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Energy self-sufficiency and sustainability in a defined neighbourhood: Bio-methanation to green gas can outperform green hydrogen

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ABSTRACT

In Europe, green hydrogen and biogas/green gas are considered important renewable energy carriers, besides renewable electricity and heat. Still, incentives proceed slowly, and the feasibility of local green gas is questioned. A supply chain of decentralised green hydrogen production from locally generated electricity (PV or wind) and decentralised green gas production from locally collected biomass and biological power-to-methane technology was analysed and compared to a green hydrogen scenario. We developed a novel method for assessing local options. Meeting the heating demand of households was constrained by the current EU law (RED II) to reduce greenhouse gas (GHG) emissions by 80% relative to fossil (natural) gas. Levelised cost of energy (LCOE) analyses at 80% GHG emission savings indicate that locally produced green gas (LCOE = 24.0 €ct kWh^{-1}) is more attractive for individual citizens than locally produced green hydrogen (LCOE = 43.5 €ct kWh^{-1}). In case higher GHG emission savings are desired, both LCOEs go up. Data indicate an apparent mismatch between heat demand in winter and PV electricity generation in summer. Besides, at the current state of technology, local onshore wind turbines have less GHG emissions than PV panels. Wind turbines may therefore have advantages over PV fields despite the various concerns in society. Our study confirms that biomass availability in a dedicated region is a challenge.

1. ıntroduction

At all levels, policies on energy supply are shifting from large-scale oil and natural gas use to further penetration of renewable energy in the energy mix [1]. In Europe, green hydrogen and biogas or green gas are considered important renewable energy carriers in various sectors and applications, besides renewable electricity and heat [2]. Using biomass waste flows for energy production may contribute to sustainability [3]. Green gas is biogas upgraded to Dutch natural gas quality (elsewhere, sometimes called biomethane), but the Dutch green gas is usually low caloric). Here, green gas is considered to be a mixture of methane (CH_4) and carbon dioxide (CO_2), such that the higher Wobbe Index is 44.17 MJ Nm^{-3}. It can be injected into the (Dutch) natural gas distribution grid directly. The Netherlands aims at two billion cubic meters (bcm) of green gas in 2030 [4]. Still, incentives proceed slowly, and the feasibility is doubtful, notably because of biomass's inefficient use and unavailability [5]. Assessments of biomass potential in defined geographical areas are difficult to translate into sustainable energy supply chains [6]. Any renewable supply chain should meet the Renewable Energy Directive II (RED II) requirements on GHG emission saving [7]. Currently, an amendment (2026 RED II) is being proposed [8]. According to RED II, GHG emission saving is relative to the fossil fuel replaced. 70% GHG emission saving is required for electricity, heating, and cooling installations if started between 2021 and the end of 2025, and a minimum of 80% if started from January 1, 2026. The amendment implies that all installations should save 80% or more from January 1, 2026. Renewable energy supply chains do not automatically meet these RED II requirements [9]. For example, hydrogen produced from PV technology does not satisfy the saving requirements of replacing natural gas [10].

Based on the Paris Agreement [11], Dutch municipalities are challenged to develop local policies for establishing local climate neutrality. Decisions on renewable energy options increasingly take place on this policy level [12]. Decentralised hydrogen production is one of the options to convert or store renewable electricity until needed. Local production of green gas profits from the existing natural gas infrastructure and experience. Both are being considered for urban areas. Farm-scale green gas production with bio-methanation (bio-P2M) can reduce GHG emissions. Bio-P2M is methane formation from CO_2 and hydrogen (H_2) by micro-organisms. However, the desired hydrogen production from decentralised intermittent electricity bsources is relatively

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Abbreviations and nomenclature

bcm	billion cubic meters
bio-P2M	biological power-to-methane, technology for methane formation that involves the bioconversion of carbon dioxide (CO_2) and hydrogen (H_2) to methane (CH_4) by hydrogenotrophic methanogenic archaea
CAPEX	capital expenditures
EU	European Union
GHG	greenhouse gas(ses)
GWP	global warming potential
green gas	biogas upgraded to Dutch natural gas quality (elsewhere, sometimes called biomethane). Here, green gas is considered to be a mixture of methane (CH_4) and carbon dioxide (CO_2), such that the higher Wobbe Index is 44.17 MJ Nm^{-3}
HHV	higher heating value
LCA	life cycle analysis
LCOE	levelised cost of energy
MILP	mixed integer linear programming
n.a.	not applicable
Nm^3	normal cubic meter (at standardised conditions $p = 1.01325$ bar, $T = 273.15$ K)
O&M	operation and maintenance
oDM	organic dry matter
OPEX	operational expenditures
PV	photovoltaic
PEM	proton exchange membrane
RED	Renewable Energy Directive (EU)
WACC	weighted average cost of capital
WTW	well to wheel

expensive compared to large-scale and constant sources [13]. Combining local hydrogen production from local electricity (PV or wind) with local green gas production from local biomass may make reaching climate neutrality more attractive or feasible. Here, we compare the levelised cost of energy (LCOE) of locally produced green hydrogen with the LCOE of green gas produced with green hydrogen (bio-P2M). The preconditions for the analyses are that both scenarios satisfy the heat demand of a given (small) neighbourhood and comply with the 2026 RED II requirements on GHG emission saving. This allows for assessing the economic feasibility of sustainable decentralised green hydrogen and green gas in a defined neighbourhood. The impact on land use of decentralised PV, wind, and biomass is included in the analyses to estimate the area needed. Such a comparison of different technological solutions may help to formulate future strategies for a local energy transition.

2. Methods and data

2.1. Calculations of LCOE and GHG emission saving

The LCOE [€ct kWh^{-1}] is calculated on a project basis according to Eq. (1) [14]. The LCOE is the outcome of the analyses, and the lower the LCOE, the better the economic viability of the setup analysed.

$$LCOE = \frac{CAPEX + \sum_{n=1}^{N}\left(\frac{OPEX}{(1+WACC_{nominal})^n}\right)}{\sum_{n=1}^{N}\left(\frac{Yield}{(1+WACC_{real})^n}\right)} \tag{1}$$

In Eq. (1), $CAPEX$ [€] comprises all investments, $OPEX$ [€] is both the fixed (operation and maintenance, O&M) and variable (energy consumption) operational cost per year. $Yield$ [kWh] is the energy delivered each year in the form of either green hydrogen or green gas. n [year] is the time, and N [year] is the project duration during which the investments are amortized. $WACC_{nominal}$ [%] is the nominal weighted average cost of capital per annum, calculated according to Eq. (2) [14].

$$WACC_{nom} = \frac{D.k_D.(1 - CT) + E.k_E}{D + E} \tag{2}$$

In Eq. (2), D [%] is the debt ratio, k_D [%] is the interest rate of debt financing, CT [%] is the corporate tax, E [%] is the equity rate, and k_E [%] is the return on equity financing. $WACC_{real}$ [%], the real weighted average cost of capital, including inflation, is calculated according to Eq. (3) [14].

$$WACC_{real} = \left[\frac{1 + WACC_{nominal}}{1 + Infl}\right] - 1 \tag{3}$$

In Eq. (3), $Infl$ [%] is the inflation. Estimates for all parameters are given in Appendix A.

GHG emission saving [%] represents the reduction of GHG emissions when replacing natural gas with green hydrogen or green gas. It is calculated according to Eq. (4) [15].

$$GHGemissionsaving = \frac{GHG_{comparator} - GHG_{emission}}{GHG_{comparator}}.100\% \tag{4}$$

in which $GHG_{comparator}$ is the GHG emission [g_{CO2eq} kWh^{-1}] of natural gas to which green hydrogen and green gas are compared, $GHG_{emission}$ is the GHG emission per kWh green hydrogen or green gas injected into the gas grid. This approach to GHG emission savings can be considered an attributional life cycle analysis (LCA) rather than a marginal LCA [16]. The GHG emission saving relative to natural gas was set to be at least 80% to comply with the 2026 RED II requirements.

2.2. Case: The city of Hoogeveen

Hoogeveen, The Netherlands, was the frame of reference for this study. Hoogeveen is a medium-sized city of about 35 thousand inhabitants located in the province of Drenthe, surrounded by a predominantly rural and agricultural area. The city has about 18 thousand households. The natural gas for heating in a given neighbourhood of Hoogeveen is currently considered for conversion to green hydrogen in a demonstration project [17]. The neighbourhood is a test and demonstration site for the organisation, realisation, and embedding of a future domestic green hydrogen supply. The test site consists of 500 households (about 2.8% of the total) and is considered here. All energy (natural gas, green gas, or green hydrogen) is assumed to be used exclusively for heat (including cooking). Hoogeveen's regional distribution system operator for electricity and gas provided the hourly profile of heating demand [kWh h^{-1}] for an entire year (2017). The heat demand profile is based on data from similar households as in the section considered here.

2.3. Green hydrogen supply chain

For green hydrogen, the LCOE was calculated with a validated mixed integer linear programming (MILP) minimisation procedure in MATLAB (release R2022b) as described previously [10]. The hydrogen supply chain consists of a variable number of wind turbines, size of solar photovoltaics (PV) area, amount of grey grid electricity, and size of electrolyser and hydrogen storage. The electrolyser is a proton exchange membrane (PEM) electrolyser. Given the 30 bar of PEM electrolysis output [18], no need for further compression is considered for hydrogen storage.

The electrolyser and hydrogen storage are positioned close to the

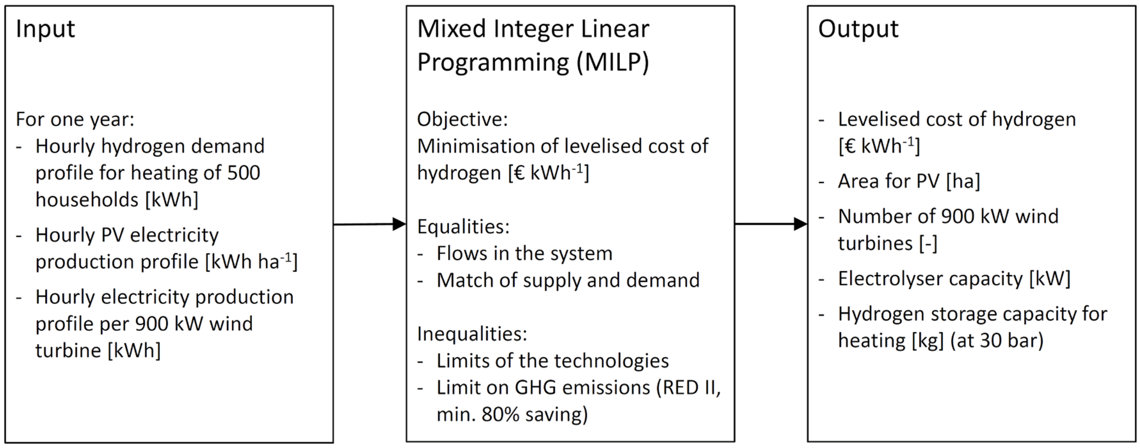


Fig. 1. Flowchart of the MILP model used for modelling the green hydrogen supply chain, adapted from [10].

place of hydrogen use. Hydrogen is injected into the existing gas distribution grid, assuming that natural gas has been replaced by hydrogen at no additional costs. The costs of the hydrogen grid itself are not included. The outline of the MILP procedure is shown in Fig. 1. The green hydrogen supply chain was optimised to minimize the LCOE of green hydrogen.

2.4. Green gas supply chain

For green gas, the LCOE was calculated using the Microsoft Excel model described previously [9]. Cow manure, together with the organic substrates grass (not suitable for cows; from nature, fields, or roadsides) and household organic waste, are the feedstock for the biogas production facility. All are assumed to be available at zero cost, except for transport to the biogas plant. The mass of the manure used is equal to or larger than the mass of other substrates to allow using digestate as fertiliser on farmland [19]. The biogas is converted to green gas with the specifications for the Dutch gas grid [20] in a bio-P2M reactor using locally produced green hydrogen. The biogas + bio-P2M production facility is considered to deliver a constant flow of green gas: manure and organic waste constitute relatively stable input flows, and all components can be stored if desired. A continuous hydrogen delivery to the bio-P2M plant is also assumed in the model, optimised with the same MILP procedure as decribed above.

Care was taken to ensure that the GHG emissions meet the 80% or more saving requirements of 2026 REDII. Methane leakage is taken into account, and a portion of the green gas is used for the temperature management of the installation. The entire production facility, including the bio-P2M reactor, electrolyser, and hydrogen storage, is positioned in an area (possibly at a farm) about 15 km away from the place of use. The green gas is injected into the existing gas distribution grid that is large enough to handle the green gas at a constant rate. The connection to an existing gas grid is included in the model, but not the cost of the gas grid itself.

2.5. Data collection

All data were collected from public databases and from literature. Data on wind turbines, PV setup, electrolyser, hydrogen storage, and injection were presented earlier [10]. Two changes relative to that earlier analysis [10] were incorporated: a wind turbine of 900 kW instead of 60 kW was considered more appropriate for the number of households in this study, and the GHG emission of PV panels was set at 61 g_{CO2eq} kWh^{-1} [21], instead of 93 g_{CO2eq} kWh^{-1}, due to progressive technology. Data on biogas production and bio-P2M were also presented earlier [13]. Data on heat demand and bioenergy supply for the green gas supply chain are shown in Table 1. Table A.1 (Appendix A) presents the data on PV, wind, electrolysis, hydrogen storage, transport, digester, bio-P2M, and injection of green gas in a gas grid, as well as all economic and GHG emission parameters.

3. Results and discussion

Two scenarios for meeting the heat demand of 500 households in a medium-sized Dutch city were designed and analysed. Key transformation blocks of the scenarios are shown in Fig. 2. For each flow (arrow), it is indicated whether it is a constant (straight line) or a variable (wave) flow. The variation taken into account is the hourly profile per day over a year.

In the green hydrogen scenario (Fig. 2A), the heat demand of 500 households (6,370 MWh a^{-1}) is supplied by hydrogen (1.8×10^6 Nm^3 a^{-1}, with an HHV of 12.75 MJ Nm^{-3}) locally produced with an electrolyser powered by a combination of local wind turbines, PV panels and (grey) grid electricity, such that the GHG emission saving of hydrogen is at least 80% compared to natural gas. In the green gas scenario (Fig. 2B), the same heat demand is supplied by green gas obtained from biogas (0.65×10^6 Nm^3 a^{-1}) produced from locally collected manure and co-substrates. The biogas is upgraded to green gas (0.65×10^6 Nm^3 a^{-1}, with an HHV of 35.75 Nm^3 a^{-1}) in an *ex situ* bio-P2M reactor with hydrogen (0.9×10^6 Nm^3 a^{-1}) from a local electrolyser powered by local wind turbines and PV panels. Parameters taken into account in the two scenarios are detailed in Table 1 and in Table A.1 of the appendix. The results of the MILP and Excel analyses are presented in Table 2.

Table 2 presents the LCOE of hydrogen and green gas in €ct kWh^{-1} to allow a direct comparison between the two scenarios. All energy values in kWh or MWh are based on the higher heating value (HHV). In units more commonly used in the literature, this yields 17.1 € kg^{-1} and 11.4 € kg^{-1} for green hydrogen in scenario A and scenario B, respectively, and 238 €ct Nm^{-1} for green gas (Table 2).

Our analyses show that meeting the heat demand is almost two-fold more expensive in the case of green hydrogen in scenario A than in the case of green gas in scenario B (43.5 €ct kWh^{-1} versus 24.0 €ct kWh^{-1}, respectively). This also becomes apparent when considering the LCOE of hydrogen in scenario B. Although in scenario B, hydrogen is not the final product, the LCOE of hydrogen was estimated at 11.4 € kg^{-1}, which can be recalculated to amount to 28.9 €ct kWh^{-1}. Thus, the LCOE of hydrogen in scenario B (28.9 €ct kWh^{-1}) is smaller than the LCOE of the final product in scenario A (green hydrogen, 43.5 €ct kWh^{-1}).

In scenario B, there is less need for green hydrogen. The electrolyser can be considerably (almost four times) smaller and has higher operational hours. Also, there is less need (hence costs) for hydrogen storage. Moreover, no changes in the in-house infrastructure have to be put in place. However, the latter is not part of the cost analyses presented here. Combined, house owners may prefer scenario B over scenario A. It

Table 1
Demand and supply of heat. Detailed information on biomass parameters is given in Appendix B.

Quantity	Variable[a]	Value	Unit	Reference or explanation
Heat demand				
Number of households	*d1*	500	–	[17]
Current natural gas demand per household	*d2*	1300	$Nm^3\ a^{-1}$	[22], data 2020, privately owned "average" house
HHV natural gas	*d3*	9.8	$kWh\ Nm^{-3}$	[23], low-calorific (Dutch standard)
Total heat demand	*d = d1*d2*d3*	6370	$MWh\ a^{-1}$	
Bioenergy				
CH_4 content (after bio-P2M)	*e1*	89.7	% of green gas volume	volumetric
HHV CH_4	*e2*	11.064	$kWh\ Nm^{-3}$	[23]
Cow manure				
Number of cows[b]	*c1*	300	–	3 (Dutch) average farms, [24]
Manure production	*c2*	20	$tonne\ animal^{-1}\ a^{-1}$	Adapted from [25]
Organic dry matter (oDM)	*c3*	8.0	% of *c2*	[26]
Biogas potential	*c4*	310	$Nm^3\ tonne^{-1}$ oDM	[26]
Methane potential		180	$Nm^3\ tonne^{-1}$ oDM	[26]
Biogas from cow manure	*c5 = c1*c2*c3*c4*	148,800	$Nm^3\ a^{-1}$	
Energy from cow manure	*c6 = c5*e1*e2*	1477	$MWh\ a^{-1}$	
Cost		0	€ $tonne^{-1}$	[27]
Transport		15	km	One biogas plant on a farm; manure from other farms in the same area (4000 Mg a^{-1}) is transported to this biogas plant
Grass				
Amount	*g1*	3636	$tonne\ a^{-1}$	Total availability in the municipality is estimated to be 6,000 Mg a^{-1} [6]. A fraction (3,636 Mg a^{-1}) is used here: the value is chosen such that it, together with the 6,000 Mg a^{-1} manure (=*c1*c2*) and 150 Mg a^{-1} organic waste (=*o1*), can meet the heat demand.
oDM	*g2*	25	% of *g1*	Adapted from [26,28]
Biogas potential	*g3*	560	$Nm^3\ tonne^{-1}$ oDM	[26]
Methane potential		275	$Nm^3\ tonne^{-1}$ oDM	[26]
Biogas production from grass	*g4 = g1*g2*g3*	566,720	$Nm^3\ a^{-1}$	
Energy production from grass	*g5 = g4*e1*e2*	5624	$MWh\ a^{-1}$	
Cost		0	€ $tonne^{-1}$	
Transport distance		18	km	Assumed average distance based on local conditions [6]
Organic waste				
Amount	*o1*	150	$tonne\ a^{-1}$	500 households, assuming 300 kg a^{-1} organic waste per household, estimated from [29].
oDM	*o3*	18.3	% of DM	[26]
Biogas potential	*o4*	260	$Nm^3\ tonne^{-1}$ oDM	[26]
Methane potential		156	$Nm^3\ tonne^{-1}$ oDM	[26]
Biogas from organic waste	*o5 = o1*o2*o3*o4*	7137	$Nm^3\ a^{-1}$	
Energy from organic waste	*o6 = o5*e1*e2*	71	$MWh\ a^{-1}$	
Cost		0	€ $tonne^{-1}$	
Transport distance		5	km	Assumed average distance between the neighbourhood and the farm where the digester is located, based on local geography
Total heat supply	*s = c6 + g5 + o6*	7172	$MWh\ a^{-1}$	
Losses	*s-d*	802	$MWh\ a^{-1}$	Due to losses in biogas production (incl. leakage) and green gas used for the production facility itself (temperature)

[a] Defined to be able to show mutual relationships.
[b] With this number of cows, Dutch regulations allow using the digestate as fertiliser because the total mass of co-substrates (grass, organic waste) is not larger than that of manure.

indicates that the attractivity and role of green gas in the future energy supply of a municipality may be underestimated [30].

Earlier, the LCOE of green gas was calculated to be about 65–80 €ct Nm^{-3} depending on the scenario considered [13], while the LCOE is 238 €ct Nm^{-3} here. Also, a constant hydrogen production at 8000 h a^{-1} was assumed with surplus electricity available at 2.0 €ct kWh^{-1} [13]. Here, the electricity production is intermittent, and costs are higher: 6.0 €ct kWh^{-1} and 5.9 €ct kWh^{-1} for PV and wind electricity, respectively (Table 2), and 6.5 €ct kWh^{-1} for grid electricity (Table A.1). Therefore, the relatively high costs of scenario B are partly due to (a) the relatively small scale of the heat demand of 500 households), (b) the relatively high costs of hydrogen because of the relatively high electricity cost, and (c) the intermittent character of the electricity supply for hydrogen production.

Using green gas based on bio-P2M helps reduce the number of wind turbines required (Table 2). Assuming one hectare (ha) per wind turbine, the area required for wind energy would reduce from 9 ha in scenario A to 4 ha in scenario B. In scenario B, an additional 3.5 ha is

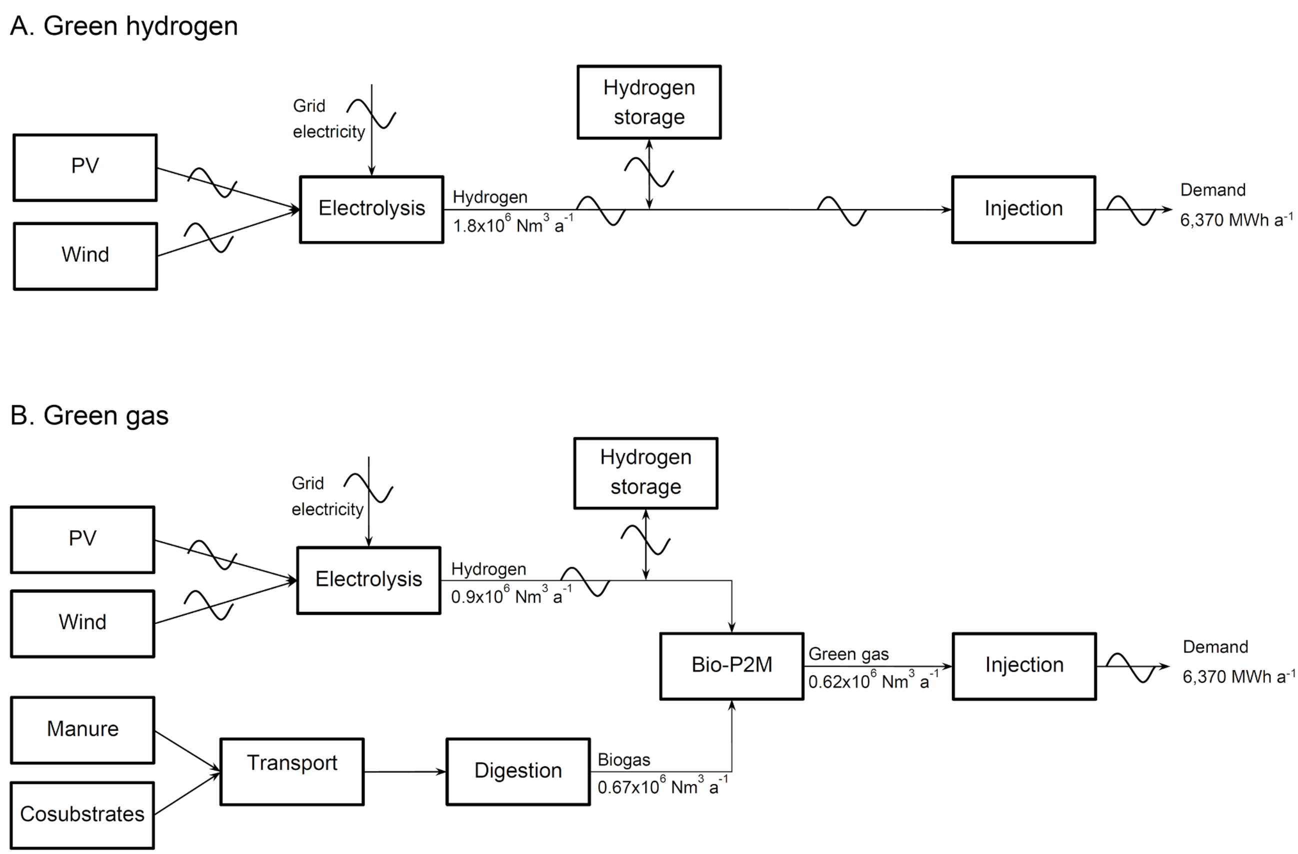


Fig. 2. Key transformation blocks in two scenarios for meeting the heat demand of households. A. Green hydrogen; B. Green gas. Each arrow represents a flow of energy between transformation blocks. The flow is constant (straight arrow) or variable with an hourly profile (arrow with a wave). The different flows are quantified in the text.

needed for PV. Although in scenario B the biomass requires land, it is not attributed to the scenario, because the biomass would be considered waste if not used for biogas production. Thus, from a land use perspective, scenario B is more attractive than scenario A. Scenario B requires, in addition, biomass transport of manure, waste, and digestate. The societal acceptability of such transportation should be considered before implementing scenario B's green gas infrastructure.

It may seem surprising that scenario A results in more wind turbines and a complete absence of PV panels compared to scenario B. The common perception is that PV energy is more attractive on land than wind energy. However, the heat demand is much greater in winter than in summer, while PV energy production predominantly occurs during summer. Our analyses show that the inherent seasonality of PV energy can be partly compensated for with green gas (scenario B). Otherwise, the cost of hydrogen storage becomes prohibitive (scenario A). From the perspective of seasonal hydrogen storage, local wind energy is more attractive than local PV energy. Onshore wind may considerably contribute to local energy systems. Yet, the social acceptance of onshore wind energy tends to be substantially lower than the acceptance of PV. Such factors were not included in the models here used for analyses.

In both scenarios, not all electricity produced is used. In scenario A, 59% of wind electricity is used for hydrogen production (Table 2). Similarly, 56% of the PV electricity is used in scenario B. Such electricity could be used for the electrical demands in households. Any surplus electricity could be supplied to the electricity grid with concomitant revenues. This reduces the overall system costs but would require additional organization (hence costs) for attributing costs based on gas and electricity demands. Such revenues and costs were not considered.

The contribution of the transformation blocks (Fig. 2) to the LCOE of the final product (Fig. 3) was analysed. This may help identify strategies to minimise the costs of either scenario.

In both cases, electricity contributes most to the costs of hydrogen. The significant contribution of wind electricity to the overall costs is due to the lower cost of wind electricity compared to PV and grid electricity, and the need to achieve at least 80% GHG emission savings. Electricity from wind has the lowest emission (14 g_{CO2eq} kWh^{-1}) relative to PV (61 g_{CO2eq} kWh^{-1}) and the grid (524 g_{CO2eq} kWh^{-1}). PV electricity alone would not achieve 80% GHG emission saving: 61 g_{CO2eq} kWh^{-1} is more than 20% of the GHG emission of natural gas (0.2 * 213 g_{CO2eq} kWh^{-1} = 42.6 g_{CO2eq} kWh^{-1}).

The higher share of (now grey) grid electricity in scenario A compared to scenario B shows that it is cheaper to use grid electricity than PV electricity in scenario A. In contrast, in scenario B it is cheaper to use PV at the expense of grid electricity. It could be argued that the inclusion of grey grid electricity affects the green nature of the supply chains. However, in the future, all grid electricity should be green. The results indicate, not surprisingly, that a more constant heat demand during the year would decrease the overall cost. Better isolation would help, or acceptance of lower living temperatures in winter. Climate change is predicted to bring more extreme weather patterns. Therefore, minimising the significant heat demand during the winter season is not likely something that is going to be realistic for The Netherlands.

The analyses presented were based on achieving at least 80% GHG emission saving. Further reduction of GHG emissions deserves attention. Future policies will likely demand more savings than 80% to deal with climate change. Fig. 4 shows how transformation blocks (Fig. 2) contribute to the GHG emissions in both scenarios. In both scenarios, the GHG emission saving is precisely 80% (the lower limit set), so higher GHG emission savings would lead to higher costs. In scenario A, the GHG emission saving is due to replacing natural gas with hydrogen from wind energy. In scenario B, PV and wind contribute the most, followed by transport (manure, co-substrates, and digestate).

Table 2
Estimates of the parameters for the two scenarios outlined in Fig. 2.

	Scenario A: Green hydrogen	Scenario B: Green gas
Overall		
LCOE [€ct kWh^{-1}][a]	43.5	24.0
LCOE green hydrogen [€ kg^{-1}][b]	17.1[b]	11.4[b]
LCOE green gas [€ct Nm^{-3}]	n.a.[c]	238[d]
Green hydrogen production [kg h^{-1}]	18	11
Biogas production [Nm^3 h^{-1}]	n.a.	77
PV		
Area needed for PV [ha]	0	3.5
PV electricity used [x10^3 MWh a^{-1}]	0	0.9
PV used/PV produced [%]	n.a.	56
LCOE PV [€ct kWh^{-1}]	n.a.	6.0
Wind		
Number of wind turbines	9	4
Wind electricity used [x10^3 MWh a^{-1}]	10	5.2
Wind used / Wind produced [%]	59	66
LCOE Wind [€ct kWh^{-1}]	5.9	5.9
Electrolysis and hydrogen storage		
Grid electricity used [MWh a^{-1}]	241	55
Electrolyser capacity [MW]	5.6	1.5
Operational hours electrolyser [h a^{-1}]	5,777	8,172
Hydrogen storage capacity needed (x10^3 kg)	11	2.2

[a] LCOE of green hydrogen (HHV 12.75 MJ Nm^{-3}, 39.4 kWh kg^{-1}) in scenario A and green gas (HHV 35.75 MJ Nm^{-3}) in scenario B. All calculations are based on the HHV.
[b] calculated as (LCOE of green hydrogen × HHV).
[c] n.a., not applicable.
[d] calculated as (LCOE × HHV/3.6).

In the literature, GHG emissions from PV and wind are sometimes considered to be zero, e.g., in well-to-wheel (WTW) analyses [21]. Actual values were here used to include life cycle emissions of the technologies: 14 g_{CO2} kWh^{-1} for wind and 61 g_{CO2} kWh^{-1} for PV. The 80% 2026 EU REDII target on GHG emission saving allows for a small share of grid electricity. The results show that grid electricity is modestly used in both scenarios. With current technology emissions and conversion efficiencies, using only wind electricity results in 89% GHG emission saving as the maximum achievable in scenario A. Also, more effort is recommended to minimise methane losses of digesters, bio-P2M plants, or other environmental impact of processes [31], and use renewable fuels (green gas) for biomass transport in scenario B for further GHG emission saving.

For scenario B, the 6,370 MWh a^{-1} heating demand is delivered by biogas and hydrogen, which form to green gas in the bio-P2M reactor. Biogas is produced from manure, grass and organic waste, each having its own biogas potential. Fig. 5 shows the contribution of the energy carriers hydrogen, manure, grass and organic waste to meeting the heating demand. Hydrogen has the largest share (51%), followed by biogas from grass (35%). Our analyses show that the contribution of organic waste to the heating demand is only marginal (2%), although such waste is generally considered a promising renewable energy source. Still, the relatively low volume of such biomass (per household) and the relatively low energy content impair the promise.

Our study focuses on the costs of new technologies and electricity. It is very challenging to keep such analyses up-to-date because the situation in the world is changing rapidly. Energy prices are now highly volatile, yet at higher levels than two years ago could be anticipated. Inflation is on the rise accordingly. Energy use and generation also need more attention in the context of climate change (IPCC, 2022). Moreover, the cost of biomass is likely to go up because demand is likely to increase in all sectors that claim biomass [32].

On the other side, technologies continue to develop. Future costs of electrolysis are expected to decrease. The CAPEX for proton exchange membrane (PEM) electrolysis (here estimated at 1,000 € kW^{-1}) may reduce to less than 500 € kW^{-1} [33]. Also, bio-P2M technology is likely to become more cost-effective after further market penetration [34]. The water produced may be valorised (revenue), and the CO_2 may come from other sources than biogas; 40 € Mg^{-1} for CO_2 production cost, and 10 € Mg^{-1} for transport cost were reported [35]. Such technological developments and options, as well as global developments, will affect the cost attractivity of one scenario over the other. The models and analyses presented here are tools to reanalyse the scenarios given anticipated or observed parameter changes.

In reality, households have more energy demand than only heat in winter. A combination of demands is expected to lower costs [10], for example, when households use hydrogen or green gas for their mobility. The electricity demand of houses could also be included. However, its influence on the earlier calculated LCOE was modest compared to including mobility [10]. In all such cases, more renewable energy would be needed, and more biomass in the green gas scenario. The energy availability from waste biomass strongly depends on biomass type, transport distances, geographical area, and alternative uses. Biomass is less readily available in an urban environment than in a rural area, so scenario B must be considered for each specific situation. Also, a combination with hybrid heat pumps is possible. Although energy prices fluctuate and are uncertain [36], the current high natural gas prices and CO_2 cost developments will likely accelerate the implementation of

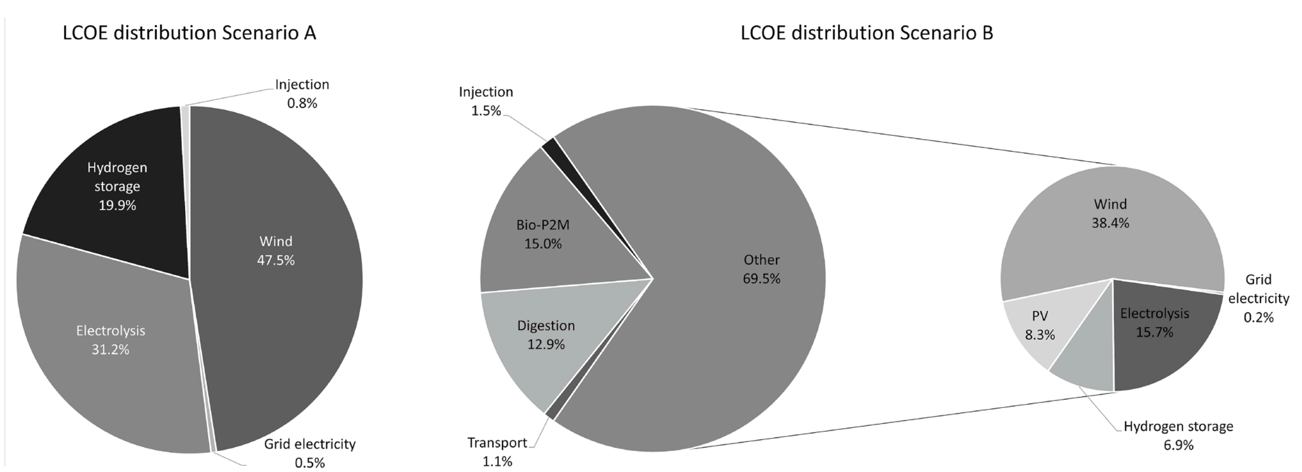
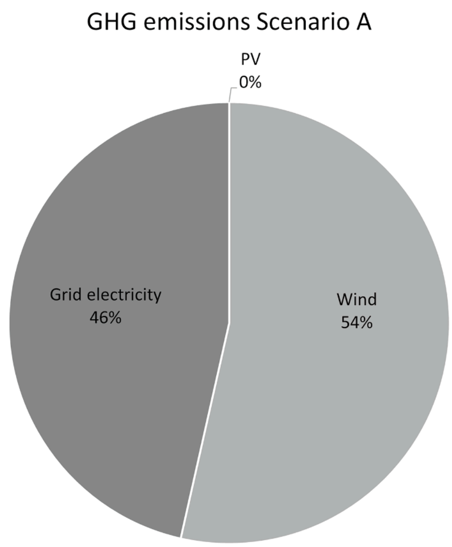


Fig. 3. Relative contribution of the different transformation blocks (Fig. 2) to the LCOE of the final product in the two scenarios.



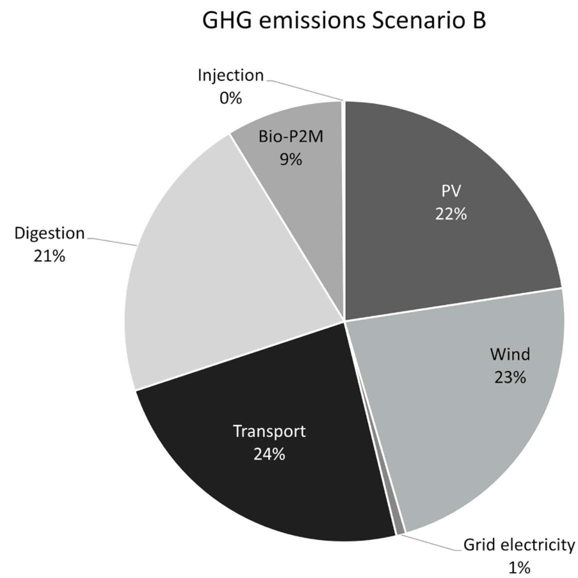


Fig. 4. GHG emission contribution of the transformation blocks in both scenarios.

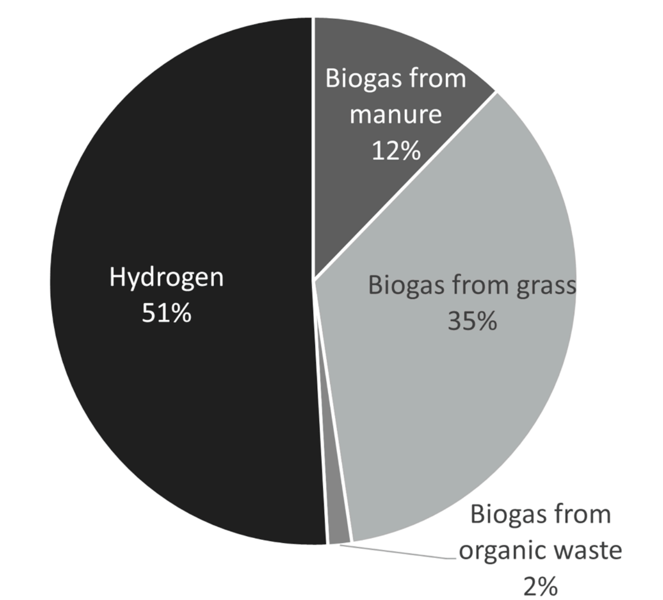


Fig. 5. Contribution of the individual energy carriers, as input of bio-P2M, to meeting the heating demand in scenario B (6,370 MWh a^{-1}). E.g., 12% of 6,370 MWh a^{-1} is delivered by manure.

decentralised hydrogen and/or green gas production facilities.

A major issue in the scenarios presented here is how costs and revenues are divided over individual stakeholders, e.g., a farmer, a municipality, a distribution system operator, a citizen, and more. In our model, the transport costs for manure and co-substrates are included, implying that the green gas producer pays for the transport. However, other options are feasible. The collection of nature/roadside grass and organic waste is nowadays paid for by the municipality from local taxes. If the costs of biomass transport are covered by local taxes, the LCOE of scenario B drops. Including such fees could imply lower local taxes. Such decisions are up to local policymakers.

Cow manure and organic waste are deemed to correspond to what could plausibly be available in the vicinity of the neighbourhood, while 75% of the grass expected to be available in the municipality is used in scenario B, i.e. for the heating demand of 500 households (see Appendix B). Note that the entire municipality comprises 18,000 households. There seems little potential for increasing the availability of grass or other co-substrates in scenario B. The analysis suggests that biomass use is case and location specific. Using biomass on one location may hamper the use on other locations. As such, the analysis conducted can be seen as an illustration of a desired but limited contribution of green gas to the energy supply in The Netherlands [37]. In Dutch agriculture, mono-digestion, i.e., digestion of only cow manure, is currently promoted, mainly because of the complex Dutch legislation concerning co-digestion and digestate handling. In the scenario presented here, it would require more manure and more transport and result in an increase in GHG emissions, apart from the availability of such manure. From an energy and climate perspective, mono-digestion would seem a poor choice [9]. The role of hydrogen in the future energy system is an issue of debate [38]. Hydrogen may have better alternatives than domestic heating, notably when houses are well insulated, and electrical heat pumps are adequate. The need for hydrogen to deliver high temperatures in the industry or as an energy carrier for (heavy) transport may have priority. In contrast, green gas is expected to play a prominent role in the heating demand of houses, notably the older ones that are not-so-easy to insulate (monuments, farms). The approach presented should give similar outcomes in other areas of the world, depending on parameters such as heating demand, population density and biomass availability. And the same approach can apply to countries where high caloric natural gas is used for heating.

Hydrogen could help facilitate further penetration of green gas in the energy system. In the present study, a decentralised energy system was modelled. Still, large-scale centralised hydrogen production in combination with a national hydrogen transport infrastructure could be envisioned [17]. Part of the hydrogen could then be used for local application in green gas. Hydrogen can also be blended with natural gas [39]. This could help to further green existing gas supplies, but the extent to which this is possible depends on the natural gas grid requirements and end-user equipment. Such blending could be scope of a future study.

4. Conclusions

A novel method is presented to assess local options for green hydrogen and green gas while meeting the heating demand of households constrained by the desire to reduce GHG emissions according to EU law. Scenario B which delivers locally produced green gas is preferable above locally produced green hydrogen if the LCOE of the final

Table A1
Parameters to evaluate the scenarios defined in Fig. 2.

Parameter	Description	Value	Unit	Remark/source
General				Unless otherwise stated in other transformation blocks
	Operational hours	8,760	h a^{-1}	
D	Debt ratio	70	%	[27]
k_D	Interest rate debt financing	2.7	%	[27]
CT	Corporate tax	25	%	[27]
E	Equity ratio	30	%	= 100% - debt ratio [27]
k_E	Required return on equity	14.5	%	[27]
$Infl$	Inflation	1.5	%	[27]
	Operation and maintenance (O&M)	5	%	Standard percentage of investment, per year
N	Project duration	15	years	[27]
	Grid electricity price	6.5	€ct kWh^{-1}	[13] Average in The Netherlands over the years 2015–2017, without VAT but including energy tax [40].
	GHG emission grid electricity	524	g_{CO2eq} kWh^{-1}	[21,41,42]
	GHG emission natural gas (comparator)	213	g_{CO2eq} kWh^{-1}	Is 2.085 kg_{CO2eq} Nm^{-3} [21], using HHV = 9.8 kWh Nm^{-3}
	GWP CH_4	25	kg_{CO2eq} kg_{CH4}^{-1}	[7,43]
PV				For more details the reader is referred to [10]
	Overplant factor	30	%	The highest 30% of installed capacity is not used
	CAPEX	297,000	€ ha^{-1}	540 € kW_p^{-1} [44–47], and 0.55 MWp ha^{-1} [46,48]
	OPEX	2.5	%	Annual percentage of CAPEX, estimated from [44–47]
D_{PV}	Debt ratio	90	%	[27]
$k_{D,PV}$	Interest rate debt financing	1.7	%	[27]
E_{PV}	Equity ratio	10	%	= 100% - debt ratio [27]
$k_{E,PV}$	Required return on equity	8.5	%	[27]
	GHG emission	61	g_{CO2eq} kWh^{-1}	[21,49]
Wind				For more details the reader is referred to [10]
Z_i	Height wind speed measured	10	m	[50]
ρ	Standard air density	1.225	kg m^{-3}	
α	Wind shear exponent	0.19	–	[51]
P_r	WT rated power	900	kW	[52]
Z	Hub height wind turbine	75	m	assumption
d	Rotor diameter	54	m	[52]
v_r	Rated windspeed	13.5	m s^{-1}	[52]
v_{cut-in}	Cut-in windspeed	2.5	m s^{-1}	[52]
$v_{cut-out}$	Cut-out windspeed	25	m s^{-1}	[52]
C_p	Power coefficient	0.45	–	[52]
τ_{WT}	Wind turbine loss factor	0.9	–	[53]
	CAPEX	1,170,000	€ $unit^{-1}$	1,300 € kW^{-1} was assumed, adapted from [44,54]
	OPEX	3.0	%	Annual percentage of CAPEX, estimated from [44,55]
D_{wind}	Debt ratio	85	%	[27]
$k_{D,wind}$	Interest rate debt financing	1.7	%	[27]
E_{wind}	Equity ratio	15	%	= 100% - debt ratio [27]
$k_{E,wind}$	Required return on equity	9.5	%	[27]
	GHG emission	14	g_{CO2eq} kWh^{-1}	
Electrolysis				For more details the reader is referred to [10]
	Electricity consumption	5.0	kWh Nm^{-3} H_2	[56]
	CAPEX	1.0×10^3	€ kW^{-1}	[13,57–59]
	CAPEX stack	320	€ kW^{-1}	Electrolyser stack replacement in year 6 and 11 [10]
	OPEX	3.0	%	Annual percentage of CAPEX [57,58,60]
Hydrogen storage				For more details the reader is referred to [10]
	CAPEX	12.4	€ kWh^{-1}	[61], 490 € kg^{-1}
	OPEX	1.0	%	Annual percentage of CAPEX [60]
Transport				
	Transport costs truck	1.24	€ km^{-1}	[62]
	Load/unload costs truck	0.50	€ Mg^{-1}	[63]
	GHG emission diesel	91	g_{CO2eq} MJ^{-1}	[21], B7 blend
Co-substrate storage				
	CAPEX	30	€ t^{-1}	
Digester				This includes biomass storage, digestion, and digestate handling as fertiliser and waste
	Biogas production	4.0×10^6	Nm^3 a^{-1}	Typical farm-scale digester in The Netherlands

(continued on next page)

Table A1 (*continued*)

Parameter	*Description*	*Value*	*Unit*	*Remark/source*
	Biogas composition (mol/mol)	55.0% CH_4, 45.0% CO_2		
	CAPEX	436×10^3	€	
	OPEX	5	%	Annual percentage of CAPEX
	CH_4 loss	0.8	%	Loss into the environment, as a percentage of the output flow (biogas) of the digester
Digestate	Transport distance	50	km	Assumption
	Cost	10	€ t^{-1}	Removal cost
Bio-P2M				
	H_2 to biomass	0.4	vol%	[64]
	CO_2 to biomass	1.6	vol%	[65]
	H_2 slip	0.0	vol%	All H_2 converted to CH_4 or biomass
	CO_2 slip	0.0	vol%	All CO_2 converted to CH_4 or biomass
	CH_4 loss	0.5	vol%	Loss into the environment, as a percentage of the output flow (green gas) of the bio-P2M reactor
	Electricity consumption	0.16	kWh Nm^{-3}	Per Nm^3 input gas flow (H_2/biogas for B and H_2/CO_2 for C and D
	CAPEX	1.5×10^6	€	ex situ trickle-bed reactor + compressor
	OPEX	5	%	Annual percentage of CAPEX
Injection				
	Green gas composition (mol/mol)	89.7% CH_4, 10.3% CO_2		[20]
	CAPEX	165×10^3	€	[66]
	OPEX	5%		Annual percentage of CAPEX

product is the determining parameter. The GHG emission saving is precisely 80% in both scenarios. With the current state of technology, only wind energy could contribute to higher savings. The contribution of organic waste to the heating demand is only marginal. This contradicts the general perception of organic waste as a promising renewable energy source. We present a comparative analysis of hydrogen with green gas for residential heating demand. Many more applications other than heat exist for hydrogen use. The same holds for using renewable electricity for residential heating. Such options can be assessed in more comparative analyses that deserve future attention.

CRediT authorship contribution statement

Jan Bekkering: Conceptualization, Methodology, Software, Validation, Formal analysis, Investigation, Visualization, Writing – original draft. **Jan-Peter Nap:** Conceptualization, Methodology, Writing – review & editing, Funding acquisition.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data are included in the Appendix in the manuscript.

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Appendix A

See Tables A.1.

Appendix B

Biomass availability for biogas production is location-specific, and local availability may be hard to determine. Biomass potential analyses are usually on a broader scale than needed for a specific case. In previous research [6], cow manure, pig manure, poultry manure, (municipal) organic waste, grass (nature, roadside), sugar beet tops, potato tops, and wheat straw were identified as a potential feedstock for biogas production in Hoogeveen. From these, cow manure, grass, and organic waste were selected as feedstock. The other feedstock is not available enough to substantially contribute to energy production (pig/poultry manure), or is typically used as soil improvement (sugar beet tops, potato tops, wheat straw).

B.1. Cow manure

The province of Drenthe had 1060 dairy farms in 2017, with, on average, 106 cows [24]. In this study, 100 cows per farm were assumed. 400×10^3 Mg a^{-1} manure is estimated to be available in the Hoogeveen area [67]. With 24,351 households in the municipality in 2022 [68], this is approximately 8200 Mg a^{-1} per 500 households. The 6000 Mg a^{-1} for 500 households assumed in the model is based on the biogas demand that covers the heat demand, and is available. Three farms are sufficient to deliver the manure, keeping its mass higher than the mass of the co-substrates. This has legal advantages for the use of the digestate.

B.2. Grass (roadside, nature, ditches)

It is estimated that 'at least' 43,000 Mg a^{-1} is available in the province of Drenthe [67]. If evenly divided over the 220,380 households, about ((500/220,380) * 43,000) = 97 Mg a^{-1} would be available for the 500 households considered. A similar value can be derived from the estimation that some 4800 Mg a^{-1} is easily collectible in the entire municipality [6]: approximately 75% thereof is used in the households considered, while ((500/18,000)*4,800 = 133 Mg a^{-1} would be available for the 500 households considered when evely divided over the 18,000 households in the municipality. The 3,636 Mg a^{-1} (Table 1) used in our model is an overestimation. This confirms the challenge to obtain sufficient biomass.

B.3. Organic waste

Estimates of organic waste availability in Hoogeveen range from 5000 Mg a^{-1} [67] to 6,341 Mg a^{-1} [6]. With 24,351 households in the municipality 2022 [68], the organic waste of one household ranges between 205 kg a^{-1} and 260 kg a^{-1}. In the model 150 Mg a^{-1} was used for 500 households (Table 1). This minor underestimation does not affect the small contribution of organic waste to the energy demand.

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