THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

Hydrogen in the European energy system

- The cost dynamics and the value of time-shifting electricity generation

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Department of Space, Earth, and Environment

CHALMERS UNIVERSITY OF TECHNOLOGY

Gothenburg, Sweden 2022

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Abstract

If the European Union is to become climate-neutral by Year 2050, as envisioned in the European Green Deal, the European energy system must undergo an unprecedented transformation towards eliminating its carbon emissions. For this transition, renewable electricity plays a central role, not only in replacing the current fossil-based electricity generation, but also in promoting the electrification of other sectors, such as transport and industry, sectors which are currently based on fossil fuels. In the European Hydrogen Strategy, hydrogen is considered a key priority for enabling the transition outlined in the European Green Deal. This is because hydrogen can reduce emissions levels across several sectors, including the hard-to-abate sectors, and can act as an energy carrier, reactant, or feedstock. Thus, this work aims to elucidate the dynamics of future energy systems, focusing on how different applications of hydrogen will affect the costs of electricity and hydrogen, and how these demands for hydrogen interact with variations arising from renewable electricity generation.

This work applies a techno-economic optimization model, which includes both the historical electricity demand and new demands from an electrified transport sector and several electrified industrial processes, to evaluate the dynamics of a future European energy system with zero-carbon emissions. The model includes both exogenous (industry and transport) and endogenous (time-shifting of electricity generation) hydrogen demands, to allow evaluation of the impacts of hydrogen demands with different characteristics and the value of shifting electricity generation in time through the use of hydrogen.

The results show that electricity is the main parameter that influences the cost of hydrogen, although cost-optimal dimensioning of the electrolyzer and hydrogen storage capacities also affects the hydrogen cost, as these capacities recurrently limit hydrogen production over the year, and thus set the marginal cost of the hydrogen supply. Another decisive factor is the nature of the hydrogen demand, where a flexible demand can have a considerable impact on the hydrogen cost, reducing it by up to 35%, as compared to a constant demand for hydrogen. Moreover, it is shown that a lower level of flexibility with respect to the hydrogen demand is often sufficient to attain this cost reduction.

We conclude that time-shifting of electricity generation through the use of hydrogen provides a value to the system by reducing the average electricity cost by 2%–7%, and this strategy is primarily competitive in regions with large shares of wind power. The reason for the stronger competitiveness in regions that are dominated by wind power is linked to the characteristics of the variations of the electricity generation patterns. Thus, fluctuations in generation from wind power can be described as fewer, more-irregular, and longer in duration, as compared to variations from solar PV, which are shorter in time and occur at a higher frequency (diurnal), and for which batteries are a more-suitable time-shifting technology. For reconversion of hydrogen back to electricity, gas turbines are shown to be the most-competitive technology, where flexible mixing of hydrogen in biogas increases the competitive edge, as the gas turbine can be used also when the cost of hydrogen is too high to generate a gross margin profit, which is required to recover the investment.

Keywords: Hydrogen, cost, time-shifting, gas turbine, energy systems modeling, system dynamics

List of publications

The thesis is based on the following appended papers, which are referred to in the text by their assigned Roman numerals:

I. S. Öberg, M. Odenberger and F. Johnsson. "The cost dynamics of hydrogen – a techno-economic study". Submitted.

II. S. Öberg, M. Odenberger and F. Johnsson. "The value of flexible fuel mixing in hydrogen-fueled gas turbines – a techno-economic study". Submitted to *International Journal of Hydrogen Energy*.

III. S. Öberg, M. Odenberger and F. Johnsson. "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems". *International Journal of Hydrogen Energy*, vol. 47, no. 1, pp. 624-644, 2022, doi: 10.1016/j.ijhydene.2021.10.035.

Simon Öberg is the principal author of **Papers I–III** and performed the modeling and analysis for all three papers. Professor Filip Johnsson contributed with discussions and editing to **Papers I–III**, and Mikael Odenberger contributed to the method development in **Papers I–III**, as well as with editing and discussions for all three papers.

Other publications by the author, not included in the thesis:

A. V. Walter, L. Göransson, M. Taljegård, S. Öberg and M. Odenberger (2022). “Hydrogen production in an expanding electricity system – providing flexibility or competing for resources?”. To be submitted.

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Simon Öberg,
Gothenburg, May 2022

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1. Introduction

In 2019, the European Commission presented the European Green Deal [1], which aims to make the European Union climate-neutral by Year 2050, and thereby increasing the likelihood of limiting global warming to below 2°C, relative to pre-industrial levels, as outlined in the Paris Agreement [2]. Following the European Green Deal, the European Commission in 2020 launched the European Hydrogen Strategy [3], which nominates hydrogen as a key priority towards achieving the clean energy transition outlined in the European Green Deal.

Following these political decisions, and the fact that this thesis is written in Year 2022, the given timeframe to achieve a climate-neutral continent is 28 years, with all sectors included. If the scope is narrowed to the electricity sector, the timeframe is probably even shorter because the electricity system is seen as easier to decarbonize than other sectors such as transport and industry. In addition, the electricity sector is likely to be the foundation upon which the entire future energy system will be established, assuming widespread electrification of transport and industry. Thus, it can be argued that there is little time for ground-breaking innovations, and that already-existing technologies constitute the available options for the transition, notwithstanding that these technologies can be developed further, and in some cases, take on new roles.

In a future energy system, based on electricity from variable renewable technologies, such as solar and wind power, and with new loads from electrified sectors that are currently supplied by fossil energy, new dynamics will arise within the system. For such a system that is constrained to have zero carbon emissions, it is understandable that hydrogen is regarded as promising based on its potential to reduce emissions across several sectors, including also hard-to-abate sectors, and to act as an energy carrier, reactant, or feedstock [4]. Furthermore, as hydrogen can be stored, it provides additional flexibility to the system, such that hydrogen production does not have to coincide with the temporal demand for hydrogen when hydrogen storage is available. However, this additional flexibility adds complexity to the system, and this needs to be understood and defined in order to support future decision-making processes.

1.1 Aims and scope

The overall aims of this thesis are to elucidate the dynamics of future energy systems, focusing on how different hydrogen applications will affect the costs for electricity and hydrogen, and to understand how these hydrogen demands interact with the variations inherent to variable renewable electricity (VRE) generation. One application that is investigated in detail is the use of hydrogen for time-shifting electricity generation in order to balance variations that arise in the future energy systems described above. These overall aims are addressed in the following research questions:

I. What are the main parameters setting the cost of supplying hydrogen?

II. What characterizes an energy system in which time-shifting of electricity generation *via* hydrogen is cost-competitive?

III. How will hydrogen-fueled gas turbines operate in future energy systems, considering the number of full-load hours, number of start-stop cycles, and fuel-mixing?

IV. When in time will time-shifting of electricity generation *via* hydrogen become a competitive solution to balance electricity systems?

These four questions form the basis for **Papers I–III**, appended to this thesis. **Paper I** investigates how different hydrogen applications influence the costs for electricity and hydrogen in four different

European regions with different VRE resources. For the same regions, **Paper II** studies the operation of hydrogen-fueled gas turbines with flexible mixing of hydrogen in biogas, where an estimation is made of the willingness-to-pay for hydrogen in this application, i.e., the acceptable cost for hydrogen to be used in hydrogen-fueled gas turbines. In **Paper III**, the competitiveness of hydrogen-fueled gas turbines is evaluated for the transition of the energy system, indicating the time-point at which hydrogen-fueled gas turbines could become competitive in the European context.

1.2 Contributions of the thesis

The system dynamics considered in this thesis refers to the impacts that different types of hydrogen demands have on the system, considering mainly the effects on the costs for electricity and hydrogen, but also the operation of electrolyzers, hydrogen storage and dispatchable technologies, such as gas turbines. **Paper I** investigates, among other things, how different levels of flexibility in industrial hydrogen demand affect the variations in electricity and hydrogen costs, and furthermore describes in detail those aspects that set the cost of hydrogen in the different time-steps. **Paper II** focuses on the parameters that influence the operation of hydrogen-fueled gas turbines for time-shifting electricity generation, where for example, the cost and availability of biomass and availability of low-cost hydrogen storage technologies are evaluated. The operation of gas turbines, which represent a conventional technology, albeit with a requirement for further development considering the combustion of hydrogen, is analyzed in **Papers I–III**. It is found that the operation of gas turbines deviates significantly from their historical operation, especially for the combined cycle configuration, which means that the gas turbine technology is taking on a new role in the future energy systems modeled in this work.

2. Background and related work

Energy systems modeling studies that include hydrogen production and different types of hydrogen applications are plentiful in the literature. Yet, studies focusing specifically on the cost dynamics of hydrogen in energy systems and that include several different sectors are not found in the literature. Even though the combustion of hydrogen in gas turbines has been studied extensively, there are no published papers covering the operation of hydrogen-fueled gas turbines in complete energy systems. Studies reported in the literature that deal with the cost of hydrogen and the use of hydrogen in gas turbines are presented in the following sections.

2.1 The cost of hydrogen

A common approach used in the literature to calculate the cost of electrolytic hydrogen is to use the levelized cost of electricity (LCOE) from wind or solar power, together with an assumed cost and capacity factor for the electrolyzer. This approach has been used by Longden et al. [5], who conclude that hydrogen can be produced at a cost of 1.76–2.37 $/kg$_{H2}$ from solar PV in Year 2030, and 2.04–2.44 $/kg$_{H2}$ from wind power, where the ranges reflect the assumed electrolyzer investment cost. For these results, capacity factors of 30% and 45% are assumed for solar PV and wind, respectively. Similar results have been obtained by Bartels et al. [6] and Genk et al. [7], using the same approach. This method of using LCOE and a capacity factor for the electrolyzer may have value when evaluating the impact of changes in cost or capacity factor for the included technologies. However, the method has limited ability to estimate accurately the real cost of hydrogen, since it does not take into account the dynamics within the system, whereby a time-dependent hydrogen demand is supplied by intermittent electricity generation. From the previous results [5-7], it may appear that hydrogen is always available at a fixed cost, independently of when and how much hydrogen is required, which is clearly not the case in an integrated energy system.

Other studies in the literature have considered the cost of hydrogen when applying comprehensive energy systems models that include several sectors in addition to the electricity system. Vom Scheidt et al. [8] have assessed the cost of hydrogen in a Year 2030 scenario with a high spatial resolution in Germany, which included a detailed representation of the hydrogen supply chain. In this case, hydrogen costs in the range of 2.5–5.5 €/kg$_{H2}$ are attained, depending on the distribution cost. However, as the hydrogen cost is only presented as an annual average cost, it does not disclose any information about the variations or dynamics of the hydrogen cost within the modeled energy system.

Another method to assess the cost of hydrogen has been suggested by Lux et al. [9], who constructed a supply curve for electrolytic hydrogen in the European energy system. They estimated how much hydrogen would be supplied for a set of fixed hydrogen prices, while minimizing the total system cost. Thus, in order to reduce the total system cost, the model can choose to produce and sell hydrogen at an exogenously defined price. By varying the hydrogen price, the model generates a curve that describes the cost-optimal supply of hydrogen at different hydrogen prices. The results show that more than 1,500 TWh of hydrogen could be supplied at 3.7 €/kg$_{H2}$, a volume that is in line with the future hydrogen demand envisioned by the European Commission [10][11]. However, as the hydrogen demand has neither a time-resolved demand profile nor a geographic distribution, the model minimizes the total system cost by producing large amounts of hydrogen in regions with good conditions for low-cost electricity, mainly in regions with good wind resources, during relatively short periods (1,600 to 2,500 full-load hours for electrolyzers). As the model only considers the revenue accrued from selling hydrogen, and not the extent to which the production of hydrogen matches the temporal and spatial demands for hydrogen, the analysis is limited in terms of the dynamics of supply and demand being disregarded.

2.2 Hydrogen-fueled gas turbines

The current interest in hydrogen-fueled gas turbines is driven by political decisions taken by the European Union (EU). The first decision was announced in 2019 by the European Investment Bank, which stated in their climate strategy that they will no longer grant funding to power generation projects that generate emissions exceeding 250 gCO_2/kWh_{el} [12], a limit which would disqualify even combined cycle gas turbines (CCGT) with specific emissions of 330 gCO_2/kWh_{el}, assuming an efficiency of 60%. Furthermore, the EU Taxonomy [13], published in the middle of Year 2020 and updated in Year 2022 with particular regulations regarding the use of natural gas, mandates a gradually declining threshold for emissions from power and heat production fueled with natural gas, starting at 100 gCO_2/kWh and decreasing at 5-year intervals to reach zero emissions in Year 2050. Thus, for future investments to be considered sustainable, emissions must be reduced considerably. In addition, it must be technically feasible to reach net-zero emissions by Year 2050, which could be achieved with hydrogen gradually replacing natural gas in gas turbines.

Gas turbines are well-known for their operational flexibility, and as described by Cambell et al. [14] and Huth and Heilos [15], gas turbines are also known for their fuel flexibility. The fuel flexibility ranges from the use of pure methane to by-product gases from refineries (containing mostly propane and butane), gases containing large shares of inert gases (N_2, CO_2), syngas containing 25%–50% H_2 and 35%–65% CO, and liquid fuels such as bio-ethanol [16] and bio-diesel [17]. In terms of the combustion of hydrogen, the effect on flame stability has been studied by several groups, underlining the importance of this factor. Liu et al. [18] have concluded that hydrogen-enriched methane significantly influences the flashback limits, and An et al. [19] have concluded that flame blow-out is a risk during the transition between flame shapes. Furthermore, Li et al. [20] have investigated the flame stability of hydrogen-enriched syngas, finding that flame stability is reduced at 50 vol.-% hydrogen.

Considering instead the impact on power output during hydrogen blend-in, Ciani et al. [21] have shown that 50 vol.-% hydrogen can be mixed with methane without derating the power output. In a separate study, Bothien et al. [22] confirmed these results in a test facility, and concluded that stable combustion can be attained with up to 70 vol.-% hydrogen when using staged combustion, and at hydrogen levels >70 vol.-% only minor reductions in power output are expected. Magnusson et al. [23] obtained similar results in a full-engine test with 60 vol.-% hydrogen, maintaining stable combustion and nitrogen oxide (NOx) emissions of <25 parts per million (ppm). In addition, according to a report issued by a gas turbine manufacturer association [24], mixing ratios of 60 vol.-% are currently possible in most of their gas turbines. Some suppliers, e.g., Siemens [25] and Kawasaki [26], are claiming higher mixing ratios, with Kawasaki also claiming full fuel flexibility, i.e., the ability to mix hydrogen and methane across the full range of 0%–100% hydrogen.

In energy systems modeling, the concept of using hydrogen for time-shifting of electricity generation, i.e., through the application of electrolyzers, hydrogen storage, and reconversion technologies to convert hydrogen back to electricity, has been investigated in numerous studies in the literature. For instance, Ferrero et al. [27], Fang et al. [28], and Ishaq et al. [29] have studied the cost of time-shifting using hydrogen, although they only allow for the use of fuel cells (FC) as the reconversion technology. Pathways for the reconversion of hydrogen involving technologies other than FCs have been studied by Welder et al. [30]. The results favor CCGT over the options of open cycle gas turbines (OCGT), FCs, and gas engines. However, as the reconversion technologies were evaluated in separate model runs, the work by Welder et al. [30] does not capture how the different reconversion technologies could complement each other in the energy system modeled, considering the different technical and economic characteristics of those technologies. Reconversion of hydrogen in CCGTs has also been included in the work conducted by Jülch et al. [31], who studied the levelized cost of storage (LCOS), and in addition to the reconversion of pure hydrogen in CCGTs, they evaluated synthetic natural gas (SNG) use in CCGTs, batteries, compressed air energy storage, and pumped-hydro energy storage. The results showed that CCGTs fueled with hydrogen are associated with a lower LCOS than CCGTs fueled with

SNG. However, similar to the work of Welder et al., Jülch and colleagues also modeled the different options in separate model runs, so the interactions between the different technologies were not captured. Finally, Cloete at al. [32] have investigated the utilization factors of different technologies in a future German energy system, in which hydrogen is used both for industrial processes and as energy storage within the electricity system. Their work included hydrogen-fueled gas turbines, although, similar to both the Welder and Jülch studies, no analyses of either the installed capacity or the operation of these hydrogen-fueled gas turbines were presented.

3. Methodology

The models used in **Papers I–III** are linear techno-economic optimization models that minimize the total cost of the energy systems modeled for the European continent, including both the investment and operational costs of the technologies installed. In the models, investments are made in generation technologies, electricity transmission technologies, and energy storage technologies. The models include both the historical electricity demand and new demands from an electrified transport sector and a number of electrified industrial processes, wherein electrification is to some extent indirect, i.e., *via* hydrogen. In addition to the electricity demands, the model also include a district heating demand.

In **Papers I** and **II**, a greenfield model is applied for zero-emissions energy systems in compliance with the European aims for the Year 2050, whereby the greenfield designation requires that all current power plants are removed and that all investments are instead made independently of the historical capacity mix. This applies to all technologies, with the exceptions of hydro-power and the existing transmission capacity, which are assumed to remain in the system. This model was originally formulated by Göransson et al. [33], and further developed by Johansson et al. [34] and Ullmark et al [35]; and a full mathematical description can be found in **Paper II**.

In **Paper III**, a model that transitions from the current energy system into a future energy system is applied, where the existing capacity is phased out as the assumed technical lifetime is reached when the model progresses in time, and this capacity is replaced with technologies that comply with specified constraints, e.g., an emissions trajectory for CO_2. The existing capacity is retrieved from the Chalmers Energy Infrastructure databases [36], which have almost full coverage of power plants with a rated electric capacity of >10 MW. This model is divided into two parts: the long-term investment model ELIN; and the operational dispatch model EPOD (Figure 1). The two models are connected such that the investments found in ELIN, including the installed capacity, fuel prices and transmission capacity, are used in the EPOD model to identify the least-cost hourly dispatch of the system. However, since the ELIN model spans four different years (2020, 2030, 2040, and 2050), it cannot have a full hourly representation of time, due to computational limitations, so a method that uses representative days [37] is employed. The impact of this method is discussed in Section 5. The ELIN model was originally developed by Odenberger et al. [38], and further developed by Göransson et al. [39]. The EPOD model was originally developed by Unger et al. [40], and further developed by Göransson et al. [39] and Goop et al. [41].

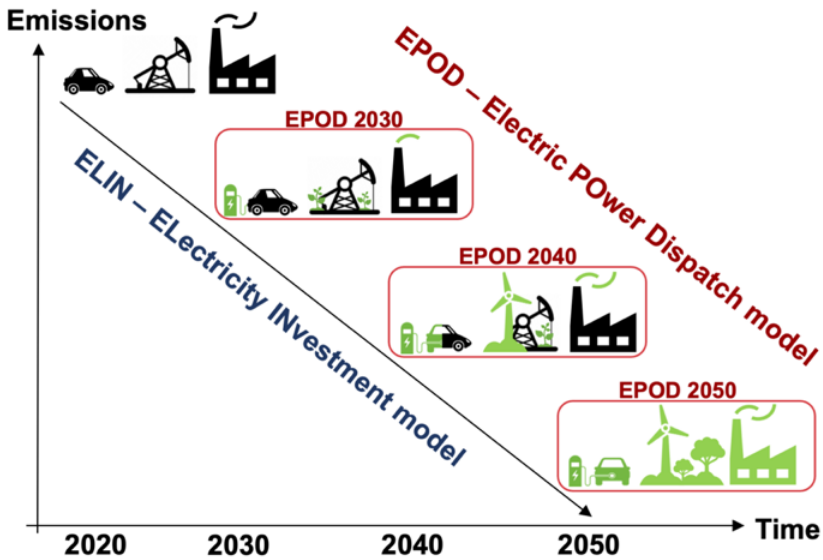

Figure 1: Visualization of the ELIN-EPOD model, which models the transitioning of an energy system.

Three different categories of electricity demands are included in the models described above. This is depicted in the left-most box in Figure 2, where "Household" represents the historical demand, and "Industry" and "Transport" represent the new demands added to the historical demand as the assumed electrification of these sectors progresses. The historical demand is based on annual data from Eurostat [42], with the data subjected to hourly demand profiles retrieved from the European Network of Transmission System Operators for Electricity, ENTSO-E [43]. The electricity demand for transport is taken from the work of Taljegård et al. [44], and the assumptions regarding electrification of industrial processes, which include a significant fraction of indirect electrification *via* hydrogen, are described in detail in **Paper I**. A summary of how the different demand categories relate to each other in terms of size is shown in Figure 3 for the United Kingdom (UK), Germany (DE), Spain (ES), and Sweden (SE). The boxes in the middle column in Figure 2 display the parameters in the model that are varied throughout the modeling, and the right-most box displays an off-grid energy system that is operated in island-mode, as modeled in **Paper I**.

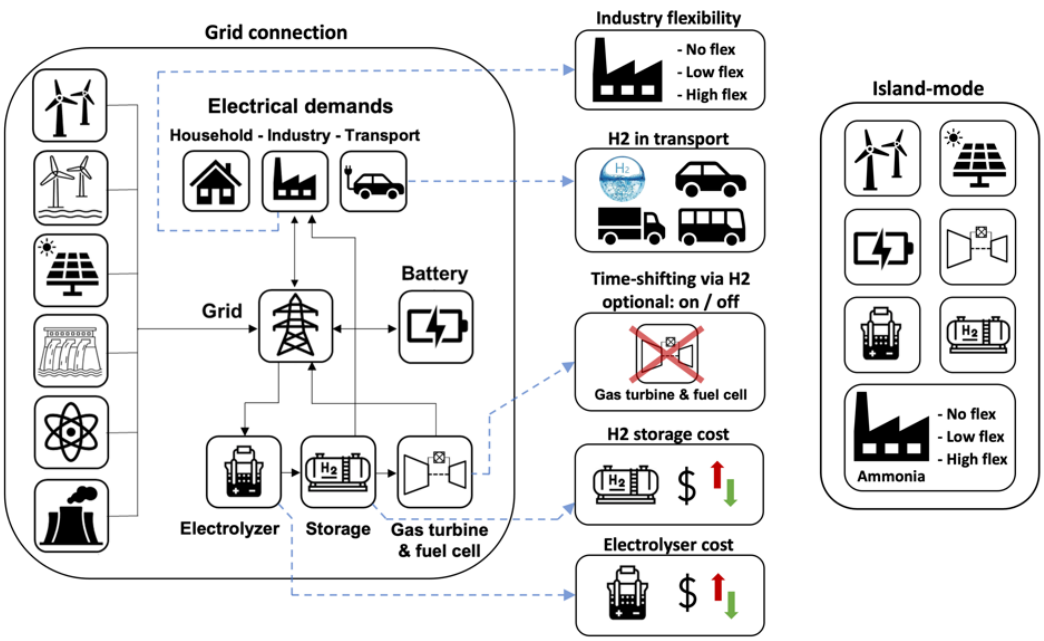

Figure 2: Overview of the energy systems modeled.

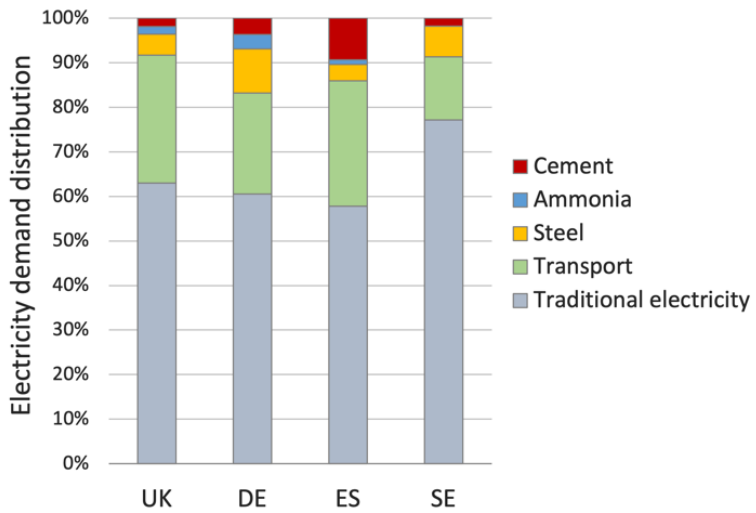

Figure 3: The electricity demand distributions for four countries included in the modeling: the United Kingdom (UK), Germany (DE), Spain (ES), and Sweden (SE).

The generation technologies available in the models, shown in the left-most box in Figure 2, are onshore and offshore wind power, solar photovoltaic (PV), gas turbines fueled with biogas (with or without the option of hydrogen blend-in), nuclear power, and other thermal generation technologies (a full overview of the options can be found in Appendix B in **Paper II**). Investments in hydropower are not allowed, as these resources are considered to be fully exploited, although the existing capacity is included in the regions in which the capacity is located. The district heating demand can be supplied by combined heat and power plants, industrial heat pumps and electric boilers, whereas heat storage is not included. Considering the storage of electricity, batteries and hydrogen storage units are included as options, whereby hydrogen storage units distinguish between salt caverns and lined-rock caverns (LRCs). The difference between the two storage technologies is that salt caverns have a lower specific investment cost than LRCs, although they are less-flexible in terms of injection and withdrawal rates. The European potential for salt caverns is taken from the work of Caglayan et al. [45]. For hydrogen production, electrolyzers are always available for investment, and in some scenarios, steam methane reforming (SMR) with carbon capture and storage (CCS) is also made available. Conversion of hydrogen to electricity can be done in either FCs or hydrogen-fueled gas turbines, which include both OCGTs and CCGTs. Finally, the transmission capacity between regions can also attract investment. Cost data for thermal plants are taken from World Energy Outlook [46], and for renewable technologies and storage technologies, the cost data are taken from the Danish Energy Agency [47].

Investments in hydrogen-fueled gas turbines are available for a set of different upper mixing ratios, as presented in Table 1, for both OCGTs and CCGTs. It should be noted that the mixing ratios are presented as volumetric mixing ratios, and that the corresponding energy shares are significantly different, corresponding to 11%, 23%, 50% and 100%, respectively. In **Papers I** and **II**, the mixing ratios are flexible, i.e., the blend-in of hydrogen (in biogas) is flexible between 0% and the upper mixing ratio, whereas in **Paper III** the mixing ratio is assumed to be fixed. The investment cost for hydrogen-compatible gas turbines is assumed to be higher than that for a gas turbine fueled with methane, since more-complex fuel and safety systems would be required and changes to the burners and combustion chamber equipment might have to be made. It is furthermore assumed that the investment cost will increase with an increasing upper mixing ratio. The assumed investment costs in **Papers I–III** are the "Medium H2GT CAPEX" shown in Table 1, although a sensitivity study of this parameter was performed in **Paper II**, which also included "Low H2GT CAPEX" and "High H2GT CAPEX".

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

Upper mixing ratio 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

In the model, biogas is assumed to be produced through gasification of solid biomass and used thereafter in gas turbines that are dedicated to biogas combustion, or used as a complementary fuel to hydrogen in hydrogen-fueled gas turbines. The solid biomass cost is in the range of 40–80 €/MWh, which yields a biogas cost range of 77–134 €/MWh, which includes both the energy penalty and the investment cost of gasification. The availability of solid biomass is also considered, and the use of biomass is controlled by the upper share of electricity that can be supplied from technologies fueled either with solid biomass or biogas in a modeled region. The three different levels modeled are 20%, 3%, and 1%, which are explained in greater detail in **Paper II**.

The geographic scope of the thesis is the European continent, with regions defined according to the European statistical NUTS regions [48]. These regions are assigned different potentials for wind and solar PV installations, as well as production profiles for these technologies, based on the work conducted by Mattson et al. [49]. In **Papers I** and **II**, four European regions with different potentials for wind and solar power (and inherently, a potential for hydropower) are studied (Figure 4). These four regions consist of six or seven sub-regions, as indicated by the color-coding in Figure 4. The green-colored regions with white diagonal lines are boundary regions that are included to facilitate the import and export of electricity to the regions in focus, which are the regions colored in blue, yellow, orange, and red. All the sub-regions, independently of color, are treated as equal by the model, although the results from the boundary regions are not explicitly analyzed. The sub-regions of the British Isles and Iberian Peninsula are consistent with the statistical NUTS2 regions, whereas most of the sub-regions in central Europe (Figure 4b) and in the Nordic countries (Figure 4c) are composed of a number of clustered NUTS2 regions, as indicated by the color-coding. In **Paper III**, a single but larger region is modeled instead of the four regions displayed in Figure 4, covering the major parts of central Europe, although still with the same methodology regarding the boundary regions. This is described in Section 2 of **Paper III**.

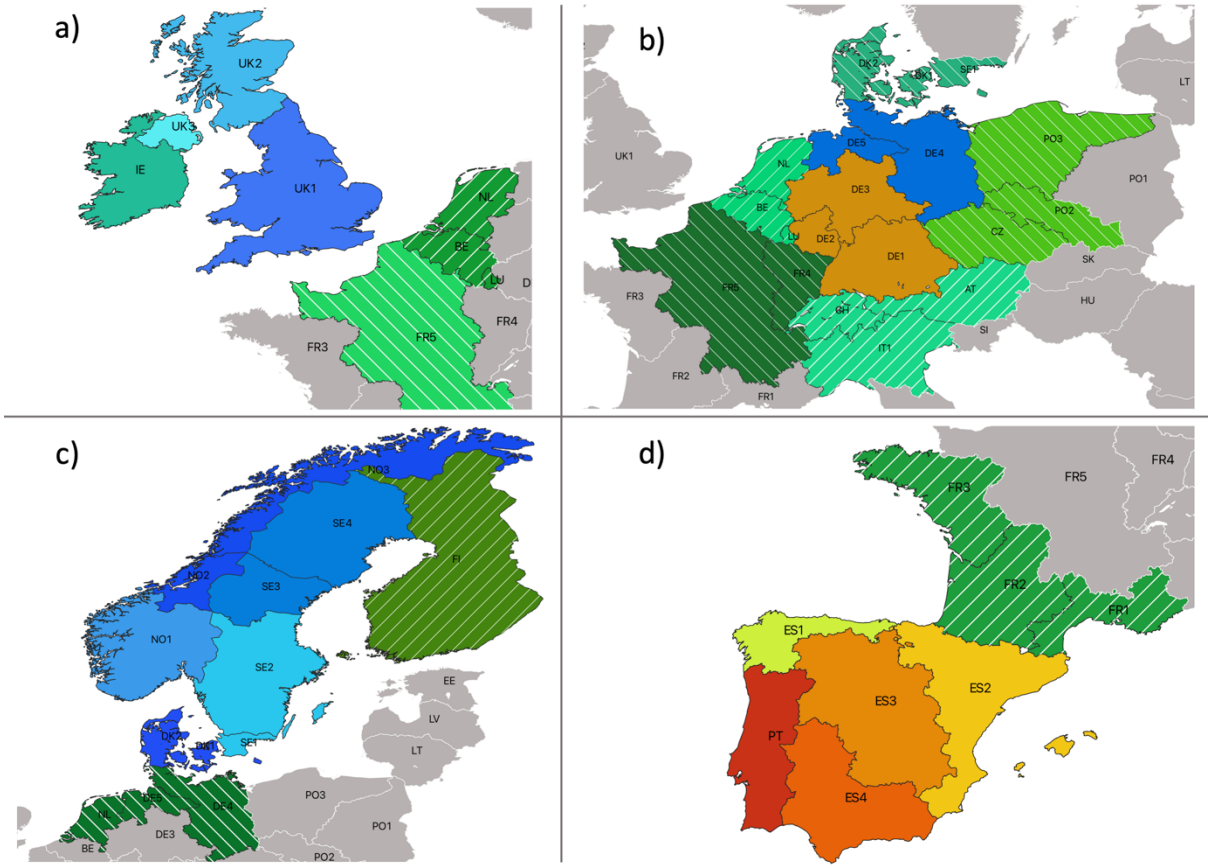

*Figure 4: The four regions applied in the modeling in **Papers I** and **II**: a) British Isles plus European shoreline of the English canal; b) Central Europe; c) the Nordic countries; and d) the Iberian Peninsula. The color-coding indicates the regions modeled, which can be either actual NUTS2 regions or a cluster of NUTS2 regions. Regions indicated in green with diagonal white lines are boundary regions for trade, which are not analyzed.*

4. Results

The results presented in this section are a combination of selected results from the appended **Papers I–III**, along with some additional results. The new results are based on either data that were not presented in the appended papers or new model runs investigating aspects that were identified as future work in the appended papers. The four sub-sections focus on: 1) the dynamics of hydrogen cost; 2) the impacts that time-shifting technologies have on the electricity cost and electricity supply mix; 3) the future operation of gas turbines; and 4) the competitiveness of hydrogen gas turbines in the expected transition of the energy system.

4.1 Dynamics of hydrogen cost

In **Paper I**, the cost of hydrogen was investigated for a number of scenarios entailing hydrogen demands with different characteristics, e.g., different levels of flexibility in industries that use hydrogen or hydrogen utilization in the transport sector. Figure 5 shows that the cost of electricity has a significant impact on the cost of hydrogen, and that cost-optimal investments in electrolyzers and hydrogen storage capacity limit the production levels of hydrogen during different periods, thereby setting the marginal cost of producing an additional unit of hydrogen. This is described in greater detail in **Paper I**, where it is highlighted that the cost-optimal storage capacity clearly limits electrolyzer operation during low-cost electricity hours, especially when there is no flexibility in the industrial process (Figure 5a). A fourth parameter that affects the cost of hydrogen is the flexibility of the hydrogen demand. This is displayed in Figure 5b, where it can be seen that the cost of hydrogen is smoothed, and that the cost level is partly set by the alternative cost of producing the industrial commodity at another time.

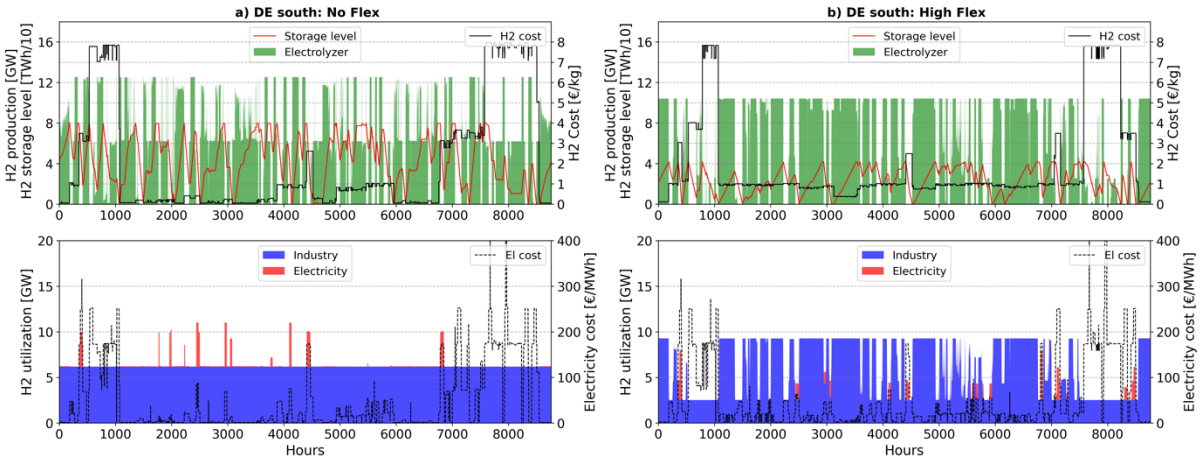

Figure 5: The production and utilization of hydrogen in southern Germany for two scenarios with different levels of flexibility in industry. Figure 2a has no flexibility (Scenario 1a in Paper I), and Figure 2b has high-level flexibility (Scenario 3a in Paper I).

Figure 6 summarizes the impacts of flexibilities in industries and hydrogen utilization in transport on the cost of hydrogen for four European regions with different potentials for VRE. The average cost for hydrogen experiences a clear drop when flexibility is allowed in the industrial processes in all the regions, apart from UK1 (Figure 6a), although there is a limited benefit of having an industry with high-level flexibility (for a definition, see **Paper I**, Section 2.1). Therefore, it can be concluded that a lower level of flexibility of the hydrogen demand may be sufficient to reduce significantly the cost of hydrogen. It should be clarified that this flexibility refers to the production of the produced commodity (e.g., steel or ammonia), and not the implementation of hydrogen storage. Hydrogen storage is included in the model, although it is centralized for each region.

In Figure 6, it is evident that the cost of hydrogen increases considerably when hydrogen is used in the transport sector. The reason for this cost increase is partly an increased demand for hydrogen, which

entails a higher demand for electricity, which is mainly supplied from VRE with a lower capacity factor, since the best VRE sites are already occupied. However, the hydrogen demand of the transport sector differs significantly from that of the industry sector, in that the former involves frequent peaks of high amplitude, as shown in the lower panel of Figure 7. The effect of this type of demand is that the hydrogen is to a greater extent supplied on-demand, which means making less use of hydrogen storage to avoid high-cost electricity hours. For southern Germany, the hydrogen demand is four-times higher when hydrogen is used for transport, as compared to when it is not, while the installed electrolyzer capacity alone is increased by a factor of three. This increases the full-load hours of the electrolyzer by 32%, from 4,492 hours to 5,909 hours, which means that it is operating during more high-cost hours. Furthermore, the hydrogen storage capacity is only 64% larger when hydrogen is used for transport, which indicates that it is too costly to smoothen the hydrogen production curve and avoid high-cost hours when the demand consists of such frequent peaks of considerable amplitude.

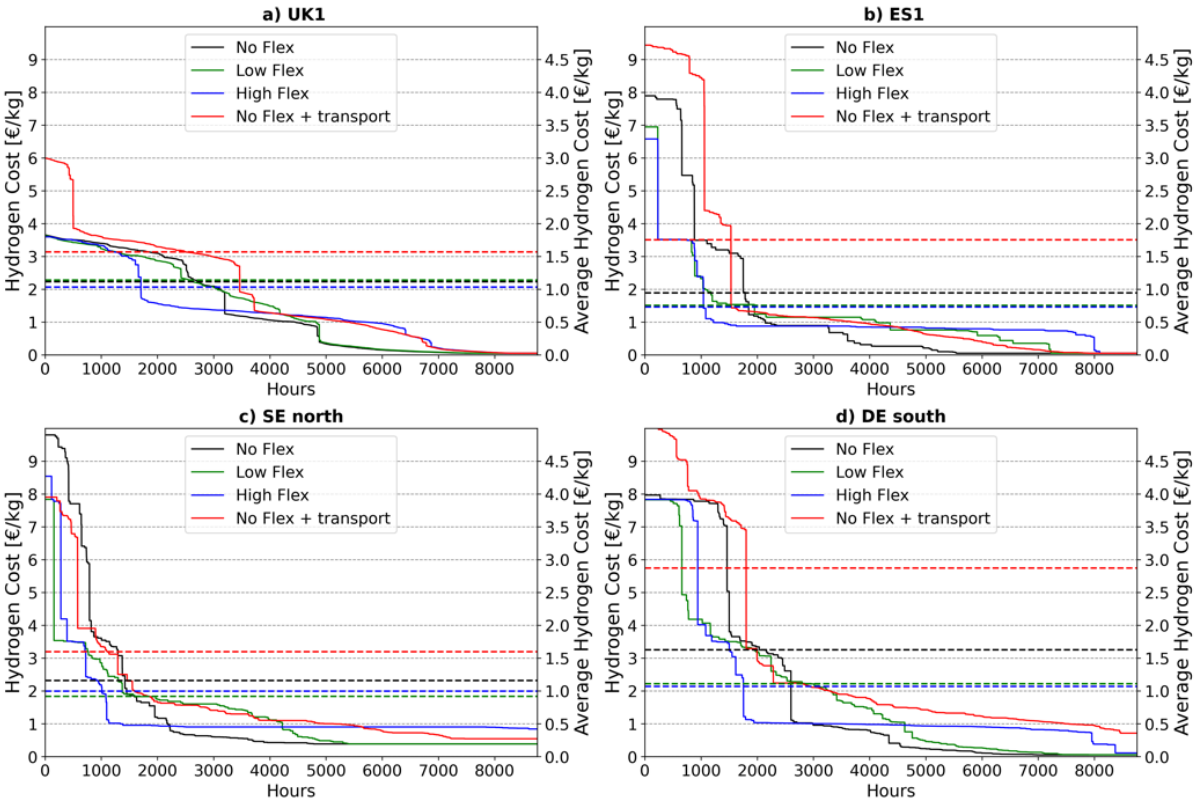

Figure 6: Cost durations of the marginal supply cost of hydrogen, as well as the average annual hydrogen costs for four scenarios with different characteristics of the hydrogen demand for four European regions.

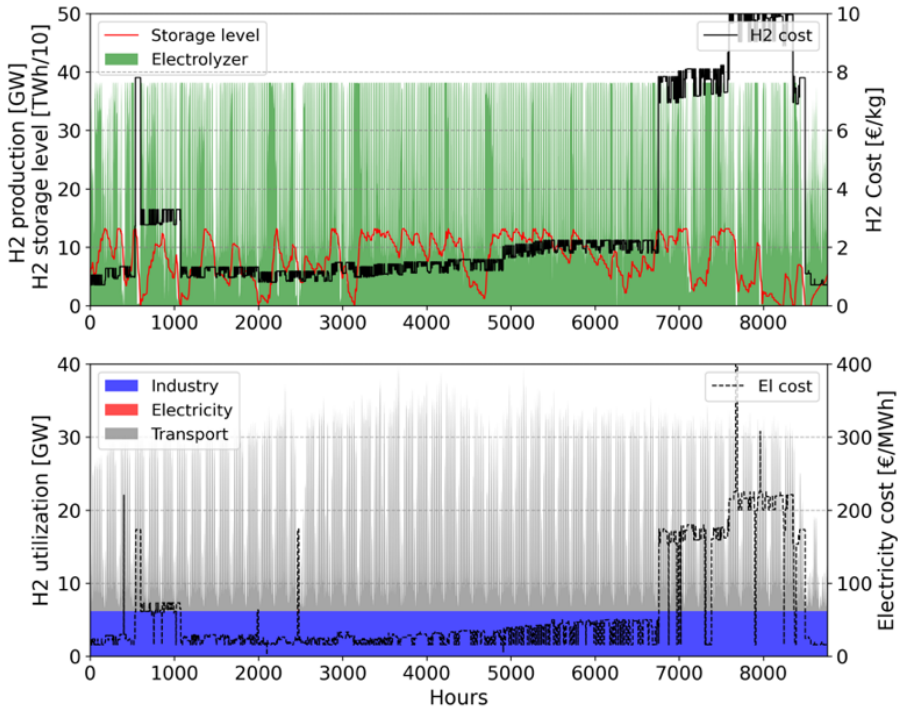

Figure 7: The production and utilization levels of hydrogen in southern Germany when hydrogen is also used in the transport sector.

4.2 Impacts of time-shifting with hydrogen and batteries

In **Paper I**, the value of time-shifting electricity generation through the use of hydrogen was evaluated. It was concluded that for the regions presented, the annual electricity cost decreased by 2%–7% when time-shifting *via* hydrogen was included. For the purpose of this thesis, the evaluation is expanded to include also the effects of time-shifting using batteries. As shown in Figure 8, compared to time-shifting *via* hydrogen, batteries have a stronger impact on the annual average electricity cost and in some regions they account for the entire cost reduction. The value of batteries could perhaps be challenged if the resources required, i.e., different types of metals, become scarce, increasing the cost of batteries. It should also be mentioned that these results are obtained with a constant industrial hydrogen demand over time, and as was shown in the previous section, a flexible industrial demand can have a strong impact on the system, potentially affecting the optimal combination of time-shifting technologies.

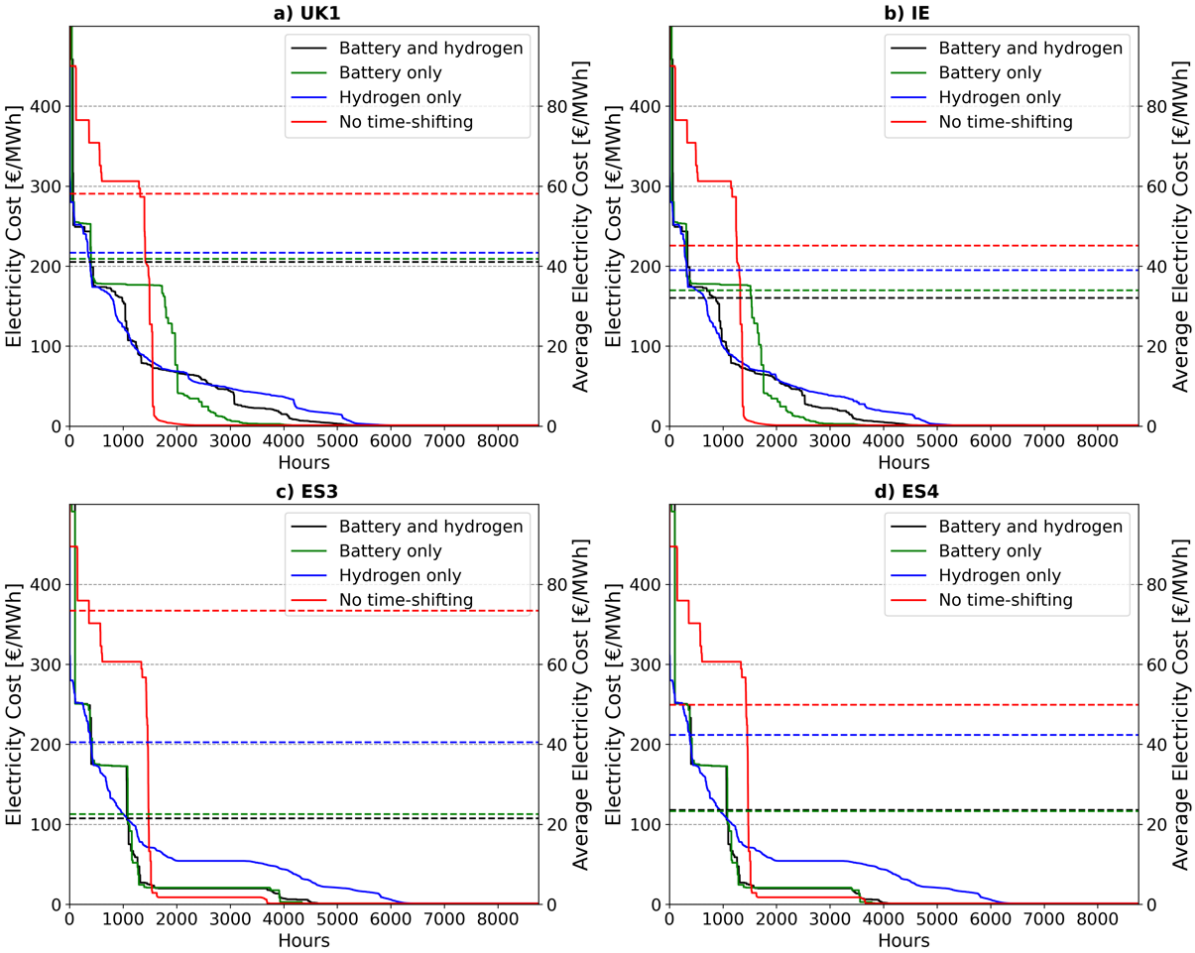

Figure 8: The electricity cost in four modeled regions for four scenarios with different combinations of batteries and hydrogen for time-shifting of electricity generation.

From Figure 8, it can be concluded that the technologies that are available for time-shifting exert impacts on the electricity cost. In **Paper II**, it is concluded that batteries are more-competitive in regions with a large share of electricity production from solar power, and that time-shifting *via* hydrogen is more-competitive in regions with a large share of wind power. This is primarily due to the characteristics of the variations from wind and solar power generation, and less so to the cost of electricity or hydrogen. However, the evaluation conducted for this thesis shows that the energy mix, and thus the investments, are also affected by the available time-shifting technologies. Table 2 shows the following four time-shifting cases: both hydrogen and batteries available for the model to invest in for time shifting; only batteries available; only hydrogen available; and no time shifting available in the modeling. When hydrogen is the only time-shifting technology available, the share of electricity supplied from wind power increases significantly, except in the case of Ireland, which is a country that is supplied almost exclusively by wind power in all the scenarios. When only batteries are available, the main impact is seen in UK1, where the share of electricity from solar power increases quite significantly. Finally, when there are no time-shifting technologies available, two of the regions attain investments in nuclear power, a technology option that rarely appears in the results due to its low-level flexibility and high investment cost.

Table 2: The resulting electricity generation mixes for three different time-shifting cases and without time-shifting for the scenarios presented in Figure 8.

Region	Technology	Battery and hydrogen	Battery only	Hydrogen only	No time-shifting
UK1	Hydro	-	-	-	-
	Wind	66.4%	57.2%	72.1%	58.8%
	Solar	27.0%	38.3%	19.5%	30.1%
	Nuclear				6.5%
	Gas Turbine	0.6%	4.5%		4.6%
	H_2 Gas Turbine	6.0%		8.4%	
IE	Hydro	0.7%	0.5%	0.5%	0.5%
	Wind	98.6%	98.6%	96.1%	98.7%
	Solar				
	Nuclear				
	Gas Turbine	0.7%	0.9%	0.2%	0.8%
	H_2 Gas Turbine			3.2%	
ES3	Hydro	6.5%	7.0%	7.4%	10%
	Wind	6.1%	6.4%	62.1%	49.6%
	Solar	87.2%	86.1%	25.1%	4.2%
	Nuclear				32.7%
	Gas Turbine	0.1%	0.5%		3.5%
	H_2 Gas Turbine	0.1%		5.4%	
ES4	Hydro	5.2%	5.1%	6.6%	9.7%
	Wind	9.1%	8.9%	26.5%	33.5%
	Solar	85.7%	85.9%	55.8%	54.8%
	Nuclear				
	Gas Turbine		0.1%		2.0%
	H_2 Gas Turbine			11.1%	

4.3 Operation of gas turbines in future energy systems

In **Papers I–III**, only the operation of hydrogen-fueled gas turbines was presented and evaluated. In this thesis, the focus is broadened to include gas turbines that are not fueled with hydrogen. Figure 9 displays the operational profiles of CCGTs and OCGTs fueled with biogas, as well as those of CCGTs fueled with a mixture of hydrogen and biogas, for the UK and Spain. The data are taken from Scenario 1a (no flexibility in industry and only electrolytic hydrogen) in **Paper I**, and the results shown in Figure 9, a–c and d–f are an aggregate of all the regions in the UK (UK1, UK2, UK3) and Spain (ES1, ES2, ES3, ES4), respectively. From these results, it can be seen that all types of gas turbines, irrespective of which fuel they are fed, are operated with few consecutive hours of operation. Thus, their role is mainly to balance the electricity supply with regards to variations in demand and generation from VRE. Furthermore, it is the hydrogen-compatible CCGTs that attain the highest number of full-load hours, and the main fuel used in these CCGTs is hydrogen.

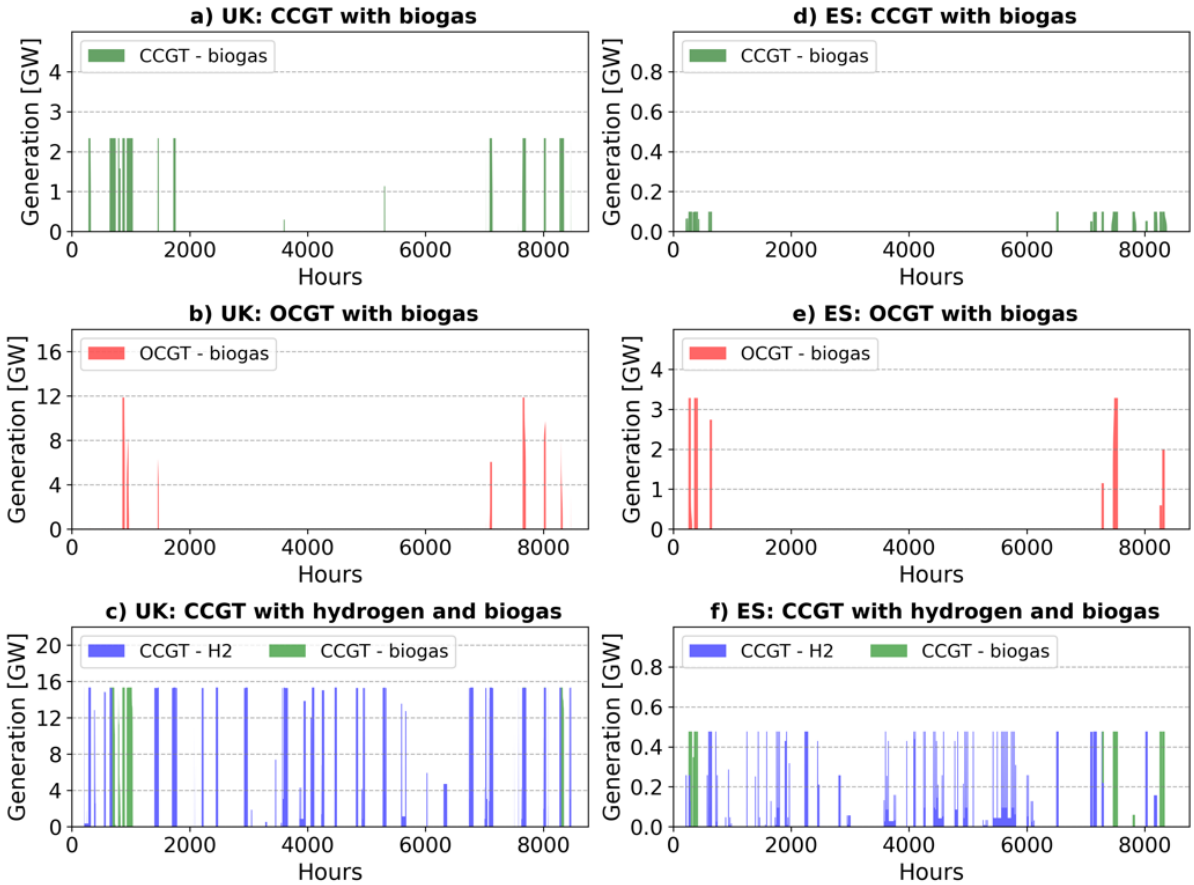

Figure 9: The operation of CCGTs and OCGTs with different fuels in the UK (a–c) and Spain (d–f).

In **Paper II**, the operation of gas turbines with flexible mixes of hydrogen and biogas was evaluated; one of the main findings was the cost of hydrogen when hydrogen was used in hydrogen-fueled gas turbines. This is shown in Figure 10, which is taken from **Paper II**, where the middle and right-most panels display the cost of hydrogen when the gas turbine (CCGT) is in operation. By analyzing the cost of hydrogen when hydrogen is used to fuel the gas turbine, the willingness-to-pay can be estimated. Furthermore, as the complementary fuel to hydrogen is biogas, which is produced from solid biomass, Figure 10 presents a sensitivity study of the influences of the cost of biomass. The impacts of an increased cost for biomass can be seen by comparing Figure 10, a, b and c, indicating that: i) the installed gas turbine capacity is significantly increased when the biomass cost is increased; and ii) the willingness-to-pay for hydrogen is increased from 3 €/kg_{H2} to just below 5 €/kg_{H2} when the biomass cost increases from 40 €/MWh to 80 €/MWh.

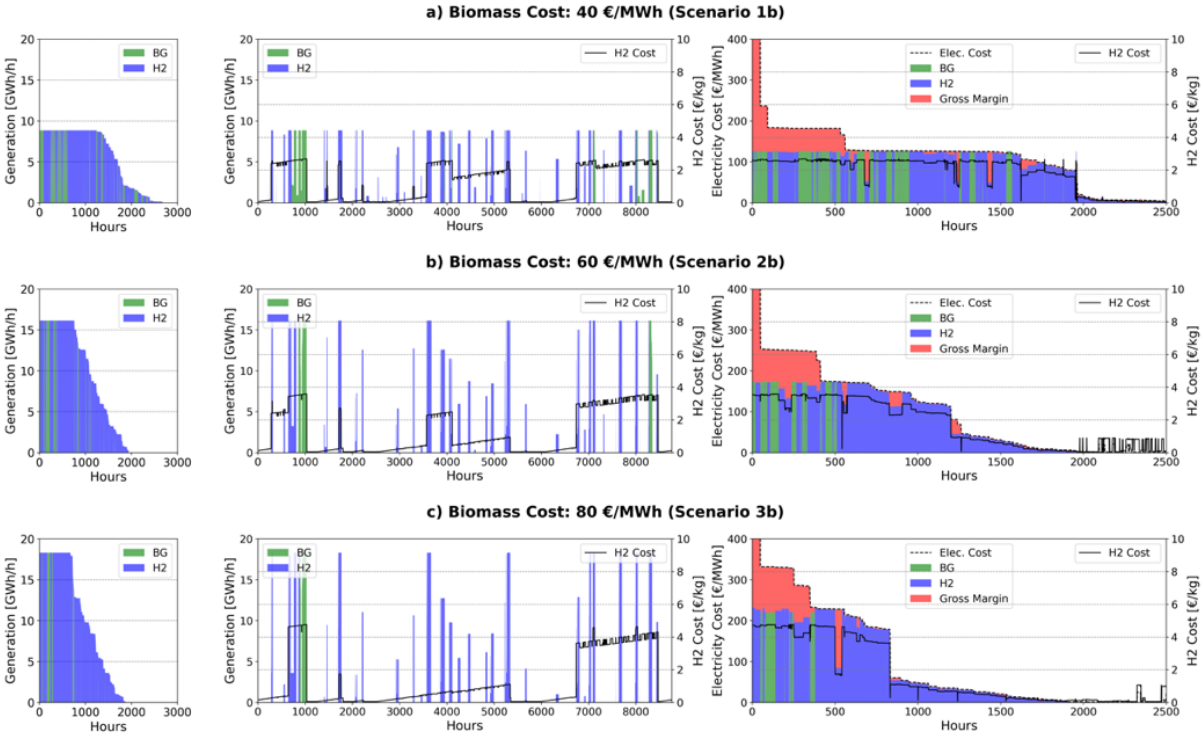

*Figure 10: Operation of CCGTs with 100% hydrogen capability in UK1 for scenarios in which the biomass cost is increased as the biomass availability is decreased (Scenarios 1b, 2b and 3b in **Paper II**). All three scenarios include the use of salt caverns for hydrogen storage.*

4.4 Hydrogen-fueled gas turbines in the electricity system transition

Paper III investigates the competitiveness of hydrogen-fueled gas turbines in the transition from the current energy system to a future zero-emissions system. The results were analyzed for Years 2030, 2040 and 2050 for the countries included in Figure 11 and Figure 12. The main differences between the analyzed years are not only the allowed levels of emissions, which reach zero in Year 2050, but also the assumed declining costs of electrolyzers, hydrogen storage, and VRE technologies.

The results show that the competitiveness (i.e., the investments) of hydrogen-fueled gas turbines is low in Year 2030, and investments are only seen when the natural gas and biomass costs are significantly increased and new investments in transmission capacity are prohibited. The low level of competitiveness is explained by the fact that significant CO_2 emissions are still permitted, such that other peak technologies with less-costly fuels are used to balance the variations that arise from the combination of demand variations and fluctuating production levels from a still relatively low penetration of VRE.

In Year 2040, the competitiveness of hydrogen-fueled gas turbines is higher because investments are made even when new transmission capacity is allowed for and when the costs of alternative fuels are not increased. The investments in hydrogen-fueled gas turbines are, however, dependent upon the assumption regarding the emissions reduction trajectory, where a lower trajectory results in larger investments in hydrogen-fueled gas turbines, as can be seen when comparing Figure 11, a and c with Figure 11, b and d. Furthermore, hydrogen-fueled gas turbines are somewhat more competitive in systems with a larger electricity demand, which can be seen by comparing the results for Ireland (IE) and the United Kingdom (UK) (Figure 11, b and d). The reason for this is that a larger electricity demand requires more generation from VRE, as the emissions allowance is already fully utilized, so more variations occur and these variations are balanced through hydrogen production and reconversion in gas turbines.

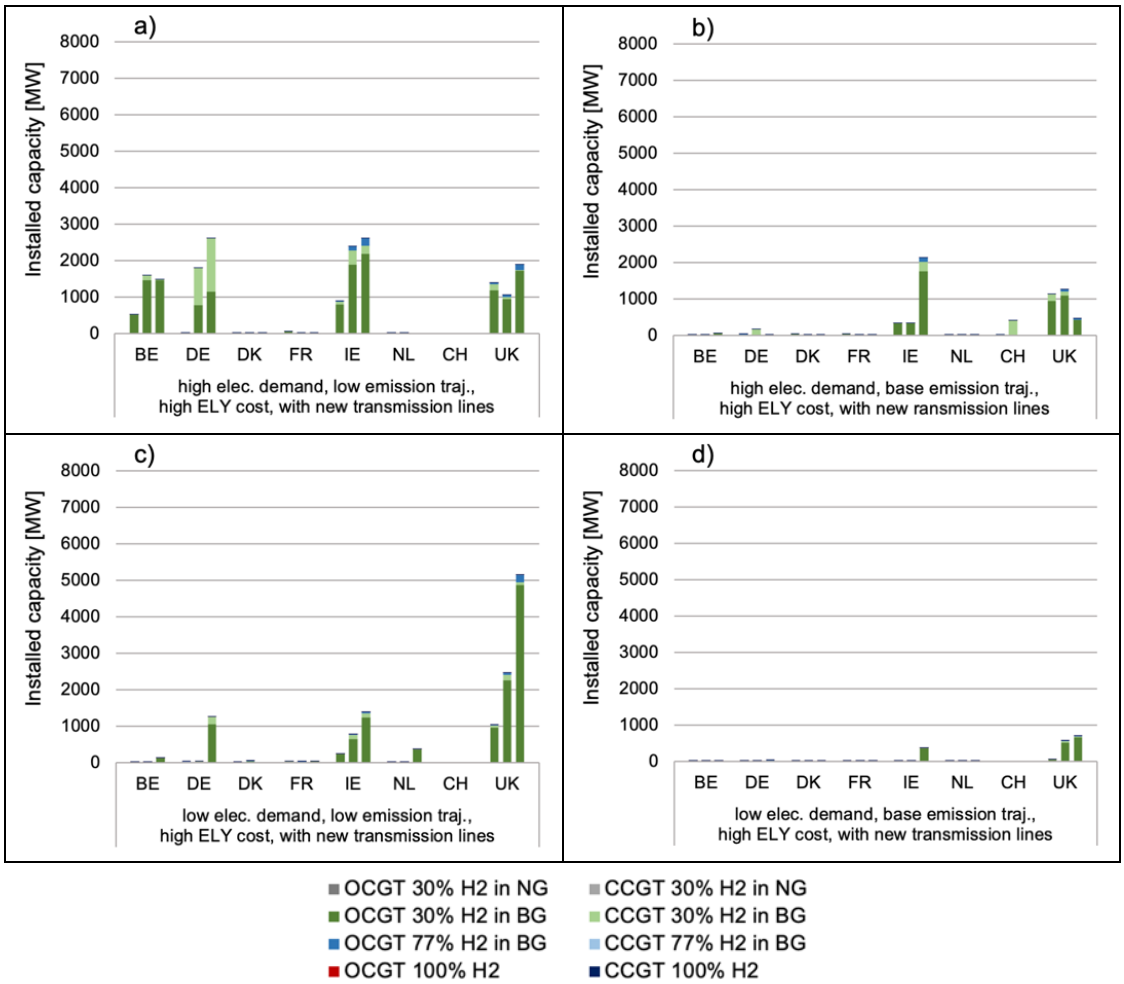

Figure 11: Installed capacity in hydrogen-fueled gas turbines in Year 2040 for four different combinations of electricity demand (high/low) and emissions trajectory (base/low). Panels: a), High electricity demand and low emissions trajectory; b), high electricity demand and base emissions trajectory; c), low electricity demand and low emissions trajectory; and d), low electricity demand and base emissions trajectory. Each country is evaluated for three different levels of assumed fuel costs for natural gas (NG) and biogas (BG), where the middle column represents the baseline cost and the left and right columns represent a cost decrease or increase of 25%, respectively.

In Year 2050, the competitiveness of hydrogen-fueled gas turbines is strong for all combinations of emission trajectories and assumptions regarding the total electricity demand, as shown in Figure 12. The reason for this is an emission cap that mandates a zero-emission system, and thus, disqualifies technologies that are driven by fossil fuels unless they are compensated by negative emissions from bioenergy carbon capture and storage (BECCS) technologies. This, in combination with an increased penetration of VRE (inducing larger variations in the electricity supply) increases the competitiveness of hydrogen-fueled gas turbines. Considering the operational profiles, the results in **Paper III** indicate that hydrogen-compatible OCGTs attain less than 400 full-load hours and CCGTs have up to 3,000 full-load hours. The operation of the CCGTs is, however, very flexible as the majority of the start-stop cycles are less than 20 hours in duration.

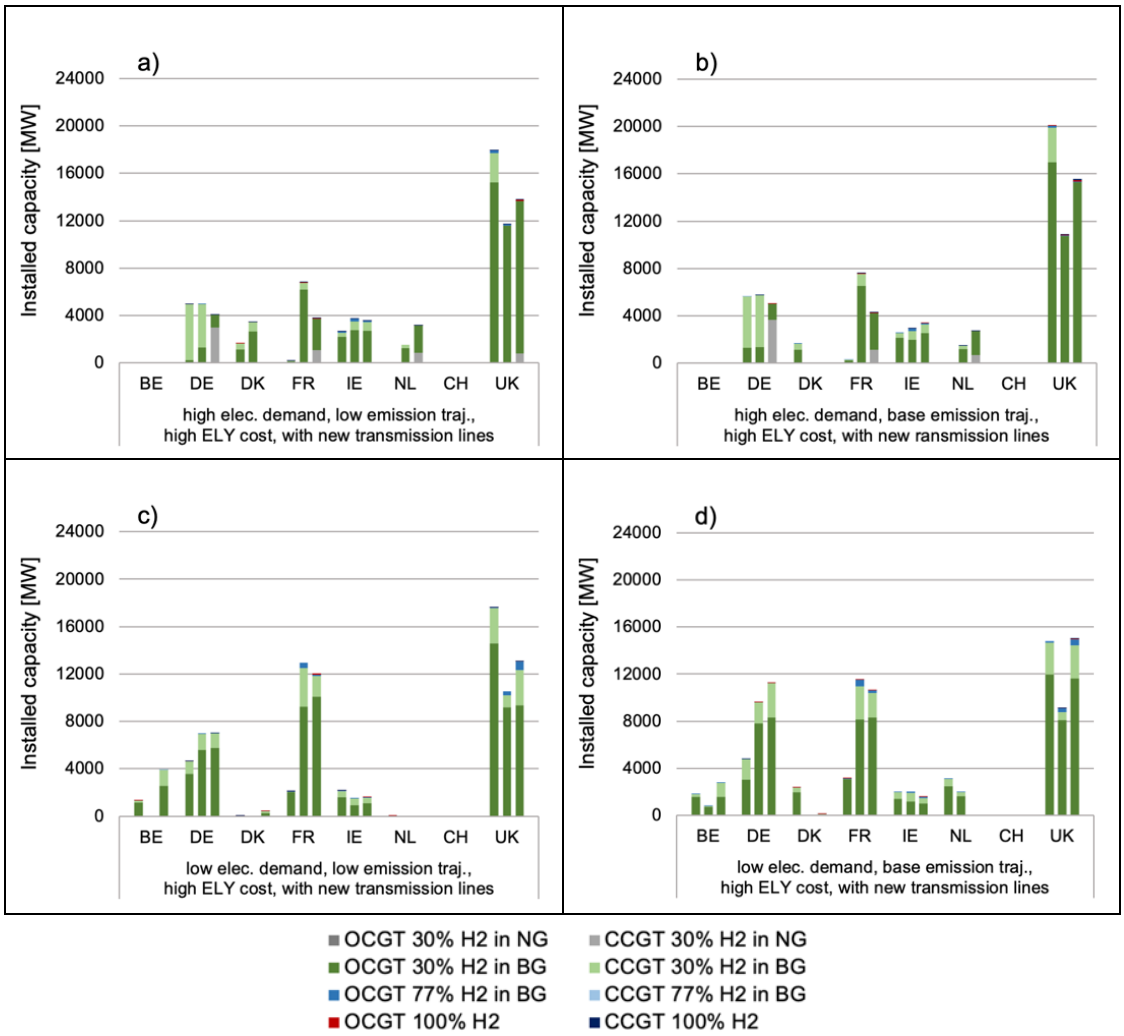

Figure 12: Installed capacity in hydrogen-fueled gas turbines in Year 2050 for four different combinations of electricity demand (high/low) and emissions trajectory (base/low). Panels: a), High electricity demand and low emissions trajectory; b), high electricity demand and base emissions trajectory; c), low electricity demand and low emissions trajectory; and d), low electricity demand and base emissions trajectory. Each country is evaluated for three different levels of assumed fuel costs for natural gas (NG) and biogas (BG), where the middle column represents the baseline cost and the left and right columns represent a cost decrease or increase of 25%, respectively.

The main investments in hydrogen-fueled gas turbines in **Paper III** are in OCGTs with a 30 vol.-% mixing ratio of hydrogen in biogas, although considerable investments are also made in CCGTs, also with a mixing ratio of 30 vol.-%. These results in **Paper III,** considering the mixing ratios of hydrogen in gas turbines, deviate from the results presented in **Papers I** and **II**. The discrepancies are explained by differences in the methods and models used in the different papers, which are aspects that are discussed further in Section 5.

5. Discussion

The discussion is divided into three sections, with the first section focusing on the obtained results, the second on the methods applied, and the third on the implications for making policy and regulations.

5.1 Reflections on the attained results

The distinction between the electricity system and energy system has up until now been quite clear, as a significant part of the energy system is based on fossil fuels rather than on electricity. However, with the increasing focus on direct and indirect electrification, i.e., with or without hydrogen as an intermediate energy carrier, the electricity system will increase its share of the energy system, and the boundary between these systems will fade. With increasing electrification, incorporating new sectors into the electricity system, a system that most likely will be supplied mainly with electricity from intermittent generation, new dynamics will arise within the system. Such a future system will impose new requirements on the system, including grid reinforcements and an expanded capacity to store energy. More importantly, such a system will require a new level of understanding and capability to perform in-depth analyses, to facilitate both appropriate investment decisions and day-ahead planning, but also to increase the accuracy of implementation of policies and regulations.

The results in the appended papers show that the modeled future energy systems are supplied with electricity mainly from VRE generation, and in principle with no investments in nuclear power, which is obviously dependent upon the assumed future costs of nuclear power. Thus, if the costs for nuclear power turn out to be significantly lower in the future or if there is a political will to subsidize nuclear power, this technology may take on a role in the future energy system. If this is the case, the dynamics of the system is likely to be different from that of a system based on VRE generation, and the competitiveness for time-shifting of electricity generation *via* hydrogen will likely be lower, since the variability of electricity production will decrease. Notwithstanding the size of the required investment, nuclear technology is associated with hazardous waste and nuclear proliferation, so it may be overlooked for reasons other than cost. On the one hand, one nuclear reactor generates the same amount of electricity as hundreds of wind turbines, so from a redundancy perspective, a nuclear reactor requires completely different measures to comply with the N-1 contingency criteria if it is unexpectedly shut down. On the other hand, wind power requires larger land areas, and may be regarded as a more-intrusive technology, although if one wind turbine malfunctions it can be repaired without any major impact on the neighboring turbines, such that the aggregate wind installation can still supply electricity to the system.

In the presented work, wind and solar power are the technologies that supply the bulk of the electricity required to meet the assumed future demands in a system that is constrained to meet the requirement of zero carbon emissions. However, the practicalities of attaining such a system are not considered in the modeling, i.e., the rates at which wind and solar power can be implemented, considering the need for permits and public acceptance, as well as the limitations regarding raw materials and a qualified workforce. From this work, it is not possible to specify how the system would be designed if any of these aspects could not be fulfilled. It can only be emphasized that these, and probably several other aspects, are important and that governmental bodies and decision makers must do their best to remove obstacles to the ongoing transition.

Another factor that is not considered in the modeling is the requirement to maintain grid stability, which is an important aspect of today's electricity system. For instance, the future energy systems presented here are based on technologies that lack inertia (i.e., rotating mass), as compared to thermal generation, which means that concerns regarding stability of the grid could be raised with respect to the robustness of the system to maintain frequency and voltage levels. Under the assumption that inertia will be handled in the same way as it is today, a constraint for a minimum level of inertia could be included,

which could support the use of nuclear power or increased implementation of gas turbine technologies. Such a constraint might also influence the operation of the gas turbines already seen in the results. However, with modern power electronics and digitalization, future systems can handle grid stability in other ways, e.g., so-called synthetic inertia could be an option for future electricity systems in that it would reduce the need for synchronous inertia.

In **Papers I** and **II**, the most-competitive gas turbine configuration is a CCGT with flexible mixing of up to 100% hydrogen with biogas. The higher electrical efficiencies of CCGTs (61%), compared to OCGTs (42%), is an important parameter in the competitiveness of CCGTs as it has a potent impact on the overall efficiency of converting electricity to hydrogen and back again. Interestingly, the effects of the higher electrical efficiency of CCGTs not only compensate for an investment cost that is twice that of an OCGT, but also for the fact that CCGTs are modeled with a 6-hour start-up time, which entails an additional cost because fuel is indeed consumed during this period. These results are particularly interesting, as the resulting operation of CCGTs is highly flexible with a considerable number of start- and stop-cycles. However, as the model considers neither back-up power nor redundancy criteria, additional investments may be required in a real-world system, features that would likely benefit investments in OCGTs due to their low investment cost and high flexibility.

From the results in **Papers I-III**, the operation of CCGTs can be described as flexible with many start-stop cycles and few hours in consecutive operation, which is different compared to how this technology has been operated historically. A more frequent cycling may result in shorter technical lifetime and/or higher maintenance costs as some components may have to be replaced earlier due to thermo-mechanical fatigue, an aspect which must be considered by gas turbine manufacturers, both in the design phase of the gas turbine as well as when service agreements for gas turbines are established. Another aspect considering the flexible operation of CCGTs is which size these installations should have. In the model, technologies are represented with an aggregate capacity per region, a capacity which in most regions will be divided on several installations. A benefit with larger gas turbines is that they normally have a higher electrical efficiency at rated power, although, as is shown in the work by Guandalini et al. [50], the part-load electrical efficiency can be significantly improved if the total capacity is comprised by a number of smaller gas turbines, which clearly would be beneficial in a system where the operation of CCGTs is characterized with flexibility. Distributed installations of smaller gas turbines could also support the local distribution grid, although with a higher total investment cost as they would then not benefit from synergies of installing them on the same site. However, to evaluate the optimal gas turbine size, and the potential positive impact in the distribution grid, a model with a higher geographical resolution and a more detailed representation of the distribution grid would be required.

5.2 Methodological reflections

The method used in **Paper III** applies a model package that consists of two soft-linked models, where the bulk investments are made in the investment model ELIN, and the detailed dispatch is modeled in the EPOD model. However, since the ELIN model makes investments in several different years (2020, 2030, 2040 and 2050), still with perfect foresight, the time-resolution must be reduced due to computational limitations. Thus, to simplify the computational effort, a method using representative days is applied. This method has good accuracy in terms of capturing the bulk investments in electricity generation, although it has a limited ability to capture the value of energy storage that exceeds the intra-day timeframe given that the representative days do not occur in consecutive order, and furthermore, the ELIN model tends to underestimate the demand for peak power. Owing to these limitations, the EPOD model, which has an hourly time-resolution and is run for each of the modeled years individually, was adjusted to include the option of complementary investments in electrolyzer capacity, hydrogen storage, and gas turbine technologies, including gas turbines with the possibility to blend in different shares of hydrogen. This means that the additional investments made in EPOD were made in an already existing energy system, which in combination with fixed mixing ratios for hydrogen blend-in in gas

turbines, i.e., that a fixed share of the fuel input had to be hydrogen, meant that a low mixing ratio (30 vol.-%) of hydrogen was the most-common investment made among the investment options available for hydrogen-fueled gas turbines in **Paper III**. Consider instead **Papers I** and **II**, both of which apply a so-called greenfield model for a single year (Year 2050), an approach in which no existing technologies are considered (apart from existing hydropower and transmission capacity). This means that all investments are made simultaneously by the model, so that the cost-optimal combination of VRE and energy storage technologies, including reconversion technologies, can be established. With this approach, the optimal mixing ratio of hydrogen in hydrogen-compatible gas turbines is most often up to 100 vol.-%, i.e., a flexible mixing of between zero and 100 vol.-% hydrogen. Thus, it can be concluded that the optimal mixing ratio of hydrogen in hydrogen-compatible gas turbines is affected by the choice of method. It is not clear as to which of these approaches represents most accurately the reality, and thus which mixing ratio is the most likely. However, it can be concluded that a capability that allows for flexible mixing provides an advantage because the gas turbine can be utilized also when the cost of hydrogen is too high to generate a gross margin that is sufficient to recover the investment cost.

A greenfield approach can of course be questioned, as investments are in reality made in the context of an existing system, with estimated projections of the future system. However, as the modeled year in **Papers I** and **II** is Year 2050, it can be argued that the current electricity mix will be substantially different by then, as a consequence of either expiration of the technical lifetimes of existing installations or the early phase-out of technologies that are no longer economical feasible when there is a higher cost for emissions allowances. Instead, the results in **Papers I** and **II** should be seen as indicators of how future energy systems could be designed, and more importantly, of the dynamics of such systems and the roles that different technologies will assume.

Another methodological aspect that may influence the results is the lack of price elasticity in the different demands included in the model. For some scenarios, the model does include flexible production in the industrial processes, albeit with an unchanged annual demand. Furthermore, even if the hydrogen demand for time-shifting electricity generation is endogenous, and therefore flexible, the vast majority of the electricity demand has a fixed hourly profile, a profile which in reality would likely be influenced by a high electricity cost, leading to a decreased demand. In addition, the fuels used in the model have a constant cost, which does not represent very accurately the reality. If the model included a cost elasticity for fuel, this would definitely impact the results, especially if the model also incorporated price elasticity into the demand.

5.3 Policies and regulations

The results from **Paper I** show that the cost of hydrogen in an off-grid system is always higher than the hydrogen cost attained in a grid-connected system. However, the results do not take into account applicable taxes and fees. Thus, the hydrogen cost resulting from the grid-connected system would increase relative to the off-grid system in the current financial setup. This is because the hydrogen producer would have to buy the electricity from the market, and thus would pay taxes and grid fees, expenses that can be avoided in an off-grid system where the consumption automatically occurs "behind the meter". However, the results clearly show that the off-grid system is more expensive, as such a system has limited options for managing the variations from VRE generation, which leads to unnecessary over-dimensioning of the electrolyzer and storage capacity, as compared to a grid-connected system or curtailment of electricity, two options that entail inefficient usage of resources. Thus, it can be argued that the financial system, considering taxes and grid fees, should be designed so as not to encourage the development of parallel systems that lead to sub-optimization of the overall energy system, resulting in inefficient use of resources.

The investments in the model are represented as aggregate capacities for each technology in each of the modeled regions, which for the production and storage of hydrogen can be compared to centralized

production and storage facilities. This is not considered to be an issue, as the results are analyzed from an overall system perspective, i.e., a societal perspective rather than the perspective of a consumer. Thus, the impacts of a large hydrogen demand in the energy system can be evaluated. However, as the majority of the hydrogen is likely to be consumed by a few actors in industry that would likely have their own hydrogen production and storage units, these actors would attain market power. With asymmetric information, they could exploit this situation for their own benefit, i.e., there is a risk of oligopoly. Thus, the hydrogen market may need regulations similar to those applied in the electricity market.

6. Conclusion

The results obtained in the presented work reveal that existing technologies have the potential to meet the requirement of a decarbonized energy system, including the electricity system, the transport sector, and significant electrification of industrial processes. The electricity is primarily supplied by VRE technologies, i.e., wind and solar, which are technologies that are already today mature and competitive without subsidies. The variations from the intermittent generation patterns of these technologies are to a great extent managed through the use of batteries, while hydrogen production and storage to meet industrial hydrogen demands exert a considerable impact through the smoothening effect of flexible operation of the electrolyzer. The variations can, furthermore, be managed by reconversion of the hydrogen back to electricity, which is performed exclusively in hydrogen-compatible gas turbines. Even if gas turbines fueled with 100% hydrogen are not commercially available today, their development is ongoing and gas turbine manufacturers have pledged that turbines with 100% hydrogen capability will be available within the foreseeable future.

In the energy systems studied, wherein hydrogen is used in several applications with different characteristics of the hydrogen demand profile and with large shares of electricity supplied by VRE generation, the results show that the cost of hydrogen varies considerably over the year, similar to the cost of electricity. Thus, the cost of electricity has a major effect on the cost of hydrogen. However, this work also emphasizes the impacts of the cost-optimal electrolyzer and hydrogen storage capacity, and shows that these factors can have significant impacts on the cost of hydrogen during different periods of the year, as both the electrolyzer and storage capacity can limit the production of hydrogen, thereby setting the marginal cost of hydrogen. The variations in hydrogen cost can be emphasized by concluding that the weighted annual average hydrogen costs for UK1 and ES1 are 1.1 €/kg_{H2} and 0.94 €/kg_{H2}, respectively, albeit with variations that give UK1 and ES1 1,000 hours with hydrogen costs >3.5 €/kg_{H2} and >5.5 €/kg_{H2}, respectively. Furthermore, the results show that the characteristics of the hydrogen demand can have a strong impact on the cost of hydrogen, where potential flexibility in hydrogen-based industries can reduce the cost of hydrogen by up to 35% compared to a constant hydrogen demand, and that a lower level of flexibility is often sufficient to achieve this reduction in hydrogen cost.

The time-shifting of electricity generation *via* the production, storage, and reconversion of hydrogen, is found to be predominantly competitive in electricity systems with 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 from solar PV, which are shorter in time and occur at a high frequency (diurnal), and for which batteries are a more suitable time-shifting technology. Thus, the competitiveness linked to shifting electricity generation in time *via* hydrogen is not determined by the cost of hydrogen. Spain has one of the lowest costs for hydrogen, yet the competitiveness of hydrogen-fueled gas turbines is low in this solar-dominated region.

The future operation of gas turbines can for CCGTs be described as highly flexible with approximately 40 start-stop cycles per year and with 1,000 to 3,000 full-load hours, depending on the country and scenario. For OCGTs, a few hundred hours of operation can be expected, distributed across numerous start-stop cycles during high-cost electricity hours. The results also indicate a strong competitive edge for gas turbines that incorporate flexible mixing of hydrogen, since the gas turbine can be utilized also when the cost of hydrogen is too high to generate the gross margin required to recover the investment. Furthermore, the competitiveness of hydrogen-fueled gas turbines increases when the cap on carbon emissions is more-stringent and the penetration of VRE generation increases. Therefore, hydrogen-fueled gas turbines can be expected to become competitive towards Years 2040 and 2050.

7. Future work

Possible future directions for the work presented in this thesis are suggested below, divided into three different categories.

Methodology:

- The geographic scope of the work presented in this thesis has in most of the scenarios included boundary regions to capture at least a minimum level of import and export to and from the regions analyzed. This is because trade in electricity is an important measure to manage variations from VRE generation. However, it would be valuable to investigate further how many layers of these boundary regions must be added before the model accurately represents the focus region.

- As trade between regions is an important measure to manage variations, investments in transmission capacity ought to be analyzed further. In one of the modeled scenarios, the transmission capacity between two regions increased from the current 2.6 GW to 78 GW, an increase that might seem unreasonable considering public acceptance and the impacts on wildlife. Thus, it would be interesting to investigate the impacts on, for example, investments in gas turbines, if the investments in transmission capacity were limited to different degrees. Furthermore, a constraint on self-sufficiency regarding power supply could also be investigated.

- As the current work is based on a linear optimization model with aggregated technologies per region, the operation of a normal-sized gas turbine cannot be properly evaluated. Thus, in order to evaluate the operation of such a gas turbine, with greater technical detail, a unit commitment model could be applied, albeit with the downside of a reduced geographic scope.

- In **Paper III**, it is concluded that the competitiveness of hydrogen-fueled gas turbines starts to increase when the requirements regarding emission levels and technology costs assumed for Year 2040 are applied. However, to advance the development of the hydrogen-fueled gas turbines, it would be of value to investigate which types of subsidies for time-shifting *via* hydrogen would be required in order to make this a competitive and self-sustaining technology. Such study could also include the new directives from the EU Taxonomy considering natural gas and thus the role of natural gas-fired technologies in the transition of the electricity system.

- All the modeled scenarios in the three papers are based on weather data from Year 2012, as it was a "representative" year considering the capacity factors for wind and solar power. However, since all years are by definition not "representative", two major questions arise: i) How would the investments change if they were based on weather data from other years? and ii) How would a system, based on weather data from Year 2012, perform during another year modeled with a different set of weather data?

Technical aspects:

- In the work conducted to date, only batteries and hydrogen have been used for time-shifting electricity generation. A third option is ammonia, which although it originates from hydrogen is significantly easier to store and transport, and may thus provide a different dynamic to the system. Different scenarios for ammonia usage could be modeled, for instance ammonia that is produced in Europe or imported from another continent, e.g., Africa.

- In the presented papers, hydrogen cannot be transported between regions, which means that the hydrogen produced in one region must also be stored and utilized there. It would be interesting to evaluate the impacts when investments in hydrogen transportation are available in the model.

- In this work, it is concluded that time-shifting of electricity generation through the use of hydrogen is particularly competitive in electricity systems with large shares of wind power. However, the modeled wind technologies do not include the latest wind turbine designs, e.g., with higher towers and/or with lower specific power, designs which may affect the variations in electricity production from wind power, and thus the value of time-shifting *via* hydrogen.

- In the work presented in this thesis, hydrogen has only been used in gas turbines that generate electricity, and not in gas turbines in cogeneration-mode, generating also heat for the district heating system. Such application could be interesting to investigate, where electricity during low-cost periods could be used to produce hydrogen and heat in heat pumps or electric boilers, and where hydrogen would be used to generate both electricity and heat during high electricity cost periods.

Byproducts of electrolysis:

- In a future scenario with a large demand for hydrogen produced *via* electrolysis, it would be of great value if the two byproducts of electrolysis, oxygen, and low-grade heat, could be included in some value chains. This would improve the overall use of resources, i.e., renewable electricity, and would also reduce the cost of hydrogen, which is likely to be seen as the main product of the electrolytic process. This warrants investigations.

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