Techno-economic performance of sustainable international bio-SNG production and supply chains on short and longer term

Batidzirai, Bothwell; Schotman, Geert S.; van der Spek, Mijndert W.; Junginger, Martin; Faaij, Andre P. C.

Published in:
Biofuels bioproducts & biorefining-Biofpr

DOI:
10.1002/bbb.1911

Publication date:
2019

Modeling and Analysis

Biofpr
Biofuels Bioproducts & Biorefining

Techno-economic performance of sustainable international bio-SNG production and supply chains on short and longer term

Bothwell Batidzirai, Energy Research Centre, University of Cape Town, Cape Town, South Africa
Geert S. Schotman, Mijndert W. van der Spek, and Martin Junginger, Copernicus Institute of Sustainable Development, Utrecht University, Utrecht, The Netherlands
André P. C. Faaij, University of Groningen, Groningen, The Netherlands

Received January 03, 2018; revised May 29, 2018; accepted June 05, 2018
View online at August 6, 2018 Wiley Online Library (wileyonlinelibrary.com);
DOI: 10.1002/bbb.1911; *Biofuels. Bioprod. Bioref.* 13:325–357 (2019)

Abstract: Synthetic natural gas (SNG) derived from biomass gasification is a potential transport fuel and natural gas substitute. Using the Netherlands as a case study, this paper evaluates the most economic and environmentally optimal supply chain for the production of biomass based SNG (so-called bio-SNG) for different biomass production regions and location of final conversion facilities, with final delivery of compressed natural gas at refueling stations servicing the transport sector. At a scale of 100 $MW_{th, in}$, delivered bioSNG costs range from 18.6 to 25.9\$/$GJ_{delivered\ CNG}$ while energy efficiency ranges from 46.8–61.9%. If production capacities are scaled up to 1000 $MW_{th, in}$, SNG costs decrease by about 30% to 12.6–17.4\$ $GJ_{delivered\ CNG}^{-1}$. BioSNG production in Ukraine and transportation of the gas by pipeline to the Netherlands results in the lowest delivered cost in all cases and the highest energy efficiency pathway (61.9%). This is mainly due to low pipeline transport costs and energy losses compared to long-distance Liquefied Natural Gas (LNG) transport. However, synthetic natural gas production from torrefied pellets (TOPs) results in the lowest GHG emissions (17 kg CO_2e GJ_{CNG}^{-1}) while the Ukraine routes results in 25 kg CO_2e GJ_{CNG}^{-1}. Production costs at 100 MW_{th} are higher than the current natural gas price range, but lower than the oil prices and biodiesel prices. BioSNG costs could converge with natural gas market prices in the coming decades, estimated to be 18.2\$ GJ^{-1}. At 1000 MW_{th}, bioSNG becomes competitive with natural gas (especially if attractive CO_2 prices are considered) and very competitive with oil and biodiesel. It is clear that scaling of SNG production to the GW_{th} scale is key to cost reduction and could result in competitive SNG costs. For regions like Brazil, it is more cost-effective to densify biomass into pellets or TOPS and undertake final conversion near the import harbor. © 2018 Society of Chemical Industry and John Wiley & Sons, Ltd

Keywords: biomass energy; bioSNG; synthetic natural gas; supply chain; economics

Correspondence to: Bothwell Batidzirai, Energy Research Centre, University of Cape Town, P Bag X3 Rondebosch 7701, South Africa.
E-mail: bothwell.batidzirai@uct.ac.za

Introduction – Developments in bioSNG

The global demand for natural gas is expected to increase in the coming decades, driven mainly by increasing power production from natural gas.[1,2] Several countries want to phase out nuclear electricity production and with increasing shares of wind, solar and other intermittent sources of power, natural gas backup plants can therefore play an important role.[2–4] In the EU, natural gas production is decreasing,[5,6] so the increased demand will lead to a greater dependence on natural gas imports including LNG (liquefied natural gas)[1,3,6–8] and shale gas exploitation.[7] For the Netherlands, the fact that the Dutch Groningen gas fields are expected to be depleted by 2030–2035 at current extraction rates is a matter of concern.[9]

Although natural gas is a relatively low carbon-intensive fuel compared to other fossil fuels, the need for drastic CO_2 emission reduction is attracting investigations into renewable gas (or biomass derived gas).[10,11] For example, the Dutch 'Energy Transition Platform New Gas' has formulated the vision that 50% (750 PJ) of the natural gas consumption in the Netherlands can be replaced by renewable gas in 2050.[12–14] This biomass-derived renewable gas can be upgraded to natural gas quality to produce the so-called bioSNG (biomass based synthetic or substitute natural gas) and injected in the existing gas infrastructure.[4,6,15]

For countries with limited biomass production potential such as the Netherlands,[16] large-scale bioSNG supply would inevitably involve importing either raw biomass (for conversion near the import terminal) or producing bioSNG in another country and transporting the bioSNG to the Netherlands. In all cases, long-distance shipping is necessary (in the latter case, long-distance shipping of bioSNG is by pipeline or LNG ship).

It is therefore of interest to investigate optimal supply chains for the production of bioSNG for application in the Netherlands by comparing different bioSNG production chains. A few studies on bioSNG conversion techno-economics have been conducted to date. Zwart *et al*.[13] provided a detailed techno-economic feasibility assessment of an integrated bioSNG demonstration project (at different scales and based on experimental work) using imported biomass. Carbo *et al*.[5] investigated the techno-economics and greenhouse gas (GHG) impacts of imported solid biomass gasification into synthetic natural gas (SNG) at 500 $MW_{th, in}$ scale combined with CO_2 capture and storage (CCS). Gassner and Maréchal[17] modeled and compared the thermo-economic performance of different technological alternatives for SNG production from lignocellulosic biomass, focusing only on the conversion plant analysis. Gassner and Maréchal[18] use process modeling developed in Gassner and Maréchal,[17] to perform thermo-economic optimization and determine the most promising options for SNG production at different scales. Cozens and Manson-Whitton[19] assess the techno-economic feasibility of bioSNG production in the UK based on different production scales and using imported and local biomass. Heyne and Harvey provide a detailed techno-economic comparison of bioSNG production with CCS in Sweden based on three alternative pathways. All these studies exclude upstream and downstream supply-chain analysis (with respect to the conversion plant), i.e. they do not assess the techno-economic and environmental performance of the complete value chain of bioSNG production. Other studies have much narrower focus. For example van der Meijden *et al*.[20] and Ahrenfeldt *et al*.[21] provide technical comparisons of different bioSNG production technologies mainly focusing on conversion efficiencies.

It is therefore important to assess not only the final bioSNG conversion economics, but also to evaluate the techno-economics and environmental sustainability of the entire value chain, identify optimization opportunities, and compare different supply-chain pathways to enable the selection of viable and sustainable bioSNG supply pathways.

The overall objective of this study is to determine the most economically and environmentally optimal supply chain for bioSNG using Netherlands as a case study. The Netherlands is taken as a case study because it has an important global gas market. Natural gas is the most important energy carrier in the Dutch energy mix, contributing about 50% of the primary energy consumption.[14,20,21] The Dutch gas infrastructure is also one of the most developed in the world[21] and it makes sense to secure this infrastructure for future use. This study also compares energy efficiency and greenhouse gas emissions performance of the selected bioSNG supply chains. To achieve this, different bioSNG production and supply chains are assessed and compared based on different biomass production regions (Brazil and Ukraine), biomass types (eucalyptus and poplar), pretreatment technologies (pelletizing and torrefaction), shipping modes and final conversion location (Brazil, the Netherlands and Ukraine).

  | *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

BioSNG production and supply chains

BioSNG can be produced via either anaerobic digestion or gasification. Digestion is often applied in processing organic waste streams and is a mature technology.[6,15] In the Netherlands, currently, out of a total of 252 digestion plants about 25 plants are upgrading biomethane and deliver up to 230 million m^3 green gas to the low- and medium-pressure gas grid. Digestion plants use mainly local organics streams (manure, sewage water, and landfills), which typically limit the capacity to a few MW_{th} and therefore limit potential energy production.[6,14,20,22,23]

Larger scale bioSNG production (hundreds of MW_{th}) can be achieved via gasification of biomass: biomass is converted under high temperature to a producer gas, which is upgraded to bioSNG. Biomass gasification for fuel production is still being developed and a few commercial plants are currently operational.[24–26] An advantage of gasification is that lignocellulosic biomass can be used as fuel, which increases the feedstock resource base and the corresponding potential production of renewable gas compared to digestion.[12,22] This study therefore focuses on bioSNG production by gasification, given its potential to substitute natural gas at a larger scale than digestion.

BioSNG production via gasification

Biomass can be gasified at a high temperature (above 1300 °C) or at low temperature (700–1000 °C). With high-temperature gasification, biomass is completely converted into H_2 and CO.[27] This can be useful for the production of Fischer Tropsch diesel or chemicals. But a high methane content is desirable for producing bioSNG.[28] Therefore, low temperature gasification is more suitable for bioSNG production, because the producer gas contains 10–15% methane. In addition, low temperature gasification is less energy intensive than high-temperature gasification. However, low temperature gasification results in significantly higher tar formation, which requires a greater cleaning effort (Raas H, 2009, private communication).

As shown in Fig. 1, biomass gasification technologies include bubbling or circulating fluidized bed (BFB or CFB) gasification, indirect gasification, and entrained flow (EF) gasification.[29–31] The most promising technology for bioSNG production is indirect gasification (employing two dual-bed reactors). This type of gasifier has separate gasification and combustion chambers (see Fig. 2). Steam is added into the gasification chamber, while air is added into the combustion chamber. Since the air in the combustion chamber is separated from the gasification chamber, the resulting producer gas has low nitrogen content and no energy-intensive input of pure oxygen is needed.[32,33] This study therefore assumes bioSNG production using indirect gasification.

The indirect gasification technology has been developed and demonstrated in different projects, such as the Milena project at ECN in the Netherlands, the Güssing project in Austria, and the Silvagas project in the USA. The first commercial project is the Gobigas project in Sweden, where the Güssing technology is being scaled up to 140 $MW_{th,\ in}$. The first Gobigas stage of 20 MW_{gas} was commissioned in 2016.[26,31,34–36] In this study, we mainly focus on the Milena technology, because it has 10% higher overall efficiencies than the Güssing technology, and furthermore, its capability for upscaling has greater promise for larger cost reduction. In addition, we had access to detailed characterization of the technology which enables us to conduct a proper techno-economic analysis evaluation. However, we also compare the performance of Milena with the Güssing technology in terms of upscaling optimization.

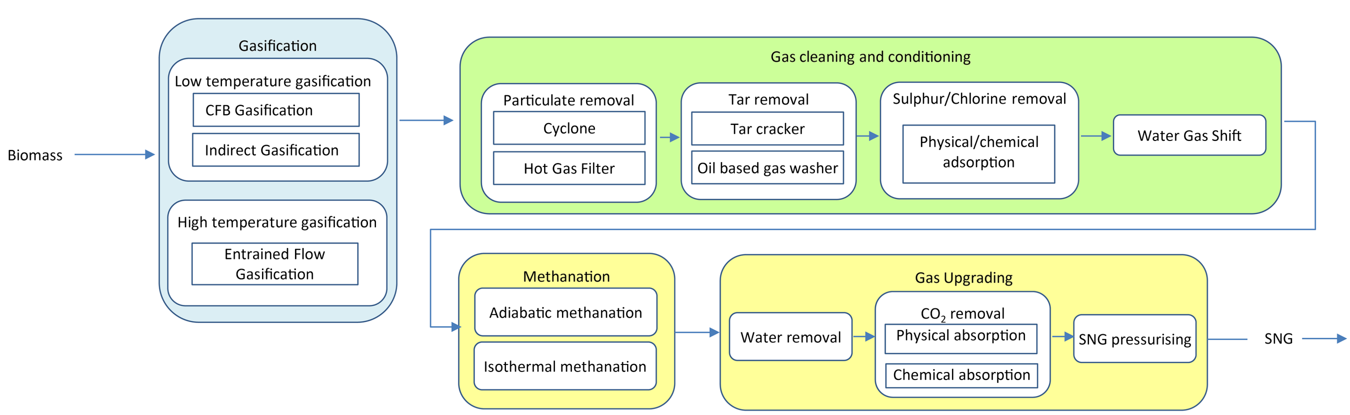


Figure 1. General outline of possible bioSNG production systems via gasification.

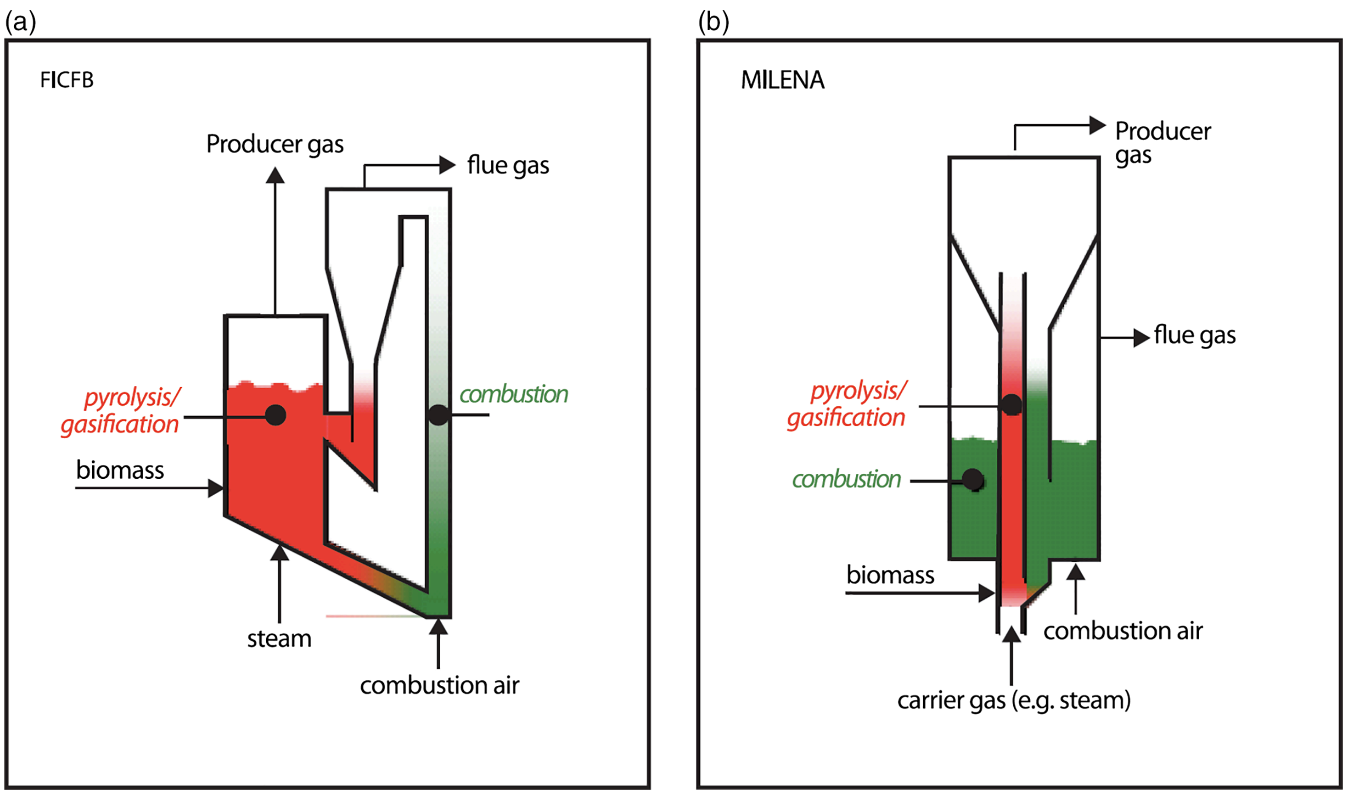


Figure 2. Schematics of the Güssing gasifier (a) and Milena gasifier (b). Source: Zwart *et al.*[13]

The gross conversion efficiency (GCE) of biomass to SNG with the Milena gasifier can be up to 74% (assuming biomass with 10% moisture content) (Raas H, 2009, private communication). The GCE is the ratio of the energy content in the final product gas to the energy input into the integrated production facility (including process energy demand and feedstock energy content).[37] BioSNG production efficiency of the Güssing installation is about 10% lower than the Milena installation, but can probably be optimized to the same efficiency in the future (Raas H, 2009, private communication). In this study, a gross conversion efficiency of 70% is assumed for biomass moisture contents of up to 20%.[20] In contrast, the cold gas efficiency (CGE) is a measure of the gasifier performance and defined as the ratio of the product gas energy content to the energy content in the biomass feedstock.[38] For the Milena system, the CGE is estimated to be 80%.[20]

Key BioSNG production steps

As shown in Fig. 3, bioSNG production consists of seven key steps: biomass pretreatment, gasification, tar removal, gas cleaning, water-gas shift, methanation and SNG upgrading. First biomass is pretreated to meet the required specifications for gasification, including drying and sizing. In the next stage the biomass is gasified, resulting in a product gas consisting mainly of H2, CO, CH4, and CO2. This product gas contains tars, which are removed in the next step. After that the gas is further cleaned to remove HCl and sulfur components. The resulting syngas can be used directly in a power plant. For bioSNG production, the syngas is shifted to a required CO:H2 ratio after which the gas is methanized to form CH4, water, and CO2. The last reaction is highly exothermic. The released heat is used to generate steam, which is combined with other waste heat and can be used to produce electricity in a steam turbine. In the last step, water and CO2 are removed to meet the desired Wobbe index gas quality. The output of the installation is at high pressure grid quality at 66 bar.13

The key bioSNG production stages are summarized below.

Gasification

Biomass is gasified in an indirect gasifier of the ECN Milena type under atmospheric pressure at temperatures of 892 °C in the gasification section and 964 °C in the combustion section. Steam is added to the gasification section (5 wt% of biomass), and hot sand is used as bed material.

  | *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

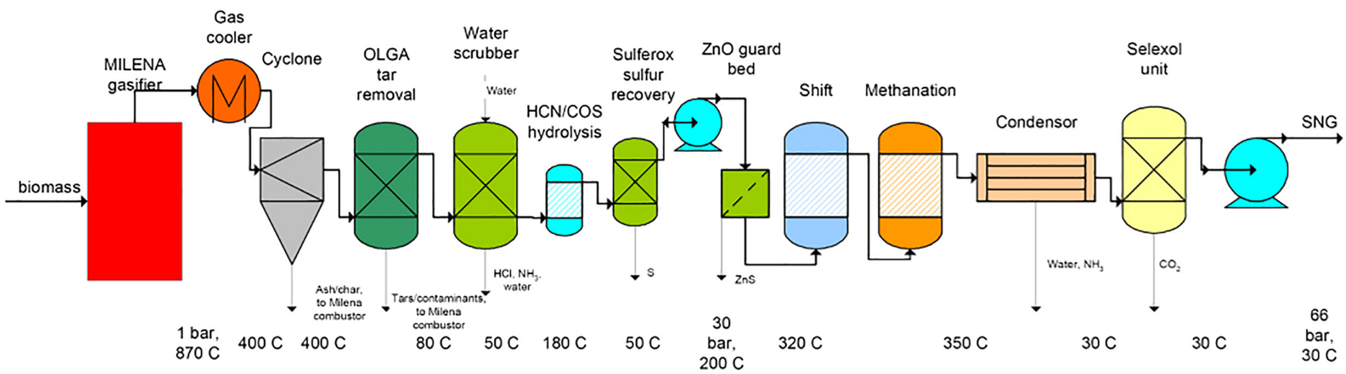


Figure 3. BioSNG production process based on Milena system. Source: van der Spek.[39]

Gas cooling and particulates removal

The gas is cooled to 400 °C, which is above the tar dew points, and fly ash and char are removed in a cyclone. The cyclone removes about 95% of the ash and char particles and the rest are removed during tar removal. Removed ash is sent back to the Milena combustion section.

Tar removal

Tar is removed using the ECN OLGA tar removal technology. The temperature in this process is gradually reduced to 80 °C. All captured tars and particles are recycled to the gasifier combustion section in order to reduce energy losses.

Gas cleaning

Carbonyl sulfide (COS) and HCN are converted in a hydrolysis reactor where HCN reacts with water to form NH_3, while COS reacts with water to form H_2S and CO_2. Hydrogen chloride (HCL) and H_2S have to be removed to concentrations below 100 ppbV. Hydrogen chloride is removed in a water scrubber and H_2S is removed using the Sulferox process. This process is suitable and economic for gas streams with low sulfur concentrations. The remaining sulfur traces are removed in a zinc oxide guard bed at 200 °C to avoid the formation of mercaptans (organosulfur compounds).[13,40] Ammonia is partially removed in the water scrubber and completely removed by cooling the gas stream to 50 °C before the Sulferox process. After the Sulferox process, the syngas is compressed to 30 bar.[39]

Gas conditioning

The shift reactor used for gas conditioning in this process is a modification of the normal shift reactor and combines two separate functions. First, unsaturated hydrocarbons are converted to prevent soot formation in the methanator.[13] Second, the H_2/CO ratio is shifted to 3:1. Both take place in an isothermal shift reactor at 320 °C under steam (steam-to-dry-gas ratio is 30%, hence a dry shift is performed). Ethylene and benzene are converted to CO, H_2 and CH_4.[39]

Methanation

The methanation process consists of three adiabatic reactors with intermediate cooling and a recycle after the first reactor. The process is promoted by a nickel catalyst. Inlet temperature of the first reactor is 300 °C; that of the second and third reactor is 250 °C to push the reaction equilibrium towards methane. After the third reactor, most of the CO is converted.

Gas upgrading

After methanation the SNG product is upgraded to pipeline specifications. First, the gas is cooled to 30 °C in a condenser to knock out water. After that, CO_2 is removed with a Selexol unit; about 1% of the CH_4 is lost in this process. Approximately 1.5% of the product gas is hydrogen. There is also some 10% of CO_2 present to lower the Wobbe index to Dutch grid specifications.

BioSNG supply chains

The shortage of locally produced biomass in the main SNG centers of demand (such as the Netherlands) necessitates the import of biomass or gas. Due to the unique characteristics of biomass, biomass supply chains need to be carefully evaluated to ensure the imported biomass fuel is delivered at competitive cost. A typical international value chain of SNG includes feedstock production, preprocessing of raw biomass, local biomass transport and logistics at source, final conversion to SNG, liquefaction to LNG at export harbor, international transport, regasification at import harbor, distribution by pipeline, compression to CNG and storage at refueling station.

Several SNG supply configurations are possible and these depend on the feedstock characteristics, pretreatment requirements, infrastructure, and final market requirements. The principal possibilities include import of solid biomass with final conversion in the Netherlands. Alternatively, biomass can be processed into SNG in the biomass producing country, liquefied at the export harbour to LNG and shipped to the final market by LNG carriers. Where international distances are shorter, pipelines can be used to transport SNG from the producing country to the final market.

Biomass production, preprocessing and transport

Potential biomass feedstocks for SNG production via gasification are varied – biomass production in this study is based on woody energy crops (short rotation coppice). In Ukraine, poplar production is assumed whereas in Brazil eucalyptus is assumed. The production of these energy crops from planting up to harvesting is described in detail in studies such as De Wit and Faaij[41] and Smeets and Faaij[42] and therefore not discussed fully in this paper. Eucalyptus and poplar can be harvested as stems or directly chipped during harvesting.[43,44] Stems can be dried in the field for at least six weeks to a moisture content of around 30%, but chips have to be transported with a moisture content of 50% as chips tend to decompose and lose dry matter.[45] Transport of wet chips increases transport costs as it involves additional drying costs and storage of dried chips result in dry matter losses, and therefore is largely avoided.

Generally harvested biomass is collected at production sites and transported to a gathering point (GP) at a road or railway siding. Trucks provide first transport to the GP while second transport to a central gathering point (CGP) is by truck or train. At the CGP the wood is stored, chipped, dried, pelletized, or torrefied. The purpose of such preprocessing is to increase energy density, improve fuel homogeneity, and reduce handling costs.

Conversion to BioSNG can also be done at the CGP if sufficient volumes of biomass can be mobilized within the catchment area of the CGP. While logs and stems can be stored outside, chips have to be stored in a covered storage to prevent decomposition and moisture ingression.[45] For centralized chipping, a hammermill is assumed because it has relatively low investment cost and high efficiency for larger capacities.[45] The wood is chipped to a particle size of 30 mm, which is small enough to fuel the bioSNG production process. More detailed descriptions of the local transport and preprocessing of biomass are provided in studies such as Hamelinck *et al*.[45] Batidzirai *et al*.[44] and van der Hilst and Faaij.[46]

For mechanical drying, a rotary drum dryer is the proven technique and it has relatively low costs and primary energy use.[45] The biomass has to be in the form of chips to be dried in a rotary drum dryer and drying energy is provided by burning part of the biomass.[47] When the biomass is dried at the SNG conversion facility, waste heat of the bioSNG production process can be used for the biomass drying and no additional heat demand is required.

Pelletizing and torrefaction

For international biomass logistics, it is essential to transport either final liquid or gaseous biomass energy carriers or highly densified intermediate biomass such as pellets or torrefied pellets.[44] Because of the high energy density, long-distance shipping becomes more efficient. Pelletizing biomass is currently the most important densification approach for solid biomass and wood pellets are the most important internationally traded biomass commodity. However, pelletizing only improves the energy density of raw biomass from 2–4 GJ m^{-3} to about 7–10 GJ m^{-3}, and this is still relatively low compared to other energy commodities such as coal (25–40 GJ m^{-3}). Torrefaction (combined with pelletization) is a promising biomass pretreatment technology which has potential to produce a homogeneous biomass carrier with improved energy density that could improve biomass supply chain economics.[47]

International transport

International ocean shipping

International shipping is via dry bulk carriers for solid biomass and tankers for liquid biomass. Shipping can be done through spot market chartering or annual chartering. The cost and energy use of ocean transport depends on the size of the ships. For economies of scale, large bulk carriers such as Panamax ships and LNG tankers are assumed. Charter costs are very sensitive to global demand and supply. Figure 4 shows the extensive volatility of the spot charter prices (the price when one wants to rent a ship directly on the market).[48]

A comparison of Figs 4 and 5 shows that dry bulk carriers and LNG tankers follow entirely different cost variation trends. Bulk carriers appear to follow the performance of the global economy (e.g. during 2008 economic crisis,

  | *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

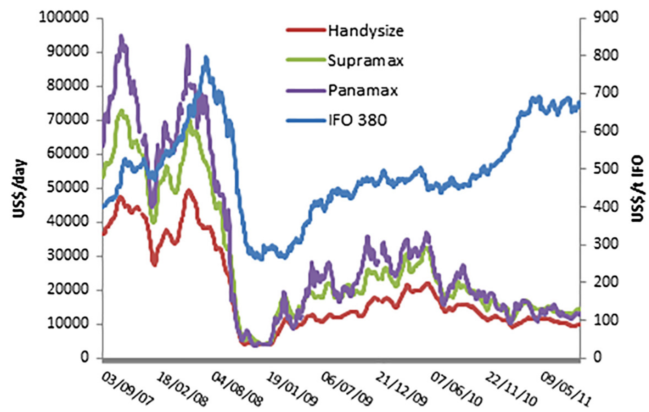


Figure 4. Freights rates (charter rates and fuel prices) for bulk carriers (2007–2011). Source: Hoefnagels *et al*.[49]

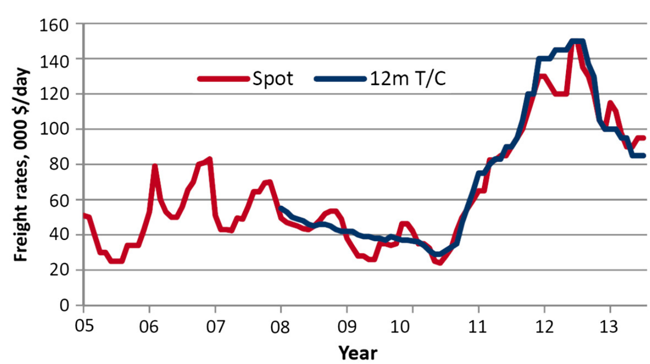


Figure 5. Freight rates for LNG shipping (spot market vs 12 month time charter rates-T/C). Source: RS Platou.[51]

shipping rates went down) due to linkages between shipping, trade and financial markets.[50] The LNG carriers on the other hand follow different dynamics, as they cater for a specific niche market.

Pipeline transport

Prior to pipeline transport, SNG should be injected into the transport grid at high pressure (around 80 bar) at the production location.[52] As the output of the bioSNG installation is at 66 bar,[13] an extra compression step is needed. From the injection point in the SNG-producing country (e.g. Ukraine) the gas is transported through several countries (in this study the pipeline would pass through Poland and Germany to the Netherlands). In this case, transport capacity has to be allocated in all transit countries and relevant charges need to be included.[53] Compressor stations (13–35 MW_e capacity) in the pipelines keep the pressure of the gas on the desired level, to compensate for pressure losses due to friction in the pipelines.[54] Booster stations are installed for roughly every 50–100 km to maintain gas pressure. According to Knoope *et al.*[54] this is more cost-effective than a system with a very high inlet pressure, which requires thicker wall pipelines.

LNG sea transport

In the case of LNG transport by ship, the gas has to be liquefied before transport in a liquefaction terminal. The LNG is transported with dedicated ships, which are powered with boiled-off LNG (BOG) when loaded and with fuel oil when unloaded. After transport, the gas has to be regasified at a regasification terminal at the import harbor. The liquefaction, LNG tanker, and regasification processes can also be powered using some of the gas. Around 8–10% of the gas is consumed DURING liquefaction,[55] a further 3–5% is used during international shipping and around 1.5–3% of the gas is consumed during regasification.[56–58] See Table 1. According to Lowell *et al.*[59] methane losses in the LNG value chain occur during its storage, transport and handling (so-called bunkering activities). Overall, about 13–15% of the gas is lost or used for liquefaction, LNG tanker power and regasification.

LNG liquefaction and regasification

Liquefaction

Liquefaction of SNG is necessary for ease of long-distance transport. Liquefied natural gas has a density of 468 kg m^{-3} and takes up about 1/600th of the volume of SNG. Depending upon gas composition, liquefaction is achieved at –162 °C at atmospheric pressure. The major elements of typical LNG liquefaction facilities include feed gas handling and treating, liquefaction, refrigerant, fractionation, LNG storage section, marine and LNG loading and a utility and offsite section.[62] Raw gas feed is cleaned and dried before it is liquefied. Cleaning is via scrubbing of entrained hydrocarbons and removal of H_2S and CO_2 contaminants. The gas is also cooled and dehydrated to remove water. Liquefaction is achieved by cooling the gas with a compressed refrigerant through heat exchangers. The liquefied natural gas is stored in an insulated storage tanks before being loaded onto LNG tankers.[63]

Regasification

Liquefied natural gas regasification facilities or receiving terminals are specially built offloading and storage facilities for shipped LNG before vaporization and transmission of gas into the local natural gas pipeline grid. Key regasification facilities comprise offloading berths and port facilities, LNG storage tanks, vaporizers to convert the LNG into the gaseous phase, and a pipeline link to the local gas grid.[55]

Table 1. SNG losses during transportation by LNG tanker.

Activity	Leakage[a]	Value	Remark
LNG carrier loading	Displaced vapor (% of LNG fill mass)	0.13%	BOG handling system captures BOG
	Recovery rate (%)	95%	
LNG carrier transport[b,c]	Boil-off rate (% day^{-1})	0.15%	BOG used for vessel propulsion
	Assumed duration (days)	20	
	Recovery rate (%)	100%	
LNG receiving at import terminal[d]	Displaced vapor (% of LNG fill mass)	0.13%	BOG handling system captures vapors
	Recovery rate (%)	95%	
LNG storage at import terminal[b,e]	Boil-off rate (% day^{-1})	0.05%	BOG handling system captures BOG
	Assumed duration (days)	5	
	Recovery rate (%)	95%	
LNG vessel fueling[f]	Displaced vapor (% of LNG fill mass)	0.22%	BOG handling system captures vapors
	Recovery rate (%)	95%	
LNG vessel boil off	Boil-off rate (% day^{-1})	0.15%	BOG used for vessel propulsion unless vessel is idle
	Assumed duration (days)	4	
	Recovery rate (%)	98%	

Source: Lowell et al.[59]

[a]Other studies, e.g. Jaramillo et al.,[60] PACE[56] and Tamura et al.[61] estimate gas loss at the liquefaction terminal to be 8.8–12.8% of liquefied gas.

[b]Losses are due to venting from storage tanks and tankers over time – so-called boil-off gas (BOG) to regulate tank pressure, typically set to 0.7 bar. The cryogenically cooled LNG at –162 °C absorbs heat in storage resulting in pressure build up in container. BOG losses are estimated to be 0.1–0.25% of stored LNG per day; Thus BOG losses are a function of trip duration, size and construction of containers, number and type of transfers. However BOG handling measures are normally put in place to capture about 95% BOG and recycle it. During international shipping, losses also occur from the ship's fuel system and the engine's exhaust during operation. The BOG is withdrawn continuously to power the ship's engines.[59]

[c]Flash losses occur especially when transferring LNG from a high-pressure to a low-pressure tank.

[d]Losses occur due to venting of displaced vapor when filling storage tanks.

[e]Leakage due to purging of LNG liquid and vapor from hoses and lines after fueling a vessel.

[f]PACE[56] estimated a gas loss of 5% during LNG transport for a distance of 7369 nautical miles. LNG tankers are equipped to capture 'boil-off' gas and reuse it as fuel. The rate of bio-off is lower than the rate of consumption of LNG tanker.[59]

Storage and regasification can be either onshore or offshore aboard the LNG carrier (so-called floating storage and regas unit -FSRU).[64]

Vaporizers warm LNG from about –162 °C to over 5 °C into gas and in their simplest form comprise simple tubular units or paneled heat exchangers in which LNG is pumped through, allowing the temperature to rise. In warmer climates, seawater keeps the heat exchangers warm and, to avoid ice build-up on the panels while in colder climates, heated water is used.[55] Seawater has drawbacks as it freezes at –160 °C in the heat exchanger. To improve the process efficiency, reliability, and economics, a combination of propane and seawater in cascade loops to warm the LNG can be used.[64] Common LNG vaporizer technologies include open rack vaporizers (ORV), submerged combustion vaporizers (SCV), shell and tube vaporizers (STV), intermediate fluid vaporizers (IFV) and ambient air vaporizers (AAV). Open rack vaporizers and SCVs are the most common technologies.[65] We assume ORVs at Rotterdam.

Compression to bio-CNG (compressed natural gas)

Using bioSNG as a transport fuel requires the establishment of necessary infrastructure for vehicle refueling with sufficient national coverage.[66] The gas is supplied to the fuel station via the low-pressure grid at 8 bar with a distribution efficiency of about 99%.[58] Bio-CNG is supplied at pressures of 230–250 bar (vehicle tanks and engines have a working pressure of 200 bar) and requires costly compression investments at the fueling station.[6]

Refueling of bioCNG can be done via a 'fast-fill' public refueling station (similar to the regular petrol fueling stations) or via an exclusive 'slow-fill' refueling station (e.g. for large bus fleets).[67] Storage cylinders (capacity 500 Nm^3) provide a buffer at the fueling stations between the supply of gas from the grid (after compression) and the supply to the vehicle. On average, public refueling stations have a 50 $Nm^3\ h^{-1}$ hydraulic multistage compressor while larger stations have between 400 and 1000 $Nm^3\ h^{-1}$.

  | *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

Methodology

Supply chain analysis – comparison framework

To find optimal bioSNG supply routes, it is necessary to compare various technological pathways in terms of least cost economic and most energy efficient delivery of the final fuel. As shown in Fig. 6, we selected six supply-chain scenarios based on different:

- biomass production regions (Brazil, Ukraine);
- biomass types (eucalyptus, poplar)'
- pretreatment (drying, wood pellets (WPs), torrefied pellets (TOPs));
- bioSNG transport (pipeline, shipping tanker);
- bioSNG conversion locations (Brazil, Ukraine, Netherlands)/

As shown in Fig. 6, the following scenarios were analyzed:

- Ukraine – SNG conversion is done at the CGP and fed into the national gas grid;
- Brazil – SNG conversion at coast (wood chips dried at inland CGP and transported by train);
- Brazil – SNG conversion at coast (wet wood transported to coast by train);
- Brazil – SNG conversion at CGP (SNG transported to coast by pipe and to EU by tanker);
- Brazil – SNG conversion in Netherlands (TOPs transported by train and bulk carrier);
- Brazil – SNG conversion in Netherlands (WPs transported by train and bulk carrier).

The justification for selecting the regions and pathways is discussed below. As there is insufficient biomass in the Netherlands for large-scale bioSNG production, the starting point is to identify potential biomass feedstock production regions and location of the final conversion facility. Ukraine and Brazil were selected as potential feedstock production regions because previous studies have indicated large biomass production potential in those countries.[41,42,68] The two countries were also selected because infrastructure is available for transporting biomass and bioSNG. These two regions (Ukraine and Brazil) offer contrasting possibilities for producing and supplying bioSNG for the Netherlands market. While, for tropical Brazil, eucalyptus would be a suitable woody energy crop, poplar is more suitable for the temperate climate in Ukraine. Woody energy crops are preferred in this study as there is experience and demonstrated potential in the selected countries,[41,42] and also because their suitability for gasification compared to other biomass types such as

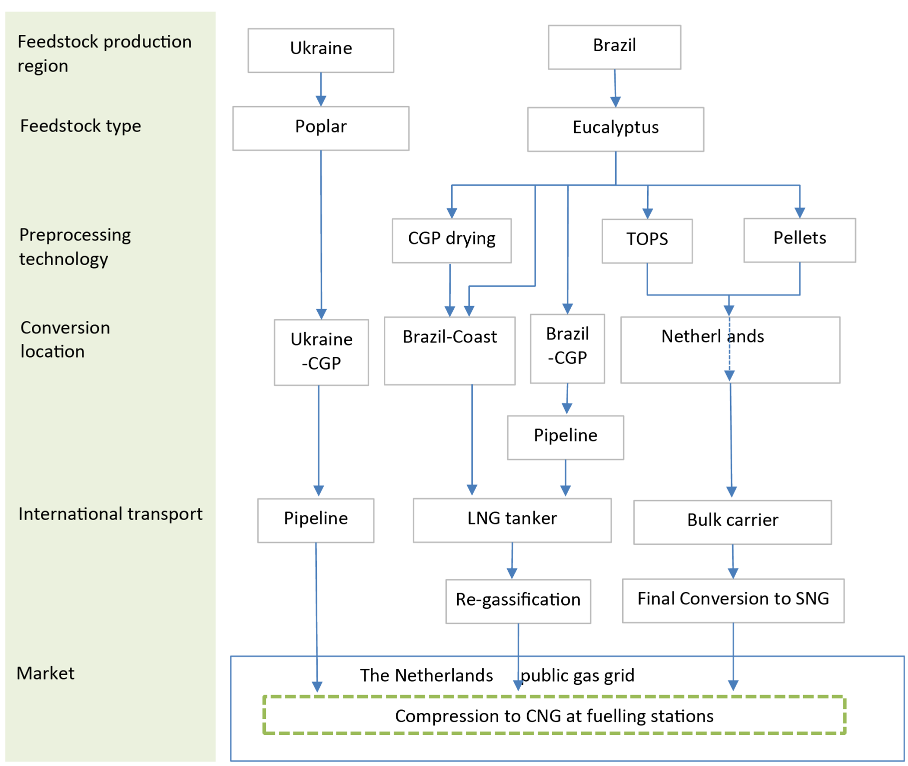


Figure 6. BioSNG production and supply chain pathways (scenarios).

grasses.[69] There are other potential biomass production regions such as Canada or Scandinavia. While western Canada is an interesting prospect, the long-distance transport distances (>16 500 km)[70] are comparable to Brazil (9700 km).[71] Scandinavian countries are also another potential source of biomass but most of this biomass is committed as the region has a large bioenergy market.[72,73]

The final conversion of biomass to bioSNG can take place in the production regions or in the Netherlands. If final conversion is done in the Netherlands, then typically preprocessed biomass (such as chips, WPs or TOPs) has to be transported from the production regions to the Netherlands. Alternatively, if bioSNG is produced in the biomass feedstock production region, the gas needs to be transported either by pipeline (from Ukraine) or as liquefied natural gas (LNG) by shipping tanker (from Brazil). While in Ukraine, pipeline infrastructure already exists for natural gas transportation to western Europe, in Brazil, new LNG-handling facilities would need to be established.

For pipeline transport, Ukraine was selected because it has access to the European gas grid and a large potential for economic energy crops production.[41] Ukraine is also connected by gas pipeline to the Netherlands through Poland and Germany (Gas Infrastructure Europe, www.gie.eu.com). Similarly, compared to other developing countries, Brazil has comparatively advanced infrastructure, which enables economic transport and handling of biomass to international markets. There are already fledgling biofuels export activities from Brazil to the EU.[74]

For the LNG transport cases, the best short-term option would be to locate the bioSNG production near an existing LNG liquefaction terminal. There are, however, only a few liquefaction terminals in the world located in regions with significant biomass production potential. Currently, the largest LNG facilities are located in Qatar, Indonesia, Malaysia, Australia, Algeria, Russia, Yemen, Angola, and Papua New Guinea (IEA, https://www.iea.org/about/faqs/naturalgas/). In this case, therefore, a location for bioSNG production is selected based on biomass potential and a new LNG liquefaction facility is included in the value chain.

We also consider long-distance transport of WPs and TOPs to improve the supply chain competitiveness by increasing the energy density of the raw biomass. While WPs are currently the most widely traded solid biomass commodity, TOPs are a more attractive tradeable commodity in the near future.[75] We do not consider WPs or TOPs production from Ukraine as low- cost natural gas pipeline infrastructure linked to the Netherlands already exists. Pellets and TOPs would have to be transported by rail over long distances (which is uneconomic compared to pipelines).

Modeling the bioSNG supply chain

Biomass production and logistics

Biomass production is modeled with energy-crop plantations around a selected central gathering point (CGP). The biomass is cultivated and harvested at the plantation, dried in the field, and then transported by truck to the CGP. Biomass is harvested at 55% moisture content with an oven-dry heating value of 18.4 and 17.7 GJ t_{dm}^{-1} for eucalyptus and poplar, respectively.[41] Biomass production costs for eucalyptus and poplar are taken from recent studies are as shown in Table 2.

In Brazil, bioSNG production is either at an inland CGP or at the coast, as shown in Fig. 6. In the latter case, raw biomass is transported by train over an average distance of 300 km to the coast. When biomass final conversion takes place at the CGP, the bioSNG is transported to the coast by pipeline. A new LNG liquefaction and export terminal is assumed and factored into the value chain. Subsequent long-distance shipping to Rotterdam (9710 km) is done using LNG shipping tanker.

In the chains with bioSNG production in Ukraine, bioSNG production takes place at the CGP. It is assumed

Table 2. Key data on biomass production and local transport.

Item	Average used value	Unit	References
Eucalyptus production costs Brazil	2.1	$ GJ^{-1}	42
Poplar production costs Ukraine	2.3	$ GJ^{-1}	76
Eucalyptus yield	16	t_{dm} ha^{-1} year^{-1}	42
Poplar yield	10	t_{dm} ha^{-1} year^{-1}	42,43,77
Truck weight capacity	28	t	78
Truck weight capacity	100	m^3	79
Truck costs (Brazil)[a]	0.06	$ t-km^{-1}	79
Truck costs (Ukraine)	0.1	$ t-km^{-1}	80
Truck diesel consumption[b]	17.5	MJ km^{-1}	78
Train weight capacity	1000	tons	79
Train volume capacity	2500	m^3	79
Train costs (Brazil)[a]	0.03	$ t-km^{-1}	79
Train costs (Ukraine)	0.07	$ t-km^{-1}	80
Train energy consumption	240	MJ km^{-1}	45

[a]Based on transport costs for Argentina.[79]
[b]Based on diesel consumption of 0.5 L km^{-1} and 35 MJ L^{-1}.

| *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

the gas can be injected into the gas grid at the CGP and transported by pipeline from Ukraine to the Netherlands (we assume a distance of 2100 km from central Ukraine to the Netherlands through existing long-distance pipelines). For bioSNG production in the Netherlands, we assume TOPs and WPs are transported from Brazil by bulk carrier ships. For use in vehicles, SNG has to be distributed via the local gas grid and compressed (and stored) at refueling service stations to a pressure of 250 bar.[6]

Biomass preprocessing

We consider a preprocessing scale of 250 kt year^{-1} output wood pellets (WPs) and torrefied pellets (TOPs) to take advantage of economies of scale (although larger capacity pellet-production plants exist, e.g. the 750 kt year^{-1} plant in Georgia or the 900 kt year^{-1} Vyborgkaya plant in Russia, current integrated torrefaction plants are being designed for this range).[47] Per ton of product, TOPs require a larger biomass input than WPs due to losses during processing. A typical mass and energy balance for woody biomass torrefaction is that 70% of the mass is retained as a solid product, containing 90% of the initial energy content. The other 30% of the mass is converted into torrefaction gas.[47] Typically, less than 5% of the biomass is used to meet the thermal demand during preprocessing of biomass. For WPs, the thermal demands are mainly for drying feedstock (about 4% of biomass is used for drying). For torrefaction, part of the thermal demand (at least 60% with current technologies) can be met by using torrefaction off-gases.[75] Table 3 shows the overall energy requirements for preprocessing biomass.

Preprocessing costs are based on investment and O&M costs for integrated pellet and torrefaction plants. As shown in Table 4, we assume integrated torrefaction systems with a compact moving bed reactor as the core technology. The investment costs are estimated to be about 6.3 MUS$ for 5 t h^{-1} operational capacity.

Table 3. Preprocessing energy use for TOPs and WPs (MJ t_{dm}^{-1}).

Supply chain stage	Fuel type	WPs	TOPs
Chipping	Electricity	79.35	90.87
Drying	Electricity	179.75	103.90
	Biomass	840.05	195.96
Torrefaction	Electricity	–	232.01
	Biomass	–	3,779.66
Milling	Electricity	200.00	36.95
Pelletizing	Electricity	296.00	162.00

Source: Batidzirai *et al.*[47]

Truck transport

To estimate the required harvested areas area for feedstock production to supply a 250 kt year^{-1} preprocessing plant and corresponding transportation distances, we use the methodology developed by van der Hilst and Faaij,[46] which takes into account required biomass supplies (based on a scale of 100 $MW_{th, in}$ normalized at the bioSNG final conversion stage), spatial distribution of available land, and potential biomass yields. The method assumes that the biomass distribution over an area is constant and that the biomass is transported over a marginal transport distance, which is the radius of a circle in which the biomass is spread with the given distribution density. We assume biomass is harvested over 10% of available land in the selected regions with average productivity of 16 t_{dm} ha^{-1} for eucalyptus and 10 t_{dm} ha^{-1} for poplar.[42]

The first truck transport from the plantation is 'dedicated', meaning that the truck has no new load on its way back. Key factors that influence costs include average speed, truck capacities, load-unload costs and ton-km operating costs. Operating costs on unpaved roads are higher due to lower speeds. Weight is the limiting factor for truck transport of biomass (due to low bulk density). While larger capacity trucks have lower tonne-km costs due to economies of scale, road vehicle weight regulations limit the maximum truck capacity. We assume in both regions that the gross vehicle weight limit is at 28 tons on public roads.

Rail transport

We assume that diesel trains are used to transport biomass from the CGP to the coast in Brazil. For raw biomass, the train capacity is limited by volume, for pellets and TOP pellets the train capacity is limited by weight. For example, for 1000 tons (4167 m^3) of raw chips with bulk density of 240 kg m^{-3},[44] two trips of 2083.3 m^3 are required to transport all the biomass because capacity is limited to 2500 m^3. In comparison, for 1000 tons of TOPs with a bulk density of 750 kg m^{-3}[75] a single trip carrying 1333 m^3 is necessary.

Long-distance ocean shipping of solid biomass

The cost and energy use of ocean transport depends on the size of the ships. We assume large Panamax ships because they provide economies of scale (although this is currently not happening, it allows a fair comparison with LNG tankers). Charter costs are very sensitive to global demand and supply. According to Hoefnagels *et al.*[49] charter costs in the period 2007 to 2011 ranged from about 4000 to

Table 4. Economics of integrated torrefied pellet production system at scale of 250 kt year^{-1} (compact moving bed system).

	Base scale (t/h)	Max scale (t/h)	Base cost (MUS$)	O&M costs (MUS$)	No of units	Scale factor	Total invest (MUS$)
Chipping (chipper)	5	80	0.07	0.12	2	0.70	0.61
Drying (rotary drum type)	6	50	0.44	0.11	9	0.65	3.75
Torrefaction reactor (moving bed reactor)	5	12.5	6.25	3.77	4	0.72	47.03
Milling (hammermill)	5	50	0.07	0.02	1	0.70	0.37
Pelletizing (pellet mill and cooler)	5	20	1.47	0.41	7	0.61	10.18

Source: Batidzirai *et al*.[75]

Table 5. Ocean transport data (Panamax bulk carrier).

Item	Value	Reference
Capacity (dead weight tonnage)[a]	75 000	[49]
Capacity (m^3)	90 000	[49]
Investment (M$)[b]	40.4	van Overklieft C, 2011, personal communication
Lifetime (years)[b]	25	
Charter costs 2013-average (2007–2011) ($ day^{-1})	19 588	[49]
Port costs ($ t^{-1})	1.90	[49]
Load/Unload speed (t h^{-1})[c]	600	Westerberg E, 2011, personal communication
Load/unload costs ($ t^{-1})[c]	2.0	[49]
Travelling speed unladen (knots)	15	[49]
Travelling speed laden (knots)	14	[49]
Fuel use t day^{-1} (IFO 180)	33	[49]
Fuel price (IFO 180) ($ t^{-1})[d]	498	[49]

[a]Based on a Panamax dry bulk carrier, general range 60 000–75 000 DWT (Dead weight tonnage cargo). Capacity is expressed as DWT, this is the actual mass of cargo, stores, fuel, passengers and crew that can be carried by a vessel when fully loaded to summer load-line mark.[81] Cargo capacity is a percentage of the dead weight tonnage of a ship (equivalent to an effective capacity 53 400 tons).[49] For biomass the amount that can be transported is volume dependent because of the stowage factor of the selected ship.
[b]The investment figures are based on a newly built ship, delivery price in the first quarter of 2011 (van Overklieft C, 2011, private communication)
[c]The time taken to load and unload the ship in the port. Charter costs and fuel use in the port are taken into account in the cost (Westerberg E, 2011, private communication). Based on Port of Rotterdam current capabilities to unload/load coal.
[d]Prices for heavy fuel oil (IFO 180) are volatile, and varied from 260 to 795 US$ ton^{-1} in the period 2007–2011. An average of 498 is used in this study (Bunkerworld, www.bunkerworld.com).

50 000 $ day^{-1} (we use an average value of 19 588 $ day^{-1}). Table 5 shows the assumed shipping parameters used in this study.

Pipeline transport

From the injection point in Ukraine the gas is transported for about 2100 km through Poland and Germany to the Netherlands where investment costs are estimated to be 0.86 M$ km^{-1} and operational costs are 0.026 $ km^{-1}/1000 m^3 (as shown in Table 6). The pipeline costs are based on the Yamal – Europe Russia gas pipeline (length 4107 km, diameter 1.4 m, capital cost of 3.5 billion $) (Hydrocarbons-technology (Net Resources International) http://www.hydrocarbons-technology.com/projects/yamal-europegaspipel/). The pipeline has 31 compressor and is made of steel grade X80, capable of withstanding pressure of 80 bars (Gazprom, www.gazprom.com/about/production/projects/mega-yamal/)

LNG Liquefaction

Capital costs of an LNG liquefaction facility are site specific and less than 50% of the LNG plant cost is capacity related as shown in Table 7. The key cost elements in most LNG plants include feed gas handling and treating, liquefaction, refrigerant, fractionation, LNG storage section, marine and LNG loading, and a utility and offsite section.[62]

  | *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

Table 6. Background data of pipeline and SNG transport.

Item	Value	Unit
Length of pipeline (estimate)	2100 (Ukraine–Netherlands)	km
Length of pipeline (estimate)	300 (Brazil inland CGP to coast)	km
Diameter of pipe	1.42	m
Capacity of pipeline (mass flow)	33	billion m^3 $year^{-1}$
Cost per km[a]	0.86	M$ km^{-1}
Cost per km per unit gas[b]	0.026	$ km^{-1} 1000 m^{-3}
Energy use (electricity) for compression	3.3E–4	MJ km^{-1} m^{-3}

[a]Capex for long-distance, large diameter pipes (1.17–1.52 m), with capacity of about 15–30 billion m^3 $year^{-1}$, is estimated to be in the range 1–1.5 $\$_{2003}$ billion/1000 km.[82] An alternative approach for estimated levelized pipeline costs is proposed by Knoope *et al*.[54] and uses the following formula to estimate costs for CO_2 transport:

$$LC = \frac{a_f{}^*(I_{boost} + I_{comp}) + \alpha^* I_{pipe} + OM_{boost} + OM_{pipe} + OM_{comp} + EC_{boost} + EC_{comp}}{m^* H^* 3.6}$$

where *LC* are the levelized cost of CO_2 transport *($ t gas^{-1})*; α is the capital recovery factor; $I_{boost/pipe/comp}$ and $OM_{boost/pipe/comp}$ are the investment and operation and maintenance (O&M) costs of boosters, pipeline and compressor, respectively *($)*; $EC_{boost/comp}$ are the energy costs of boosters and compressor, respectively *($ year^{-1})*; *m* is the CO_2 mass flow *(kg s^{-1})*; *H* are the number of operation hours *(*8760 h $year^{-1}$*)*; a_f is the annuity factor as defined in Eqn (4).
[b]According to Knoope *et al*.,[54] the energy requirement (E_{boost}) and capacity for booster stations (W_{boost}) can be calculated as follows: $E_{boost} = \frac{P_2 - P_1}{\eta_{boost}{}^* \rho}$; $W_{boost} = E_{boost}{}^* m$; where E_{boost} is the energy consumption of pumping (MJ kg^{-1}); P_2 is the outlet pressure (MPa); P_1 is the inlet pressure (MPa); η_{boost} is the efficiency of the booster station (75%); ρ is the gas density (kg m^{-3}); W_{boost} is the capacity of booster station (2 MW_e) and m is the mass flow (kg s^{-1}).

Table 7. Liquefaction cost distribution for a 70 MWth, in LNG plant (source: Kotzot *et al*.[62]).

Component	Investment cost (M$)[a]	Percentage of total cost (%)
Gas treating	0.91	7
Fractionation	0.39	3
Liquefaction	3.65	28
Refrigeration	1.83	14
Utilities	2.61	20
Offsites (storage, loading, flare)	3.52	27
Site preparation	0.13	1
Total investment cost	13.05	100

[a]Di Napoli[83] gives a different investment cost breakdown as follows: liquefaction trains (34–38%), utilities (12–16%), LNG storage and loading (10–15%), buildings and miscellaneous (3–5%), EPC contractor (14–16%), marine related (3–6%), infrastructure (0–6%), other project related (10–12%).

The liquefaction portion of any LNG project typically represents 35–40% ($1–1.2 billion at $300/tpy and 10 Mt $year^{-1}$) of the total petroleum-LNG value chain.[83,84] In the 1980s, LNG facility costs reached a high of $600/tpy, but declined to around $200/tpy in 2005 due to technological learning and scaling. Further economies of scale are now limited by equipment and train-size limitations but also high demand for engineering labor and material (especially steel and nickel) are overshadowing technical improvements.[84] About 8–10% of gas delivered to the LNG plant is used to fuel the refrigeration process.[55,58]

LNG sea transport

Liquefied natural gas transport is by dedicated LNG tankers of capacity 155 000 m^3. These tankers are powered with boiled-off LNG (BOG) when loaded and with fuel oil when unloaded. As shown in Table 8, we assume about 4% of the gas is consumed during international shipping.[56–58]

LNG Regasification

Regasification costs are estimated to be 0.6 $ GJ^{-1}.[87] An example of the tariff structure of an LNG regasification facility at the Montoir de Bretagne (France) is given in Table 9. The vaporizer equipment represents the largest capital cost element of the regas facility.[55] The Rotterdam Gate terminal was built at an estimated cost of €800 million for a capacity of 12 billion m^3 and has two jetties for unloading LNG carriers, three storage tanks (180 000 m^3 each) and eight ORVs (Gate Terminal, http://www.gate.nl/). For a 150 000 m^3 storage capacity system, Foster Wheeler gives Capex for an onshore regas facility of 300 $ million and for a leased FSRU at 70 $ million.[88]

Table 8. LNG transport data by tanker.

Item	Value	Unit	Reference
Capacity ship[a]	155 000	Nm^3	51
Average speed LNG carrier	20	knots	60
Charter costs[b]	92 000	US\$ day^{-1}	51
Energy consumption by LNG ship (as percentage of gas transported)	4%		56–58
Fuel oil consumption (return trip)	172	ton day^{-1}	60
(Un)load speed	1000	$m^3\ h^{-1}$	85
Energy required for liquefaction (as a percentage of gas being liquefied)[c]	10–20%		59

[a]LNG average charter rates for a 155 000 m^3 capacity tanker range from a low of about 20 000 \$ day^{-1} in 2010 to above 140 000 \$ day^{-1} in 2012. An average of 92 000 \$ day^{-1} is used for 2013.[51]
[b]According to Das,[86] future LNG shipping costs are likely to stabilize (based on the market developments in the last few years) due to: (a) availability of a large number of LNG carriers, (b) new technology which allows for reliquefying boil-off gas and thereby offers more cargo to buyers, and (c) development of new generation of LNG carriers that will increase cargo capacity. LNG shipping rate are estimated to be \$0.27/GJ (considered minimum shipping cost) to U.S.\$0.84 GJ^{-1} (for shipments from Russian Far East to the North American West Coast).
[c]Agarwal and Babaie[65] estimate that about 500 kWh t_{LNG}^{-1} is used for compression and refrigeration during LNG production. Most of this invested energy is embodied in the LNG and potential exists for energy recovery during the re-gasification process. In Rotterdam, eight open rack vaporizers (ORVs) are used with warm cooling water of the E.on power plant for vaporization of LNG to enable a daily delivery capacity of 12 billion m^3 of gas per year (Gate Terminal, http://www.gate.nl/).

Table 9. LNG Regasification terminal tariff structure (source: Elengy http://www.elengy.com/en/commercial-section/tariffs/price-estimate-for-access-to-lng-terminals.html).

Cost item	Cost value
Berthing rate	65 000 \$ per unloading
Unloading costs	0.85–1.13 \$ MWh^{-1} (0 °C) unloaded
Regasification capacity use cost[a]	0.16 \$ × Q × N
Regularity rate[b]	0.05 – 0.27 \$ × | $Q_h - Q_e$|
Gas taken off cost[c]	0.50% of unloaded quantities

[a]The gasification capacity use rate applies to the average interval over 1 year between two tanker arrivals and the quantity unloaded over the year. Q: quantity of LNG unloaded over the year in MWh (0 °C); N: average time between two tanker arrivals, expressed in months. 1 MWh (0 °C) is equivalent to 150 m^3 of LNG.
[b]The regularity rate is applied to the difference in absolute value between LNG (in MWh, 0 °C) unloaded in winter (Q_h) and the quantities of LNG unloaded in summer (Q_e).
[c]The gas taken off rate covers gas consumption at the terminal corresponding to the fixed amount of gas needed to handle the cargo.

Regasification of LNG requires a very large amount of energy in the form of heat for LNG vaporization. We assume that about 1.5% of the gas is consumed during regasification.[56–58] According to Strande and Johnson,[64] to vaporize 14 million m^3 of gas per day would require about 100 MW of heat. Direct and indirect heat-transfer processes used in LNG regasification are inefficient and LNG cold energy is wasted.[55] However, LNG cold energy can be used in various applications (e.g. cooling media for power plants or adjacent industrial facilities). The Rotterdam Gate Terminal has eight ORVs, which use warm cooling water of the E.on power plant for LNG vaporization at a capacity of about 1.67 million Nm^3 per hour (Gate Terminal, http://www.gate.nl/).

Compression to bio-CNG (compressed natural gas)

Bio-CNG requires costly compression investments at the fueling station. Currently, the investments for an average refueling station are about \$325 000–\$455 000 (average \$390 000).[6] The investment costs for the compressor (capacity 50 $Nm^3\ h^{-1}$) for such a refueling station are about 50% of these costs,[89] which is about \$162 000–\$227 000 (average \$194 500). Opex is estimated to be 2% of capex. The economic lifetime of the fueling station is assumed to be 15 years with an average load factor of 7 h per day.[89]

Estimating CNG compression energy requirements

The energy requirements for compression are a major cost item. For compression from 8 to 250 bar, the energy requirements are estimated to be 789 kJ kg_{SNG}^{-1} (or 175 kWh $m^{-3}{}_{SNG}$) while corresponding energy costs are estimated to be 0.055 \$ Nm^{-3} gas. Compression energy requirements are estimated using the following formula based on the isentropic specific work (W in J kg^{-1}) of a gas compressor for specific inlet pressures:[90,91]

$$W = \frac{k}{(k-1)} \times R \times T \times \left(\left(\frac{P_2}{P_1} \right)^{\frac{K-1}{k}} - 1 \right) \quad (1)$$

where: κ – ratio of specific heat – 1.32 (natural gas); R – individual gas constant 518.3 J kg^{-1} K (natural gas); T – absolute temperature K 283 (ground temperature); P_2 – outlet pressure N m^{-2} 25 million (= 250 bar); P_1 - Inlet pressure N m^{-2} (= 8 bar)

  | *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

From the theoretical work, the energy requirement for compression (E – kWh kg^{-1}) is calculated using the following formula:

$$E = \left(\frac{W}{\eta_c}\right) \times \frac{\rho_g}{3.6} \tag{2}$$

where: η_c is the efficiency of the compressor (80%[54]), ρ_g is density of natural gas (66.7 kg m^{-3} at 15 °C and 8 bar (Unitrove, http://www.unitrove.com/engineering/tools/gas/natural-gas-density).

BioSNG production plant investment costs

The investment costs estimated here are for a conceptual design of a first generation *'nth plant'* and not for a pioneer plant. Economics of the *'nth-plant'* is useful for studying new process technologies or integration schemes and assumes that several plants using the same technology have already been built and are operating. In this study we assume that although the technology is commercialized, the plant is not fully optimized and significant scaling up and learning is still expected. This approach avoids inclusion of costs associated with first-of-a-kind or pioneer plants (e.g. artificial inflation of project costs associated with risk financing, longer start-ups, equipment overdesign), because these costs can overshadow the real economic impact of research advances in conversion or process integration.[92] Investment costs for bioSNG production plant can be categorized into fixed capital investment, working capital, and start-up costs. Fixed capital costs can be further split into direct and indirect costs as shown in Table 10. Direct costs include bare equipment costs and fittings and account for about 70% of the total capital investment (TCI), whereas indirect costs comprise 30% of TCI. Investment costs given here are total installed costs, which include equipment costs, material, and labor costs, inside battery limit costs, outside battery limits costs as well as engineering procurement cost and construction.

As shown in Table 10, the capex is dominated by the gasifier/biomass feed/cooler/cyclone combination estimated to be 93 M$, OLGA tar reformer (31 M$), Selexol CO_2 remover (28 M$) and Syngas compressor (14.5 M$). Biomass feeding-system costs are included in the Milena gasifier costs. Capital costs for the cooler and cyclone are also aggregated into the gasifier costs. As a comparison to given capital costs, Van der Drift B (2013, private communication) estimates that the capital cost breakdown of the Milena gasifier based bioSNG production system is: solids handling (8%), gasifier (15%), cooler/cyclone/OLGA/water-system (25%), compressor (5–10%), ultracleaning and methanation (30%), and CO_2 and water removal (15%).

Some of the component costs are not publicly available and the estimates given here are original estimates based on component sizing modeling. For instance, Sulferox costs are not available publicly and the estimated costs are based on the Shell Paques sulfur treating system. According to Cline *et al.*[99] a 0.696 kmol S s^{-1} Shell Paques system requires total investment and 10-year O&M cost of 16.6 M$. We therefore estimated that the total investment cost account for 50% of these costs, or 8.3 M$.

To estimate the capital costs of the ZnO guard bed, the reactor vessel is sized as a function of sulfur flow, sorbent loading and sorbent volume. Sorbent loading is assumed to be 12 wt%,[100] sulfur mass flow is 0.88 g s^{-1}, sorbent density is 5.61 t m^{-3}, required sorbent is 41.4 m^3 year^{-1}, and the reactor volume is estimated to be 24.8 m^3 per reactor. The bare equipment costs for the reactor vessel including piping and instrumentation are estimated to be about $250 000.[89]

The main cost elements of the methanation process are three reactor vessels, two heat exchangers and a recycle compressor. According to Chen,[101] the process facility costs of a fixed-bed reactor are a function of catalyst volume and pressure of reactor. The catalyst volume is a function of the gas flow through the reactor and its space velocity. We assume that the gas space velocity is 4.7 m$_n^3$ m^{-3} s^{-1},[103] reactor pressure is 30 bar, gas-flow rate is 94 m$_n^3$ s^{-1}, and the catalyst volume is estimated to be 22.6 m^3. Given these parameters, the bare equipment costs are estimated to be about 4.9 M$: i.e. three reactors at 0.087 M$ each, heat exchangers at 4.4 M$ and recycle compressor at 0.22 M$ (assuming a 150 hp compressor capacity).

Production costs

For economic comparison of the chains, the bioSNG costs (based on compressed natural gas (CNG) delivered to the Netherlands) are chosen as the target parameter. For each part of the production chains, the annual investment and operational costs are calculated based on literature and expert advice. All costs are calculated for the reference year 2013. Electricity costs are shown in Table 11. The total bioSNG production costs (C_{SNG} (\$ GJ$_{CNG}^{-1}$)) are calculated following Eqn (3):

$$C_{SNG} = \frac{\sum_i \left(a_f \times I_i + O\&M_i + F_c + T_{ci}\right)}{SNG} \tag{3}$$

where: a_f is the annuity factor; I_i investment costs for the supply-chain stage i (\$); $O\&M_i$ – operation and maintenance costs for supply chain stage i (\$); F_c – feedstock

Table 10. Capital investment costs for bioSNG production system with a 100 $MW_{th, in}$ capacity.

Component	Base costs M$	Scale factor	Base scale	Installed scale	Scale units	Installed Costs M$	Reference
Pretreatment (total)	**2.2**	**0.77**	**65**	**19.6**	$t_{a.r.}\ h^{-1}$	**0.87**	
Biomass receive and handling	0.41	0.8	33.5	19.6	$t_{a.r.}\ h^{-1}$	0.27	93
Biomass storage	1.16	0.65	33.5	19.6	$t_{a.r.}\ h^{-1}$	0.825	93
Feeding system							
Gasification							
Milena gasifier[a]	18-632	0.7	4.6-75	7.5	$kg_{a.r.}\ s^{-1}$	93	13,93–95
Gas cooling and particulate removal							
Cooler							
Cyclone							
OLGA tar removal[b]	1-6	0.7	0.5-25	139	$MW_{th, in}$	30.89	96
Gas cleaning and conditioning							
Water scrubber (HCL removal)[c]				12.1	$m^3\ s^{-1}$	10.19	39
Hydrolysis reactor (COS/HCN conversion)	3.9	0.7	58	7	kg syngas s^{-1}	0.84	97,98
Sulferox unit (H_2S removal)	8.3	0.7	0.7	0.3	kmol S s^{-1}	5.70	99
ZnO guard bed				6.9	kmol S s^{-1}	0.25	89,100
Syngas compressor[d]	0.5–26	0.7	0.09-4	5.68	MW	14.51	13,101
Shift reactor[e]	3.1	0.7	59.4	7.34	kg feed s^{-1}	0.72	97,98
Methane synthesis							
Methanation isle				8.8	kg feed s^{-1}	4.9	101
Gas Upgrading							
Condenser[f]	14	0.7	488	7	MW	0.71	97,98
Selexol (CO_2 removal)[g]	61–90	0.7	25–50	7.6	kg CO_2 s^{-1}	28.4	97,98,101
SNG compressor[d]	0.5–26	0.7	0.09–4	0.363	MW	2.12	13,101
TIC						193.36	

[a]Zwart *et al.*[13] modeled four different scales of the Milena gasifier based bioSNG production at 10 MW_{th} at atmospheric pressure, 100 MW_{th} atmospheric, 100 MW_{th} 7 bar and 1000 MW_{th} 7 bar. Gasifier costs were estimated to be 5.0, 25.1, 39.9 and 200 $M€_{2006}$ respectively. Based on experimental results at lab scale, Zwart *et al.*[13] assumed the MILENA (bubbling fluidized bed) gasifier takes 15% wet biomass feedstock, gasification and combustion sections are operated at 870 and 975 °C respectively. Smit R, 2009, private communication gives revised investment costs for Milena gasifier for a 1000 MW_{th} as 283 $M€_{2009}$. Waldner and Vogel[102] provide estimates for large CFB gasifiers. These estimates have been calculated to TIC by Van der Spek[39]: 510 $M€_{2004}$ for a 38 kg biomass/s Fast Internal CFB and 252 $M€_{2004}$ for a 38 kg biomass/s CFB-E gasifier. In comparison, another FICFB gasifier is estimated to cost 11.2 $M€_{2005}$ for a 52.7 MW_{th} system.[93] Paisley and Overend[95] estimate the cost of a 4.6 kg biomass s^{-1} gasifier as 18.18 $M\$_{2002}$.
[b]Boerrigter *et al.*[96] made estimated the economics of the OLGA system for four different process scales, i.e.: a 500 kW_{th} ECN pilot circulating fluidized bed (CFB) gasifier 'BIVKIN' with investment cost of 1 M$, a potential ECN demonstration project (2.2 MW) with estimated investment cost of 2.1 M$, commercial stand-alone plants (10 and 25 MW_{th}) with estimated investment costs of 2.8 and 6 M$ respectively. Operational costs are estimated to be 0.67 € $kWhe^{-1}$ (for energy and scrubbing liquid).
[c]van der Spek[39] estimates the costs of water scrubber to be 1/3 of cost of OLGA since only 1 column is required instead of 3.
[d]SNG compressor capital costs range from 0.57 $M\$_{2000}$ for a 0.09 MW capacity to 21 $M€_{2008}$ for 4 MW capacity.[101] Zwart *et al.*[13] gives compressor costs of 17.5 $M€_{2006}$ for 4 MW capacity.
[e]NETL[97] gives bare equipment costs of 1.1 M$2007 for a 59.4 kg s^{-1} capacity.
[f]Based on cost estimated from NETL,[97] bare equipment cost of 4.7 $M\$_{2007}$ for a 448 MW capacity.
[g]Equipment cost for CO_2 removal by the Selexol process is estimated to be 30 $M\$_{2007}$ for a 43 kg s^{-1} capacity,[101] 3 $M€_{2006}$ for 50 kg s^{-1},[13] 20.2 $M\$_{2000}$ for capacity of 25 kg s^{-1}[101] and 3.6 $M€_{2009}$ for a 50 kg s^{-1} system (van der Meijden CM, 2009, personal communication).

  | *Biofuels, Bioprod. Bioref.* **13**:325–357 (2019); DOI: 10.1002/bbb

Table 11. Average price of electricity by country ($ MWh^{-1}).

Item[a]	Value	Reference
Average electricity price Brazil[b]	104	104
Average electricity price Ukraine[c]	127	105
Average electricity price the Netherlands[d]	198	106

[a]*Exchange rate 2.4 BRL (Brazilian Real):$; 8.1 UAH (Ukrainian Hryvna):$; 1.3 $:€ (XE, http://www.xe.com/currencyconverter/).
[b]Average tariffs for all consumer categories and all geographic regions of Brazil.
[c]Electricity tariffs as at 1 August 2013 including VAT for 'All users except the population, human settlements, urban electric transport and household needs or religious organizations.' The given tariffs is for Class I voltage 27.5 kV and above (i.e. industrial consumers). Class II voltage to 27.5 kV tariffs are given as 123.89 UAH kWh^{-1}.[105]
[d]Average electricity tariffs in Netherlands including VAT and taxes.

production costs ($); T_{ci} – transportation costs for supply chain stage *i* ($); SNG – SNG production per year (GJ $year^{-1}$).

The annuity factor is calculated with Eqn (4):

$$a_f = \frac{r}{1-(1-r)^{-equipment\,lifetime}} \tag{4}$$

where *r* is the interest rate (assumed to be 8%).

We compare the delivered CNG costs with the current and future price of natural gas, biodiesel, and oil prices in general. We also assess the impact of the current and future CO_2 prices on the competitiveness of bioSNG. When bioSNG is sold to parties with an emission ceiling (e.g. a power plant), an extra value of bioSNG compared to natural gas is the CO_2 price, which does not have to be paid when bioSNG is used. Carbon dioxide prices range from a low of €5 ton^{-1} (= price level 2013) to €56 ton^{-1} (= highest estimate coming decade).[107]

Energy efficiency

To calculate the energy efficiency of the bioSNG supply chains, the primary energy use (PEU_i) and thermal efficiency (η_i) are estimated for every stage of the supply chain *(i)*. Energy values in this study are all based on lower heating values. The energy efficiency of the entire value chains (η_{total}) is represented by the relative primary energy loss (*RPEL*) along the chain according to Eqn (5):

$$\eta_{total}=1-RPEL \tag{5}$$

The relative primary energy loss is defined as the sum of the relative primary energy use (the primary energy use divided by the initial energy content ($E_{biomass}$) of the biomass) and the thermal losses of every part of the chain, which are shown in the following equation:

$$RPEL = \sum_i \left(\frac{PEU_i}{E_{biomass}} + (1-\eta_i) \right) \tag{6}$$

RPEL represents the total energy inputs and losses along the biomass energy value chain compared to the total energy embodied in the biomass feedstock. A low RPEL implies a highly efficient biomass supply chain where, overall, the different supply chain stages consume small amounts of energy and experience low levels of thermal energy losses, allowing a higher return on energy produced for energy invested.

Chain comparison and optimization

Comparison of the supply chains are based on a scale of 100 $MW_{th,\,in}$ normalized at the bioSNG final conversion plant. The bioSNG production costs are also compared with the current market price of natural gas, petroleum diesel, and biodiesel in the Netherlands.

Scaling effects

We investigated the optimal scale for the selected bioSNG supply chains by varying the production scales in the range of 10–1000 $MW_{th,\,in}$. As the SNG conversion represents the largest cost element in the SNG value chain, we apply and discuss below the scale effect for SNG conversion. For this exercise, we compare the MILENA technology with the Güssing gasification system to evaluate the effect of scaling on both technologies and its impact on the SNG value chain. This analysis assists in optimization of the value chain by selecting the most cost effective scale and technology for final SNG conversion. The Milena SNG system has developed from a 2004 lab-scale unit (30 kW_{th}–5 kg h^{-1}) to a 2008 pilot-scale installation (800 kW_{th}–160 kg h^{-1}). Construction of a demonstration plant (12 MW_{th}) was initially scheduled for 2013 (Hofbauer H, 2009, private communication). However, due to funding delays and the need to bring in new partners, the project was delayed. Construction is now planned for 2017 and production is expected to start in 2018. Now called AMBIGO, the project partners now include Investment Fund Sustainable Economy North-Holland (PDENH) and ENGIE alongside Royal Dahlman, ECN and Gasunie New Energy.[108,109]

BioSNG production costs for different plant capacities are determined using Eqn (7):

$$C_2 = C_1 \times \left({}^{P_2}\!/\!{}_{P_1} \right)^{\alpha} \quad (7)$$

where C_1 is the investment cost of the base scale P_1, C_2 is the investment cost of the required scale P_2, and α is the scale factor.

The scale factors for the various components of the SNG conversion capital investment are estimated to be between 0.67 and 0.90.[17,52] The Milena technology from ECN can be scaled up to 1 $GW_{th,\,in}$ without major changes in the design, whereas other technologies such as the Güssing technology might be limited in capacity to 100–200 $MW_{th,\,in}$ without significant and costly changes in design. According to van der Drift *et al.*[110] the Güssing system is typically aimed at 50 MW plants for the supply of both SNG and heat at a high overall efficiency, whereas the MILENA system is built to achieve low cost on a large scale. The limiting factor is the large bubbling bed in the gasification chamber of the Güssing gasifier, which cannot be fluidized when the chamber diameter becomes too large.[111] A lower scaling factor of 0.9 is therefore applied for the Güsssing system and this assumes that higher capacities would require significant and costly changes in the design (Hofbauer H, 2009, private communication). The Milena gasification chamber is much smaller and does not contain a bubbling bed. The combustion chamber of the Milena does contain a bubbling bed but this chamber only requires 20% of the capacity of the gasification chamber (van der Meijden CM, 2009, private communication).

We did not investigate technological learning for bioSNG production as we did not have adequate data on expected learning rates for the various components of the bioSNG value chain. From previous analysis (see Batidzirai *et al.*[75] and Batidzirai *et al.*[47]), scaling effects contribute more to cost reduction of novel technologies than scale-independent learning effects.

Greenhouse gas emissions

The methodology for estimating GHG emissions along the bioSNG supply chain follows the European Commission (EC) guidelines[71] for calculating the GHG performance of bioenergy pathways for solid and gaseous biomass fuels. The functional unit used in this study is the kg CO_2e $GJ_{CNG\ delivered}^{-1}$. To estimate GHG reduction potential, two cases are compared in this study: a reference case, which is based on oil use for transport, and the alternative scenarios where CNG substitutes oil in transport.

System boundaries

The system boundary considered in this study include all GHG emissions from feedstock production (including fertilizer and chemical inputs) to delivery of CNG at the pump. Eight subsystems can be identified: feedstock production, first transport, preprocessing (chipping, drying, torrefaction, milling, pelletizing), second transport (rail, ship, pipeline), final conversion, liquefaction, regasification, and compression. Apart from GHG emissions associated with fertilizer/chemical use at plantation level, emissions from activities in the other subsystems along the supply chain are calculated for the selected scenarios based on the energy use at each stage of the supply chain as given in Eqn (8). The GHG emissions (kg CO_2 eq) associated with the construction of plant and equipment supply are not considered.

$$GHG = \sum_i \left[EF_i \times (E_i) + \left(FZ \times EF_{fz} + CH \times EF_{CH} \right) \right] \quad (8)$$

where:

EF_i – emission factor for energy use at stage *i* (kg $CO_{2\ eq}$/unit fuel);

E_i – energy use at stage I of the SNG value chain (includes energy use for feedstock production (E_{fp}), first truck transport (E_{tt}), preprocessing (E_{pp}), second transport (E_{st}), final conversion to SNG (E_{fc}), liquefaction of SNG to LNG (E_{lf}), regasification of LNG to SNG (E_{rg}), compression of SNG to CNG (E_{cp});

FZ – fertilizer use in feedstock production) (t $year^{-1}$);

EF_{fz} – emission factor for fertilizer use (kg $CO_{2\ eq}$/t fertilizer);

CH – chemical use in feedstock production (L $year^{-1}$);

EF_{CH} – emission factor for chemical use (kg $CO_{2\ eq}$ L^{-1}).

For electricity, we use the average grid emission factor for the Ukraine grid (157.6 kg CO_2e GJ_e^{-1}) and Brazil (24.7 kg CO_2e GJ_e^{-1}).[76] Other assumptions are summarized in Table 12.

Sensitivity analysis

We also performed a sensitivity analysis to assess the variability of the delivered bioSNG costs and chain energy efficiency by varying some selected input parameters (using a low and a high case for both the production costs and the relative primary energy loss). This analysis is important to identify the factors that strongly influence the performance of the chain and thereby check the level of uncertainty and robustness of the results. The criteria for selecting the factors is based on the outcome of the analysis, i.e. from the chain analysis, it is apparent that

Table 12. Basic assumptions used for GHG emission calculations.

Item	Energy crop			Reference
Fertilizer emissions from production	Eucalyptus (Brazil)	Poplar (Ukraine)	Unit (kg CO_{2eq} ha^{-1} $year^{-1}$)	
N-fertilizer (kg N)	2191.2	1210.95		76
P_2O_5-fertilizer (kg P_2O_5)	151.4	8.75		76
K_2O-fertilizer (kg K_2O)	181.3	40.72		76
CaO-fertilizer (kg CaO)	59.1	2.75		76
Pesticides	17.4	293.93		76
Total emissions	2600.4	1557.11		
Emission factors			Unit	
Oil baseline	88		kg $CO_{2\ eq}$ GJ_e^{-1}	112
Diesel	73.2		kg $CO_{2\ eq}$ GJ_e^{-1}	113
HFO	78		kg $CO_{2\ eq}$ GJ_e^{-1}	113
LNG	85.96		kg $CO_{2\ eq}$ t_{LNG}^{-1}	56,59
Electricity (Brazil)	24.7		kg $CO_{2\ eq}$ GJ_e^{-1}	76
Electricity (Netherlands)	205.56		kg $CO_{2\ eq}$ GJ_e^{-1}	114
Electricity (Ukraine)	157.6		kg $CO_{2\ eq}$ GJ_e^{-1}	76

biomass production, preprocessing, long-distance shipping, and final bioSNG conversion represent the largest cost elements to bioSNG production costs. These factors are therefore used in the sensitivity analysis. The variation in parameter values is based on ranges of values found in the literature.

De Wit and Faaij[41] and Smeets and Faaij[42] give ranges of cost estimates for energy crop cultivation for Ukraine and Brazil respectively. In Ukraine the biomass can be produced at a cost of 1.9–7.3 $ GJ^{-1}, whereas in Brazil the cost is 1.9–4.2 $ GJ^{-1}. These ranges are used for the high and low cases. For the production costs of pellets and TOPs we use the range of values derived in Batidzirai *et al*.[47] and Batidzirai *et al*.[44] These are estimated to be in the range of –18% to +11% for pellets and –24% to +43% for TOPs. Thermal efficiencies are estimated to vary from 92% to 98% as shown in Table 13. Charter costs are highly volatile and have the largest impact on long-distance shipping. They are highly sensitive to market trends and respond to the state of the global economy. According to Hoefnagels *et al*.[49] recent trends in bulk carrier charter costs show a variation of between 3500 and 95 000 $ day^{-1}. Charter costs for LNG tankers are higher and vary widely depending on market demand. Currently, charter costs are estimated to be 92 000 $ day^{-1}. Fuel oil prices also show large variations, and a range of ±20% is assumed.

For bioSNG conversion, the capital cost is the main sensitive parameter of the installation. These capital costs are based on estimates from literature and from industry experts. For the low and high cases a sensitivity range of –20% to +40% is therefore assumed. Using several references from literature, we estimated the pipeline transport costs to be in the range of 0.010–0.016 $/1000 m^3km^{-1}. The lower end is taken as the low case while for the high case the current price of gas transport from Ukraine to the Netherlands was taken – the latter was estimated using data from different grid operators.

Results

Energy balance comparison of different chains

Figure 7 shows the primary energy loss of the selected bioSNG supply chains. The major primary energy loss in all chains occurs during bioSNG production (up to 30%). Other important activities include torrefaction (21%) and international transport (up to 11%) and liquefaction of LNG (up to 10%). BioSNG production in Ukraine shows lower energy loss than in Brazil, which is mainly caused by the high energy loss of more than 10% for LNG transport from Brazil.

The torrefied pellets chain has a higher energy loss (54%) compared to the pellet chain (44%), mainly due to the high energy loss during densification (20.7%). Pellets incur a higher international transport loss of 2.7% compared to 2% for TOPs. Pellets also incur a higher drying energy loss (5%) compared to TOPs (1.5%), which is similar to drying biomass at the CGP.

Table 13. Range in parameters used for sensitivity analysis.

Item	Low	Used	High	Reference
Eucalyptus production costs Brazil ($ GJ^{-1})	1.9	2.1	4.2	41,42,78,115
Poplar production costs Ukraine ($ GJ^{-1})	1.9	2.3	5.6	41,42
TOPs production costs ($ GJ^{-1})	2.2	2.7	3.0	47
Pellet production costs ($ GJ^{-1})	1.9	2.5	5.1	47
Thermal efficiency pelletizing	92%	95%	97%	47
Thermal efficiency torrefaction	92%	97%	98%	47
Charter costs bulk carrier ($ day^{-1})	3500	19 000	95 000	49
Charter costs LNG tanker ($ day^{-1})	85 000	92 000	158 000	51
HFO price ($ GJ^{-1})	4.47	5.95	11.54	49
Total capital investment (SNG conversion)	–20%	100%	+140%	
SNG conversion efficiency[a]	67%	70%	73%	
Conversion electricity consumption (kW_e MW_{th}^{-1})[b]	–17	0	10	
Lifetime of conversion plant (yr)	30	20	15	
Conversion plant O&M (% of capital cost per year)[c]	5%	8.6%	10%	13
Pipeline transport costs ($/1000 m^3 km^{-1})	0.011	0.013	0.017	54,82
Primary energy use pipeline transport (kJ m^{-3} km^{-1})	0.27	0.33	0.49	54,116

[a]Raas H, (2009, personal communication) calculated a conversion efficiency of 73% with a 10% moisture content of the biomass.
[b]Raas H, (2009, personal communication) calculated that with an optimal heat integration more electricity can be produced during bioSNG production than needed for own consumption (17 kW_e MW_{th}^{-1}). In case of less optimal heat integration there might be a small electricity shortage.
[c]Zwart *et al.*[13] assume 10% operating costs for small scale bioSNG production, which is used as high case. For the low case 5% is assumed, which is a more common value for large power plants.

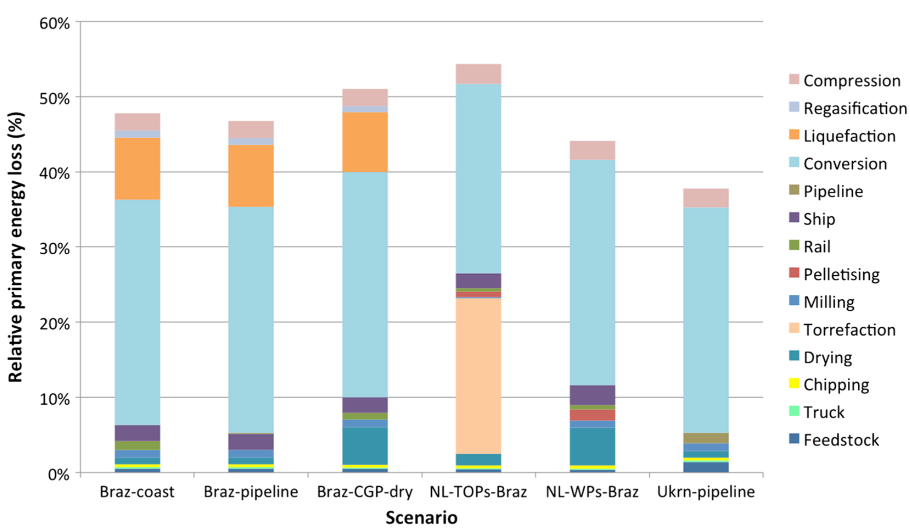


Figure 7. Relative primary energy loss of bioSNG value chain across selected scenarios (100 $MW_{th, in}$ capacity all chains).

Ukraine has the lowest energy loss (38%) because the chain does not involve liquefaction and sea transport. Drying biomass with waste heat at the coast results in lower energy loss (48%) than drying by burning part of the biomass at the CGP (51%). However, higher energy losses of transporting wet biomass (1.2%) offset some of the gains of centralized drying (0.9%).

Although the overall primary energy loss for most of bioSNG value chains does not differ significantly, the contributory factors for losses in each value chain differ widely. The differences between the chains are mainly attributed to liquefaction, LNG transport, drying, biomass pretreatment, and ocean transport steps.

Cost comparison of different chains

The delivered cost of bioSNG (in the form of CNG at fueling station on the Dutch market) ranges from 18.6 to 25.9 \$ GJ_{CNG}^{-1} for the various scenarios. Ukraine-based chains have the lowest bioSNG production costs of the three potential SNG production locations. From Fig. 8, the lowest delivered cost (18.6 \$ GJ^{-1}) is for bioSNG produced in Ukraine and transported by pipeline to the Netherlands. The comparatively shorter biomass transport distance and low pipeline transportation costs (0.16 \$ GJ^{-1}) contribute significantly to these low final delivered costs compared to shipping liquefied SNG by LNG tanker (2.1–2.2 \$ GJ^{-1}) over much longer distances from Brazil. The additional liquefaction costs also incur a gas penalty of about 10%.

Generally, bioSNG produced in Brazil is delivered to Rotterdam at higher costs (21.5–25.9 \$ GJ^{-1}) compared to bioSNG production in Ukraine (18.6 \$ GJ^{-1}). This is

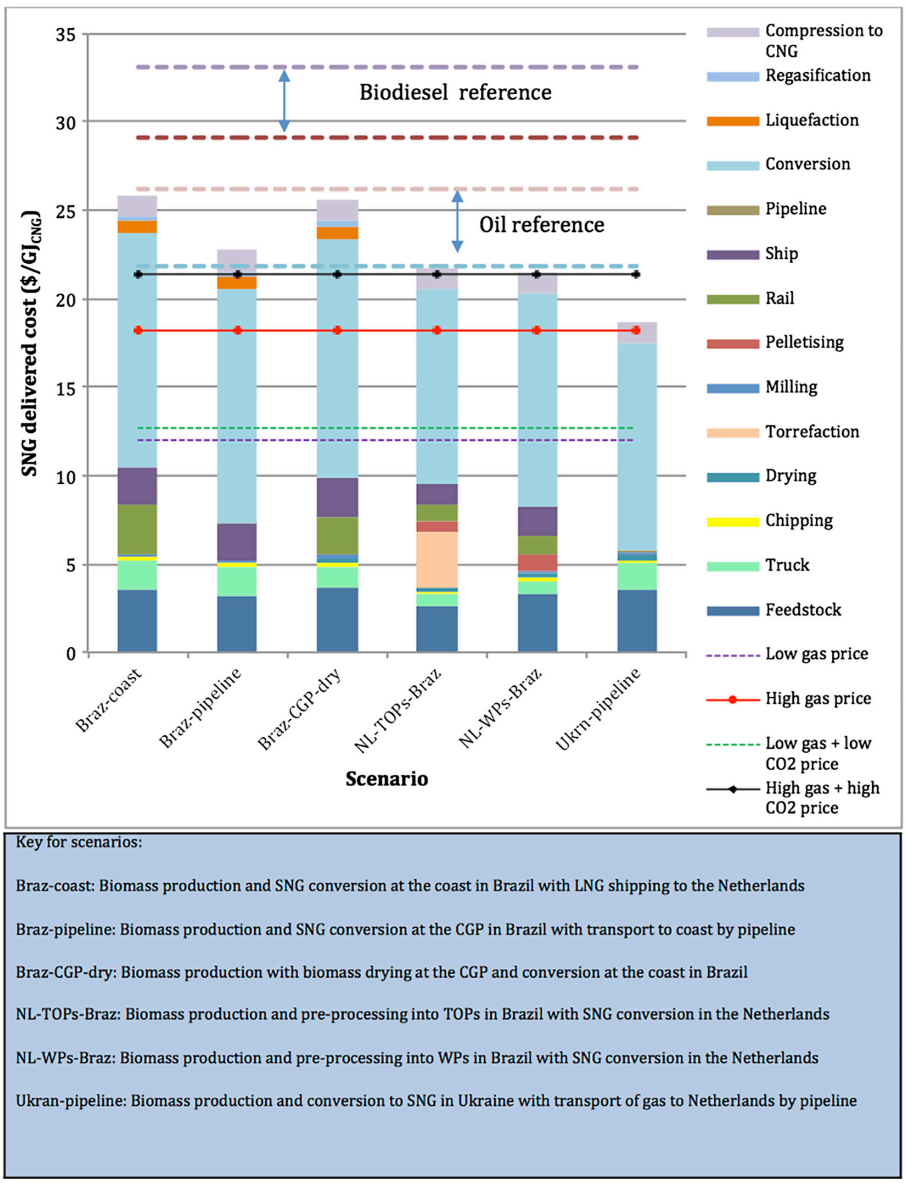


Figure 8. BioSNG production costs compared to natural gas prices, oil and biodiesel (100 $MW_{th,\ in}$ capacity all chains).

mainly caused by the high international shipping costs for LNG transport and the additional rail transport costs to the coast, which is not necessary in Ukraine.

Producing bioSNG in Brazil at inland locations with subsequent shipping of the gas to the coast by pipeline results in fuel costs of 23.1 \$ GJ^{-1}. Low pipeline costs play an important role in lowering costs in this scenario (compared to the conversion at the coast). Transporting biomass by train in Brazil and producing bioSNG at the coast results in fuel costs of 25.6–25.9 \$ GJ^{-1} delivered to Rotterdam. In Brazil, drying biomass at the coast results in more costly fuel (25.9 \$ GJ^{-1}), compared to the scenario with CGP drying (25.6 \$ GJ^{-1}) because of the higher train transport costs for wet biomass. This is despite the benefit of free waste heat for drying available from the integrated conversion facility. For the pipeline scenario, we assume that a gas pipeline is available for gas transport to the coast.

For bioSNG production in the Netherlands, the TOPs chain delivers the marginally higher cost fuel (21.7 \$ GJ^{-1}) than the pellets chain (21.5 \$ GJ^{-1}). The higher torrefaction costs (3.1 \$ GJ^{-1}) are compensated by the lower international shipping costs as well as lower feedstock and truck transport costs (compared to pellets). See Batidzirai *et al.*[75] for a more detailed discussion on the comparison of feedstock requirements for TOPs and pellets and the implications for truck transport costs.

Overall, final conversion costs dominate the bioSNG value chain (11.7–13.5 \$ GJ^{-1} or up to 63% of delivered fuel costs). Biomass feedstock contribute up to 20% of final costs, while international shipping represents up to 9%. Other significant costs include rail transport, truck transport, preprocessing, liquefaction, and compression.

BioSNG production costs are compared to what bioSNG is likely to substitute in the Dutch market, namely natural gas or diesel. Given the national objectives of developing cleaner fuels, a comparison is also made to biodiesel (which is currently the main form of renewable carrier being used to substitute diesel). As shown in Fig. 8, current natural gas prices in the Netherlands (12.0 \$ GJ^{-1})[106] and forecasted gas prices for the coming decade (18.2 \$ GJ^{-1})[117,118] are much lower than the bioSNG production costs. BioSNG are still much higher than natural gas even if a CO_2 tax is included (natural gas plus CO_2 tax is about 12.6 \$ GJ^{-1} (current) to 21.4 \$ GJ^{-1} (future)).

Greenhouse gas emissions

As shown in Table 14, greenhouse-gas emissions range from 17 to 31 kg CO_2e $GJ_{\text{CNG delivered}}^{-1}$. The highest emissions are associated with the Brazil SNG production at the coast and the lowest are the TOPs-based chain. Emissions from feedstock production represent up to 40% of overall emissions, compression to CNG (26–40%), sea

Table 14. GHG emissions across bioSNG supply chains by scenario (kg CO_2e/GJ $_{\text{SNG delivered}}$).

Supply chain stage	Brazil-coast	Brazil-pipeline	Brazil-CGP-dry	NL-TOPs-Brazil	NL-WPs-Brazil	Ukraine-pipeline
Feedstock[a]	9.77	6.69	6.71	6.77	6.78	7.84
Truck transport	0.26	0.26	0.19	0.12	0.15	0.24
Chipping	1.37	0.16	0.17	0.14	0.15	0.97
Drying	0.37	0.37	0.39	0.19	0.34	2.19
Torrefaction	–	–	–	0.35	–	–
Milling	0.43	0.43	0.43	0.05	0.38	2.54
Pelletizing	–	–	–	0.24	0.57	–
Rail transport	1.50	–	1.16	0.47	0.62	–
Sea shipping	2.80	2.80	2.85	2.11	3.29	–
Pipeline	–	0.27	–	–	–	3.37
Liquefaction	3.47	3.47	3.47	–	–	–
Regasification	3.14	3.14	3.14	–	–	–
Compression	8.09	8.09	8.09	6.16	7.95	7.95
Total	31.21	25.69	26.61	16.98	20.25	25.11
Avoided emissions[b]	56.79	62.31	61.39	71.02	67.75	62.89
Emission reduction (%)	65	71	70	81	77	71

[a]Includes fuel use, fertilizer, pesticides and field NO_x emissions.
[b]Based on oil reference.[112]

transport (9–11%), liquefaction (11–13%), and regasification (10–12%).

Emissions for all activities that are powered by electricity are higher for Ukraine compared to Brazil due to the carbon-intensive electricity mix in Ukraine.

Scale effects comparison across chains

As shown in Fig. 9, larger SNG conversion systems of up to 1 $GW_{th, in}$ have much lower investment costs and SNG production costs compared to the reference case of 100 $MW_{th, in}$. The difference in upscaling potential of the Milena and Güssing technologies has a significant effect on the bioSNG capital costs above 100 MW_{th}. At 1 $GW_{th, in}$ the capital cost reduction is estimated to be about 30% for the Milena gasifier (from about 2000 to 1400 \$ kW^{-1}) and about 20% for the Güssing system (from about 3000 to 2500 \$ kW^{-1}). However, Güssing has been demonstrated at 8 MW_{th} whereas the current Milena pilot is only 0.8 MW_{th}, and thus there is greater uncertainty with regards to scaling the Milena technology. Both technologies need further development before more accurate effects of upscaling on the investment costs and the performance can be analyzed.

Figures 10 and 11 compare the SNG production costs for five selected chains at scales of 100 and 1000 $MW_{th, in}$ (assuming the Milena technology is employed). Synthetic natural gas production costs at the 1000 $MW_{th, in}$ scale decrease by over 30% compared to production costs at 100 $MW_{th, in}$, dominated by lower SNG conversion costs.

BioSNG production on a scale of 1000 MW_{th} leads to production costs between 12.6 and 17.4 \$ GJ_{LHV}^{-1}. At these costs, bioSNG becomes competitive against the higher estimates for the natural gas price, especially if CO_2 costs are included. However, it is important to note that natural gas prices already include taxes, distribution costs and profit margin.

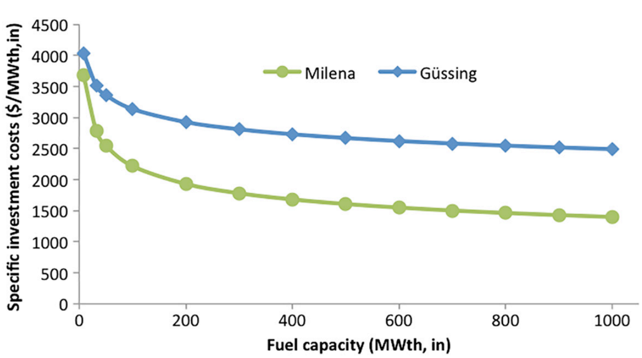


Figure 9. Impact of scaling the Milena and Güssing technologies.

It is apparent from Figs 10 and 11 that there are no significant proportionate differences in bioSNG production cost reduction for all scenarios. The Ukraine supply chain remains the lowest cost option from a scale of 10 to 1000 $MW_{th, in}$ although the highest reduction of 37% is via the Brazil pipeline scenario. At 1000 $MW_{th, in}$ the truck transport costs increase by about 50% and offsets some of the benefits of economies of scale.

Sensitivity analysis

BioSNG production costs

Figure 12 shows the range of bioSNG production costs based on the variation in the selected parameters for the different chains. There is a large uncertainty in the bioSNG production costs, which are mainly influenced by the final conversion cost. Delivered SNG varies from a low of 12.0 \$ GJ^{-1} for the Ukraine scenario to a high of 46.0 \$ GJ^{-1} for the Brazil coastal SNG conversion case. The TOPs chain shows a wider variation (13.5–36.3 \$ GJ^{-1}) compared to the pellets chain (17.1–29.4 \$ GJ^{-1}). This is due to the uncertainties associated with torrefaction costs.

Figure 13 shows the disaggregated effects of the selected cost factors on individual supply-chain components of the bioSNG production costs. It is apparent that bioSNG conversion costs have the largest influence on the total production costs. The BioSNG production in the Netherlands has the largest sensitivity range because both the cost of ocean transport and the densification of biomass are very variable. The uncertainty associated with torrefaction costs as well as international shipping shows risks associated with the TOPs chain as the technology is being developed. This would not make LNG transport more favorable compared to TOPs chains as LNG also involves costly and variable sea shipment. In any case, the impact of more expensive shipping is (much) lower for the TOPs chains than for the LNG chain and both are dwarfed by the uncertainties of the SNG conversion.

Relative primary energy loss

Similarly SNG conversion has the largest sensivity range (of up to 14%) on relative primary energy loss compared to preprocessing (6%), international shipping (2%), and feedstock production (<1%). This shows that SNG conversion is very sensitive to conversion efficiency and therefore it is important to ensure that the the gasification technology selected for SNG production is optimized for high-efficiency conversion. Likewise, preprocessing energy use needs to be optimized, especially for torrefaction, where

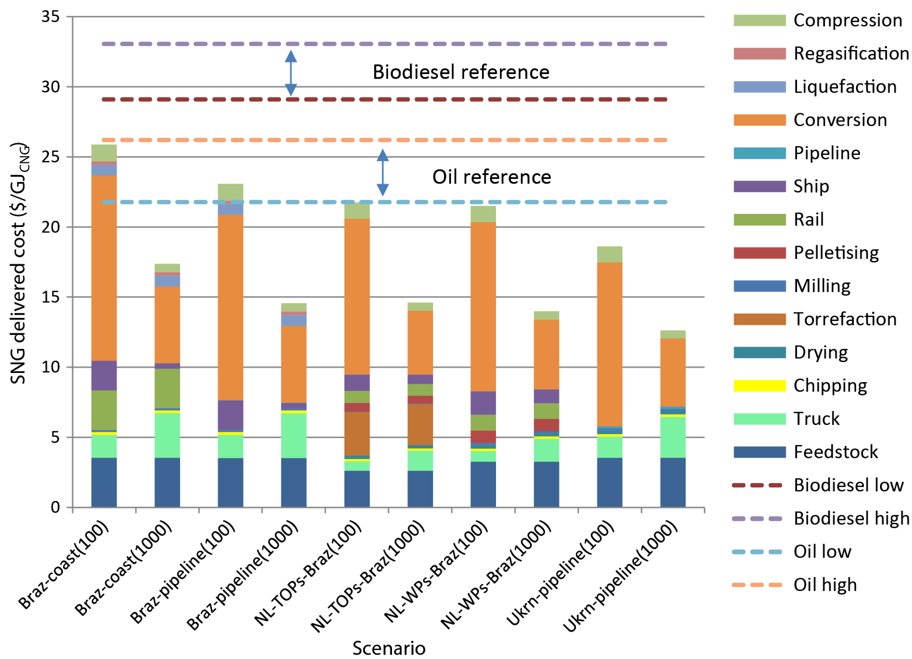


Figure 10. Comparison of bioSNG delivered costs at different production scales for selected chains. The production capacity (in $MW_{th, in}$) is given in brackets for each supply chain.

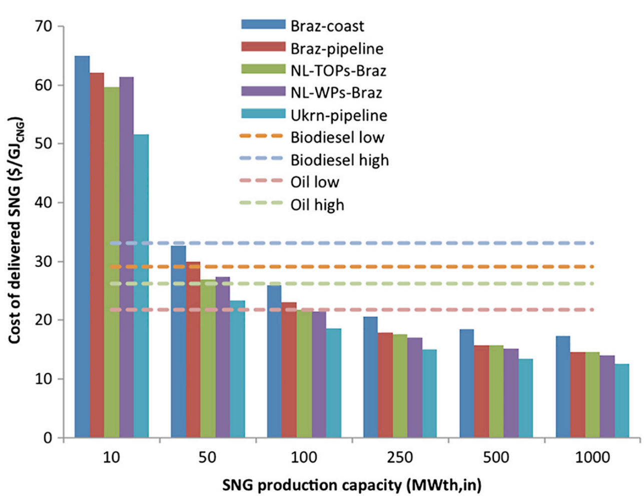


Figure 11. Scale effects on bioSNG production costs for selected supply chains.

the use of off-gases from the torrefaction process needs to be utilized effectively to reduce the external energy input and improve the overall process efficiency.

Discussion

Technical challenges

BioSNG conversion technologies are still under development. There are still some technical challenges before commercialization can be realized.[13,34] Although larger projects are planned, the largest currently operating biomass gasifier is 8 MW_{th} and the largest operating bioSNG production is 1 MW_{th} (Raas H, 2009, private communication). For both technologies, large-scale bioSNG production has to be proven before they can become commercially successful.

It is also uncertain what the effects of biomass moisture content have on SNG production efficiency and cost. Lower moisture content could increase the efficiency of the gasifier, but this has not been assessed. A balance also needs to be found between additional drying of the biomass and lower gasifier efficiency due to a higher moisture content of the fuel. Our results show that biomass drying with waste heat at the bioSNG production facility is more efficient than biomass drying earlier in the chain. However, the technical feasibility of this option has not been explored yet. A more detailed mass and energy balance of such an integrated facility needs to be conducted.

For international pipeline transport, bioSNG must meet the grid Wobbe index requirements. Simulations by Raas (Raas H, 2009, private communication) showed that the maximum Wobbe index of the bioSNG is marginally higher than G-gas. All the international pipelines from Eastern Europe are transporting H-gas. G-gas is the Dutch standard for low calorific gas with a Wobbe index of 43.5–44.4 MJ m^{-3} while H-gas is high calorific gas with a Wobbe

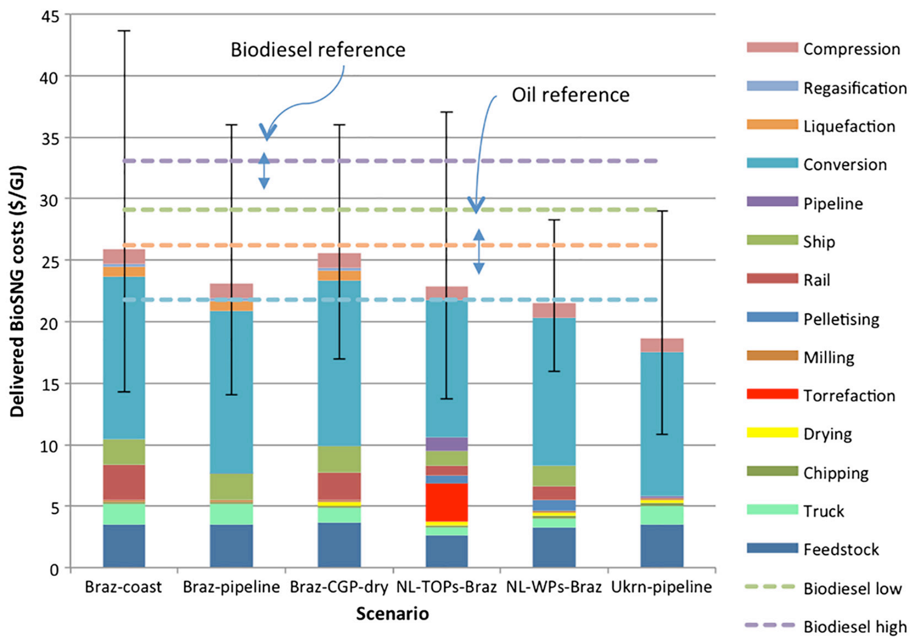


Figure 12. Sensititivity range in delivered BioSNG cost with variation in cost factors (100 MW_{th} case).

index of 48–56 MJ m^{-3} (Gasterra, www.gasterra.nl). The bioSNG should therefore either be upgraded to H-gas level before grid injection or it should be injected in a grid with a tolerance for lower Wobbe indices. The cost implications of producing bioSNG with H-gas quality has not been evaluated (van der Meijden CM, 2009, private communication).

Thus although the results from this study show promising and attractive technical feasibility of the bioSNG from the selected value chains, these technical factors, challenges, and uncertainties are important risk factors that could affect the practical feasibility of the technology.

Geographical factors

Pertinent geographical factors include security of mobilizing sufficient volumes of feedstock or SNG supply as well as infrastructure availability in the selected regions. The two regions of Ukraine and Brazil were selected as biomass and SNG production regions due to their potential for producing competitive and sustainable biomass as well as availability of necessary infrastructure. But, like any other region in the world, export of this resource could be affected by geopolitical dynamics, change of national policies and priorities, or structural changes in the economies. This discussion is important but beyond the scope of this paper. We therefore only focus on infrastructural adequacy in this article.

Availability of infrastructure for gas transportation is a major limiting factor for BioSNG production especially in developing countries. The scale of bioSNG production in the foreseeable future is too small to build long-distance gas transport infrastructure exclusively for bioSNG. BioSNG transport is therefore limited to existing natural gas transport infrastructure. Gas transport by pipeline to the Netherlands is limited to Europe, Russia, and North Africa and in the future possibly the Middle East. Eastern Europe is the most promising region for bioSNG production because of the large potential for biomass with low production costs and the large capacity of long-distance gas pipelines (for Russian gas). In this study, Ukraine is chosen because of its high biomass potential and low production costs, but other countries like Poland, the Czech Republic or Russia are promising bioSNG production regions as well.

Gas transport in the form of LNG to the Netherlands is limited to locations with an LNG liquefaction terminal. These terminals are located in regions with large natural gas export potential, like North Africa, the Middle East, Norway and Siberia. The LNG market is growing strongly and many new terminals are planned. However, there are no LNG liquefaction terminals in regions with large biomass production potential such as Latin America. Only Trinidad and Tobago has a liquefaction terminal, although new terminals are planned in Peru, Venezuela,

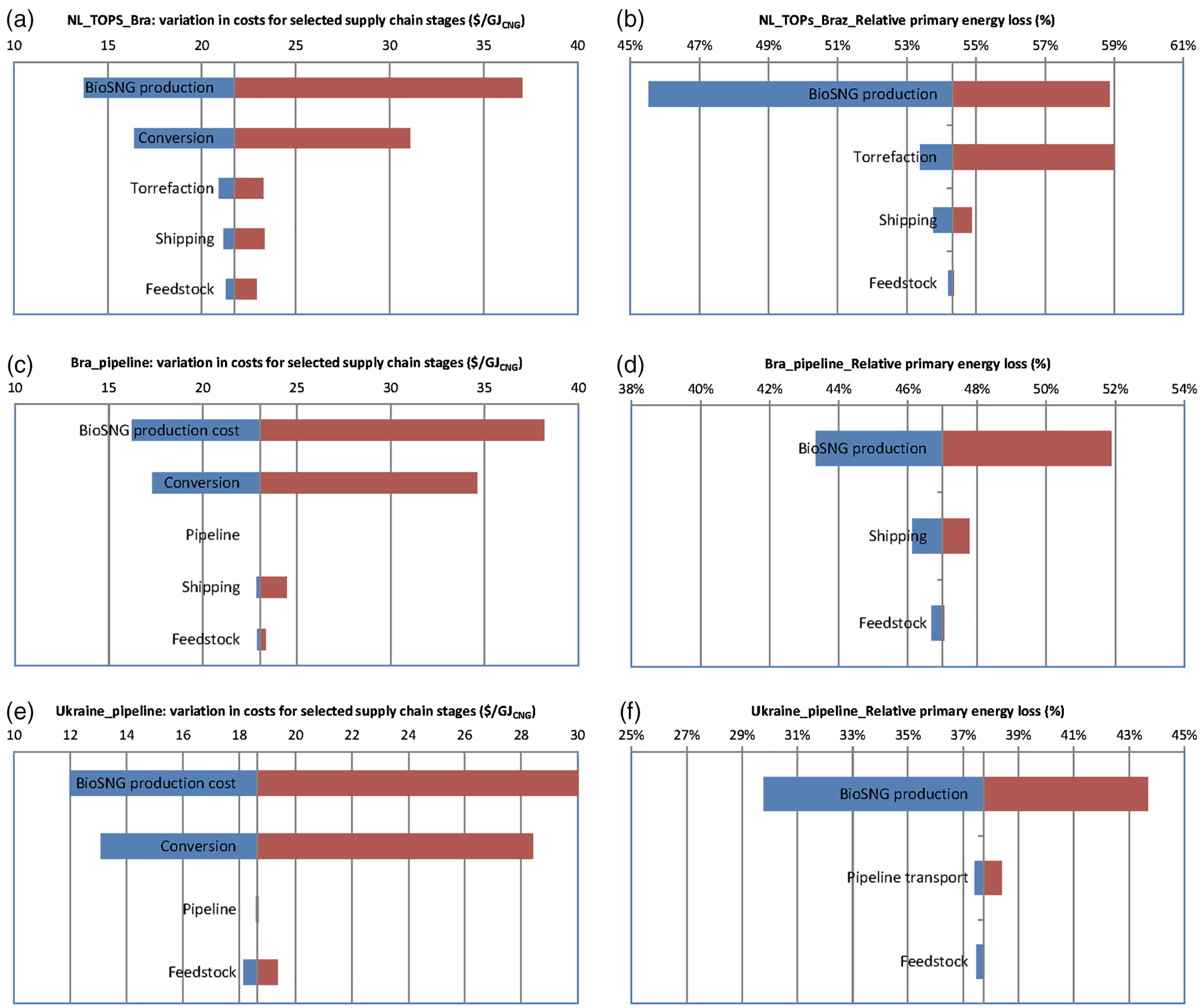


Figure 13. Sensitivity of the selected supply chain elements on the total bioSNG delivered costs and primary energy loss.

and Colombia. For Brazil, we assumed that a new LNG facility is built and the costs are included in the SNG value chain and this increases the LNG supply costs. If existing infrastructure was available, these costs would be lower. In Africa, liquefaction terminals are planned in Nigeria and Mozambique, which have possibilities for large-scale biomass production. Other regions with (planned) LNG liquefaction terminals where large-scale biomass production might be possible are Indonesia, Brunei, Alaska, and the Russian east coast, but the transport distances to the Netherlands are much higher than for Brazil and Africa (CEC, www.energy.ca.gov).

This study therefore demonstrates the infrastructural preconditions that need to be established if a successful bioSNG supply chain is to be established in these and other regions of the world.

BioSNG end use applications

BioSNG can be used to substitute natural gas and provide a cleaner alternative gas fuel. However, from the analysis, bioSNG is not competitive against natural gas at current market prices, unless a high premium is paid for CO_2 mitigation. Current CO_2 prices are too low to cover the difference between bioSNG production costs and natural gas prices.

We therefore consider the transport sector as a more viable market for bioSNG, although additional compression costs are required (which raise the cost of delivered CNG). Sufficient CNG refueling stations also would need to be established across the country to allow nationwide use of the fuel. CNG is competitive against oil (petroleum diesel) and delivered at much lower cost compared to biodiesel as discussed in the results.

However, the use of CNG requires a switch from conventional diesel and petrol vehicles to more costly CNG vehicles (although in the Netherlands, subsidies are available for public fleets and lower taxes are charged on CNG vehicles and CNG fuel costs 40% lower than equivalent amount of petrol in energy terms).[6] In terms of energy use, the specific energy consumption of CNG vehicles (2.32 MJ km^{-1}) and petrol vehicles (2.25 MJ km^{-1}) is comparable. According to Fuelswitch,[119] a CNG-fueled car with a standard tank capacity of 20 kg (about 25 Nm^3 or 125 L), can drive about 350 km, compared to about 1000 km driven by a petrol-fueled car with a standard tank capacity of 70 L. Already the CNG market is building up – in the Netherlands, there are currently 4300 CNG vehicles and 85 refueling stations as of 2011.[120]

It is also interesting to consider the co-production of SNG and chemicals such as benzene and ethylene. Benzene and ethylene are much more valuable products than SNG,[121] and this could improve the economics of bioSNG production.

As an alternative to grid injection, bioSNG can also be used as fuel in existing natural gas combined cycle power plants (NGCC) or co-firing syngas in an existing NGCC. If a bioSNG conversion facility is located next to an existing NGCC, raw syngas can be co-fired directly as methanation is not required. This saves investment in methanation and the CO_2 removal components, and the conversion efficiency of biomass to producer gas is 80% instead of 70% for SNG (Raas H, 2009, private communication). Our analysis showed that this option is not attractive as electricity production costs are much higher than current electricity market prices. Co-firing of syngas results in power production costs of 123.5 \$ MWh^{-1} compared to SNG based power production (195.3 \$ GJ^{-1}). These differences are caused by the 30% lower investment costs for syngas conversion and the 10% higher efficiency of syngas production compared to the bioSNG production route.

Comparison with other studies

BioSNG cost estimates from this study are in the same range as other studies such as Zwart *et al.*[13] Cozens *et al.*,[19] Gassner and Maréchal[17] and Gassner and Maréchal.[18] Other studies show higher costs as they include other aspects such as CCS. Zwart *et al.*[13] estimate bioSNG production to be 20 \$ GJ^{-1} at 100 $MW_{th, atm}$ and 19.2 \$ GJ^{-1} at 100 $MW_{th, 7bar}$; at 1000 $MW_{th,7bar}$ SNG production costs are 12.1 \$ GJ^{-1} assuming biomass feedstock costs of 5.2\$ GJ^{-1}.

Cozens *et al.*[19] assume SNG feedstock costs of 11.1 \$ GJ^{-1} (imported wood pellets in UK), 8 \$ GJ^{-1} (mix of imported and local woodchips), and (–2.4 \$ GJ^{-1}) (processed solid recovered fuel from mixed-waste streams). They estimate bioSNG production costs of 29.4–45.2 \$ GJ^{-1} for small-scale facilities (50 $MW_{th, in}$) and 14–32 \$ GJ^{-1} for large-scale facilities (300 $MW_{th, in}$). Based on the FBG,[122] estimated specific production costs for SNG and CO_2 capture for a process input of 100 $MW_{th,LHV,\ 20\ wt\text{-}\%\ moisture}$ vary between 37.2 and 45.9 \$ $GJ_{SNG}{}^{-1}$.

Gassner and Maréchal[17] explored different bioSNG production pathways and estimate bioSNG production costs to be 27–36 \$ $GJ_{SNG}{}^{-1}$ at a scale of 20 $MW_{th, in}$ and 21–35 \$ $GJ_{SNG}{}^{-1}$ for 150 $MW_{th, in}$ conversion capacity. Gassner and Maréchal[18] investigate the polygeneration of SNG, heat, and power and estimate production costs of 33 \$ GJ^{-1} for bioSNG and a breakeven (with respect to fossil fuels) biomass feedstock cost of 6.7 \$ GJ^{-1} at the plant gate at a scale of 20 $MW_{th, in}$ and up to 25 \$ GJ^{-1} for a conversion scale of 100 $MW_{th, in}$.

This comparison shows that bioSNG production costs are strongly dependent on the value chain considered, including feedstock used, delivered feedstock cost, and final conversion technology used.

Conclusion

The goal of this study was to find the optimal production chain for bioSNG production for different biomass production regions and location of final conversion facilities, with final delivery of compressed natural gas at refueling stations servicing the transport sector. Delivered bioSNG costs were estimated to be between 18.6 and 25.9 \$ $GJ_{delivered\ CNG}{}^{-1}$ at a scale of 100 $MW_{th, in}$. These costs are higher than the current estimates of the natural gas price but lower than the oil prices and biodiesel prices. BioSNG costs could converge with natural gas market prices in the coming decades, estimated to be 18.2 \$ GJ^{-1}. Total energy efficiency of the selected chains was estimated to be 46.8–61.9%. The major part of the energy loss is caused by the bioSNG production, with an energy efficiency of around 70%.

BioSNG production in Ukraine and transportation of the gas by pipeline to the Netherlands results in the lowest delivered cost (18.6 \$ GJ^{-1}) and highest energy efficiency pathway (61.9%). This is followed by BioSNG production in the Netherlands using TOPs and WPs from Brazil (about

 |

21.0 \$ GJ^{-1}). BioSNG production in Brazil with LNG transport to the Netherlands results in the most costly delivered SNG (25.9 \$ GJ^{-1}) associated with the conversion of wet biomass at the export terminal in Brazil. A key factor in increased LNG transport cost is the liquefaction, shipping, and regasification processes, which are costly and incur about 13% SNG losses, mostly used to power the processes.

Synthetic natural gas production from TOPs results in the lowest GHG emissions (17 kg CO_2e GJ_{CNG}^{-1}) while the Ukraine routes results in 25 kg CO_2e GJ_{CNG}^{-1} (the latter is affected by a high electricity grid emission factor). The production of SNG using wet biomass at the export harbor in Brazil also results in the worst GHG performance (31 kg CO_2e GJ_{CNG}^{-1}).

If production capacities are increased to 1000 $MW_{th,\ in}$, delivered SNG costs decrease by about 30% to between 12.6 and 17.4 \$ $GJ_{SNG,\ delivered}^{-1}$ mainly influenced by reduction in capex of the final conversion facility. At these costs, bioSNG becomes competitive with natural gas (especially if attractive CO_2 prices are considered) and very competitive with oil and biodiesel.

It is clear that scaling of SNG production to the GW_{th} scale is key to cost reduction and could result in significant production cost reduction even if technological learning is not factored in. Capex cost reduction due to scaling is more dominant than additional local biomass logistics. For regions like Brazil it is more cost-effective to densify biomass into pellets or TOPS and undertake final conversion near the import harbor.

From the results, it is clear that early conversion of biomass into bioSNG in Ukraine and subsequent transport by pipeline provides the best economics and also a low carbon footprint. There are marginal differences between the pellets, TOPs and LNG supply chains from Brazil (although at lower scale, the LNG chains are less attractive). Generally, early conversion of biomass to bioSNG in Brazil with subsequent shipment as liquefied natural gas (LNG) to the Netherlands is a less attractive option from an economic perspective.

Overall, this study has shown that bioSNG can be produced and delivered at competitive costs compared to fossil fuels, especially in the transport sector. BioSNG can also be delivered with over 60% GHG emissions reduction (and thus surpasses the EU Renewable Energy Directive on Biofuels threshold). In terms of economics, bioSNG conversion early in the chain is beneficial if pipeline transport is feasible. Where this is not possible, densifying biomass into pellets or TOPs and undertaking final conversion in the importing country offers better economic performance.

Recommendations for further research

Our analysis has shown that scaling up bioSNG conversion results in significant lowering of delivered fuel costs. However, the scaling of individual components is not well understood as current systems are available at very low scale and therefore this requires more detailed analysis. It is also important to investigate the impact of scale-independent learning on future economic performance of bioSNG facilities.

Large-scale biomass energy supplies demand the mobilization of large volumes of biomass, and this requires complex logistics and good infrastructure to deliver biomass competitively to the market. To build up large volumes of biomass and set up decent infrastructure, especially in developing regions, would require time to implement. It is not well understood how this would be implemented and hence there is need for further research into these aspects. Furthermore, the distribution of SNG in the market was not fully analyzed. It would be important to investigate different models for implementing the distribution of bioSNG. Co-production of bioSNG with bio-based chemicals (such as benzene and ethylene) could also improve the bioSNG economics.

Acknowledgement

We want to thank Bram van der Drift of ECN for his contributions in the development of this paper, for taking time to review the work, and for providing insights into the economics of bioSNG production.

References

1. Reymond M, European key issues concerning natural gas: Dependence and vulnerability. *Energy Policy* **35**:4169–4176 (2007).
2. OECD/IEA, *Area We Entering a Golden Age of Gas? Special Report. World Energy Outlook 2011*. International Energy Agency, Paris (2011).
3. Fluxys EaG, *Fuelling the Future. Towards a Sustainable Gas Market in Europe*. Reader issued on the occasion of the policy debate held by Fluxys Belgium, Energinet.dk and Gasunie, Brussels. (June 2012).
4. Calderón AJ, Agnolucc P and Papageorgiou LG, An optimisation framework for the strategic design of synthetic natural gas (BioSNG) supply chains. *Appl Energy* **187**:929–955 (2017).
5. Carbo MC, Smit R, van der Drift B and Jansen D, Bio Energy with CCS (BECCS): Large potential for BioSNG at low CO2 avoidance cost. GHGT-10 paper. *Energy Procedia* **4**:2950–2954 (2011).
6. van Rooij RLMM, Accommodating the Dutch Green Gas Infrastructure for road traffic. A feasibility and conceptual

design study of a new distribution system for (Bio-)CNG. Master's Thesis Delft University of Technology, Delft (2012). (Online). Available: https://repository.tudelft.nl/islandora/object/uuid:2302ae96-6666-487d-a867-f725188fc866?collection=education [2 September 2013].

7. Umbach F, The unconventional gas revolution and the prospects for Europe and Asia. *Asia Eur J* **11**:305–322 (2013).
8. Kjärstad J and Johnsson F, Prospects of the European gas market. *Energy Policy* **35**:869–888 (2006).
9. TNO (The Netherlands Organisation for Applied Scientific Research). Natural Resources and Geothermal Energy in the Netherlands, *Annual Review 2010. A Review of Exploration and Production Activities and Underground Gas Storage*. (2011). (Online). Available: http://www.nlog.nl/resources/Jaarverslag2010/Delfstoffen_2010_UK_rev1.pdf. [24 August 2013].
10. Steubing B, Zah R and Ludwig C, Life cycle assessment of SNG from wood for heating, electricity, and transportation. *Biomass Bioenergy* **35**:2950–2960 (2011).
11. Alamia A, Magnusson I, Johnsson F and Thunman H, Well-to-wheel analysis of bio-methane via gasification, in heavy duty engines within the transport sector of the European Union. *Appl Energy* **170**:445–454 (2016).
12. PNG, *Vol Gas Vooruit!, Platform Nieuw Gas, Energietransitie*. (2007).
13. Zwart RWR, Boerrigter H, Deurwaarder EP, van der Meijden CM and van Paasen SVB, *Production of Synthetic Natural Gas (SNG) from Biomass - Development and Operation of an Integrated bio-SNG System, Non-confidential Version*. ECN-E-06. (2006).
14. Kampman B, Leguijt C, Scholten T, Tallat-Kelpsaite J, Brückmann R, Maroulis G *et al.*, Optimal use of biogas from waste streams: An assessment of the potential of biogas from digestion in the EU beyond 2020. pp 158 (2016). (Online). Available: https://ec.europa.eu/energy/sites/ener/files/documents/ce_delft_3g84_biogas_beyond_2020_final_report.pdf [1 August 2017].
15. Gallagher C and Murphy JD, Is it better to produce biomethane via thermochemical or biological routes? An energy balance perspective. *Biofuels Bioprod Biorefin* **7**:273–281 (2013).
16. Fleuren W, Konings AJA, Lindeman JHW, Pfeiffer AE, Pustjens H, Smeets RD *et al.*, Opportunities for a 1,000 MWe biomass-fired power plant in the Netherlands, KEMA power generation & sustainables. (2005).
17. Gassner M and Maréchal F, Thermo-economic process model for thermochemical production of Synthetic Natural Gas (SNG) from lignocellulosic biomass. *Biomass Bioenergy* **33**(11):1587–1604 (2009).
18. Gassner M and Maréchal F, Thermo-economic optimisation of the polygeneration of synthetic natural gas (SNG), power and heat from lignocellulosic biomass by gasification and methanation. *Energy Environ Sci* **5**:5768–5789 (2012).
19. Cozens P and Manson-Whitton C, *Bio-SNG Feasibility Study – Establishment of a Regional Project*. Prepared by Progressive Energy Ltd and CNG Services for NEPIC, National Grid and Centrica. pp 99 (2010).
20. van der Meijden CM, Veringa HJ and Rabou LPLM, The production of synthetic natural gas (SNG): A comparison of three wood gasification systems for energy balance and overall efficiency. *Biomass Bioenergy* **34**:302–311 (2010).
21. Ahrenfeldt J, Jørgensen B and Thomsen T, *Bio-SNG Potential Assessment: Denmark 2020*. Biosystems Division, Risø DTU/Dansk Gasteknisk Center A/S. Risø-R-1754 (EN). November 2010. (2010).
22. Welink J, Dumont M and Kwant K, Groen gas; Gas van aardgaskwaliteit uit biomassa; update van de studie uit 2004, Senternovem (2007). (Online). Available: https://www.rvo.nl/file/1279 [15 July 2013].
23. van der Drift B, Biomass to gas. Presented at the Future World of Biogas: Europe 2011, London, November 24 2011, ECN-L-11-122 (2011).
24. Chum H, Faaij A, Moreira J, Berndes G, Dhamija P, Dong H *et al.*, Bioenergy Chapter 2, in *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*, ed. by Edenhofer O, Pichs-Madruga R, Sokona Y, Seyboth K, Arvizu D, Bruckner T *et al.*, Cambridge University Press Cambridge, New York, NY, pp. 209–332 (2011).
25. Held J, Gasification – status and technology. Rapport SGC 240, Svenskt Gastekniskt Center/Swedish Gas Centre (2012). (Online). Available: http://www.sgc.se/ckfinder/userfiles/files/SGC240.pdf [1 August 2013].
26. Hrbek J, *Status Report on Thermal Biomass Gasification in Countries Participating in IEA Bioenergy Task 33*. p 163 (2016).
27. van der Drift A, van der Meijden CM and Boerrigter H, Milena gasification technology for high efficient SNG production from biomass. Paper Presented at the 14th European Biomass Conference & Exhibition, Paris, October 17–21, Energy research Centre of the Netherlands (ECN), Unit Biomass (2005).
28. Kopyscinski J, Seemann MC, Moergeli R, Biollaz SMA and Schildhauer TJ, Synthetic natural gas from wood: Reactions of ethylene in fluidised bed methanation. *Appl Catal A* **462–463**:150–156 (2013).
29. Lettner F, Timmerer H and Haselbacher P, *Deliverable 8: Biomass Gasification – State of the Art Description*. Intelligent Energy, European Union. (2007).
30. Hoogendoorn A, Bierings B and van den Boom R, *Centrale Productie van Bio-SNG via Vergassing*. Report Number 0756794-R01K, Senter Novem, 83 pp (2008). (Online). Available: www.rvo.nl/sites/default/files/bijlagen/Centrale%20productie%20van%20Bio-Synthetic%20Natural%20Gas%20via%20vergassing.pdf [20 July 2009].
31. Knoef HAM (Editor), *Handbook Biomass Gasification.* BTG Biomass Technology Group, Enschede (2005).
32. Bengtsson K, *Twin-bed Gasification Concepts for Bio-SNG Production*. Department of Chemical Engineering, Lund University, Lund, Sweden. (2007). (Online). Available: https://www.chemeng.lth.se/exjobb/E450.pdf [10 August 2013].
33. van der Meijden CM, Veringa HJ and Rabou PLM, *Entrained Flow and Fluidized Bed Gasification of Biomass to Produce Sustainable Synthetic Natural Gas (SNG), ECN* (2008).
34. van der Meijden CM, Veringa HJ, van der Drift A and Vreugdenhil BJ, The 800 kWth allothermal biomass gasifier Milena. Paper presented at the 16th European Biomass Conference, June 2–6, Valencia, Spain (2008).
35. Rauch R, *Steam Gasification of Biomass at CHP Plant Guessing – Status of the Demonstration Plant*. Institute of Chemical Engineering, Vienna (2004).
36. Gunnarsson I, *GoBiGas – is On Track!, Göteborg Energi AB* (2008).
37. Nanou P, Biomass gasification for the production of methane. PhD Thesis University of Twente, Enschede, The Netherlands (2013).

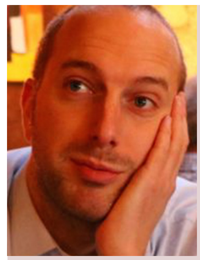
38. Meerman JC, Ramírez A, Turkenburg WC and Faaij APC, Performance of simulated flexible integrated gasification polygeneration facilities. Part A: A technical-energetic assessment. *Renew Sust Energ Rev* **15**:2563–2587 (2011).
39. Van der Spek M, Assesing the techno-ecomomic uncertainties of biomass-to-substitute natural gas systems for R&D decision making. Master thesis Delft University of Technology, Delft (2009).
40. Merkel TC, Turk B, Gupta RP, Cicero DC and Jain SC, A hybrid gas cleaning process for production of ultraclean syngas. Research Triangle Park: RTI (2005). (Online). Available: https://www.osti.gov/servlets/purl/837307/ [12 August 2013].
41. De Wit M and Faaij A, European biomass resource potential and costs. *Biomass Bioenergy* **34**(2):188–202 (2010).
42. Smeets EMW and Faaij APC, The impact of sustainability criteria on the costs and potentials of bioenergy production – Applied for case studies in Brazil and Ukraine. *Biomass Bioenergy* **34**:319–333 (2009c).
43. Corbella L, Cocchi M and Salve Diaz Miquel M. Chapter 4: Poplar in Spain and Italy, in *Energy from Field Energy Crops – a Handbook for Energy Producers*, Jyväskylä Innovation Oy & MTT Agrifood Research Finland/Intelligent Energy Europe, Jyväskylä Innovation Oy, JYVÄSKYLÄ, Finland (2009).
44. Batidzirai B, Faaij A and Smeets E, Biomass and bioenergy supply from Mozambique. *Energy Sustain Dev* **X**(1):54–81 (2006).
45. Hamelinck CN, Suurs RAA and Faaij APC, International bioenergy transport costs and energy balance. *Biomass Bioenergy* **29**(2):114–134 (2005).
46. van der Hilst F and Faaij APC, Spatiotemporal cost-supply curves for bioenergy production in Mozambique. *Biofuel Bioprod Biorefin* **6**:405–430 (2012).
47. Batidzirai B, Mignot APR, Schakel W, Junginger M and Faaij APC, Biomass torrefaction technology - status and future prospects. *Energy* **62**:196–214 (2013).
48. Bradley D, Diesenrieter F and Tromborg E, *World Biofuel Maritime Shipping Study*. IEA Bioenergy Task 40 (2009).
49. Hoefnagels R, Searcy E, Cafferty K, Cornelissen T, Junginger M, Jacobson J *et al*., Lignocellulosic feedstock supply systems with intermodal and overseas transportation. *Biofuel Bioprod Biorefin* **8**:794–818 (2014).
50. de Monie G, Rodrique J-P and Notteboom T. Economic cycles in maritime shipping and ports: The path to the crisis of 2008, in *Integrating Seaports and Trade Corridors*, ed. by Hall P *et al.,* Ashgate, Surrey, pp. 13–30 (2010).
51. RS Platou, *Newbuilding from the Platou Monthly. RS Platou Monthly – LNG Shipping Market Remains Tight*. R.S. Platou Shipbrokers. (2013). Available: http://www.platou.com/dnn_site/LinkClick.aspx?fileticket=hYrFvtzl1aI%3D&tabid=80
52. Heyne S, Bio-SNG from thermal gasification - process synthesis, integration and performance. PhD thesis Department of Energy and Environment, Chalmers University of Technology, Göteborg (2013).
53. Ratner M, Belkin P, Nichol J and Woehrel S, *Europe's Energy Security: Options and Challenges to Natural Gas Supply Diversification*. August 20, 2013. Congressional Research Service. CRS Report for Congress. (2013).
54. Knoope MMJ, Guijt W, Ramírez A and Faaij APC, Improved cost models for optimizing CO_2 pipeline configuration for point-to-point pipelines and simple networks. *Int J Greenhouse Gas Control* **22**:25–46 (2014).
55. Chandra V, *Liquefied Natural Gas Chain*. (2013). Available: http://www.natgas.info/html/liquefiednaturalgaschain.html [6 September 2013].
56. PACE, *Life Cycle Assessment of GHG Emissions from LNG and Coal Fired Generation Scenarios: Assumptions and Results*, PACE, Fairfax, VA (2009).
57. Yang CC and Huang Z, Lower emission LNG vaporization. *LNG Journal,* November/December 2004 pp. 24–26 (2004).
58. Hekkert MP, Hendriks FHJF, Faaij APC and Neelis ML, Natural gas as an alternative to crude oil in automotive fuel chains well-to-wheel analysis and transition strategy development. *Energy Policy* **33**:579–594 (2005).
59. Lowell D, Wang H and Lutsey N, *Assessment of the Fuel Cycle Impact of Liquefied Natural Gas as Used in International Shipping*. White Paper. The International Council on Clean Transportation (ICCT), Beijing, Berlin, Brussels, San Francisco, CA Washington, DC (2013).
60. Jaramillo P, Griffin WM and Matthews HS, Comparative life-cycle air emissions of coal, domestic natural gas, LNG, and SNG for electricity generation. *Environ Sci Technol* **41**(17):6290–6296 (2007).
61. Tamura I, Tanaka T, Kagajo T, Kuwabara S, Yoshioka T, Nagata T *et al.*, Life cycle CO2 analysis of LNG and city gas. *Appl Energy* **68**:301–319 (2001).
62. Kotzot H, Durr C, Coyle D and Caswell C, LNG liquefaction — Not all plants are created equal, in *International Conference on Liquefied Natural Gas 15th*. Gas Technology Institute, Des Plaines, IL, p. PS4–1.1 (2007).
63. USDOE (U.S. Department of Energy). *Liquefied Natural Gas: Understanding the Basic Facts*. p. 24 (2005). (Online). Available: https://www.energy.gov/fe/downloads/liquefied-natural-gas-understanding-basic-facts [29 August 2017].
64. Strande R and Johnson T, Completing the LNG value chain. *Wärtsilä Technical Journal*, 01. 2013 (2013).
65. Agarwal R and Babaie M, LNG regasification — technology evaluation and cold energy utilisation. Presentation at The 17th International Conference & Exhibition on Liquefied Natural Gas – Process and Plant Design and Optimization, Houston, TX**,** April 16–19 2013, Queensland University of Technology, Australia (2013).
66. ECN Refuelling Green, *Adapting the Refuelling- and Distribution Infrastructure for Alternative Transport Fuels*. Petten (2010).
67. TIAX, *U.S. and Canadian Natural Gas Vehicle Market Analysis: Compressed Natural Gas Infrastructure*. Final Report. America's Natural Gas Alliance (2012).
68. Hoogwijk M, Faaij A, Eickhout B, de Vries B, Turkenburg W, Potential of biomass energy out to 2100, for four IPCC SRES land-use scenarios. *Biomass Bioenergy* **29**(4):225–257 (2005).
69. van der Meijden CM, Rabou LPLM, Van der Drift A, Vreugdenhil BJ and Smit R, Large scale production of bio methane from wood. Presented at the International Gas Union Research Conference IGRC, Seoul, October 19–21 (2011). ECN-M–11-098 (2011).
70. Sikkema R, Junginger M, Pichler W, Hayes S and Faaij APC, The international logistics of wood pellets for heating and power production in Europe: Costs, energy-input and greenhouse gas balances of pellet consumption in Italy, Sweden and the Netherlands. *Biofuel Bioprod Biorefin* **4**:132–153 (2010).
71. *European Commission. Report from the Commission to the Council and the European Parliament on Solid and Gaseous Bioenergy Pathways: Input Values and GHG Emissions*. 2015 Version 1a. pp 248 (2015).

  |

72. Ericsson K and Werner S, The introduction and expansion of biomass use in Swedish district heating systems. *Biomass Bioenergy* **94**:57–65 (2016).
73. Lamers P, Hoefnagels R, Junginger M, Hamelinck C and Faaij A, Global solid biomass trade for energy by 2020: An assessment of potential import streams and supply costs to North-West Europe under different sustainability constraints. *GCB Bioenergy* **7**(4):618–634 (2015).
74. Lamers P, Hamelinck CN, Junginger HM and Faaij APC, International bioenergy trade—A review of past developments in the liquid biofuel market. *Renew Sust Energ Rev* **15**(6):2655–2676 (2011).
75. Batidzirai B, van der Hilst F, Meerman JC, Junginger M and Faaij APC, Optimisation of biomass supply chains with torrefaction technology. *Biofuel Bioprod Biorefin* **8**:253–282 (2014).
76. Franke B, Reinhardt G, Malavelle J, Faaij A and Fritsche U, *Global Assessments and Guidelines for Sustainable Liquid Biofuels*. A GEF Targeted Research Project. Heidelberg, Paris, Utrecht, Darmstadt. (2012).
77. Fischer G, Hizsnyik E, Prieler S and van Velthuizen H, *Assessment of Biomass Potentials for Biofuel Feedstock Production in Europe: Methodology and Results*. Refuel Work Package 2, Intelligent Energy, EU (2007).
78. Hoffmann BS, Szklo A and Schaeffer R, An evaluation of the techno-economic potential of co-firing coal with woody biomass in thermal power plants in the south of Brazil. *Biomass Bioenergy* **45**:295–302 (2012).
79. van Dam J, Faaij APC, Hilbert J, Petruzzi H and Turkenburg WC, Large-scale bioenergy production from soybeans and switchgrass in Argentina. Part B. Environmental and socio-economic impacts on a regional level. *Renew Sust Energ Rev* **13**:1679–1709 (2009).
80. Gusev A, *Transportation Balance of Ukraine: 2013/2014*. (2014).
81. Clark M, Deans B, Banks K and Goddard T, *Glossary of Marine Insurance and Shipping Terms*. Association of Marine Underwriters of San Francisco, Inc., San Francisco, CA, 186 pp. (2002). (Online). Available: http://www.gibsonrobb.com/pdf/MarineGlossary.pdf [11 July 2013].
82. Cornot-Gandolphe S, Appert O, Dickel R, Chabrelie M and Rojey A, The challenges of further cost reductions for new supply options (pipeline, LNG, GTL). Paper Presented at the 22nd World Gas Conference, Tokyo, June 1–5 2003 (2003).
83. DiNapoli RN and Yost CC, III *LNG Plant Costs: Present and Future Trends*. Merlin Associates, Houston, TX. Available: http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/1998/Papers/7-4-DiNapoli.PDF [25 August 2013].
84. Phalen T and Scotti J, Update on LNG facility construction. Offshore Technology Conference. Paper Presented at the 2008 Offshore Technology Conference, Houston, TX May 5–8 2008 (2008).
85. The Linde Group/StarLNG, *The Leading Small-to-mid Scale Standard LNG Plant*. (2013). Available: http://lppusa.com/international/web/le/us/likeleuslbpp30.nsf/repositorybyalias/lpp_starlngbrochure/$file/2012%20StarLNG%20brochure_Issue%202.0.pdf [25 August 2013].
86. Das DK, Issues facing U.S. shale gas exports to Japan. *Pipeline Gas J* **238**(12) (2011).
87. Ebinger C, Massy K and Avasarala G, *Evaluating the Prospects for Increased Exports of Liquefied Natural Gas from the United States*. An Interim Report. Energy Security Initiative at BROOKINGS. (2012).
88. Bulte A, *An Innovative Solution for Fixed Offshore LNG Regasification Terminals*. Foster Wheeler, Madrid (2012).
89. DACE, Dutch Association of Cost Engineers, *Prijzenboekje*, editie 25. Lamfers/Reed Business Information, Doetinchem (2006).
90. Müller N and Jijo OJ. A closer look at CO_2 as a refrigerant. American Society of heating, refrigerating and air-conditioning engineers. *ASHRAE Trans* **115**(2):456–462 (2009).
91. Orlov I and Kozak V, Use of compressed natural gas (CNG) as motor fuel in Ukraine, prospects and problems. In Volume 3: Proceedings of the 23rd World Gas Conference, June 5–9, 2006, Amsterdam, pp. 1406–1417 (2006).
92. Humbird D, Davis R, Tao L, Kinchin C, Hsu D, Aden A *et al.*, Process design and economics for biochemical conversion of lignocellulosic biomass to ethanol dilute-acid pretreatment and enzymatic hydrolysis of corn stover. Technical Report NREL/TP-5100-47764, National Renewable Energy Laboratory/Harris Group Inc., Seattle, Washington and Atlanta, GA (2011).
93. Vogel A, Brauer S, Müller-Langer F and Thrän D, *Integrated Project Sustainable Energy Systems*. Deliverable D 5.3.7 "Conversion Costs Calculation". Project: RENEW – Renewable Fuels for Advanced Powertrains. Institute for Energy and Environment. SES6-CT-2003-502705. Leipzig, November 2007 (2007).
94. ECN, *Personal Communication on the Capital Costs of the Milena Technology.* Anonymous, Amsterdam (2009).
95. Paisley MA and Overend RP, Verification of the performance of the future energy resources' silvagas biomass gasifier – operating experience in the vermont gasifier. (2002).
96. Boerrigter H, van Paasen SVB, Bergman PCA, Könemann JW, Emmen R and Wijnands A, "Olga" tar removal technology" proof-of-concept (PoC) for application in integrated biomass gasification combined heat and power (CHP) systems. ECN-C--05-009, ECN/Dahlman Industrial Group (2005).
97. NETL, *Cost and Performance Baseline for Fossil Energy Plants*, *Volume 1: Bituminous Coal and Natural Gas to Electricity*. Final Report. National Energy Technology Laboratory (2007).
98. NETL, Updated costs (June 2011 Basis) for selected bituminous baseline cases. DOE/NETL-341/082312, National Energy Technology Laboratory (2012).
99. Cline C, Hoksberg A, Abry R and Janssen A, Biological process for H_2S removal from gas streams. The Shell-Paques/Thiopaq™ gas desulfurization process. Paper presented at the Laurance Reid Gas Conditioning Conference 53. Norman, Oklahoma (2003).
100. Slimame RB, Lau FS, Pandya K and Carty RH, *Validation and Deployment of GTI's Leading Zinc Titanate Sulfur Sorbent*. Interim Final Technical Report. Gas Technology Institute, Chicago (2002).
101. Chen C, A technical and economic assessment of CO2 capture technology for IGCC power plants. PhD dissertation Carnegie Mellon University, Pittsburgh, PA (2005).
102. Waldner MH and Vogel F, Renewable production of methane from woody biomass by catalytic hydrothermal conversion. *Ind Chem Eng Res* **44**(13):4543–4551 (2005).
103. Rostrup-Nielsen JR, Pedersen K and Sehested J, High temperature methanation. Sintering and structure sensitivity. *Appl Catal A* **330**:134–138 (2007).
104. ANEEL (Brazilian Electricity Regulatory Agency). Tariffs Consumers (In Portuguese) (2013). (Online). Available: www.aneel.gov.br. http://relatorios.aneel.gov.br/_layouts/xlviewer.aspx?id=/RelatoriosSAS/RelSampRegCC.xlsx&Source=http://relatorios.aneel.gov.br/RelatoriosSAS/Forms/AllItems.aspx&DefaultItemOpen=1 [22 August 2013].

105. Kyivenergo, *Tariffs for Electricity (Except Population)*. Available: http://kyivenergo.ua/ee-company/tarifi [22 August 2013].
106. CBS (Centraal Bureau voor de Statistiek), *Natural Gas and Electricity, Average Prices Final*. Central Bureau of Statistics Netherlands, The Hague/Heerlen. (Online). Available: https://www.cbs.nl [23 August 2013].
107. Junginger M, Schouwenberg P, Nikolaisen L and Andrade O, Chapter 7: Drivers and barriers for bioenergy trade, in *International Bioenergy Trade*, ed. by Junginger M, Goh C, Faaij A. Springer, Dordrecht Heidelberg New York, London, pp. 151–172 (2013).
108. Dahlman*, PDENH and ENGIE also Become Partner in Biomass Energy Plant Ambigo in Alkmaar*. (2017). (Online). Available: http://www.royaldahlman.com/news/news-release-ambigo [5 May 2017].
109. Rietveld G, van der Drift A, Grootjes AJ, van der Meijden CM and Vreugdenhil BJ, *Commercialization of the ECN MILENA Gasification Technology*. (2014).
110. van der Drift A, Zwart RWR, Vreugdenhil BJ and Bleijendaal LPJ, Comparing the options to produce SNG from biomass. Presented at the '18th European Biomass Conference and Exhibition', Lyon, 3–7 May, ECN-M--10-050 (2010).
111. Glicksman LR, Chapter 13: Fluidized bed scaleup, in *Handbook of Fluidization and Fluid-Particle Systems*, ed. by Yang W-C. Marcel Dekker, New York, NY; Basel, pp. 348–383 (2003).
112. van Vliet OPR, Faaij APC and Turkenburg WC, Fischer-Tropsch diesel production in a well-to-wheel perspective: A carbon, energy flow and cost analysis. *Energy Convers Manage* **50**(4):855–876 (2009).
113. Maestas R, Alexandrou A, Bushoven JT, Goorahoo D and Adhikari D, Energy inputs and carbon dioxide emissions from turf maintenance equipment on a golf course in California. *Agric Eng Int* **14**(151):51–56 (2012).
114. van den Broek M, Faaij A and Turkenburg WC. Planning for an electricity sector with carbon capture and storage - Case of the Netherlands. *Int J Greenhouse Gas Control* **2**:105–129 (2008).
115. Stephen JD, Mabee WE and Saddler JN, Lignocellulosic ethanol production from woody biomass: The impact of facility siting on competitiveness. *Energy Policy* **59**:329–340 (2013).
116. van Oostvoorn F, *Long-term Gas Supply Security in an Enlarged Europe*. Final report ENGAGED project, ECN. (2003).
117. Berghout N, van den Broek M and Faaij A. Techno-economic performance and challenges of applying CO_2 capture in the industry: A case study of five industrial plants. *Int J Greenhouse Gas Control* **17**:259–279 (2013).
118. Saygin D, van den Broek M, Ramírez A, Patel MK and Worrell E. Modelling the future CO_2 abatement potentials of energy efficiencyand CCS: The case of the Dutch industry. *Int J Greenhouse Gas Control* **18**:23–37 (2013).
119. Fuelswitch, *Vehicles on CNG and Bio-CNG*. (2011). Available: http://www.fuelswitch.nl [15 September 2013].
120. Boisen P, *NGV's and Refuelling Stations Worldwide*. NGVA Europe, Madrid (2011).
121. Rabou, LPLM and van der Drift A. Benzene and ethylene in Bio-SNG production: nuisance, fuel or valuable products? In *Proceedings of the International Conference on Polygeneration Strategies* 11, ed. by Hofbauer H and Fuchs M. Vienna 30 August – 1 September 2011, pp. 157–162 (2011).
122. Heyne S and Harvey S. Impact of choice of CO2 separation technology on thermo-economic performance of Bio-SNG production processes. *Int J Energy Res* **38**(3):299–318 (2014).

Bothwell Batidzirai
Bothwell has been a senior researcher with the Energy Research Centre at the University of Cape Town since 2014. He has been involved in sustainable energy research for over 20 years mainly in sub-Saharan Africa and Europe. He has a background in energy engineering and sustainable development. His current research is focused on upscaling the deployment of sustainable energy technology in the global South.



Geert Schotman
Geert has a master's degree in energy science from Utrecht University. He spent some time working with NV Nuon Energy exploring the BioSNG production and supply pathways. Currently, Geert is involved in logistics and operations management at the Euromedica Limburg BV, Netherlands.

Mijndert van der Spek
Mijndert is currently working as a postdoctoral researcher at ETH Zürich, in the separation processes laboratory. His research there focuses on the development, optimization, and assessment of advanced sorbent-based technologies for CO2 capture from hydrogen production. Subsequently, his research has covered the assessment of CO2-utilization technologies, and bioenergy with CCS. Mijndert studied systems engineering, policy analysis, and management at Delft University of Technology, with a specialization in chemical engineering. He has also worked for Shell Chemicals for three years, in supply-chain optimization and in process technology. From 2013 to 2017, Mijndert pursued his PhD at the Copernicus Institute of Sustainable Development of Utrecht University. His PhD research involved process modeling, cost engineering, and uncertainty analysis of power plants with existing and emerging CO2 capture technologies.

Martin Junginger
Prof Dr Martin Junginger holds the Chair of Bio-Based Economy at the Copernicus Institute, Utrecht University, and works on sustainable biomass production, supply chains, conversion and end use for energy and materials, among other subjects. He is task leader of IEA Bioenergy Task 40 on sustainable biomass markets and international trade to support the bio-based economy.

André P. C. Faaij
André has been appointed as academic director of Energy Academy Europe and Distinguished Professor of Energy System Analysis at Groningen University. Prior to this position he was professor and scientific director of the Copernicus Institute of Utrecht University. His research covers, amongst other subjects, bio-based economy, carbon capture and storage, renewable energy, alternative transport fuels, energy system and scenario analysis, technological learning, and energy policies. He works as an advisor for governments, the European Commission, International Energy Agency, the UN, Global Environment Facility (GEF), The Organisation for Economic Co-operation and Development (OECD), The World Economic Forum (WEF), World Energy Council (WEC), the energy sector in general and nongovernmental organizations. He contributed to various Intergovernmental Panel on Climate Change reports, the World and Global Energy Assessment, and the IEA's World Energy Outlook. He was appointed Young Global Leader by the World Economic Forum and awarded the Linneborn Prize for outstanding contributions to the development of energy from biomass. He published over 700 titles in scientific journals, reports, books, and proceedings, qualifies as 'highly cited researcher' (top 1% of research field) by Thomson Reuters ISI Web of Science and frequently lectures across the globe.