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The role of biomass gasification in the future flexible power system – BECCS or CCU?

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ABSTRACT

In this work we study if biomass gasification for production of advanced biofuels can also play a role in managing variability in the electricity system. The idea is a CCU/power-to-gas concept to enhance methane production from biomass gasification. The suggested process is flexible in that CO_2 not used for methane production can be stored through a BECCS concept that implies negative GHG emissions. For this purpose, rigorous models of three different gasification process configurations were simplified through surrogate modeling and integrated into a dynamic optimization model of regional electricity systems. The results show the diverse advantages of flexible operation between CCU and BECCS and that it is economically beneficial for the system to invest in gasification at the investigated levels of CO_2 charge. The gasification option also provides value for low-priced electricity and thus stimulate increased investments in renewable electricity generation, which indicates the importance of considering geographical diversities in the assessment and highlights the importance of studying this type of concept with a time-resolved model. It is clear that the BECCS option is the most used, however, the limited quantities of CO_2 used for the CCU option has a large impact on the investments made in the electricity system.

1. Introduction

The international energy agency (IEA) has concluded that 17% of the cumulative emissions savings to 2060 will come from bioenergy and the International Panel on Climate Change (IPCC) claims that, in order to reach the 1.5-degree climate increase target, primary bioenergy use will range from (40–310 EJ/y) [1]. A likely future scenario is an energy system heavily reliant on renewable electricity, which uses biomass for specific applications that are hard or expensive to electrify.

In the electricity sector, a phaseout of fossil fuels is likely to lead to increased shares of electricity produced from intermittent sources [2]. To maintain the grid balance in electricity systems with high shares of intermittent generation, so called variation management strategies (VMS) can be applied [3,4]. There are multiple VMS options for maintaining the grid balance under variable electricity generation. Within this multiplicity of options for handling variability in electricity/energy systems, there are studies discussing the role of power-to-gas concepts combined with gasification. These concepts can be viewed as a form of demand side management and build on production of hydrogen from electricity. It implies that the share of intermittent electricity generation can be increased during hours of high availability of wind and solar power. The generated hydrogen can be used either to produce new electricity during high net-load events or for production of fuels and chemicals [3,5]. A potential fuel to produce from hydrogen is (bio)methane. Methane can be produced with the well-known Sabatier reaction, where H_2 is reacted with CO_2 over a catalyst, forming methane (CH_4) [6]. This is most efficiently done in pressurized micro tube reactors using Ni-AL catalyst. Biomethane can also be produced through thermochemical processes, such as gasification, using lignocellulosic biomass as feedstock [7,8]. When producing biomethane using gasification, the raw gas contains CO_2 (approximately 2.5 CO_2/CH_4 ratio) that needs to be separated out to generate a product of sufficient quality. This CO_2 stream can essentially be treated in three different ways: it can be emitted to atmosphere (ATM); it can be stored in a CCS concept and it can be used as a feedstock for production of fuels or chemicals. With H_2 available from electrolysis, the abundant CO_2 can be synthesized

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Abbreviations

ATM	Atmosphere
BECCS	Bio-Energy Carbon Capture and Storage
CAPEX	CAPital EXpenditures
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
EU	European Union
GHG	GreenHouse Gas
GT	Gas Turbine
IEA	The International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCA	Life Cycle Assessment
NG	Natural Gas
NGCC	Natural Gas Combined Cycle gas turbines
OPEX	OPerational Expenditures
PV	Photovoltaic
SNG	Synthetic Natural Gas
VMS	Variation Management Strategy

into methane through the Sabatier reaction, thus increasing the product output and overall carbon conversion. Furthermore, a high charge on CO_2 emissions can potentially make the CCS pathway economically beneficial. Since the produced CO_2 comes from biomass, this CCS concept contributes to net negative greenhouse gas (GHG) emissions. Using biomass with CCS has been highlighted by the IPCC as crucial in achieving net zero emissions by 2050 [9].

This work presents the analysis of a gasification-based process with the option of using biogenic CO_2 either for carbon capture and utilization (CCU) or for bio energy carbon capture and storage (BECCS). The idea implies the combination of biomass gasification plants with water electrolysis for enhanced production of biomethane. Such a plant can be constructed to operate strictly with the CCU option throughout the year or in a more flexible design and operation, considering all options of CCU, CCS and emitting the biogenic CO_2 to the atmosphere. The less flexible design (strict CCU operation mode) is less capital intensive but requires either constant feed of hydrogen from the electrolysis to operate, regardless of the electricity price, or an over dimensioned electrolyser and a hydrogen storage. The flexible design which combines the CCU and CCS options has a higher investment cost but allows for an optimal selection according to the variations of the electricity price and the additional income of storing biogenic CO_2 emissions. This option has a higher operational flexibility in its connection to the electricity system as it only consumes hydrogen in CCU mode.

The possibility of combining biomass gasification with a power-to-gas system for enhanced biomethane production is not new. Rosenfeld et al. [10] investigated a power-to-gas system combined with biomass gasification for supplying fossil-free gas to a steel plant. They conclude that the energy supply cost of biomass and electricity has the largest impact on the economic performance of the system. Mohseni et al. [11] indicated that biomethane production by reacting hydrogen with the CO_2 abundant in the biomass gasification process can be enhanced by 110%. Gassner and Maréchal [12] applied an optimization framework to assess the impact of the electrolyser on process design of biomass gasification plants in terms of economic, thermodynamic, and environmental performance. They concluded that by appropriate integration of an electrolyser, exergy and energy efficiencies are increased for both direct and indirect bubbling fluidized bed gasification. Hannula [13] evaluated production of SNG from two production routes, biomass gasification and from CO_2 and hydrogen produced from water electrolysis. The concepts are also compared to a hybrid process of the two concepts. Results show that the gasification production route reaches the lowest production costs. Similarly, Korberg et al. [14] identifies biomass gasification as a favourable option for the production of carbon-based fuels based on the high energy efficiency offered compared to CO_2-based electro-fuel production.

Thus, previous work has shown that enhanced biomass gasification through the integration of power-to-gas is promising but that the profitability strongly depends on the electricity price, i.e., a low electricity price is beneficial for CCU to be competitive. However, in previous work the design of the gasification and hydrogen systems has not been co-optimised with the electricity system design. Thus, the amount of low-cost electricity has not been a variable that can drive demand for a flexible gasification plant. The profitability of different gasification concepts is likely to depend on its potential for dynamic interplay with the electricity system. In this regard, studies like those mentioned above do not consider the effects of gasification with power-to-gas on the electricity system. This work addresses this knowledge gap by combining process modelling with techno-economic modelling of the electricity system to account for the temporal and geographical aspects of electricity production and consumption and the interplay between the gasification plant and the electricity system.

2. Methodology

The role of biomass gasification integrated into an electricity system with high charges on CO_2 emissions was evaluated using a multi-level methodology. Fig. 1 describes the optimised integration approach divided into three steps.

In the first step, various process design options were considered using rigorous process modelling of gasification plants integrated with electrolysis units, based on the work of Ahlström et al. [15]. The process models facilitate techno-economic assessment and sensitivity analysis of the investigated process designs, especially with respect to parameters related to the plant size and flexibility (e.g., operating costs as a function of hydrogen addition and CO_2 recirculation, see the Process model section of the electronic support information (ESI)). In the second step, surrogate models of the investigated process designs were developed. The surrogate models have the form of linear functions between critical process design parameters (e.g., methane yield as a function of hydrogen addition, see the Surrogate model section of the ESI). In the third step, these linear surrogate models are required to integrate the gasification models into the linear optimization tool eNODE [16,17]. eNODE is a model of regional electricity systems and is here deployed to investigate the gasification options in an electricity system context. Through this approach it is possible to study the potential of electrolysis integrated gasification plants while accounting for the varying availability of low-cost wind and solar power. Thereby, the potential benefits of flexibility in design and operation of these plants can be thoroughly studied, while accounting also for the feedback effect gasification has on the electricity system.

2.1. Step-1: Process modelling

The considered gasification plant design produces biomethane from residual forestry biomass. For this work, two different gasification designs were investigated and modelled in Aspen Plus V 8.8. All designs assumed the use of an air-blown, bubbling, fluidized bed gasifier. The gasifier plant was based on the experiments and process modeling performed by Hannula & Kurkela [7]. The gas is cleaned of tars and Sulphur, then goes through a water-gas-shift

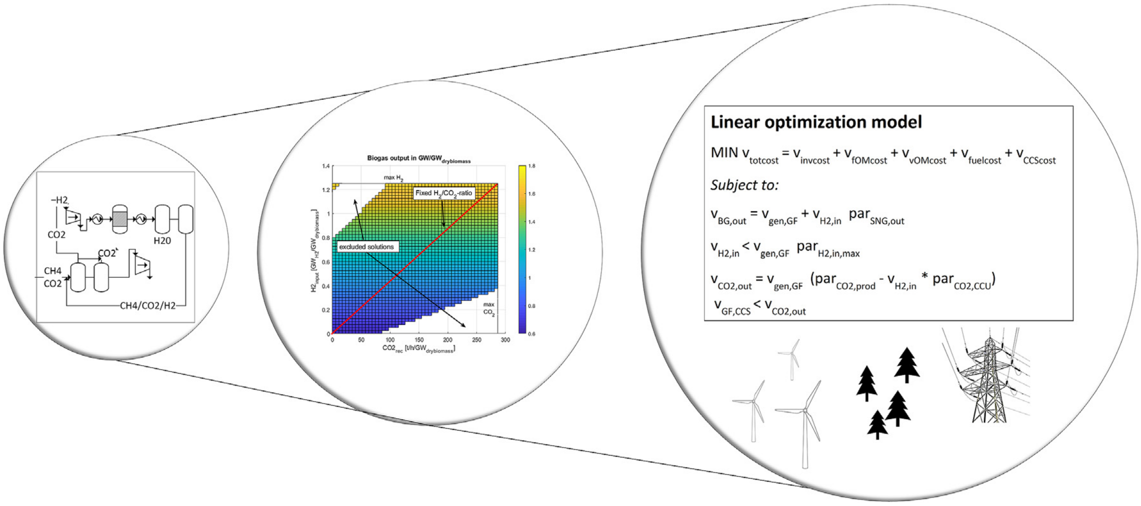

Fig. 1. Methodological principle, starting with the small system perspective of process modelling (left) converted to surrogate models and then integrated into the larger system perspective of the regional electricity system level (eNODE).

reactor and finally the methane yield is increased in a methanation reactor. A flowsheet of the base process can be found in the process model chapter of the ESI. After the methanation, the product gas only consists of CH_4 and CO_2 where the later must be separated out to get a product that can be sold at the same quality as natural gas. The biomethane production is constrained by the demands of Swedish grade A methane production, as specified in Table 1.

Thus, the plant designs differ in how the CO_2 is treated and at what stage hydrogen is added to the process [18]. This gives three main gasification process configurations (Fig. 2):

i. A base case unit that can emit the CO_2 to the atmosphere (ATM) or store the effluent CO_2 but does not have the option to perform CCU and therefore does not integrate directly with the electricity grid.
ii. A design that must perform CCU to maximize the product gas yield at sufficient quality. This implies that the process has a constant demand of hydrogen and that all input carbon is reacted to methane.
iii. A design with the option of CCU, CCS or emitting effluent CO_2 to the atmosphere. It has both the CO_2 separation as design (i) and the Sabatier reactor and a potential hydrogen demand as design (ii). In terms of how to handle the effluent CO_2, this is the most flexible design.

The mixed CH_4 and CO_2 stream from the gasification plant has the same composition and flowrate in all three designs. The first design (i) is, as mentioned, the base case and mirrors a traditional design that does not interact directly with the electricity system. Nonetheless, this design still produces CO_2 that can be stored in the CCS option. In the second design (ii), hereinafter referred to as the less flexible design, hydrogen is added to the product gas stream which is then sent to a Sabatier reactor where the CO_2 and H_2 reacts

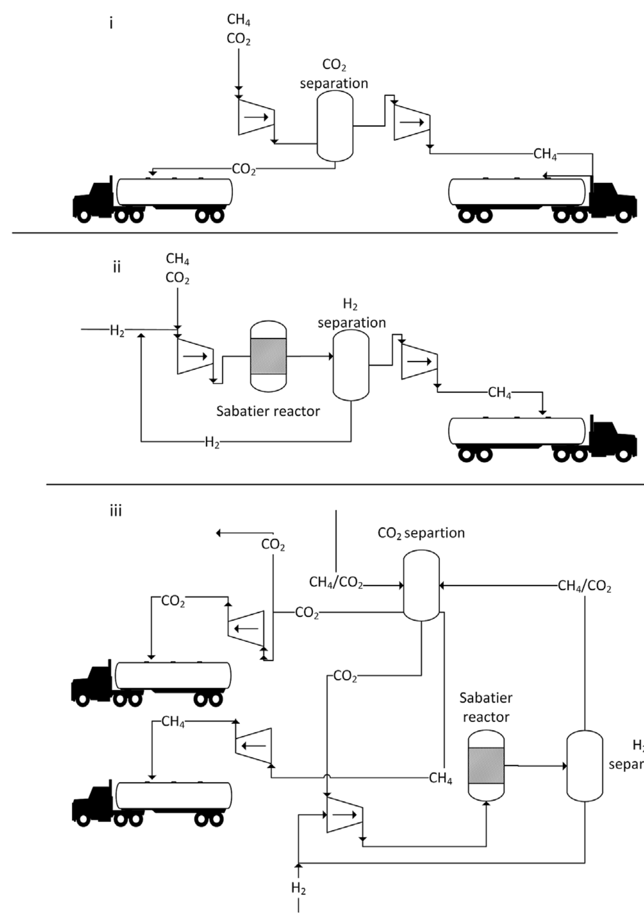

Fig. 2. Simplified flowsheets of the three considered process designs.

to form CH_4 and H_2O over a catalyst. In this case enough hydrogen is added to the process to convert all the CO_2. However, this implies that there is an abundance of hydrogen which needs to be removed in a subsequent separation step. The separated hydrogen is recycled. This process design does not include a CO_2 separation sequence. Thus, there is a need of a constant hydrogen flow to the process and in that sense the process is inflexible in relation to how

Table 1
Technical specifications for Swedish type A NG standard.

Property	Unit	Range
Wobbe index	MJ/Nm3	44.7–46.4
methane content	vol-%	96–98
$CO_2+O_2+N_2$ content	vol-%	4.0
of which O_2	vol-%	1.0

it can be operated. This Hydrogen can be provided either through a constant feed from an electrolyser or from hydrogen storage that is filled when electricity prices drop.

In the third design (iii), a Sabatier reactor is added post the CO_2 separation sequence. CO_2 is separated from the product gas and mixed with hydrogen in the Sabatier reactor. The produced gas, containing mainly methane but also remaining CO_2, is dried and recirculated to the inlet gas stream before the CO_2 removal step. A hydrogen-separation step is added to the process after the drying step. In other words, with the proper excess of H_2 design (iii) can resemble (in terms of carbon efficiency) design (ii), the only difference being that the Sabatier reactor of design (ii) works with higher volumes since all the produced CH_4 goes through it. Including separation of both CO_2 and hydrogen results in a more flexible process configuration.

Capital cost (CAPEX) estimations of the different gasification configurations and the final upgrading sequence were largely based on the works by Holmgren [19] and Thunman et al. [20]. The main aspects of OPEX and CAPEX for the proposed designs are presented in the Data section of the ESI. Process designs and operational expenditures for the gasification process were based on the same work.

2.2. Step 2: surrogate modelling

Surrogate modelling serves the purpose of efficiently integrating the gasification models into the eNODE system model (see also Step 3). eNODE is a linear, integrated optimization model of regional electricity systems, where specific investment costs (EUR/MW), specific operating costs (EUR/MWh) and the feedstock to product yield ($MWh_{product}/MWh_{input}$) are key input parameters. Thus, the various biomass gasification process designs to be integrated as new system components in eNODE should also be represented by linear functions. In practice the key input parameters are dependent on the scale of production (i.e., the quantity of biomass that the plant processes in TWh), the quantity of hydrogen added to the process, and the quantity of CO_2 recirculation. However, in process configuration (i) there is no hydrogen addition and in process configuration (ii) the hydrogen addition is constant, which leaves scale of production as the only parameter. The functions representing the gasification designs were derived from linear regression, based on detailed process modelling in Aspen Plus V.8.8 where the CO_2 recirculation was varied, for all considered levels of hydrogen addition.

The Wobbe index was calculated for all possible combinations and the cases which do not meet the type A natural gas standard are sorted out (the highest standard on the gas grid). This procedure is shown for process design (iii) in Fig. 3. It shows the biomethane output as a function of the flowrate of additional hydrogen and the flowrate of recirculated CO_2. The blank spaces in the figure show solutions which do not comply with the type A biomethane standards and thus are excluded. The biomethane output does not change decisively with constant hydrogen flow rate and varying CO_2 recirculation flow rate. Therefore, in order to simplify the surrogate model, the ratio of fresh hydrogen input to recirculated CO_2 was set as constant. The largest amount of biomethane yield is produced at maximum CO_2 recirculation rate and maximum flowrate of additional hydrogen, thus the H_2/CO_2-ratio is set to this ratio. The modelled biomethane yield and the modelled flowrate of the remaining CO_2 for both designs (only design (iii) is shown in Fig. 3) show a strongly linear behavior along added H_2 for the fixed H_2/CO_2-ratio.

The largest contributors to the OPEX are the electricity used for the electrolyser and the biomass used for gasification. The electricity price is endogenously given by the eNODE model, and the

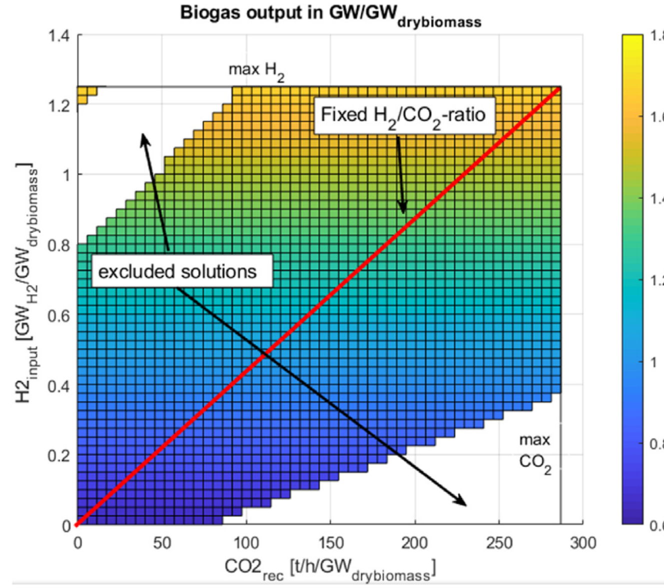

Fig. 3. Biomethane output flowrates calculated from the sensitivity analysis on the flowrate of additional hydrogen and the flowrate of recirculated CO_2 related to the biomass input [19]. Excluded solutions are blanked out and the red line indicates the H_2/CO_2-ratio that is chosen for the linear model.

biomass price is integrated into the eNODE model exogenously. The remainder of the OPEX was previously estimated by Ahlström et al. [15] and is used to design the OPEX surrogate model (see Surrogate model section of the ESI) applying the same approach as for the production yield.

OPEX and biomass-to-methane yields are typically linearly dependent on the biomass input, or assumed to be linear in literature [21]. However, the specific CAPEX is typically ascending with scale of production [22]. It was therefore assumed that all gasifiers were of the same scale (335 $MW_{biomass}$) and thus the CAPEX per energy unit is constant. A specific CAPEX equation was developed and used for each considered process design. The 335 $MW_{biomass}$ was used since it represents what could be considered a realizable yet large scale plant [23].

Moreover, considering only one gasification plant size entails that the biomass-to-methane ratio before the final upgrading sequence is constant in all designs. Thus, the number of variables in the CAPEX surrogate model is limited to the addition of hydrogen to the process (see Surrogate model section of the ESI).

2.3. Step 3: Integration of gasification models into eNODE

The three gasification options are integrated in the electricity system model, eNODE, and evaluated in different cases. eNODE, is a linear programming model that minimises the cost of investments and dispatch of the units in an electricity system. A full description as well as mathematical equations added to model the gasifiers can be seen in the energy system model section of the ESI. The model is a green-field electricity model, implying that there is no existing power generation in the system (except for hydropower for the regions investigated where hydropower is present). New investments in electricity generation are allowed from renewable sources, such as biomass, biomethane, wind, solar and hydropower, together with nuclear power and fossil fuels with or without CCS technologies. Hydrogen is implemented as an energy carrier that is produced through electrolysis and can be consumed either by the gasification processes or for electricity generation in fuel cells. Energy can be stored in batteries and in underground hydrogen storages. A single year is modelled with a 3-hourly time resolution and future costs of electricity generation technologies corresponding to Year 2050. Transmission grid bottlenecks within the modelled region are omitted, as are import and export between the region and its surrounding (i.e., modelling each region as an isolated copper plate).

The integration of gasifiers as a new technology component influences three main parts of the electricity system: firstly, the potential for hydrogen consumption for enhancing the biomethane production in designs (ii) and (iii), secondly, by sharing the available resource of biomass between electricity generation and for producing biomethane that can be sold to an exogenous demand or used for electricity generation within the system, and thirdly, the gasification and electricity system are bound by the same carbon emissions policy, i.e. the same CO_2-emission charge.

2.4. Input data & system boundaries

Costs and properties of electricity generation and storage technologies applied in this work are given in the Data section of the ESI (see table E.1, E.3 and E.4). To account for the impact of demand of biomass on the biomass price, the price was assumed to be depending on the quantity harvested. Biomass prices were taken from a study by Bryngemark et al. [24] where future biomass prices were estimated based on demand for biofuels. The data was implemented as a piecewise supply curve of biomass at three cost levels 30, 40 and 50 EUR/MWh, with 50%, 30% and 20% of the resource allocated to each level. These levels are equally proportionate to the biomass supply, regardless of biomass availability. The data is based on Sweden but due to lack of data and for coherency, the same data was applied to all investigated regions.

Without strict emission targets, natural gas is more cost-efficient compared to biomethane from biomass gasification and there is no incentive to use the biomass for fuel production. Therefore, two levels of CO_2 charge were implemented, namely 150 and 250 EUR/tonne, both representing an ambitious climate policy.

The system boundaries applied in the eNODE model are visualized in Fig. 4. The combined gasification/electrolysis process generates biomethane, which is either used within the electricity system for generation of electricity or exported outside of the system boundaries at a fixed price, corresponding to the current price of NG plus the matching CO_2 charge (this gives an upper limit to the value of biomethane), to be used as a fuel or feedstock for chemical industry. Produced biomethane thus provides an income to the system. Another potential source of income is possible through the generation of negative emissions by storing biogenic CO_2.

2.5. Scenarios

The role of gasification is evaluated in the context of three European regions. The country of Ireland (IE) is used as the reference case and is compared to southern Sweden (SE2, similar to spot price area SE3), and to the central parts of Spain (ES3) (see Figure E4 in the ESI for a map). The regional wind and PV data is found in the ESI – Data for Energy system modelling. The reason for having Ireland as a base case is its naturally favourable climate for a renewable electricity system heavily reliant on wind power. Such a system is apt to create a volatile electricity price and makes for a good starting point in the analysis presented in this work. The Swedish region has good possibilities for wind power, limited opportunities for solar PV, but has a built-in hydro power capacity that covers approximately 32% of the modelled electricity demand. The region of central Spain stands out for its sunny climate and thereby has large potential for electricity production from solar PV. The modelled cases are presented in Table 2.

Four sensitivity scenarios are included to address some main assumptions. The CO_2 emission charge is further assessed in the scenario analysis 1. In scenario analysis 2 the supply curve for biomass is replaced with a fixed, higher cost of biomass. To investigate how the integrated gasification concept would perform in a future with drastic changes in costs for other types of renewables and VMS, a scenario where the costs of solar PV and batteries were decreased with 30% and 20%, respectively, was investigated in Scenario 3. Scenario analysis 4 allows only for construction of gasification configuration (ii), to investigate the impact of less flexible gasification concepts.

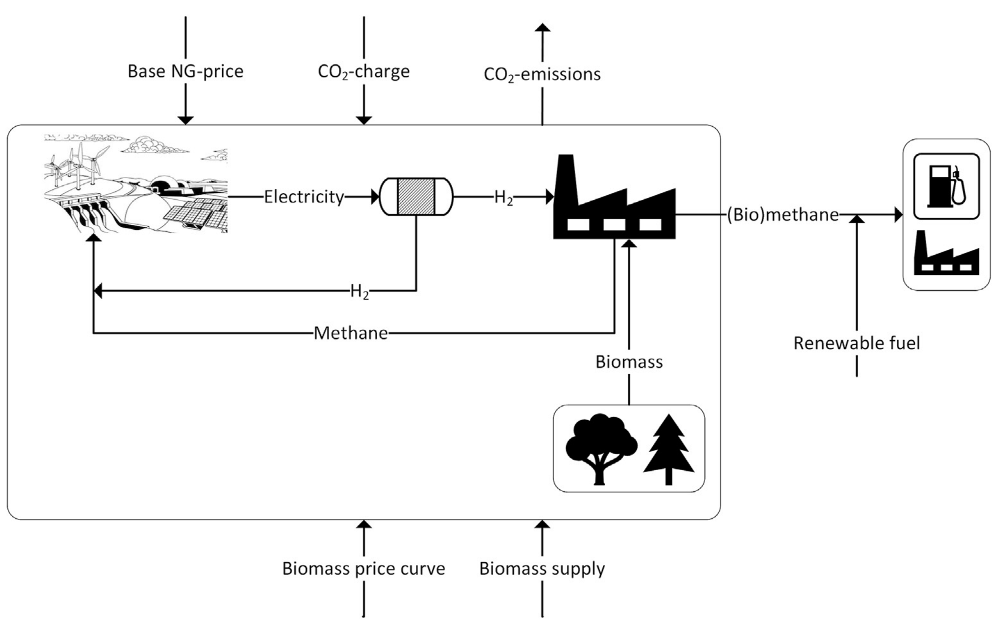

Fig. 4. System boundaries of the eNODE model. The processes inside the boundaries represent the electricity system, electrolysis and gasification.

3. Results

It is economically beneficial for the system to include biomass gasifiers in all analysed regions for the future flexible power system with high charge on CO_2 emissions. Under the considered CO_2 charge, biomass and biomethane prices, the system utilizes all available biomass for gasification, except for the cases involving high biomass availability and high CO_2 emission cost in the Swedish region. Configuration (iii) is always preferred compared to configuration (ii) in all regions. This shows that there is a value for the gasification design in having a configuration that is flexible in how it uses hydrogen (CCU) and has the possibility of storing CO_2 (BECCS). The results are a consequence of varying electricity prices combined with a high charge on CO_2 emissions, and thus highlight the value and importance of studying this type of technology and system with a time-resolved electricity price compared to having a fixed electricity price curve. If only the less flexible gasification (configuration (ii)) is allowed, investments in biomass gasification are greatly reduced in favour of biomass steam power plants with CCS. For example, with a biomass availability of 25 TWh and a CO_2 charge of 150 EUR/tonne for the Irish region (Scenario 4), excluding gasification configuration (iii) lowers the installed gasification capacity by 96%.

Fig. 5 displays the electricity price in Ireland together with the CO_2 balance of all gasifiers resolved for model timestep 700–900 (i.e., the actual price hours of 2100–2700 representing approximately the month March). The results show how the CCU and CCS trends contrast each other and how they follow the price of electricity. When the electricity price drops, the CO_2 sent to CCU increases while the CO_2 to CCS decreases. Thus, the CCU option is only operated when prices are sufficiently low to generate hydrogen that is used for methane production directly. This implies that, although hydrogen storage is available, it is not used to store hydrogen for biomethane production. According to these results, the CCU-option is used to an extent where it reduces the curtailment of electricity, but it is still not used to levels where it would contribute to an increase in electricity price higher than about 30 EUR/MWh$_{el}$. As a consequence, the gasifier sometimes operates at reduced CCU capacity (part-load operation of the electrolyser) leaving the remainder of the CO_2 emissions for storage (CCS). This can for example be seen in Fig. 5 for the lower CO_2 charge (left) at around time step 880. There is a clear difference between the low and high CO_2 charge case in that for the lower CO_2 charge case the peaks from the CCU option are lower. The reason for this is that the installed capacity of electrolysers is lower. This, in turn, is a consequence of the electricity system having lower shares of wind power capacity, which gives a more stable generation curve and thereby less demand for VMS in terms of flexible electricity consumption in electrolysers and hydrogen storage. At higher biomass availability, the electrolysis capacity saturates, and configuration (i) is chosen for additional gasifiers as no extra capacity for CCU is needed.

Fig. 6 shows the CO_2 balance of the built gasifiers in the Irish region for a CO_2 charge of 250 EUR/tonne. As displayed, the gasifier does not emit any of the generated CO_2 emissions to atmosphere, regardless of the biomass availability as the CO_2 charge more than covers the operational costs of transportation and storage of CO_2. Fig. 6 also shows that most of the CO_2 from gasification is used for CCS rather than increased biomethane production through CCU.

Table 2
Schematic of the basic model runs and the additional scenario analysis (separated by the double horizontal line).

Case group	Biomass availability [TWh]						Region	CO_2 charge [EUR/tonne]	Biomass cost [EUR/MWh]	Solar/Battery inv. cost [MEUR/MW] /[MEUR/MWh]	Gasification process designs
	0	1	5	10	25	50					
Base case	x	X	x	x	x	x	IE (SE2 & ES3)	150	30/40/50	0.42/0.1	i/ii/iii
	x	X	x	x	x	x	IE (SE2 & ES3)	250	30/40/50	0.42/0.1	i/ii/iii
Scenario 1				x			IE	50	30/40/50	0.42/0.1	i/ii/iii
– Low CO_2 charge				x			IE	75	30/40/50	0.42/0.1	i/ii/iii
	x	X	x	x			IE	100	30/40/50	0.42/0.1	i/ii/iii
Scenario 2 – Single and high biomass price				x			IE	150	75	0.42/0.1	i/ii/iii
Scenario 3 – Decreased cost of PV and Batteries				x			IE	150	30/40/50	0.3/0.08	i/ii/iii
Scenario 4 – Only Gasifier type ii					x		IE	150	30/40/50	0.42/0.1	ii

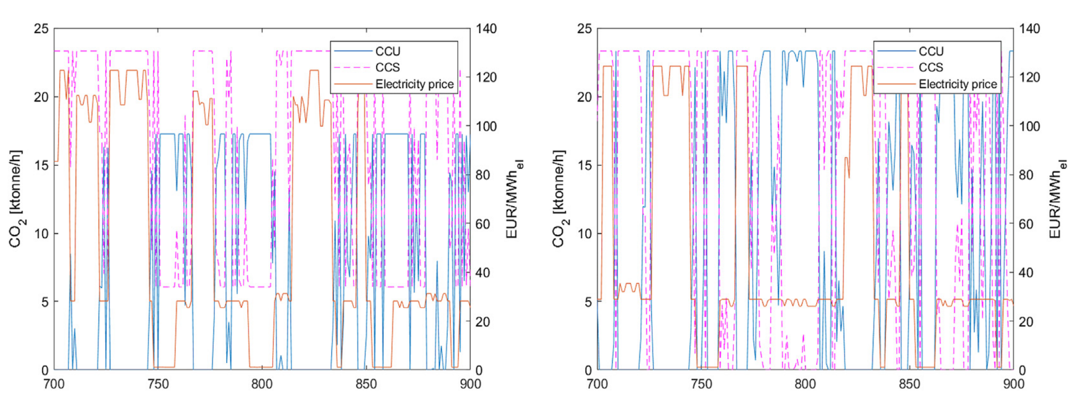

Fig. 5. Time resolved CO_2 balance of the gasifiers in kt/h and electricity price in EUR/MWh$_{el}$ for the 10 TWh biomass availability case for CO_2 charge of 150 EUR/t (left) and 250 EUR/t (right) in the Irish region in the base case.

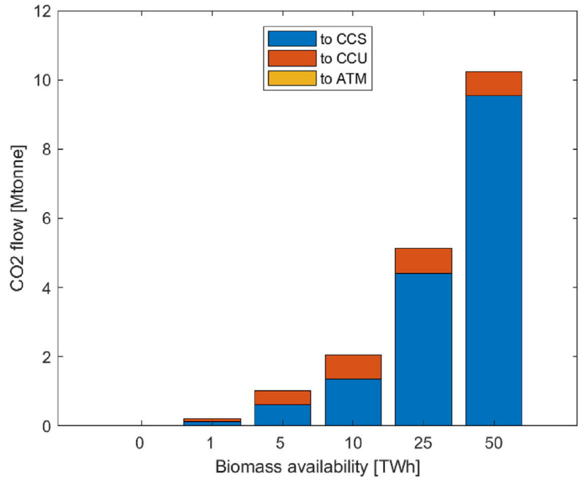

Fig. 6. CO_2 balance of the gasifiers built in the Irish region for varying levels of biomass availability and a CO_2 charge of 250 EUR/tonne in the base case.

The results for the Spanish region are similar and the CO_2 charge has low impact on the results for the range investigated (i.e., 150–250 EUR/tonne). It is also clear that the total quantity of CCU remains constant from approximately 10 TWh of biomass availability; when the quantity of gasified biomass increases, additionally produced CO_2 is used for CCS (BECCS). The reason for this saturated benefit of CCU is explained by the impact of biomass availability on investments in wind and solar power.

Fig. 7 gives the electricity generation by technology in the Irish region at different levels of biomass availability. Access to gasification as a flexible consumer of hydrogen increases the cost-optimal investments in wind and solar power at up to 10 TWh of biomass availability. For the Irish 150 EUR/tonne case, roughly 4–5 TWh of methane is used for electricity production. In the Irish 250 EUR/tonne case, the internal use of methane goes from 3 TWh to 0.5 TWh between 1 and 10 TWh available biomass. This decrease of methane usage is partly due to increased investments in wind and solar power (reduce methane usage by 1.5 TWh) and part due to dual use of electrolysis for both CCU and for producing and storing hydrogen for electricity generation in fuel cells (reduce methane usage by 1 TWh). Beyond 10 TWh of biomass availability, additional biomass does not increase wind and solar power investments and thus not the availability of low-cost electricity (<30 EUR/MWh) which is required for the CCU process. This means that at biomass availability higher than 10 TWh the only additional value gasification brings to the system comes from selling biomethane and storing CO_2.

Fig. 8 shows the yearly electricity production per technology type for the three investigated regions at a CO_2 charge of 250 EUR/tonne. The trend of the Swedish region is somewhat different from the other considered regions. In this region, the share of biomass steam turbines increases with biomass availability, while in the other regions the electricity production almost exclusively comes from intermittent sources at the same levels. These results indicate that the value of gasification with CCU option is greater in systems where there are limited natural VMS. In Sweden, the vast resources of complementing VMS from the hydropower plants decreases the importance of the flexibility provided by the gasification plants. The lower value of flexibility together with a less variable net-load relative to the other regions investigated make it more profitable to use the biomass for baseload generation of electricity through steam turbines rather than for gasification in the 50 TWh biomass case with higher CO_2 charge.

The results for Scenarios 1, 2 and 3 are presented in Figs. 9 and 10, respectively. In Fig. 9, a high biomass price (scenario 2) has a large impact on the use of biomass gasification. At a biomass price of 75 EUR/MWh (i.e., a 50% increase to the highest price in the base scenarios), no biomass is used for gasification at all, regardless of the CO_2 charge of 150 EUR/tonne, as the added cost compared to natural gas is too high. Comparing that result with the results from varying the CO_2 charge (Fig. 10) shows how increasing the (maximum) biomass price with 50% has a larger effect on quantities of biomass used for gasification than decreasing the CO_2 charge with a factor of 3 (150–50 EUR/tonne). The reason that it is easier for the system to attune to increased CO_2 charges is that with biomass present in the system there are multiple opportunities to decrease emissions. Additional wind and solar are forced into the electricity system by the CO_2 charge, but as long as biomass is available, even at low levels, it is possible for the system to adjust to this. These results emphasise that the biomass price is a highly important parameter in how the gasification plants are designed. However, as long as the price is low enough to construct the gasification plants, it is the behaviour of the electricity system that dictates what is done with the CO_2.

Scenario 3 shows that a lowered cost for building solar PV and batteries results in no additional flexibility from CCU in Ireland. The gasification is still used to the same extent and the construction of

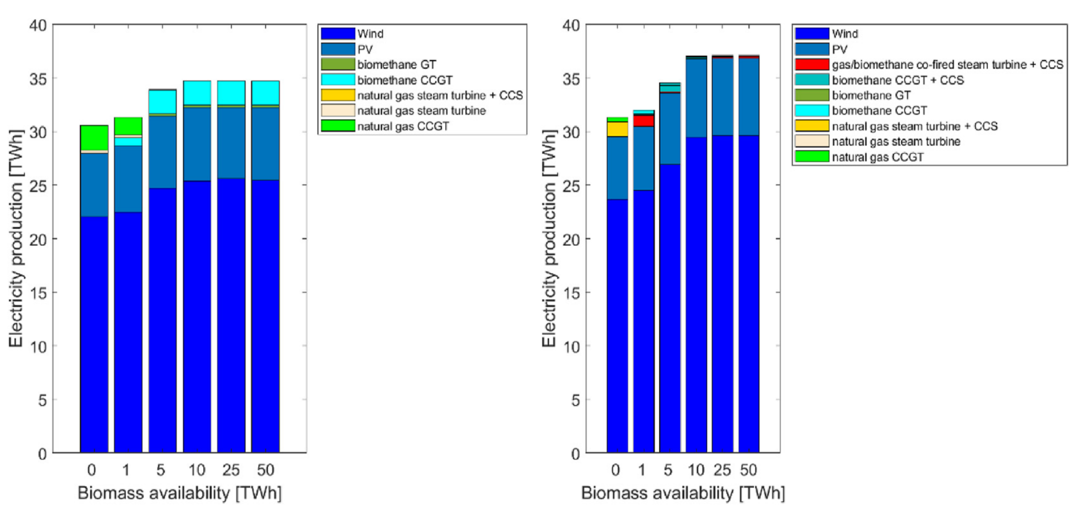

Fig. 7. Electricity generation from all installed generation capacity in Ireland. The left graph is at a CO_2 charge of 150 EUR/tonne and the right at 250 EUR/tonne in the base case.

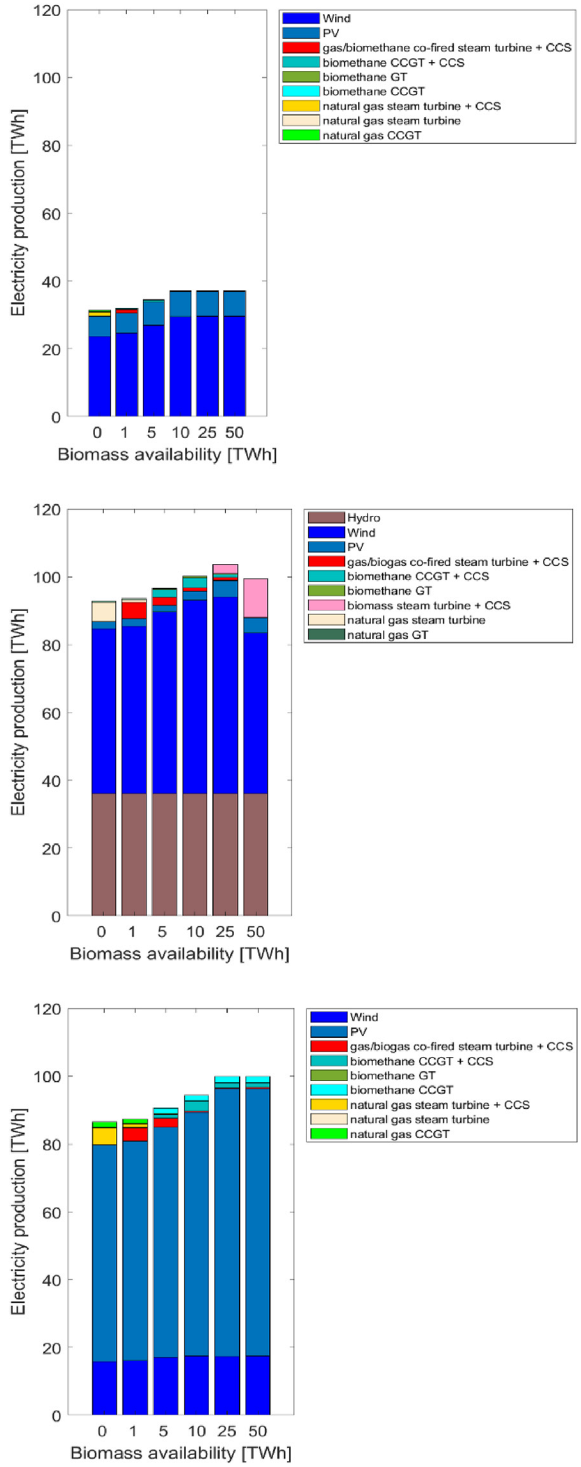

Fig. 8. The yearly electricity generation for the three investigated areas, divided per technology type for each level of biomass availability and a CO_2 emission charge of 250 EUR/tonne in the base case. The top figure represents the Irish region, the middle figure Sweden and the bottom figure Spain.

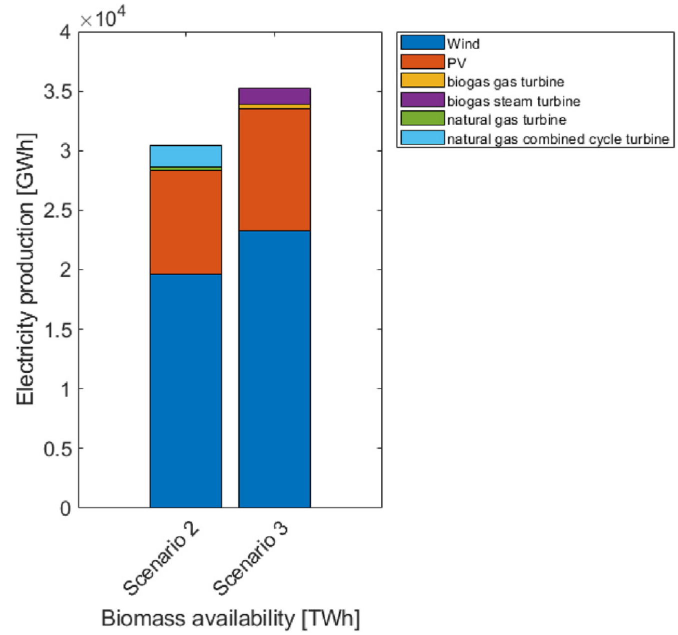

Fig. 9. The electricity production per technology for scenarios 2 and 3 with a CO_2 charge of 150 EUR/tonne and biomass availability of 10 TWh.

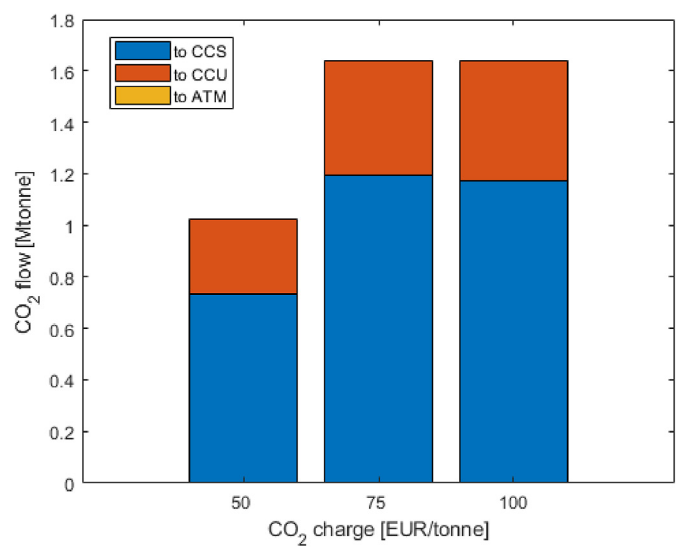

Fig. 10. The annual CO_2 balance of the built gasifiers when varying the CO_2 charge from 50 to 100 EUR/tonne with a biomass availability of 10 TWh in scenario 1.

the electricity system is similar. This indicates that the results presented here are relatively stable in terms of gasification, however, not for CCU as VMS. In the case that competing VMS technology becomes cheaper, the benefits of the CCU option are decreasing.

The results presented in Fig. 10 (scenario 1) show the impact a decreased CO_2 charge has on gasification. As seen, all biomass is used for gasification down to a CO_2 charge of 75 EUR/tonne. The CO_2 charge must decrease to 50 EUR/tonne in order for the biomass consumed in gasification to decrease. However, at that level, the low-cost parts of the biomass are still utilized and favored over fossil options. It can thus be argued that the results presented in this study are also valid for lower CO_2 charges, at least up to 75 EUR/tonne. Nonetheless, it has previously been deemed that high levels of CO_2 charge are required to reach a complete phase out of fossil fuels and are thus interesting to investigate [25].

4. Discussion

The results of this work show that it is cost-efficient to design biomass gasification such that the CO_2 from the gasification process can be both utilized for methane production and captured and stored. Results indicate that the investigated system uses most of the generated CO_2 for CCS, rather than increased biogas production, confirming previous studies in that it is more cost-efficient to use CO_2 for net-negative emissions rather than enhanced biofuel (electro-fuel) production (see e.g. Lehtveer et al. [26]). However, using generated CO_2 for CCS requires that an extended fossil fuel extraction is permitted, and that CO_2 can be stored. High restrictions on fossil CO_2 emissions and restrictions or technical limitations in storing CO_2 would increase the amount of CO_2 from combustion and gasification used for electro-fuel production, as concluded by [26]. Also, Korberg et al. [14] identifies CO_2-based electro-fuel production as a potential complement if there is insufficient biomass to meet the demand for carbon based fuels, but does not study a mix between the concept of gasification and CCU in detail.

In this work, gasification for methane production is found to be a cost-efficient deployment of biomass. Lehtveer et al. [26] argue for biomass combustion in combined heat and power (CHP) as a more cost-efficient option [26]. There are some main methodological differences which explain the difference in results. Lehtveer et al. [26] include more sectors while the time resolution is lower as compared to this work. In the absence of a heat sector representation, CHP is not included among the technology options in this work and thus, the value of heat from biomass combustion is not accounted for. However, Heinisch et al. [27] has shown that at high cost of biomass (for example stimulated by a high demand for biofuels) it is more cost-efficient with electricity-based heat production using heat pumps and electric boilers during hours of medium to low electricity prices in combination with heat storages. However, the competition between using electricity or biomass for heating may be altered by the possibility for negative emissions from bio-CHPs with CCS and thus impacting where the biomass has the highest value.

The results of this work indicate that the amount of CO_2 which is utilized for methane production depends on the availability of low-cost electricity rather than the size of the gasification process (cf. Fig. 6). In the future energy system, low-cost electricity can also be deployed for example to produce hydrogen for the steel industry, to produce heat and to charge electric vehicles. How these applications for low-cost electricity interact depends on their cost structure and the value of the end-product [28]. Results of this work indicate that available low-cost electricity is utilized but limited new investments on the supply-side are taken to increase the utilization of CO_2 with CCU. Thus, the willingness to pay for the electricity in competition with other applications is relatively low. At the same time, the option to use CO_2 for CCS removes the need for hydrogen storage and thus offer the ability to make use of low-cost electricity which is very unevenly distributed in time in a cost-efficient manner for the CCU process.

Although the objective of the applied model is to minimize the cost of supplying electricity, it can be concluded that the gasification process would also be profitable under the studied conditions. However, it is possible that optimizing the revenue of the gasification system would render larger profits for the plant-owners. Such conclusions are, however, not possible to draw by applying the methods of this work. Further studies will be required focusing on simultaneous optimization of the system and the individual processes (e.g., gasification) from a plant-owner perspective, applying price data and system behaviour developed for such work, and possibly additional econometric methods such as game theory approaches in a free market regulated system.

5. Conclusions

The aim of this work was twofold: first, to investigate if gasification integrated to the electricity system can be profitable and, in that case, if a flexible process design is favourable and, second, to study what effects the construction of such processes would have on the electricity system.

The results show that gasification integrated in the electricity system can be profitable for CO_2 charges down to 50 EUR/tonne and for a biomass price development supported by models previously presented in literature. The results also show that biomass gasifiers interconnected with the electricity system has the potential to be a cost-efficient variation management strategy (VMS). From these results, it is also clear that:

- The gasification design that has the option of both CCS and CCU is always preferred. During high net-load events, biogas-based electricity generation provides a flexible complement to wind and solar power. During low net-load events, hydrogen is produced and used to increase the bio-methane yield together with excess CO_2 from the gasification. All other hours, excess CO_2 from the gasification is captured and stored.
- The suggested gasification concept contributes to less curtailment while increasing the construction of wind and solar power plants.
- At high CO_2 charges, the system is highly variable, and switches between CCU and CCS within 3–6 hours. This demands very short start-up times. This should be further studied.
- When operating the system at a higher CO_2 charge (250 EUR/tonne), gasification is more clearly used as VMS and biofuel combustion for electricity generation is phased out in favour of renewable intermittent electricity generation.
- The suggested concept of biomass gasification is more economically beneficial in a system with low natural possibilities for VMS (e.g., lack of hydropower plants).

CRediT authorship contribution statement

Johan M. Ahlström: Conceptualization, writing, process and surrogate modelling, Formal analysis. **Viktor Walter:** Conceptualizsation, energy systems modelling, Formal analysis, Writing – review & editingediting. **Lisa Göransson:** Advising and editing of the work and. **Stavros Papadokonstantakis:** Advising and editing of the work.

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.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.renene.2022.03.100.

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