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The value of flexible fuel mixing in hydrogen-fueled gas turbines — A techno-economic study

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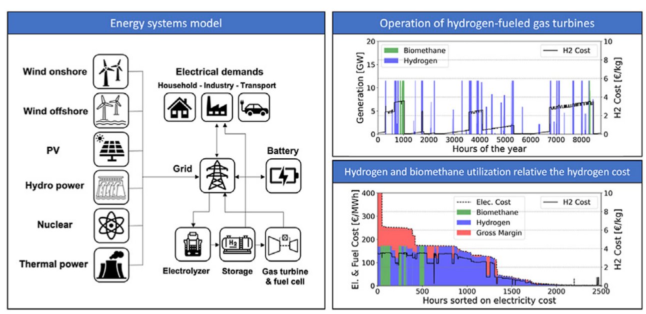
HIGHLIGHTS

- Time-shifting of generation via hydrogen-fueled gas turbines investigated.
- Hydrogen gas turbines most competitive in systems with high shares of wind power.
- Fuel flexibility important for the competitiveness of hydrogen-fueled gas turbines.
- Low willingness to pay more than 5 €/kg for hydrogen when used in gas turbines.
- Biomass cost the main parameter affecting the willingness-to-pay for hydrogen.

GRAPHICAL ABSTRACT



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ABSTRACT

In electricity systems mainly supplied with variable renewable electricity (VRE), the variable generation must be balanced. Hydrogen as an energy carrier, combined with storage, has the ability to shift electricity generation in time and thereby support the electricity system. The aim of this work is to analyze the competitiveness of hydrogen-fueled gas turbines, including both open and combined cycles, with flexible fuel mixing of hydrogen and biomethane in zero-carbon emissions electricity systems. The work applies a techno-economic optimization model to future European electricity systems with high shares of VRE.

The results show that the most competitive gas turbine option is a combined cycle configuration that is capable of handling up to 100% hydrogen, fed with various mixtures of hydrogen and biomethane. The results also indicate that the endogenously calculated hydrogen cost rarely exceeds 5 €/kg_{H2} when used in gas turbines, and that a hydrogen cost of 3–4 €/kg_{H2} is, for most of the scenarios investigated, competitive. Furthermore, the results show that hydrogen gas turbines are more competitive in wind-based energy systems, as compared to solar-based systems, in that the fluctuations of the electricity generation in the former are fewer, more irregular and of longer duration. Thus, it is the

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characteristics of an energy system, and not necessarily the cost of hydrogen, that determine the competitiveness of hydrogen gas turbines.

Introduction

Electricity generation from variable renewable electricity (VRE) in Europe has increased steadily during the past two decades, and has more than doubled its share since 2005 [1], reaching 19.7% of the total electricity generation in Year 2020. Continued expansion of the VRE share is essential to meet the targets of the Paris Agreement [2], since high costs and long lead times for nuclear power make it unlikely that this technology will represent a substantial share of new electricity generation up to mid-century. Yet, the expansion of VRE creates complications in the electricity system, as generation does not always coincide with demand. This calls for additional innovations in the electricity system, one of which can be energy storage coupled to flexible and dispatchable power generation.

As an energy storage technology, batteries are strong candidates and are suitable for balancing diurnal variations in electricity generation, such as those typically related to solar photovoltaic (PV) generation, although batteries are not suitable for longer-duration variations due to their high cost. A technology with potential to handle longer periods of variable generation, which are normally associated with wind power, is hydrogen (H_2). Hydrogen is currently attracting attention for its potential to facilitate deep decarbonization across several sectors, including hard-to-abate sectors such as aviation and the steel industry, either as an energy carrier, feedstock, or reactant. In the electricity system, fuel cells have often been considered for the (re)conversion of hydrogen in future electricity systems, in order to decarbonize the peak power supply [3–5]. Lately, attention has also been focused on the gas turbine technology [6–9]. However, independently of reconversion technology, with an electrical round-trip efficiency in the range of 30%–40%, it Is not obvious if and under what conditions reconversion of electrolytic hydrogen back to electricity can be a cost-efficient option.

As described by Cambell et al. [10] and Huth et al. [11], gas turbine technologies are known for their fuel flexibility and capability to handle both gaseous and liquid fuels. These fuels range from pure methane to by-product gases from refineries (containing mostly propane and butane), gases that contain large shares of inert gases such as nitrogen and CO_2, syngases that contain 25%–50% H_2 and 35%–65% carbon monoxide, and liquid fuels such as bio-ethanol [12] and bio-diesel [13]. Regarding the economic benefits of fuel flexibility, Omehia et al. [14] have assessed the effects on the cost of electricity and CO_2-avoided in a combined cycle gas turbine (CCGT) with carbon capture and storage (CCS) of different fuel compositions, considering an interval of 0%–10% CO_2 in natural gas. They have concluded that the cost of electricity increases with 0.46% for fuels with 10% CO_2, although with a corresponding reduction of the CO_2-avoided cost with 8.4%. However, to the best of the knowledge of the present authors, no such assessments have been conducted for gas turbines fueled with various shares of hydrogen, where electricity and hydrogen costs are endogenously determined in an energy systems model.

The competitiveness of hydrogen-fueled gas turbines was evaluated in a previous study carried out by the authors [15], in which the potential role of hydrogen-fueled gas turbines was studied in the transition to a fully decarbonized electricity system. The results showed that the competitiveness of hydrogen-fueled gas turbines – applying different mixtures of hydrogen, natural gas and biomethane – is driven by emissions restrictions. Therefore, the impact of hydrogen-fueled gas turbines in time-shifting electricity generation is mainly seen in electricity systems that are constrained to have low levels of carbon dioxide (CO_2) emissions. The results also favored hydrogen mixing rates in the range of 30–77 vol.-%, with a trend towards the lower end of the range, whereby biomethane was preferred as a complementary fuel. However, in the previous work [15], the mixing rate of hydrogen was fixed, which meant that a certain amount of hydrogen had to be consumed during the operation of the hydrogen-fueled gas turbines. Furthermore, only electrolytic hydrogen was included, and only lined-rock caverns were allowed for hydrogen storage. These three aspects were identified as warranting further investigation. Therefore, the current work aimed to investigate how flexible fuel mixing and other options for hydrogen production and storage affect the competitiveness and operation of hydrogen-fueled gas turbines.

Considering the production of hydrogen, one of the targets of the European Hydrogen Strategy [16] is to replace by Year 2030 the current annual demand of 10 Mt of hydrogen derived through steam methane reforming (SMR) of natural gas with hydrogen produced from renewable electricity and electrolysis. This would require approximately 475 TWh of additional renewable electricity, corresponding to 17.3% of the current total electricity generation in Europe [17]. There are, however, reasons to believe that electrolytic hydrogen is not the most-cost-effective option to reduce CO_2 emissions from the electricity system and industrial processes in the short-to-medium term. For instance, Dickel et al. [18] have concluded that renewable electricity has the strongest decarbonization effect if it replaces fossil power generation, and since coal power in Germany is not estimated to be phased out before Year 2035 [19], it is not expected that emissions from water electrolysis will be lower than the emissions from SMR with CCS until well beyond Year 2030 [20], assuming a CO_2 intensity in line with the average European electricity mix. Electrolysis driven by VRE would obviously yield low-carbon hydrogen,

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although such arrangement would potentially occupy VRE resources that could otherwise be used to replace electricity from fossil energy. Furthermore, both Navas-Anguita et al. [21] and Sunny et al. [22] have included several hydrogen production technologies in plans to supply the Spanish transport sector and the British heating sector with hydrogen, respectively. Both groups conclude that technologies such as SMR, implemented with and without CCS, and autothermal reforming (ATR) and biomass gasification with CCS are critical for achieving cost-effective decarbonization of the investigated energy systems. Cloete et al. [9] have proposed both electrolytic and 'blue hydrogen' production to supply a hydrogen demand corresponding to the potential combined demands of the transport, industry and heating sectors in Germany by Year 2040, and while hydrogen can also be (re) converted to electricity in gas turbines, that is not the focus of their study. Yet, when Cloete et al. [9] allowed for blue hydrogen production in their model, it supplied the entire hydrogen demand, as it was (under the assumptions made) more cost-effective than hydrogen produced through electrolysis.

Considering the impact of hydrogen storage, Welder et al. [23] have modeled a 100% renewable scenario for Germany in Year 2050, where hydrogen is used for industrial processes and in the transport sector. They conclude that the inclusion of salt caverns for hydrogen storage has a significant impact on investments in wind power, and that the salt caverns are used primarily for long-term variations, whereas other types of storage (vessels) are used for short-term variations. However, they did not include the reconversion of hydrogen in gas turbines, so the effects of cheaper hydrogen storage could not be evaluated for this technology.

To summarize, hydrogen-fueled gas turbines have been included in several different types of studies, including also energy system studies. However, to the best knowledge of the authors, the actual operation of hydrogen-fueled gas turbines in a fully integrated energy system has not been examined in detail. This work aims to explore the operation of hydrogen-fueled gas turbines and how different technical factors and assumptions influence the investment and operation of this technology. Thus, this work aims to investigate:

- The effects of flexible fuel mixing with hydrogen and biomethane in gas turbines, by examining how fuel-flexible gas turbines are operated in terms of fuel-mixing and operational patterns;
- how hydrogen production options and hydrogen storage technologies affect the competitiveness and operation of hydrogen-fueled gas turbines; and
- the willingness-to-pay for hydrogen use in gas turbines, i.e., the hydrogen cost at which hydrogen gas turbines will operate.

Method

The energy systems model applied in this work is a linear techno-economic optimization model that minimizes the total system cost for electricity and heat generation for selected regions in Europe, including both the investment and dispatch of generation technologies, electricity transmission technologies, and energy storage technologies. The model was originally formulated by Göransson et al. [24], and further developed by Johansson et al. [25] and Ullmark et al. [26], and is implemented in the General Algebraic Modeling System (GAMS) software, using Cplex as a solver. As the objective of the model is to minimize the total system cost, including both investment cost as well as fuel and operational costs, investment and dispatch decisions are primarily driven by cost, although several constraints are included in the model, e.g., to limit carbon emissions or the use of biomass. The original model is described by Equations (A.1)–(A.9) in Appendix A, and the additions related to hydrogen-fueled gas turbines are described by Equations (1)–(5) in Section Implementation of hydrogen gas turbines.

The key inputs to the model are technology costs and the demands for electricity and heat, whereas the key outputs are the investments in the available technologies and how they are operated. Other important outputs, which are presented in Section Results, are the time-resolved electricity and hydrogen costs calculated endogenously by the model. The model in this work applies a greenfield approach for the Year 2050. According to the ambitions of the European Commission [27], the 2050 energy system should be fully decarbonized and, thus, a zero-carbon-emission cap is applied in the modeling. Furthermore, all investments are made based on the projected technology costs for the Year 2050, and the only today existing technologies that are assumed to remain are hydro power and transmission line capacity. The geographic scope of the model is the European continent, divided into regions defined according to European statistical NUTS regions [28].

Assumptions and scenarios

Technologies that are included as options for investments in the model decision are: onshore and offshore wind power, solar PV, gas turbines fueled with biomethane and/or hydrogen, and several other types of thermal generation using different types

Table 1 – Capital costs for hydrogen-compatible gas turbines.

Upper mixing rate of H_2 [vol.-%]	Low H2GT Capex [% of ref. Capex]	Medium H2GT Capex [% of ref. Capex]	High H2GT Capex [% of ref. Capex]
30	100	101	102
50	100	103	106
77	100	105	110
100	100	115	130

of fuels (for a full overview of the available power plant options, see Table B1 in Appendix B) with costs taken from [50–53]. To supply the heat demand, heat pumps and electric boilers are allowed. In terms of energy storage, batteries, electrolyzers, fuel cells and hydrogen storage, including both lined rock caverns (LRC) and salt caverns, are included. Apart from electrolyzers, the model can, in some investigated scenarios, also invest in SMR with CCS (SMR-CCS) for hydrogen production. However, in order to reach zero emissions from the SMR-CCS process, with an assumed capture rate of 88.5%, 11.5% of the fuel input is biomethane, which is assumed to be climate-neutral. Biomethane is assumed to be produced from solid biomass in gasification plants with a conversion efficiency of 70%. Furthermore, in addition to the existing transmission capacity, new investments in transmission capacity can be made in either overhead alternating current (OHAC) or high voltage direct current (HVDC) transmission capacity.

In this work, it is assumed that bioenergy CCS (BECCS) is only used to create negative emissions, so as to compensate for residual emissions in "hard-to-abate" sectors, such as aviation and agriculture. Thus, BECCS is not included because this work is limited to modeling the electricity system, assuming that BECCS will not be used to offset fossil-fueled electricity generation, which is not considered a hard-to-abate sector. The effects of excluding BECCS technologies are further discussed in Section Discussion.

The model is run with hourly time resolution, and the hourly demand profiles for the traditional electricity demand, excluding new loads, such as electric vehicles (EV) and electrification of industrial processes, are obtained from European Network of Transmission System Operators for Electricity, ENTSO-E [29]. The traditional annual electricity demand for Year 2050 is taken from the work of Unger et al. [30]. The potential capacity and hourly generation for solar and wind power are based on the work of Mattson et al. [31], who used meteorological input data from ERA5 [32]. The heating demand is taken from the work by Werner et al. [33] and is displayed in Appendix C.

In addition to the traditional electricity demand, the scenarios investigated include the electricity demand for an electrified transportation sector, which includes EVs, busses and light and heavy trucks, and an electrified steel production sector. The total driving/charging demand in each region is given on an hourly basis, as presented by Taljegård et al. [34], and an optimized charging strategy is applied. This means that the charging is optimized to minimize the total system cost, in contrast to direct charging upon arrival. In this work, a full electrification of the transport sector is assumed, i.e., that all vehicle categories are electrified via batteries. From the work by Taljegård et al. [34], the annual driving distance for EVs, light trucks, busses, and heavy trucks are 17,400, 14,000, 41,000, and 57,000 km, respectively, and the corresponding fuel consumption is assumed to be 0.16, 0.33, 1.19, and 2.06 kWh per km. The batteries in all vehicles are, however, modeled as an aggregate battery; this simplification is necessary to limit the computational effort. The impacts of this simplification have been further evaluated by Taljegård et al. [35].

The steelmaking process is assumed to be electrified through hydrogen direct reduction of iron ore and electric arc furnaces for the production of crude steel, a process that according to Fischedick et al. [36] is the most-attractive route for future steelmaking, both from the economic and environmental perspectives. This process requires 1700 kWh of hydrogen and 816 kWh of electricity per ton of crude steel [37], and the process is assumed to work at a constant rate over time. Future steel production is taken from Eurofer [38] for the following regions,[1] which are all included in the modeling: BE, FR4, FR5, DE3, DE4, DE5, NL, PO2, FI, ES1, SE2, SE4, UK1. The reasons for limiting the industrial electricity use to the steel industry are that there are ongoing projects on hydrogen-based steelmaking (HYBRIT [37], ArcelorMittal S.A [39]. and Voestalpine AG [40]), and that the steelmaking industry is assumed to take the lead in electrifying the industry through the use of hydrogen. As for the potential electrification of other industries, there are fewer concrete plans and, so it is considered outside the scope of this work to speculate on the future of such electrification.

In this study, four different geographic regions are modeled separately (Fig. 1). The British Isles (Fig. 1a) and the Iberian Peninsula (Fig. 1d) are represented by four and five sub-regions, respectively, as indicated by the color-coding in the corresponding figures. The British Isles and the Iberian Peninsula are modeled without any connections to neighboring countries, as these regions have limited transmission capacities to neighboring regions due to the sea and mountains. Central Europe (Fig. 1b) is represented by seven different sub-regions, five of which act as boundary regions for trade with Germany. All boundary regions are indicated in green with diagonal white lines; the results from these regions are not analyzed. All the color-coded regions in Central Europe are formed by a number of clustered NUTS2 regions, and for Germany, the northern part with extensive wind resources is constituted by DE4 and DE5, while the southern part with large solar resources is composed of DE1–DE3. The Nordic countries (Fig. 1c) are also modeled with seven sub-regions, although only two regions are boundary regions (Finland, and the northern part of Germany together with the Netherlands). Here, Denmark is modeled as one region, and both Sweden and Norway are represented by a southern and a northern part, as indicated by the color-coding scheme.

A set of different capital costs for hydrogen-compatible gas turbines has been investigated (Table 1). The underlying idea is that the capital cost increases with the allowed hydrogen mixing rate, given that higher shares of hydrogen will likely require more-extensive changes to the fuel and safety systems, as well as to the burners and combustion chamber. The capital costs used previously [15] are in the present work subjected to a sensitivity analysis, where the relative increase in capital cost is set to zero or doubled, relative to the values used in the previous study [15] (Medium H2GT Capex), as shown in Table 1. The reference investment costs for open cycle gas turbines (OCGT) and CCGT are 450 and 900 €/kW_{el}, respectively. The electrical efficiency is assumed to be unaffected by the mixing of hydrogen.

[1] Belgium (BE), France (FR), Germany (DE), The Netherlands (NL), Poland (PL), Finland (FI), Spain (ES), Sweden (SE) and the United Kingdom (UK).

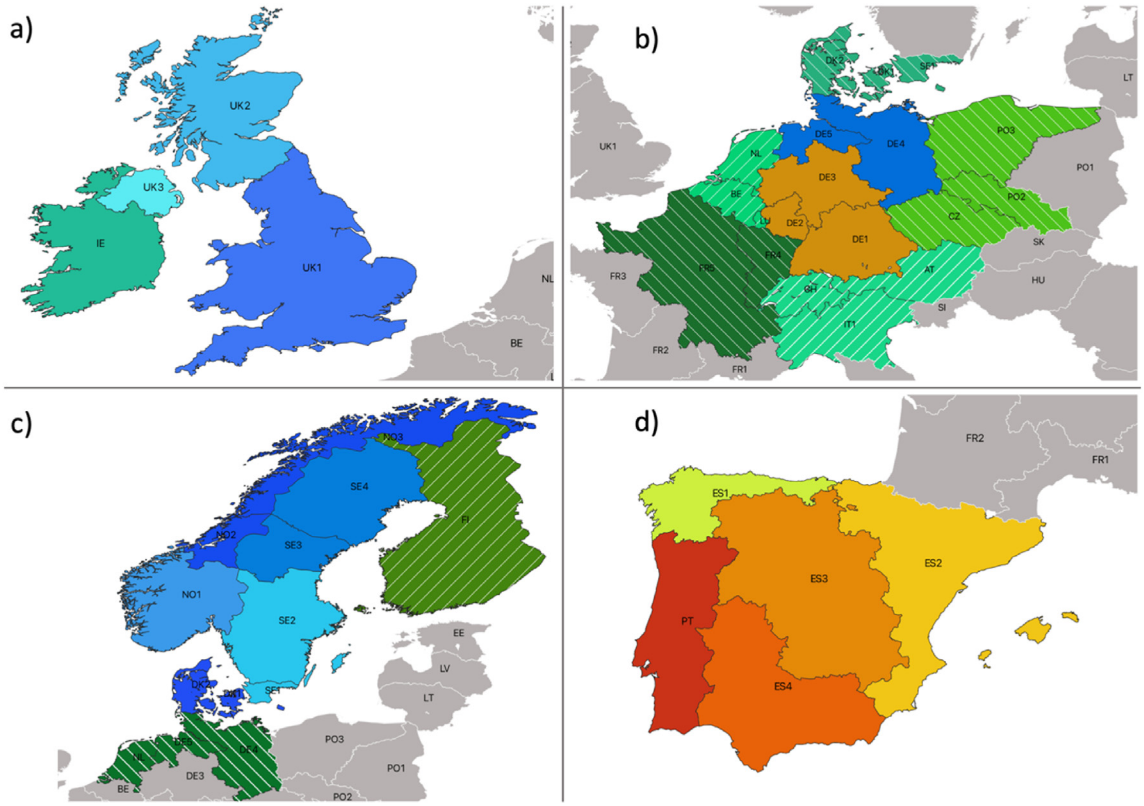

Fig. 1 – The modeled regions: a) British Isles; b) Central Europe; c) the Nordic countries; and d) Iberian Peninsula; The color-coding indicates the regions modeled, which occasionally reflect the NUTS2 regions, and sometimes constitutes a cluster of NUTS2 regions. Regions indicated in green with diagonal white lines are boundary regions for trade, which are not analyzed. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

The scenarios run in this work are designed to investigate the impacts of four parameters on the competitiveness and operation of hydrogen-fueled gas turbines (second research question). The four parameters are: the cost and availability of biomass; the capital cost of hydrogen gas turbines; the impact of the availability of low-cost hydrogen storages in the form of salt caverns; and hydrogen production decoupled from the electricity system. In Table 2, Scenarios 1–3 consider the cost and limitation of biomass use in the electricity system, and Scenarios 4–6 vary the capital cost of hydrogen gas turbines. The limitation of biomass is defined as the maximum share of electricity generated from technologies fed with biogenic fuels, such as biomass or biomethane, and it is assumed that when biomass use is limited, the cost increases. All scenarios are run twice, such that the possibility to invest in salt caverns is either allowed (a) or prohibited (b). All the regions modeled, however, do not have the possibility to use salt caverns, as this requires the availability of geologic formations in the form of salt bed deposits. The distribution of the salt cavern potential is based on the work of Caglayan et al. [41]. Finally, Scenario 2 has an additional option that includes hydrogen production from SMR-CCS (c), which allows for hydrogen production that is decoupled from the electricity system. The option of including SMR-CCS is only allowed when investments in salt caverns are also allowed, so Scenario 2c corresponds to Scenario 2b with the addition of SMR-CCS.

Table 2 – Modeled scenarios. The subscripts a and b represent the two options that include or exclude the use of salt caverns for hydrogen storage, in regions with potential for salt caverns; a: no salt cavern, b: with salt cavern.

Scenario	Biomass Cost [€/MWh]	Biomass Limit [%]	H2GT Capex	Salt Caverns	SMR with CCS
$1_{a\text{-}b}$	40	20	Medium	No/Yes	–
$2_{a\text{-}c}$	60	3	Medium	No/Yes	No/Yes
$3_{a\text{-}b}$	80	1	Medium	No/Yes	–
$4_{a\text{-}b}$	60	3	Low	No/Yes	–
$5_{a\text{-}b}$	60	3	Medium	No/Yes	–
$6_{a\text{-}b}$	60	3	High	No/Yes	–

Table 3 – Investment options for hydrogen-fueled gas turbines.

Technology[a]	Fuel	Upper limit H_2 mixing ratio [vol.-%]
OCGT	biomethane-H_2	30/50/77/100
CCGT	biomethane-H_2	30/50/77/100

[a] OCGT, Open cycle gas turbine; CCGT, Combined cycle gas turbine.

Implementation of hydrogen gas turbines

Hydrogen-fueled gas turbines are available in different configurations in the model, considering open or combined cycle turbines, with several different (upper limit) mixing ratios of hydrogen. These options are all included in the set P^{H2GT} and displayed in Table 3. In this work, the use of hydrogen in a gas turbine is flexible, meaning that hydrogen can supply any fraction of the energy input required in a time-step t, from zero to the upper mixing limit defined per technology type, and is therefore decided by the investment decision. Equation (1a) describes the energy balance with flexible fuel mixing in hydrogen-fueled gas turbines, and Equation (1b) limits the energy supplied from hydrogen to be less or equal to the upper mixing ratio of hydrogen in every time-step t.

$$g_{r,t,p} \cdot \frac{1}{\eta_p} \leq e^{H2}_{r,t,p} + e^{fuel}_{r,t,p} \tag{1a}$$

$$e^{H2}_{r,t,p} \leq \gamma_p^{H2,up} \cdot g_{r,t,p} \frac{1}{\eta_p} \tag{1b}$$

$\forall\ r,t,p \in R,\ T, P^{H2GT}$

where

$g_{r,t,p}$ is the generation from technology p in region r in time-step t.

η_p is the electrical efficiency of technology p.

$e^{H2}_{r,t,p}$ is the energy supplied from hydrogen to technology p in region r in time-step t.

$e^{fuel}_{r,t,p}$ is the supplied energy from a complementary fuel to technology p in region i and time-step t.

$\gamma_p^{H2,up}$ is the upper limit mixing ratio for hydrogen in technology p in region r in time-step t.

Equation (2) defines the constraint that limits the use of solid biomass and biomethane (produced from solid biomass via gasification). The left-hand side of Equation (2) accounts for all electricity that is generated in technologies using solid biomass or biomethane as fuel, and the constraint assures that the total share of electricity generated from biogenic fuels is less than the defined maximum share, $\gamma_r^{bio,max}$.

$$\sum_{t\in T}\left(\sum_{p\in P^{gen}, p\notin P^{H2GT}}\left(g_{r,t,p}\cdot\gamma_p^{bio}\right) + \sum_{p\in P^{H2GT}} e^{biogas}_{r,t,p} n\eta_p\right) \leq \sum_{t,p\in T,P^{gen}} g_{r,t,p}\cdot\gamma_r^{bio,max},\ \forall\ r\in R \tag{2}$$

where

γ_p^{bio} is the share of energy from biomass or biomethane used in technology p.

$e^{biogas}_{r,t,p}$ is the energy supplied from biomethane to a hydrogen gas turbine in region i at time-step t.

$\gamma_r^{bio,max}$ is the maximum share of electricity from biomass or biomethane in region i.

The injection and withdrawal rates for charging and discharging hydrogen storages are described in Equation (4). For salt caverns, the injection and withdrawal rates are 0.42% of the installed capacity per hour, based on [42], and the corresponding values for LRC are set to 5% per hour based on [43]. As LRCs are considerably more flexible in terms of flow rates, LRC and salt caverns can be connected in order to facilitate flexibility if the low flow rates of salt caverns would impose a limitation to the use of hydrogen. There is however no cost related to this ability, and thus this feature is only included to evaluate if the flow rates would ever be a limiting factor in the system modelled.

$$s^{charge}_{r,t,p^{H2storage}} + s^{toLRC}_{r,t,Cavern} \leq S^{rate}_{p^{H2storage}} \cdot i_{r,p^{H2storage}} \quad \forall\ r,t \in R,T \tag{3}$$

where:

$s^{charge}_{r,t,p^{H2storage}}$ is the energy (dis)charged to hydrogen storage technology p in region r in time-step t.

$s^{toLRC}_{r,t,Cavern}$ is the energy charged from salt caverns to LRC in region r in time-step t.

$S^{rate}_{p^{H2storage}}$ is the (dis)charge rate of hydrogen storage technology p in percentage of installed capacity.

$i_{r,p^{H2storage}}$ is the installed capacity of hydrogen storage technology p in region r.

The energy balances for the two hydrogen storage technologies LRC and salt caverns are described in Equations (4a)–(4b). The storage level in the subsequent time-step equals the storage level in the present time-step plus the sum of charging and discharging. In Equations (4a)–(4b) the potential flow from salt caverns to LRC can be seen in the term $s^{toLRC}_{r,t,Cavern}$.

$$g_{r,t+1,Cavern} \leq g_{r,t,Cavern} + s^{charge}_{r,t,Cavern} - s^{discharge}_{r,t,Cavern} - s^{toLRC}_{r,t,Cavern} \tag{4a}$$

$$g_{r,t+1,LRC} \leq g_{r,t,LRC} + s^{charge}_{r,t,LRC} - s^{discharge}_{r,t,LRC} + s^{toLRC}_{r,t,Cavern} \tag{4b}$$

$\forall\ r,t \in R,T$

where:

$g_{r,t,Cavern}$ is the storage level in salt caverns (or LRC) in region r in time-step t.

$s^{charge}_{r,t,Cavern}$ is the energy charged to salt caverns (or LRC) in region r in time-step t.

$s_{r,t,Cavern}^{discharge}$ is the energy discharged from salt caverns (or LRC) in region r in time-step t.

To maintain the wall stability in salt caverns, the storage pressure should be within 80%–30% of the lithostatic pressure [42,44], which is the natural pressure within the rock formation where the salt cavern is constructed. As the pressure-density ratio of hydrogen is relatively linear in the range of 100–300 bars, the limits of 80% and 30% of the installed capacity are used to set the maximum and minimum storage level, respectively, as is described in Equations (5a) and (5b).

$$g_{r,t,Cavern} \leq 0.8 \cdot i_{r,Cavern} \tag{5a}$$

$$g_{r,t,Cavern} \geq 0.3 \cdot i_{r,Cavern} \tag{5b}$$

$$\forall\ r, t \in R, T$$

Results

The results presented in this section are divided in four subsections, with each subsection presenting the results for energy systems characterized by its dominant electricity generation technology.

High wind-share systems

Among the modeled scenarios, the largest investments, both relative to the regional electricity demand and in absolute terms, in hydrogen-fueled gas turbines are found in the wind-dominated energy system in the British Isles. Investments are made in different gas turbine configurations depending on the scenario, although the largest and most frequent investments are made in CCGTs that have up to 100% hydrogen capability, given the prescribed zero CO_2 emissions target for Year 2050. These CCGTs are installed at the GW scale and are in operation typically for around 2000 h per year, with around 1500 full-load hours (FLH).

Fig. 2 shows the operation of a CCGTs with 100% hydrogen capability in UK1 for Scenarios 1a and 1b, where Scenario 1b allows for investments in salt caverns. From the left-most panels in Fig. 2, which is a load-duration plot, it is evident that the installed CCGT capacity increases from about 3 GW to around 9 GW when the less-costly salt cavern-based hydrogen storage technology is made available to the model. It is also clear that the major share of the CCGT operation is with hydrogen as a fuel, although the full range of fuel flexibility is used, meaning that there is operation with either 100% hydrogen or 100% biomethane, and various intermediate mixes. The middle panels in Fig. 2 show the operational patterns of the CCGTs for all the hours of the year, where the blue fields indicate operation with hydrogen and the green fields indicate operation with biomethane, while the stacked blue and green fields indicate fuel mixing. The middle panels show that operation of the CCGT consists of a significant number of start-stop cycles, indicating that the CCGT serves as a balancing technology.

In the right-most panels of Fig. 2, the data for when the CCGT is in operation is sorted based on electricity cost, which is plotted on the primary y-axis together with the fuel cost of hydrogen and biomethane, and the gross margin, which is the difference between electricity cost and operational cost (e.g., fuel cost). The annual sum of the gross margin amounts to the annualized capital cost of the gas turbine investment when using the technical lifetime as depreciation time, which is expected in this type of modeling. On the secondary y-axis, the hydrogen cost (in €/kg) is plotted, and when comparing the two scenarios outlined in Fig. 2a and b, it can be seen that the cost of hydrogen when used in the gas turbine (i.e., the cost of hydrogen when the area under the dashed black line is fully or partly filled with blue) is similar at around 2.5 €/kg$_{H2}$, although the fluctuations in hydrogen cost are less severe in the scenario that allows storage in salt caverns. Here, it should be mentioned that the cost for hydrogen includes both production and storage costs, as this total cost sets the marginal cost of hydrogen in the model.

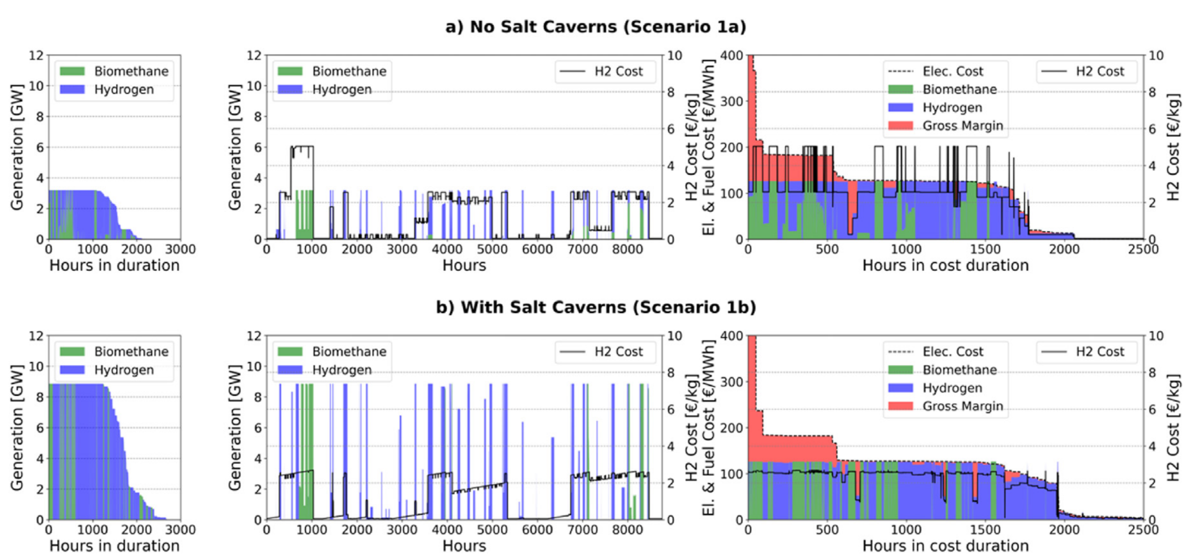

Fig. 2 – Operation of CCGTs with 100% hydrogen capability in UK1 for Scenarios 1a and 1b, where salt caverns are excluded in the modeling in a) and included in b). The biomass cost is 40 €/MWh and the availability is 20%.

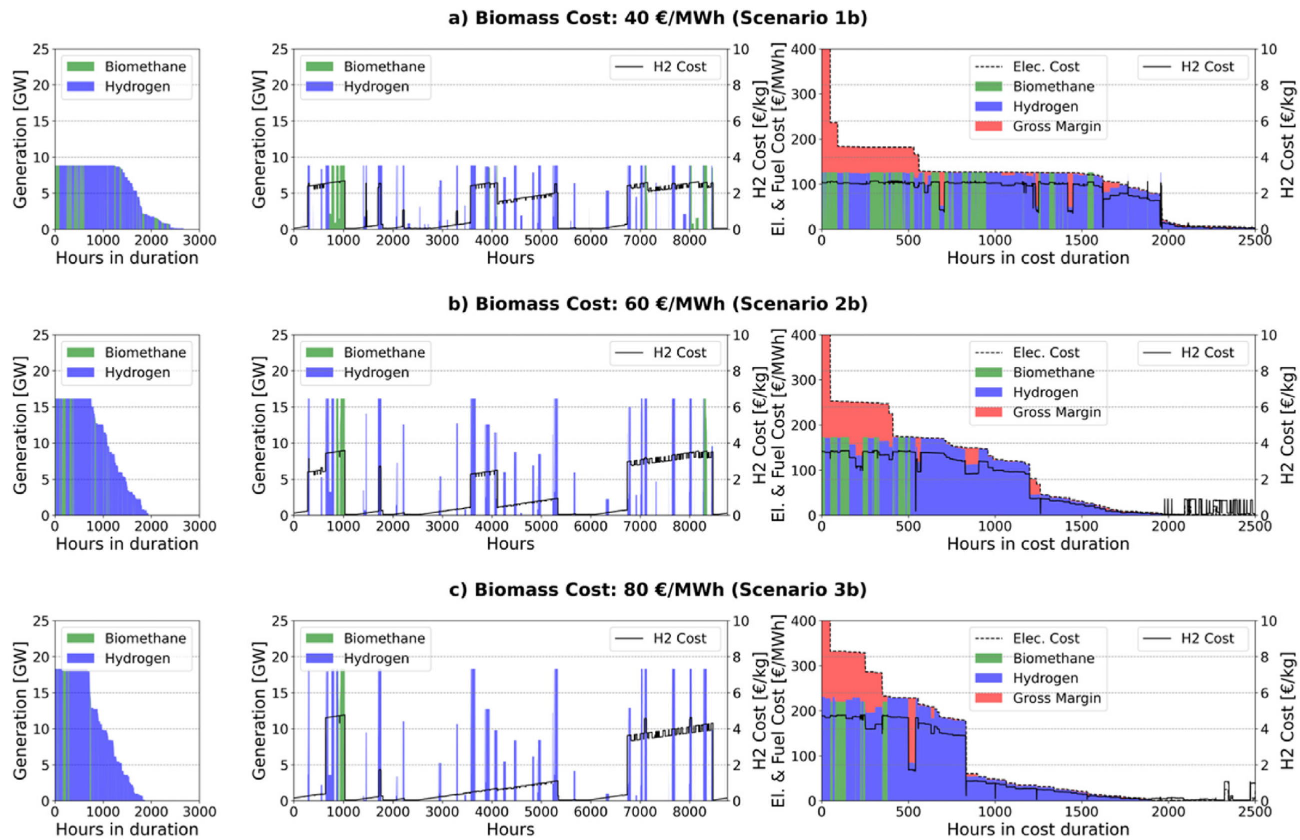

Fig. 3 — Operation of CCGTs with 100% hydrogen capability in UK1 for scenarios in which the biomass cost is increased as the biomass availability is decreased (Scenarios 1b, 2b and 3b), according to the assumptions presented in Table 2. In this figure, all the scenarios allow for the use of salt caverns for storage.

Table 4 — The resulting electricity share generated from biomass and/or biomethane in three scenarios with different limitations on the use of biomass (Scenarios 1b, 2b and 3b). The scenarios allow for storage in salt caverns and have a medium CAPEX for hydrogen-fueled gas turbines.

	Assumed upper limit on share of electricity generated from biomass and assumed biomass cost		
Maximum biomass limit Biomass cost	20% 40 €/MWh	3% 60 €/MWh	1% 80 €/MWh
Region	Biomass use in results		
IE	0.33%	0.36%	1%
UK1	3.7%	1.8%	1%
UK2	7.8%	3%	1%
UK3	2.0%	2.2%	1%

Biomass cost

Considering instead the effects of an increasing biomass cost, in combination with a limitation being imposed on the use of biomass in the electricity system, Fig. 3 shows for three scenarios (1b, 2b and 3b) that the installed CCGT capacity increases from 9 GW to 18 GW in UK1 when the biomass cost is doubled from 40 to 80 €/MWh. As expected, the willingness-to-pay for hydrogen increases with the cost of biomass, as there are few alternatives for CO_2-free peak power given that biomethane-fueled technologies represent the main alternatives in the model. In the right-most panels in Fig. 3, the cost of hydrogen increases from 2.5 €/kg_{H2} at a biomass cost of 40 €/MWh to 3.5 €/kg_{H2} when the biomass cost is 60 €/MWh, and finally increased to almost 5 €/kg_{H2} at a biomass cost of 80 €/MWh.

The limitation on biomass use is assumed to be equivalent to the maximum share of electricity in a region that is generated in technologies that are fed with either solid biomass or biomethane (produced from solid biomass in the model). Table 4 outlines the upper limits on biomass and the actual used levels from the results. It can be seen that in Scenario 1b with an upper limit of 20% electricity generation from biomass, this does not become a binding constraint, as no region in the British Isles exceeds even 10% of electricity generated from biomass. Still, in Scenario 2b where the limit is 3%, the biomass limitation becomes binding in region UK2. For Scenario 3b, with a limitation of 1% of electricity from biomass, all the regions indicate binding constraints, which means that the total system cost would decrease if more biomass was to become available in any of the regions, despite the high cost of biomass (80 €/MWh).

Gas turbine investment cost

Fig. 4 displays the results for different investment costs for hydrogen gas turbines (Scenarios 4b, 5b and 6b) in UK1. The

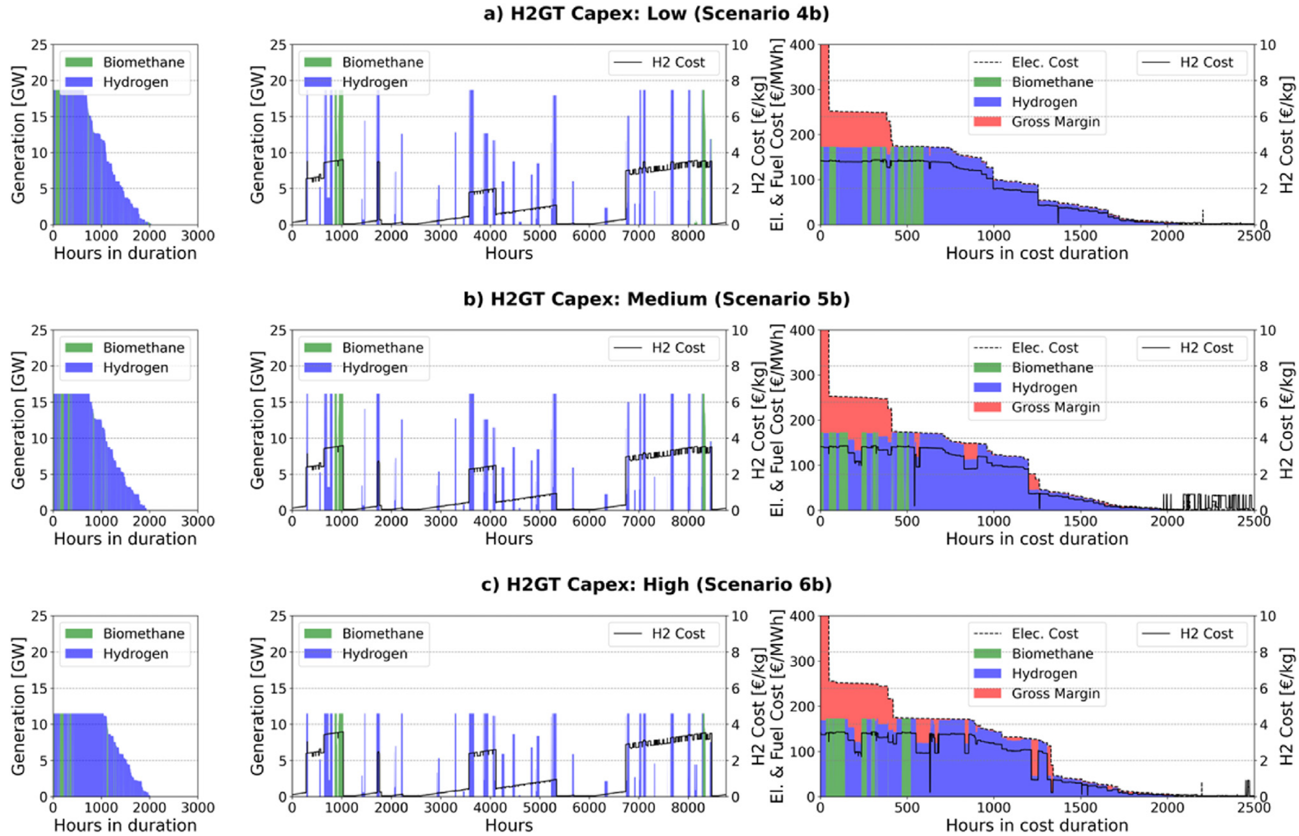

Fig. 4 – Operation of CCGTs with 100% hydrogen capability in UK1 for Scenarios 4b, 5b and 6b, scenarios in which the investment cost is varied. All scenarios include storage in salt caverns and have a biomass cost of 60 €/MWh, with a corresponding biomass availability of 3%.

most obvious and logical effect is the decrease in installed capacity when the capital cost increases. Furthermore, with a lower capital cost, the CCGTs can remain competitive at lower FLH, here indicated by more-frequent part-load operation, and thus, the FLH are 1170 and 1460 for the low and the high capital cost scenarios, respectively. It should, however, be pointed out that the 11 GW or 18 GW of investments would obviously be divided across multiple different power plants. Thus, the analysis regarding part-load operation could in reality entail a differentiation in FLH between plants depending on small technical differences and merit order. The willingness-to-pay for hydrogen is hardly affected by the variation in capital costs, i.e., the average cost of hydrogen remains at about 3.5 €/kg_{H2} in all three scenarios presented in Fig. 4.

Table 5 – Energy mixes for northern and southern Germany according to the shares of electricity production from different technologies for Scenario 1b.

	Share of electricity production [%]	
	DE south	DE north
Wind	24.4	52.0
PV	42.6	33.4
Hydro	9.5	7.5
Biomethane	4.2	0.6
Waste CHP	18.0	4.1
H_2-GT	1.3	2.4

Hydrogen production via SMR with CCS

When hydrogen production via SMR-CCS is included in Scenario 2c, the UK1 region attains an investment of 1.4 GW_{H2} of SMR, although the installed electrolyzer capacity remains the same at 13.4 GW. In this scenario, hydrogen from SMR constitutes 9% of the total hydrogen production in UK1, increasing the total hydrogen production from 43.2 TWh to 44.7 TWh, with the additional hydrogen being used to replace the biomethane (and thus biomass) used in the hydrogen-fueled gas turbines. The fact that the electrolyzer capacity remains the same as in Scenario 2b without the SMR-CCS option underlines the value of producing large quantities of hydrogen during periods with low electricity costs, while there is a benefit to the system of having hydrogen production decoupled from the electricity grid during periods with high electricity costs.

High shares of solar and wind systems

The electricity demand in Germany is to a great extent supplied by a mix of solar and wind power, where wind is the dominating technology in the north, and solar PV

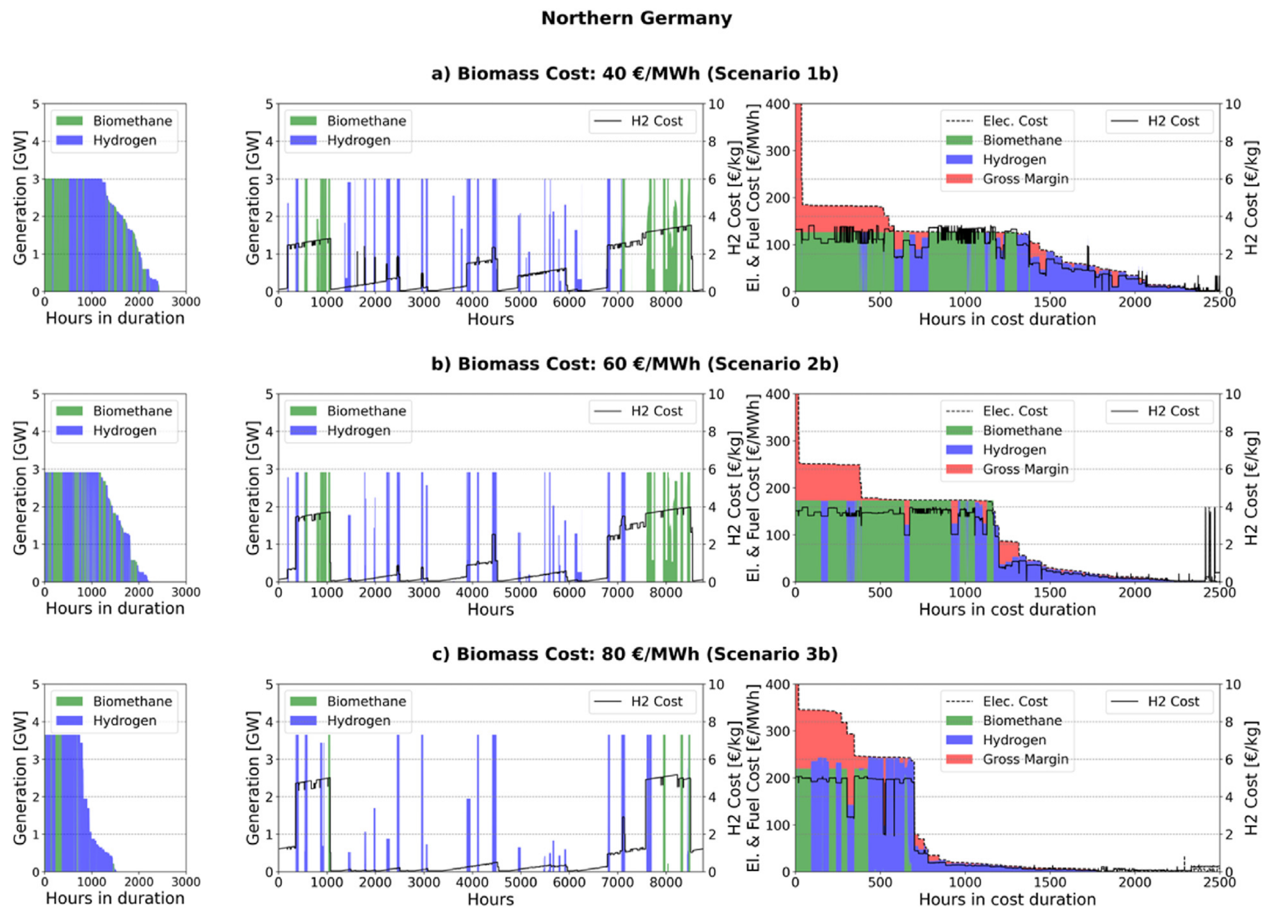

Fig. 5 – Operation of CCGTs with 100% hydrogen capability in northern Germany for Scenarios 1b, 2b and 3b, scenarios in which the biomass cost is increased as the biomass availability is decreased, according to the assumptions presented in Table 2. All the scenarios allow for storage in salt caverns.

predominates in the south, as shown in Table 5. The investments in hydrogen-fueled gas turbines (H_2-GT) are of the same magnitude with or without storage in salt caverns, so only the results from scenarios that allow investments in salt caverns are presented. The main difference between including and excluding salt caverns is that the hydrogen cost is less volatile in northern Germany when salt caverns are allowed, as this is the only region in Germany with salt cavern potential.

Biomass cost

In northern Germany, investments are made in the range of 3.0–3.6 GW for CCGTs with 100% hydrogen capability. Fig. 5 shows the results for the scenarios in which the biomass cost is increased as the biomass availability is decreased (Scenarios 1b, 2b and 3b). In Scenario 3b, when the biomass cost is 80 €/MWh the cost of hydrogen peaks at 5 €/kg_{H2}, and for lower biomass costs, hydrogen reaches a maximum cost in the range of 3–4 €/kg_{H2}. Furthermore, it is only in Scenario 3b where investments are seen in other configurations, and then mainly in OCGT with 100% hydrogen capability, a configuration that attains an investment of 1.4 GW.

In southern Germany, investments are made in the range of 1.8–4.4 GW for CCGTs with 100% hydrogen capability, as displayed in Fig. 6, which shows the results for Scenarios 1b, 2b and 3b. The larger variations in investments in CCGTs in southern Germany, as compared to northern Germany, can be explained by the fact that significant investments are made also in OCGT with 100% hydrogen capability, which highlights a greater demand for peak power in southern Germany. The largest investment of 3 GW in OCGTs is made when the biomass cost is 80 €/MWh (Scenario 3b). The marginal cost of hydrogen in southern Germany is frequently significantly higher than 6 €/kg_{H2}. Yet, at these time-points, the hydrogen gas turbines are either not in use or fueled with biomethane, and the willingness-to-pay for hydrogen in gas turbines remains below 5.5 €/kg_{H2}.

Gas turbine investment cost

Varying the investment cost for hydrogen gas turbines in Germany has a similar effect in southern Germany as in UK1, with decreasing hydrogen gas turbine capacity and increasing number of FLH as the investment cost increases, both for OCGTs and CCGTs. For northern Germany, the installed capacity of CCGTs is in principle constant at 2.9 GW, independent of the OCGT and CCGT investment costs for all the scenarios (4b, 5b and 6b), with around 1600 FLH. The only difference in northern Germany is seen for the lowest investment cost applied (Scenario 4b), when an additional 1.96 GW of OCGT is installed, albeit with only 38 FLH.

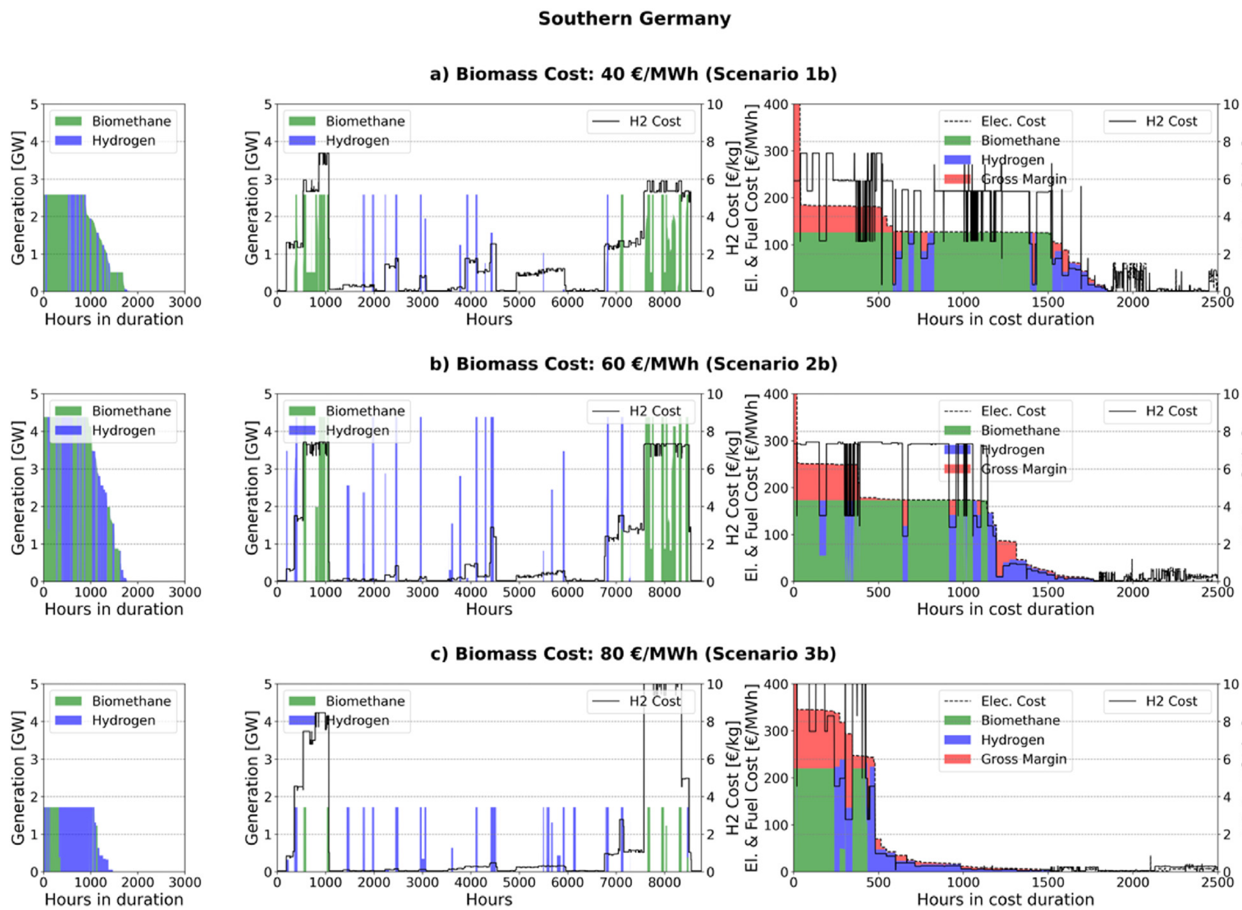

Fig. 6 – Operation of CCGTs with 100% hydrogen capability in southern Germany for Scenarios 1b, 2b and 3b, scenarios in which the biomass cost is increased as the biomass availability is decreased, according to the assumptions presented in Table 2. All the scenarios include storage in salt caverns.

Hydrogen production via SMR with CCS

Among the countries analyzed, Germany is the country that attains the highest costs for hydrogen. Therefore, hydrogen production that is decoupled from the electricity system should be a competitive complement. This is modeled in Scenario 2c, where the biomass cost is 60 €/MWh, salt caverns are allowed, and the investment cost of hydrogen gas turbines is Medium.

The results for Scenario 2c show that the total installed capacity of hydrogen gas turbines in southern Germany decreases to 2.5 GW when SMR-CCS is allowed, as compared to 6.4 GW in Scenario 2b. The installed electrolyzer capacity also decreases by more than 50% from 13.4 GW to 6.5 GW, such that the lost electrolyzer capacity is replaced with 3.9 GW of SMR-CCS, a technology that in this scenario produces 24% of all hydrogen in southern Germany. In addition, the hydrogen storage capacity decreases by almost 75% to 197 GWh of LRC (there is no potential for storage in salt caverns in southern Germany).

In northern Germany, investments in CCGTs with 100% hydrogen capability increase from 2.9 GW to 7.6 GW in Scenario 2c, despite the fact that no SMR capacity is installed in northern Germany. In addition, the electrolyzer capacity is increased by 68% to 6.7 GW, and the salt cavern storage capacity is increased from 1440 GWh to 3270 GWh. This contrasting development in northern Germany can be explained by high levels of wind power and relatively low electricity demand (as compared to southern Germany), which drives down electricity prices, especially when hydrogen from SMR-CCS in the south reduces the need for electricity export from north to south.

The effects on hydrogen production, hydrogen storage utilization, and electricity and hydrogen costs when SMR-CCS is allowed are shown in Fig. 7. Comparing the hydrogen costs in Fig. 7a,c, it is clear that when allowing for SMR-CCS the peak hydrogen cost in southern Germany is reduced from 7.4 €/kg_{H2} to 4.2 €/kg_{H2}, whereas the corresponding decrease in northern Germany (Fig. 7b,d) is marginal, even though hydrogen production is actually increased. In Fig. 7, it can also be seen that the amount of hydrogen produced is larger in southern Germany. This is due to the larger industrial demand for hydrogen, the impact of which can actually be seen in the production patterns of the electrolyzer in Fig. 7a, where the electrolyzer is mainly operating on two different levels. The lower level corresponds to the hourly industrial hydrogen demand (4.4 GWh_{H2} per hour), and when the electrolyzer is operated at higher capacity, the storage is filled with hydrogen, which can be used during hours when the electrolyzer is not in operation due to high electricity prices.

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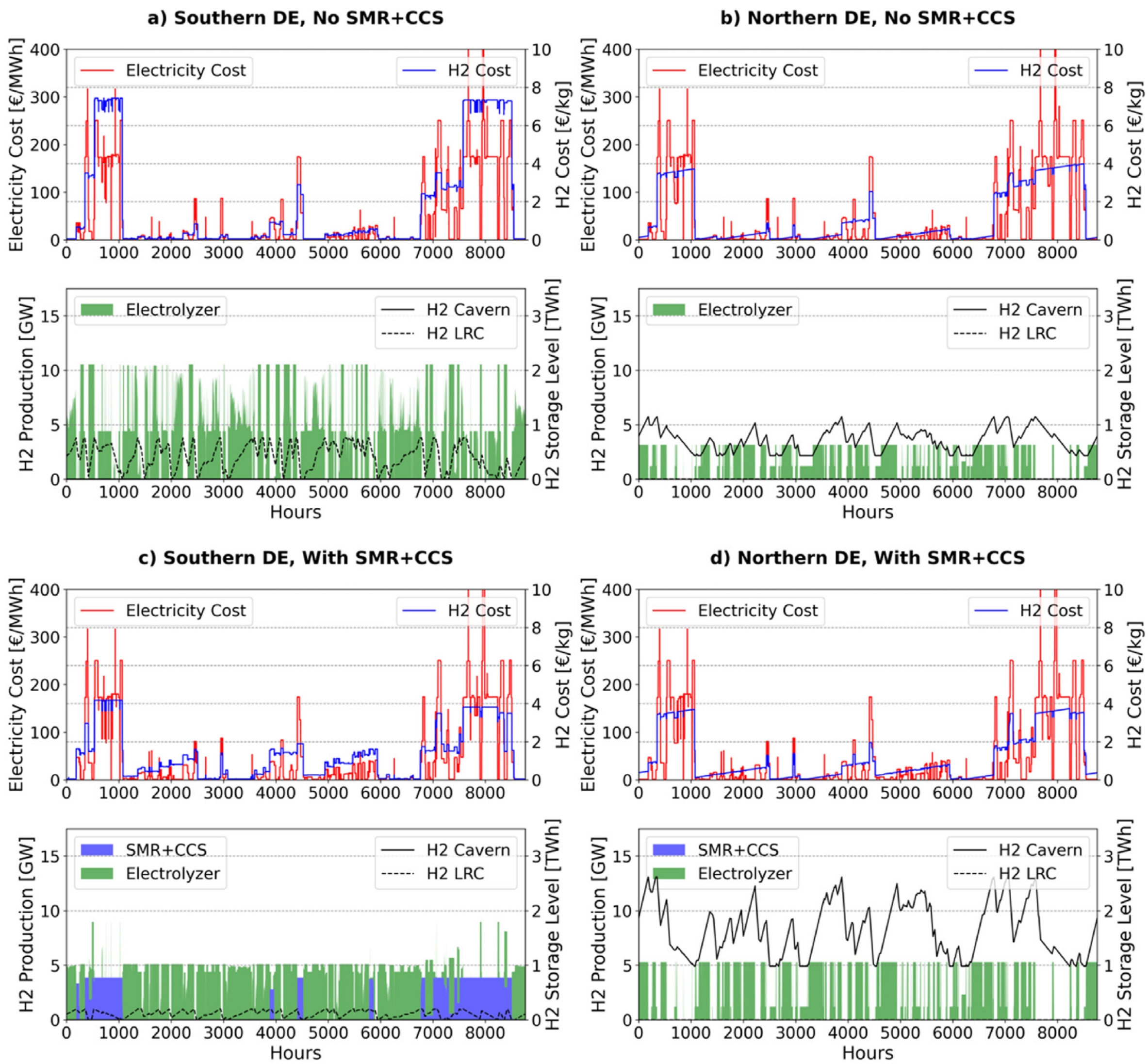

Fig. 7 — Electricity and hydrogen costs in southern and northern Germany, as well as hydrogen production and storage utilization rates. The results in panels a) and b) are taken from Scenario 2b, where SMR with CCS is not included. The results in panels c) and d) are taken from Scenario 2c, where SMR with CCS is allowed. In both scenarios (2b and 2c) the biomass cost is 60 €/MWh with biomass availability of 3%. Salt cavern storage is allowed in all the plots, although there is no potential for storage in salt caverns in southern Germany, and thus no investments are made.

Considering the marginal cost of hydrogen, the three variables that establish the cost in a system that only allows for electrolytically generated hydrogen are: electricity cost, electrolyzer capacity, and hydrogen storage capacity. This can be seen in Fig. 7a,b, where the hydrogen cost is undoubtedly affected by the electricity cost. However, it is also evident that the largest step increases in hydrogen cost occur when the hydrogen storage unit has reached its maximum capacity. In fact, the storage capacity, and thereby the capital cost of storage, tend to have a greater impact on the marginal cost of

Table 6 — Impact on hydrogen production in southern Germany of increasing the cost of natural gas in Scenario 2c. The cost of biomethane (BM) is 106 €/MWh and biomethane constitutes 11.5% of the fuel input.

NG cost [€/MWh]	Total fuel cost (NG and BM) [€/MWh]	Share of H_2 from SMR-CCS	Electrolyzer capacity [GW]	SMR-CCS capacity [GW]
18	28.1	24%	6.49	3.87
21	30.7	22%	6.66	3.75
24	33.4	21.6%	6.68	3.74
27	36.0	21.3%	6.69	3.74
30	38.7	21.2%	6.74	3.73

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Table 7 – Summary of hydrogen gas turbine investments in the Nordic countries for the scenarios in which the biomass cost is increased as the biomass availability is decreased, while also allowing for salt cavern storage (Scenarios 1b, 2b and 3b).

Biomass cost [€/MWh]	CCGT 100% H_2			OCGT 100% H_2		
	40	60	80	40	60	80
	Installed capacity [GW]					
Region						
SE south	0.21	0.75	0.13	0.10	0.11	0.27
SE north	0.13	0.60	0.04	0.22	0.36	0.50
NO south	0	0	0.65	0	0	0.10
NO north	0	0	0	0	0	0
DK	0	0	2.79	0	0	0.32

hydrogen than does the electrolyzer capacity. In all the panels outlining the cost of hydrogen in Fig. 7, there is a significant increase in hydrogen cost at approximately Hour 6,800, which is attributed to a combination of higher electricity cost and the hydrogen storage reaching its maximum level. This happens despite the fact that the electricity cost has been close to zero since Hour 6,000, and the fact that the electrolyzer has not been operating at full capacity for the period between Hours 6000 and 6800. Thus, obtaining additional hydrogen at Hour 6800 requires either direct use of the electrolyzer at a high cost or a larger investment in storage capacity.

When hydrogen is produced via SMR-CCS the hydrogen cost is set by the fuel cost, which in this case gives the model a constant marginal cost for hydrogen when only SMR is in operation. Yet, since the future cost of natural gas (NG) is uncertain, the cost of NG was varied in order to evaluate how sensitive the system would be to variations in the price of NG. Table 6 shows that the results are not particularly sensitive to an increase in the NG cost. However, at some threshold of the natural gas cost, the value of hydrogen production from SMR-CCS will diminish and investments in this technology will vanish. This threshold value is however not identified in this study.

Large share of hydro power

The competitiveness of hydrogen gas turbines in electricity systems with substantial proportions of hydro power is in this work exemplified by the Nordic countries. As shown in Table 7, only Sweden attains investments in hydrogen gas turbines for all the investigated biomass cost scenarios (Scenarios 1b, 2b and 3b), with the investments being in the range of 100–750 MW. For Denmark and Norway, hydrogen gas turbines become competitive only when the biomass cost is 80 €/MWh (Scenario 3b). In Denmark, significant investment is made in 2.79 GW of CCGT with 100% hydrogen capability. Since these countries are well-connected with respect to transmission capacity, and since both Denmark and Norway

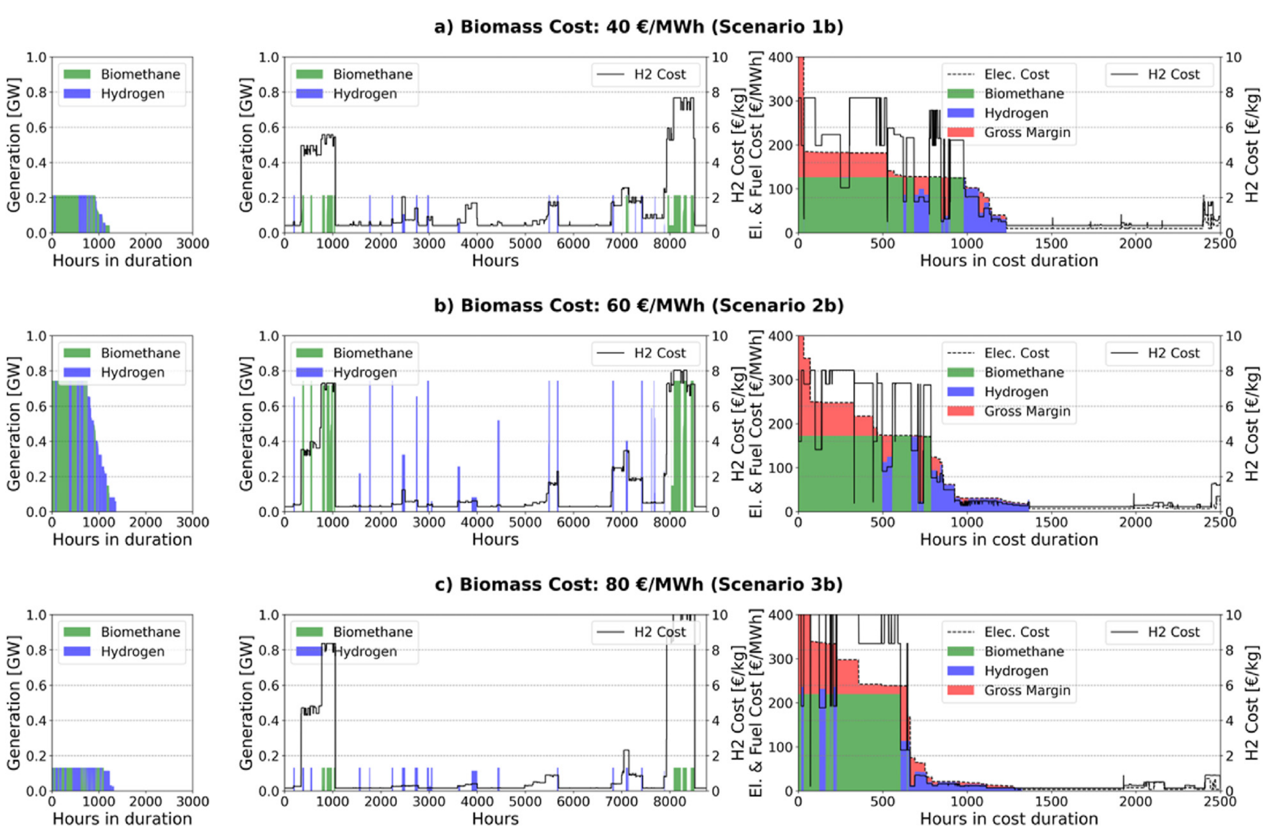

Fig. 8 – The operation of CCGTs with 100% hydrogen capability in southern Sweden (SE1 and SE2) for the scenarios in which the biomass cost is increased as the biomass availability is decreased, while also allowing for salt cavern storage (Scenarios 1b, 2b and 3b).

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Table 8 – The electricity production mix in the Iberian Peninsula in the scenario with a biomass cost of 40 €/MWh, a biomass limit of 20%, and storage in salt caverns included (Scenario 1b).

	Share of electricity production [%]				
	ES1	ES2	ES3	ES4	PT[a]
Wind	61	8	30	8	10
Solar PV	4	75	41	86	76
Hydro	31	17	27	5	14
Biomethane	3	0	2	1	0
H_2-GT	1	0	0	0	0
Battery discharge [TWh]	0	55.7	0	81.7	21.8
Total electricity demand [TWh]	50	260	119	151	102

[a] PT is Portugal.

have potential for storage in salt caverns, the investments in Sweden (especially those in southern Sweden) drop when investments are made in Denmark and Norway. Fig. 8 shows the operation of CCGTs in southern Sweden for different biomass costs (Scenarios 1b, 2b and 3b). It is evident that these CCGTs have about 1000 FLHs and are to a great extent fed with biomethane, since the cost of hydrogen is high during most of the hours when additional capacity is required.

Allowing for hydrogen production via SMR-CCS in Sweden (Scenario 2c) results in equal investments of 220 MW of SMR capacity in both southern and northern Sweden, producing 10% and 13% of the hydrogen, respectively. Correspondingly, the installed capacity of electrolyzers decreases from 1 GW to 0.7 GW in northern Sweden, and from 0.8 GW to 0.5 GW in southern Sweden. Varying the investment cost of hydrogen gas turbines has similar effects as those seen in Germany and the UK, with decreasing investments in CCGT and increasing investments in OCGT as the investment cost increases, and with increasing numbers of FLH for both configurations.

Table 9 – Installed capacity in GW for hydrogen gas turbines in the Iberian Peninsula for the scenarios in which the biomass cost is increased as the biomass availability is decreased, while also allowing for salt cavern storage, a technology that is available in all regions except ES1 (Scenarios 1b, 2b and 3b). Note that no investments are made in ES3.

Biomass cost [€/MWh]	Region	OCGT 77% H_2	OCGT 100% H_2	CCGT 77% H_2	CCGT 100% H_2
40	ES1	0.89	0	0	0
	ES2	0	0	0	0
	ES4	0	0	0	0
	PT	0	0	0	0
60	ES1	0.42	0.30	0.49	0.13
	ES2	0	0	0	0
	ES4	0	0	0	0.27
	PT	0	0	0	0
80	ES1	0.34	0.30	0.13	0
	ES2	0	0	0	0.08
	ES4	0	0	0	1.50
	PT	0	0	0	0.51

High solar-share systems

The lowest level of competitiveness for hydrogen gas turbines is found in regions where electricity production is dominated by solar power. Such regions are found on the Iberian Peninsula, for which the investigated scenarios indicate more than 75% of the electricity generation from solar PV in three out of five regions, and with only one region producing less than 40% from solar PV, as shown in Table 8.

Although the Iberian Peninsula is generally solar power-dominated, sub-region ES1 is actually dominated by wind power, and this is also the only region that attains investments in hydrogen gas turbines regardless of biomass cost and regardless of whether or not salt caverns are allowed. The investments are made in both OCGT and CCGT, and the

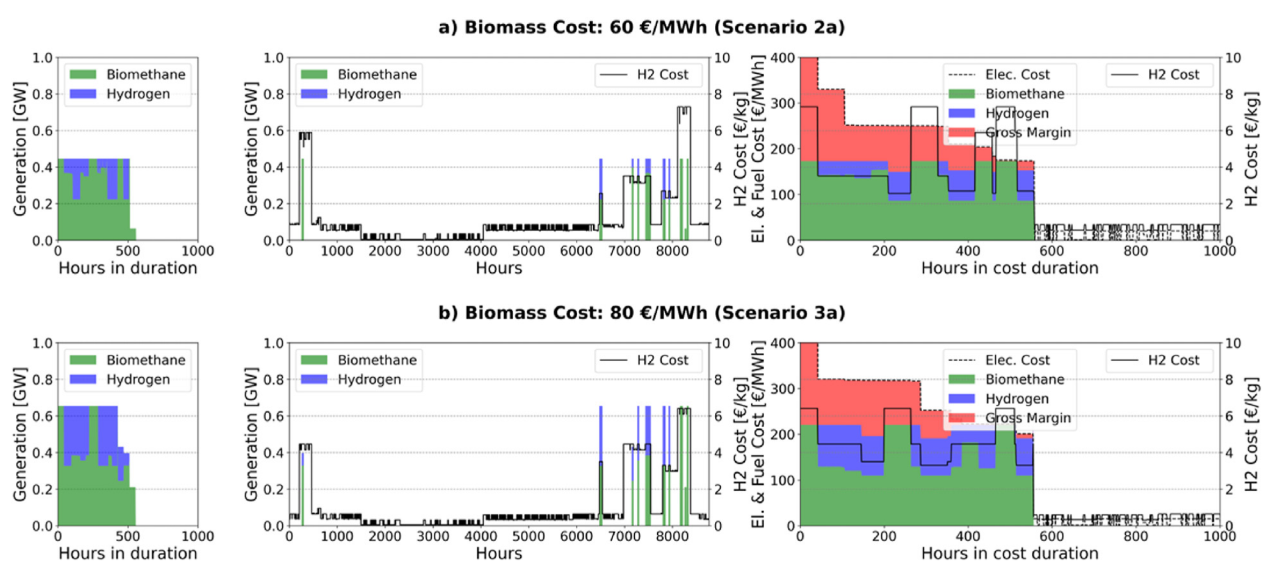

Fig. 9 – The operation of CCGTs with 77% hydrogen capability in ES1 for Scenarios 2a and 3a, scenarios in which the biomass cost is increased as the biomass availability is decreased, according to the assumptions presented in Table 2. In this figure, all the scenarios exclude salt caverns.

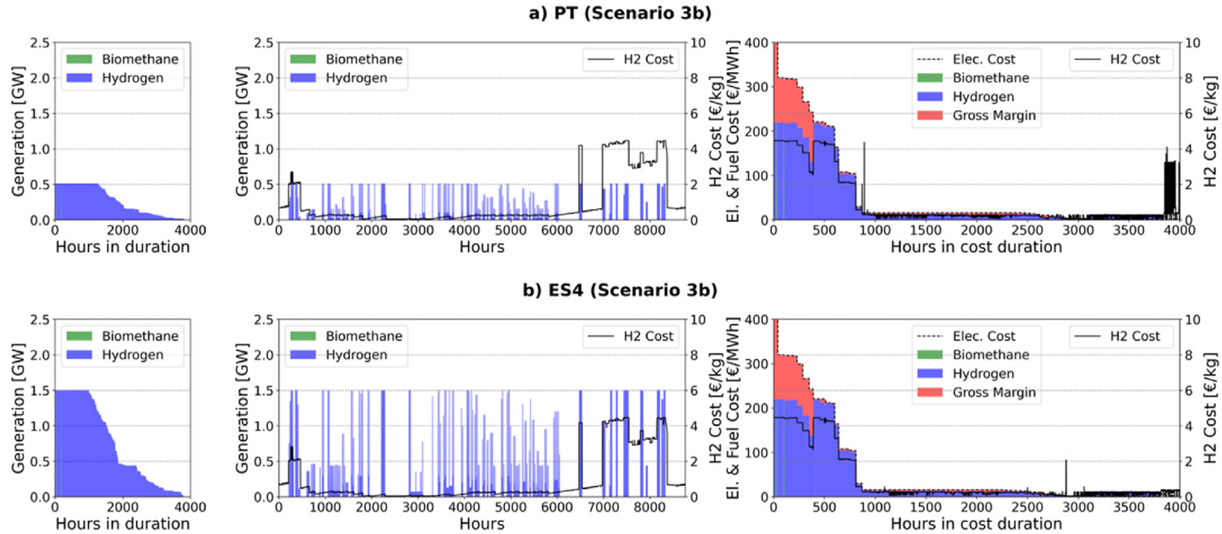

Fig. 10 – Operation of CCGTs with 100% hydrogen capability in a) Portugal and b) ES4 for Scenario 3b, a scenario with a biomass cost of 80 €/MWh, a biomass availability of 1%, and storage in salt caverns included.

majority of the investments are made in configurations that allow for only up to 77 vol.-% of hydrogen, corresponding to 50% of the energy. When the biomass cost increases to 60 €/MWh and 80 €/MWh and salt caverns are excluded (Scenarios 2a and 3a), the largest investments are seen in CCGTs with an upper limit of 77 vol.-% hydrogen. The results for Scenarios 2a and 3a are displayed in Fig. 9, where it can be seen that the main fuel is biomethane and that the CCGTs have only about 500 FLH, despite long periods with low cost for hydrogen.

When salt caverns are allowed and the biomass cost is increased to 60 €/MWh or 80 €/MWh (Scenarios 2b and 3b), investments in hydrogen gas turbines are also made in other regions (ES2, ES4 and PT), albeit exclusively in CCGTs with 100% hydrogen capability, as shown in Table 9. The operation of the CCGTs in ES4 and PT for Scenario 3b are shown in Fig. 10, where it can be seen that the operation is different from that seen in all the other investigated regions in the sense that: i) the CCGTs are in principle fed with 100% hydrogen at all time-steps; and ii) the CCGTs are in operation for almost 4000 h. The most-remarkable aspect of these results is, however, that the majority of the operation are when the hydrogen cost is below 0.5 €/kg, which is attributable to the low electricity cost in these regions.

When allowing for SMR-CCS in the Iberian Peninsula (Scenario 2c), ES1 is still the only sub-region with investments in hydrogen-fueled gas turbines. This region is also the only one in the Iberian Peninsula with an industrial hydrogen demand. The investment is, however, small and only supplies 3% of the produced hydrogen.

When the investment cost of hydrogen gas turbines is increased, the trend is similar to that seen for the other regions investigated, i.e., a shift from CCGTs to OCGTs. This is seen in ES1, where the installed capacity changes from 0.14 GW of OCGT and 0.84 GW of CCGT when the investment cost is low (Scenario 4b) to 0.98 GW of OCGT when the investment cost is high (Scenario 6b).

The regions on the Iberian Peninsula have the lowest electricity costs among the regions investigated. Moreover, as shown in Figs. 9, 10, the cost of hydrogen is low for most of the year. Yet, the use of hydrogen to balance variations in VRE is not particularly competitive, unless both the biomass cost is high and cheap hydrogen storage is available. This is explained by the characteristics of the fluctuations in generation from VRE, which are different for wind and solar power. Fig. 11 compares the solar power-dominated electricity supply system in Spain with the high wind-share system in the UK. Time-shifting of electricity generation via batteries is a competitive solution in the high solar-share energy system, since the variations are of short duration and occur with a high frequency (diurnal), whereas time-shifting via hydrogen is more suitable for the high wind-share region in which the

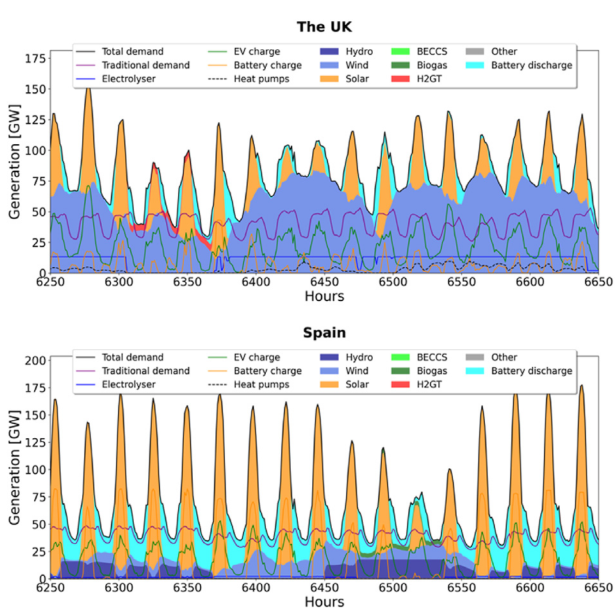

Fig. 11 – Characteristics of energy systems based either on wind (the UK) or solar (Spain) power.

fluctuations are fewer, irregular, and of longer duration. This difference is underlined by the difference in the use of batteries for time-shifting generation, where 23.4% of all the electricity in Spain passes through a battery, whereas the corresponding value for the UK is 8.5%.

Thus, a low cost for hydrogen production is not sufficient to make hydrogen gas turbines a competitive technology, as the value of time-shifting of generation via hydrogen is to a great extent dependent upon the overall electricity system composition, i.e., the dynamics of system. A low cost for hydrogen production, due to a low cost for electricity, is however likely to increase the competitiveness of other potential hydrogen uses, such as hydrogen-based industries.

Discussion

The present work shows that hydrogen-fueled gas turbines have a role to play in all the electricity systems studied, and that the willingness-to-pay for hydrogen in gas turbines, i.e., the marginal cost of hydrogen when used in gas turbines, does in some regions and scenarios approach 5 €/kg_{H2}. However, as the model includes numerous assumptions on e.g., future technology costs and electricity and hydrogen demands, the absolute number on the willingness-to-pay should be taken with some caution. Instead, an alternative description of the willingness-to-pay is suggested. As the average cost of hydrogen is slightly above 1 €/kg_{H2} for most regions, the willingness-to-pay can be described as 4.5–5 times the average hydrogen cost, making it a more general result.

In this work, it has been assumed that BECCS technologies cannot be used to compensate for fossil CO_2 emissions from fossil-fueled power plants. The exclusion of BECCS under the prescribed CO_2 cap and enforcing a zero-emissions electricity system implicitly exclude fossil-fueled technologies, even though no hard limitations are set in the model. Thus, excluding BECCS technologies for power production in this model set-up means that the electricity system will not benefit from the dispatchable power that both fossil-fueled power plants and BECCS technologies could provide. However, it is not evident that BECCS technologies would provide much flexibility to the system as the cost structure is similar to that of nuclear power, which would then imply a base-load alike operation. In addition, it is not likely that negative emissions from BECCS would compensate for fossil emissions from power production as the European Union Taxonomy [45] prescribe zero emissions from power production by the Year 2050. Nonetheless, the potential use of BECCS to compensate emissions in other sectors would supply electricity to the system, as well as increase the demand for biomass, and thereby likely increase the cost of biomass. An increased biomass cost might reduce the use of biomethane produced from solid biomass in hydrogen-fueled gas turbines and, thus, increase the running cost of hydrogen gas turbines because more hydrogen would be required. However, biomethane can also be produced from other processes, e.g., anaerobic digestion, a biomethane route not included in this work. Consequently, it is difficult to assess the impact on hydrogen-fueled gas turbines from the assumption of excluding BECCS technologies from the modeling as done in the present work.

Considering biomass, the modeled use of solid biomass, which in addition to being combusted can be used for biomethane production, is in Table 10 compared to the current use of solid biomass, in order to assess the plausibility of the results. The modeled biomass use for electricity production is below current levels in three of the four countries included in Table 10. For Germany, the results are at significantly higher levels than the current levels of biomass used for electricity generation, especially for costs below 80 €/MWh, which would at least call for some redistribution of the biomass resource. Hydrogen gas turbines in Germany are to a large extent fueled by biomethane, so if the current use of biomass could not be exceeded, more hydrogen would be required, and judging from the results obtained in this work, this would increase the cost of electricity in Germany even further. Furthermore, in the model, it is the availability constraint that limits the use of biomass rather than the biomass cost, and thus the willingness-to pay for biomass is higher than 80 €/MWh.

To put the resulting investments in gas turbines into perspective, they are compared with the currently installed capacities in Table 11, with data obtained from the Chalmers Energy Infrastructure databases [47]. It is clear that the currently installed capacity of CCGTs exceeds the model results in all countries except Sweden, and there is a clear trend in favor of OCGTs, as the model results exceed the

Table 10 – A summary of the modeled and historical uses of solid biomass [TWh] in four countries included in the modeling.

	Modeled use of solid biomass [TWh]			Total use of solid biomass for electricity in 2019 [46]	Total use of solid biomass in 2019 [46]
Biomass cost [€/MWh]	40	60	80		
Biomass availability	20%	3%	1%		
United Kingdom	46	23	12	53	94
Germany	45	51	23	17	151
Sweden	6	5	4	18[a]	111
Spain	7	6	3	12	64

[a] Share of biomass used to produce electricity in combined heat and power plants [54].

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Table 11 – Modeled investments in gas turbines, including both hydrogen and biomethane-only fueled gas turbines in Scenario 3b, as compared with the currently installed capacities. The values within parenthesis for the modeled results are the corresponding share of the total installed capacity per country.

	Modeled results [GW] (share of total capacity)		Current installed capacity [GW]	
Country	CCGT	OCGT	CCGT	OCGT
UK	19.8 (7.4%)	11.5 (4.3%)	31.2	2.9
DE	12.3 (5.2%)	4.4 (1.9)	17	3.1
SE	1.5 (4.4%)	1.1 (3.3%)	0.27	0.09
ES	3.0 (1.4%)	1.6 (0.7%)	26.8	0.42
Total	36.5	20.1	75.3	6.5

currently installed capacities in all the countries analyzed. However, it should be possible to supply the gas turbine capacities obtained, including both CCGT and OCGT, since the resulting demand is clearly lower than the currently installed capacity.

The large investments in hydrogen gas turbines in the UK1 region may reflect the excluded transmission capacity to continental Europe, which is approximately 4 GW. Including this transmission capacity would likely reduce the installed capacity of hydrogen gas turbines in UK1, although as import requires that the exporting country has an excess of electricity at a lower cost, and at the right time, transmission will obviously not replace the corresponding capacity of hydrogen gas turbines completely. Similarly, the transmission capacity between Spain and France is also excluded, although in this case, the transmission capacity of 2.6 GW is significantly larger than the hydrogen gas turbine investments seen in the Iberian Peninsula, and thus the model set-up may have an even stronger effect on the results in this region. However, due to the unprecedented transformation required to comply with climate targets, it is not unlikely that also France will experience a shortage of capacity at the same time as Spain. Furthermore, southern Spain has the possibility to produce large amounts of cheap electricity, and thus low-cost hydrogen, which could give Spain the potential to act as a balancing hub in southern Europe in a manner similar to how hydropower in the Nordic region helps to balance electricity systems far beyond the Nordic countries.

In this work, it has been assumed that gas turbines have the technical ability to mix hydrogen and biomethane across the full range (from 0% to the upper mixing limit of hydrogen set in the investment decision, which in most scenarios is 100%). The gas turbine provider Kawasaki claims that their gas turbines can handle such fuel flexibility today [48], whereas other gas turbine suppliers, such as Siemens Energy, currently only commit to mixing rates of up to 75 vol.-% [49]. In the present study, flexible mixing has proven to be an important advantage for gas turbines, although because the extent to which all gas turbines can handle such a wide range of fuel flexibility is unknown, further work is required. This includes both a better understanding of the gas turbine's combustion process for different hydrogen mixtures and a clear picture of how potential limitations on fuel flexibility impact the competitiveness as a balancing technology in the electricity system. Furthermore, in the current work, there are no investments in fuel cells unless the option to invest in hydrogen gas turbines is removed. This is partly due to the assumed costs for fuel cells, making hydrogen gas turbines more competitive in many use cases in the modeled scenarios, and partly due to the assumption that fuel cells are limited to being fueled entirely by hydrogen, without any flexible fuel mixing with biomethane. To be able to assess fully the competition between fuel cells and hydrogen-fueled gas turbines, a more detailed study is required.

Conclusions

An energy systems model is applied to investigate how gas turbines with capability for flexible fuel mixing of hydrogen and biomethane are operated in future zero-carbon emissions electricity systems in different parts of Europe. The model also provides an estimate of the willingness-to-pay for hydrogen when used in hydrogen-fueled gas turbines with an endogenously calculated cost of hydrogen.

One of the main conclusions from this work is that, even though hydrogen-fueled gas turbines are installed in all the different energy systems investigated, the strongest competitiveness for hydrogen-fueled gas turbines (together with hydrogen storage) is found in electricity systems that have high shares of wind power. The reason for this is linked to the characteristics of the variations in electricity generation from wind power, where fluctuations can be described as fewer, more-irregular, and longer in duration, as compared to variations in generation from solar PV, which are shorter in time and occur at a high frequency (diurnal), and for which batteries are a more suitable storage technology.

It can also be concluded that flexible mixing of hydrogen with biomethane can be an important feature, as it allows the installed gas turbines to operate also when the marginal hydrogen cost is too high to generate a gross margin, and thus to recover the annualized investment cost. Fuel flexibility can, therefore, strengthen the competitiveness of hydrogen gas turbines as a balancing technology in future electricity systems, given that there exists a complementary net-zero CO_2 emissions fuel alternative at a reasonable cost.

Under the assumptions given, the endogenously calculated marginal hydrogen cost, which can be considered to be an approximation of the willingness-to-pay for hydrogen use in gas turbines, is about 5 €/kg_{H2}. Yet, significant amounts of hydrogen are produced and used in hydrogen gas turbines at a cost of 3–4 €/kg_{H2}. It should also be highlighted that large amounts of hydrogen are available and used at costs <1 €/kg_{H2}, and that the most important parameters affecting the willingness-to-pay for hydrogen is the biomass cost and the availability of cheap hydrogen storage technologies.

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Finally, it can be concluded that blue hydrogen (i.e., produced through SMR with CCS), which is decoupled from the electricity system, can support the supply of hydrogen, although to a limited extent. In most of the regions evaluated, blue hydrogen could cost-competitively supply 10%–13% of the hydrogen demand, given the assumed costs for CCS technologies and the costs for fuels. However, the solar PV-dominated regions stand out, such that blue hydrogen has a limited impact in Spain. In southern Germany, which apart from being dominated by electricity production from solar PV also has a large industrial demand for hydrogen, blue hydrogen accounts for about 24% of the produced hydrogen.

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.ijhydene.2022.07.075.

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