B, Hofbauer H. Comparison of dual fluidized bed steam gasification of biomass with and without selective transport of CO_2. Chem Eng Sci 2009;64(23):5073–83.

[16] Dysert L. Sharpen your cost estimating Skills. Cost Eng 2003;46(6):22–30.

[17] Wilson C. Up-scaling, formative phases, and learning in the historical diffusion of energy technologies. Energy Policy 2012;50(0):81–94.

[18] Lawrence G. Cost estimating for turnarounds. Pet Technol Quart 2012;Q1:33–43.

[19] IHS. Available from: http://www.ihsindexes.com/; 2012.

[20] BP. BP statistical review of world energy; 2012.

[21] Hoffmann BS, Szklo A. Integrated gasification combined cycle and carbon capture: a risky option to mitigate CO_2 emissions of coal-fired power plants. Appl Energy 2011;88(11):3917–29.

[22] Huisman GH, Brinkert J, van Rens GLMA, Cornelissen RL. Cost estimate of a biomass plant with a fuel input of 20 to 80 dry tonnes/hr producing different motor fuels. CHRISGAS; 2009.

[23] Kreutz TG, Larson ED, Liu G, Williams RH. Fischer–Tropsch fuels from coal and biomass. In: Conference Fischer–Tropsch fuels from coal and biomass, Pittsburgh, Pennsylvania, USA.

[24] Larson ED, Jin H, Celik FE. Large-scale gasification-based coproduction of fuels and electricity from switchgrass. Biofuels, Bioprod Biorefin 2009;3:174–94.

[25] Liu G, Larson ED, Williams RH, Kreutz TG, Guo X. Making Fischer–Tropsch fuels and electricity from coal and biomass: performance and cost analysis. Energy Fuels 2011;25:415–37.

[26] Lu X, Norbeck JM, Park CS. Production of Fischer–Tropsch fuels and electricity from bituminous coal based on steam hydrogasification. Energy 2012;48(1): 525–31.

[27] Martelly E, Kreutz T, Consonni S. Comparison of coal IGCC with and without CO_2 capture and storage: shell gasification with standard vs. partial water quench. Energy Procedia 2009;1:607–14.

[28] Bibber LV, Shuster E, Haslbeck J, Rutkowski M, Olson S, Kramer S. Baseline technical and assessment of a commercial scale Fischer–Tropsch liquids facility. NETL; 2007.

[29] Ng KS, Sadhukhan J. Techno-economic performance analysis of bio-oil based Fischer–Tropsch and CHP synthesis platform. Biomass Bioenergy 2011;35: 3218–34.

[30] Vogel A, Brauer S, Müller-Langer F, Thrän D. RENEW project – conversion cost calculation deliverable D5.3.7, renewable fuels for advanced powertrains. Leipzig: Institute for Energy and Environment; 2006.

[31] Sarkar S, Kumar A, Sultana A. Biofuels and biochemicals production from forest biomass in western Canada. Energy 2011;36:6251–62.

[32] Swanson RM, Platon A, Satrio JA, Brown RC. Techno-economic analysis of biomass-to-liquids production based on gasification. Fuel 2010;89:S11–9.

[33] Tijmensen MJA, Faaij APC, Hamelinck CN, Hardeveld MRM. Exploration of the possibilities of Fischer Tropsch liquids and power via biomass gasification. Biomass Bioenergy 2002;23:129–52.

[34] Tock L, Gassner M, Maréchal F. Thermochemical production of liquid fuels from biomass: thermo-economic modelling, process design and process integration analysis. Biomass Bioenergy 2010;34:1838–54.

[35] Tremel A, Becherer D, Fendt S, Gaderer M, Spliethoff H. Performance of entrained flow and fluidised bed biomass gasifiers on different scales. Energy Convers Manag 2013;69:95–106.

[36] van Vliet OPR, Faaij APC, Turkenburg WC. Fischer–Tropsch diesel production in a well-to-wheel perspective: a carbon, energy flow and cost analysis. Energy Convers Manag 2009;50:855–76.

[37] Williams RH, Larson ED, Jin H. F-T Liquids Production from Coal and Coal + Biomass with CO_2 Capture and Alternative Storage Options: Aquifer CO_2 Storage vs. CO_2-Enhanced Oil Recovery. Princeton, NJ: Princeton Environmental Institute, Princeton University; January 13, 2006.

[38] Choi GN, Kramer SJ, Tam SS, Fox JM, Carr NL, Wilson GR. Design/economics of a once-through natural gas Fischer–Tropsch plant with power co-production.

[39] Meerman JC, Knoope MMJ, Ramirez A, Turkenburg WC, Faaij APC. Technical and economic prospects of coal- and biomass-fired integrated gasification facilities equipped with CCS over time. Int J Greenhouse Gas Control 2013;16: 311–23.

[40] Sues A. Are European bioenergy targets achievable?. Eindhoven: Eindhoven University of Technology; 2011.

[41] Bauman HC. Costs for chemical process plants. Ind Eng Chem 1962;54(9):40–3.

[42] DENA. Biomass to liquid – BtL implementation report summary. Deutsche Energie-Agentur GmbH; 2006. http://www.dena.de/fileadmin/user_upload/Publikationen/Verkehr/Dokumente/btl_implementation_report.pdf.

[43] Henrich E, Dahmen N, Dinjus E. Cost estimate for biosynfuel production via biosyncrude gasification. Biofuels Bioprod Biorefin 2009;3:28–41.

[44] Mantripragada HC, Rubin ES. Techno-economic evaluation of coal-to-liquids (CTL) plants with carbon capture and sequestration. Energy Policy 2011;39(5):2808–16.

[45] Phillips SD. Technoeconomic analysis of a lignocellulosic biomass indirect gasification process to make ethanol via mixed alcohols synthesis. Ind Eng Chem Res 2007;46:8887–97.

[46] Seltzer A, Robertson A. Economic analysis for conceptual design of supercritical O_2-based PC boiler. Livingston, New Jersey, USA: Foster Wheeler Power Group, Inc; 2006.

[47] Chauvel A, Fournier G, Raimbault C. Manual d'évaluation économique des procédés. Ed. Technip; 2001.

[48] Baliban RC, Elia JA, Floudas CA, Gurau B, Weingarten MB, Klotz SD. Hardwood biomass to gasoline, diesel, and jet fuel: I. Process synthesis and global optimization of a thermochemical refinery. Energy Fuels 2013;27(8):4302–24.

[49] Departe A. Étude prospective sur la seconde génération de biocarburants. Paris: DG Trésor; 2010.

[50] Hohwiller C. La production de carburants liquids par thermoconversion de biomasse lignocelluloqique: evaluation pour le système énérgétique français future. Paris: ParisTech; 2011.

[51] Hamelinck CN, Faaij APC, Hd Uil, Boerrigter H. Production of FT transportation fuels from biomass; technical options, process analysis and optimisation, and development potential. Energy 2004;29:1743–71.

[52] Tarka TJ. Affordable, low-carbon diesel fuel from Domestic coal and biomass. Natl Energy Technol Lab; 2009.

[53] McKeough P, Kurkela E. Process evaluations and design studies in the UCG project 2004–2007. VTT; 2008. p. 49.

[54] Alvarez Y, Karri V, Louw E, Luchner S, Moyer O, Peduzzi E. Comparative analysis of ICL as an alternative to crude oil; 2010.

[55] Jaramillo P, Griffin WM, Matthews HS. Comparative analysis of the production costs and life-cycle GHG emissions of FT liquid fuels from coal and natural Gas. Environ Sci Technol 2008;42(20):7559–65.

[56] Mantripragada HC, Rubin ES. Performance, cost and emissions of coal-to-liquids (CTLs) plants using low-quality coals under carbon constraints. Fuel 2013;103:805–13.

[57] Bartis LT, Camm F, Ortiz DS. Producing liquid fuels from coal, prospects and policy issues. RAND Corp.; 2008.

[58] Zhou W, Zhu B, Chen D, Zhao F, Fei W. Technoeconomic assessment of China's indirect coal liquefaction projects with different CO_2 capture alternatives. Energy 2011;36(11):6559–66.

[59] Boissonnet G, Haarlemmer GW, Setier PA. BtL process development: simulation and techno-economic assessment of several technical options. In: Conference BtL process development: simulation and techno-economic assessment of several technical options, Dresden, Germany.

[60] Festel GW. Biofuels – economic aspects. Chem Eng Technol 2008;31(5):715–20.

[61] Faaij A, Meuleman B. Long term perspectives of biomass integrated gasification with combines cycle gasification. Utrecht: NOVEM; 1998.

[62] Vallentin D. Policy drivers and barriers for coal-to-liquids (CtL) technologies in the United States. Energy Policy 2008;36(8):3198–211.

[63] Rijssen Pv. The delivery of Pearl GtL. In: Conference the delivery of Pearl GtL.

[64] Constantinou C. Expressway to U.S. energy independance GtL diesel; 2012.

[65] Economides MJ. The economics of gas to liquids compared to liquefied natural Gas. World Energy 2005;8(1):136–40.

[66] Hargreaves N. GTL adds value to gas production. Pet Technol Quar 2012;Gas: 25–8.

[67] Udaeta MEM, Burani GF, Arzabe Maure JO, Oliva CR. Economics of secondary energy from GTL regarding natural gas reserves of Bolivia. Energy Policy 2007;35(8):4095–106.

[68] Wood DA, Nwaoha C, Towler BF. Gas-to-liquids (GTL): a review of an industry offering several routes for monetizing natural gas. J Nat Gas Sci Eng 2012;9: 196–208.