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Managing wind power variations through dispatchable generation in carbon-constrained energy systems

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Abstract

If the European Union is to achieve climate neutrality by Year 2050, as envisioned in the European Green Deal, electricity generation from variable renewable energy sources will have to increase, both in share and in absolute volume, to replace fossil-based electricity generation. This will be necessary to meet the rising demand linked to the anticipated widespread electrification of the transport and industry sectors. Given the inherent variability of renewable electricity generation, the aim of this work is to advance understanding of the interplay between electricity generation, energy storage options, and flexible demands in future energy systems that match the European Union's ambitions for Year 2050. To study this interplay, techno-economic optimization models are applied. These models determine the cost-optimal capacity mix and system dispatch by minimizing the total system cost and ensuring that the supply consistently meets the demand.

A key focus of this work is the potential system value of shifting electricity generation in time via hydrogen, including its production and storage, as well as the conversion of hydrogen back to electricity. This hydrogen pathway, primarily involving hydrogen-fueled gas turbines for reconversion, presents an opportunity to enhance the value of electricity by shifting it from periods of abundant generation to periods of scarce generation. This work demonstrates that incorporating hydrogen-fueled gas turbines – or any other technology with similar cost characteristics and fuel flexibility – can lower the total system cost and reduce the amount of curtailed electricity. This hydrogen pathway is particularly competitive in wind-dominated regions, even though hydrogen production costs can be lower in solar-dominated regions. The critical factor is the residual load profile, which in wind-dominated regions often fluctuates over timescales that range from hours to several days. Notably, this hydrogen pathway remains competitive despite the low round-trip efficiency, an aspect that is often highlighted as a significant drawback for this hydrogen application.

This work also delves deeper into hydropower in energy systems modeling, aiming to enhance the representation of this technology and avoid overestimating its operational flexibility, in addition to evaluating the future role of hydropower. Concerning the role of hydropower in a future Swedish electricity system, the findings suggest that the trend of a weaker correlation between hydropower generation and intra-day load variations will persist and will even grow stronger in the future. This implies that hydropower will mainly serve as a complement to wind power rather than acting directly to balance the demand. Consequently, the value of operating hydropower at varying levels for periods ranging from several days to a couple of weeks will be higher in future electricity systems, underscoring the importance of accurately accounting for internal hydropower limitations in energy systems modeling. Moreover, the development of the Swedish electricity system appears to have a limited effect on the dispatch of Swedish hydropower. This is largely due to the fact that variations in generation that occur outside of Sweden are dominated by wind power, and due to the interconnecting transmission capacity, Swedish hydropower is exposed to these variations regardless of the system that is built in Sweden.

In addition to the intra-year fluctuations of weather-dependent electricity generation, this work also examines inter-annual variations, which are primarily driven by variations in wind power generation. Concerning the inter-annual variations, it is vital to distinguish between annual capacity factors and hourly generation profiles. While variations in the annual capacity factors mainly influence investments in the volume of wind power, variations within the generation profile mainly affect investments in different storage technologies and peak power capacity. From the work conducted for this thesis, it can be concluded that during years or extended periods of low-level wind generation, fuels such as biomethane, methanol, biodiesel, or even fossil equivalents are likely to be cost-competitive options for balancing inter-annual variations that exhibit low recurrence. These fuels are not only storable at reasonable cost but can also be used in gas turbines, which have low investment costs and, thus, do not significantly affect the total system cost. In fact, gas turbines offer a unique complement to address low-occurrence variations, including both shorter fluctuations within years and extended periods of very low generation, such as consecutive weeks of scarce generation, which occur once a decade or even less frequently.

Keywords: energy systems modeling, technology interplay, hydrogen-fueled gas turbine, energy storage, wind power, hydropower, inter-annual variations, techno-economic optimization

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. “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.

II. S. Öberg, M. Odenberger and F. Johnsson. “The value of flexible fuel mixing in hydrogen-fueled gas turbines – a techno-economic study”. *International Journal of Hydrogen Energy,* vol. 7, pp. 31,684-31,702, 2022, doi: 10.1016/j.ijhydene.2022.07.075.

III. S. Öberg, M. Odenberger and F. Johnsson. “The cost dynamics of hydrogen – a techno-economic study”. *Applied Energy*, vol. 328, no. June, 2022, doi: 10.1016/j.apenergy.2022.120233.

IV. S. Öberg, L. Göransson, H. Ek Fälth, U, Rahmlow, F. Johnsson. “Evaluation of hydropower equivalents in energy systems modeling”. Submitted to Applied Energy.

V. S. Öberg, M. Odenberger and F. Johnsson. “Inter-annual variations in energy systems modeling of future energy systems”. Submitted to Energy.

Simon Öberg is the principal author of **Papers I–V** and performed the modeling and analysis for all five papers. Professor Filip Johnsson contributed with discussions and editing to **Papers I–V**, and Docent Mikael Odenberger contributed to the method development in **Papers I–III** and **Paper V**, as well as with editing and discussions for the same papers. Docent Lisa Göransson contributed to the method development, as well as with editing and discussion in **Paper IV**. Hanna Ek Fälth and Uli Rahmlow contributed with method development, as well as with editing in **Paper IV**.

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?". *Applied Energy*, vol. 330, no. May 2022, doi: 10.1016/j.apenergy.2022.120315.

B. S. Öberg, F. Johnsson (2023). Hydrogen in the European energy system. *VGBE energy journal*, no. April, 2023.

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Gothenburg, 13th of August, 2024

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1 Introduction

In Year 2008, the European Parliament adopted a climate and energy strategy, often referred to as the EU 20-20-20 package, to combat climate change and increase the European Union's energy security. Set for Year 2020, this package aimed for a 20% reduction of greenhouse gas emissions compared to Year 1990, a 20% improvement in energy efficiency, and that 20% of energy would come from renewables [1]. However, before these targets had been met [2], the European Commission in Year 2019 presented the European Green Deal [3], aiming at making Europe the first climate-neutral continent by Year 2050, and thereby increasing the likelihood of limiting global warming to well below 2°C, relative to pre-industrial levels, as outlined in the Paris Agreement [4]. In Year 2021, the European Commission strengthened its ambitions by adopting the Fit-for-55 package [5], which included policies to speed up the transition and reduce greenhouse gas emissions by at least 55% up to Year 2030, as compared to the Year 1990 levels.

As a result of the policies set by the European Commission, which also included a scheme for trading greenhouse gas emissions allowances[1] [6], the levels of emissions in the EU-27[2] had decreased by 32% in Year 2022 compared to Year 1990 [7], while the economy had grown by 60% [5], and renewables supplied 23% of energy consumption [8]. However, in order to meet the targets of reducing emissions by 55% and renewables supplying 42.5% by Year 2030, the deployment rates of renewables must more than double compared to the past decade [8]. With this thesis being written in 2024, the timeframe within which to achieve a climate-neutral continent is 26 years, and the goals for Year 2030 must be met within 6 years. A critical component in the transition is the electricity sector, partly due to its current emissions levels, but also because the electricity sector is likely to become the foundation upon which the entire future energy system will be established, assuming widespread electrification of transport and industry. As there is little time left for ground-breaking innovations, the already-existing electricity generation technologies constitute the main options for the transition, notwithstanding that these technologies can be developed further, and in some cases, take on new roles.

Considering the technologies available, solar power is, in the global context, expected to expand considerably in the coming decades and take on a greater role in the global electricity mix [9][10]. However, in the European context, wind power is expected to be the largest electricity generating technology by Year 2050 [11][12], a projection that is even more applicable to northern Europe [13][14]. Another renewable technology that already constitutes a large share of the northern European energy system and that has been utilized for electricity generation since the 1880s [15] is hydropower, including reservoir hydropower. Being a dispatchable *and* flexible carbon-free generator, the system value of reservoir hydropower can be expected to increase when the share of intermittent generation increases. In addition to electricity generation from solar, wind, and hydropower, hydrogen is expected to play an important role in the future European energy system [16], owing to its potential to reduce emissions across several sectors, including also hard-to-abate sectors, through acting as an energy carrier, reactant or feedstock [17]. Although it is portrayed as a new component in an energy system in which large-scale utilization of hydrogen poses multiple challenges, hydrogen is a well-known compound and has been used in various processes during the past century [18].

[1] The EU Emissions Trading System (EU ETS).
[2] The 27 Member States of the European Union.

To summarize, a new interplay between supply and demand will emerge in a future energy system with large shares of the electricity demand being supplied by variable renewable electricity (VRE) generation, such as solar and wind power, and with new loads from direct or indirect electrification of sectors that are currently supplied by fossil energy sources. The primary driver of this new dynamic is the non-dispatchable VRE generation, the cost of which has declined dramatically over the past decades [19]. However, when different sectors are allowed to interact through various energy carriers and storage options, even more-intricate dynamics emerge. To support future decision-making processes, the interplays between generation technologies, storage technologies, and flexible demands must be understood and explained. To do so, this work applies energy systems modeling to study the interactions that will occur in future energy systems.

1.1 Aim and scope

The overall aim of this thesis is to advance our current understanding of the interplays between electricity generation, energy storage options, and demands in future energy systems with large shares of VRE generation. The work focuses on electricity systems that are to a large extent supplied by wind power, including a variety of options to manage supply and demand variations. The thesis takes its departure from a future energy system without any direct fossil carbon emissions from the sectors included in the modeling. A major focus of the work is on hydrogen-fueled gas turbines and hydropower – two of the few flexible generation options that lack direct carbon dioxide (CO_2) emissions. The appended papers constitute the backbone of this thesis, guided by the following research questions, which set the overall research scope:

I. Considering hydrogen in future energy systems, under which conditions would hydrogen-fueled gas turbines become competitive, and what value would such a hydrogen pathway provide to the system? Furthermore, how can the cost dynamics of hydrogen supply be characterized, and what is the value to the system of incorporating flexible hydrogen consumption alongside flexible hydrogen production?

II. How can the representation of hydropower in energy systems modeling be enhanced, and what is the anticipated future role of Swedish hydropower in light of climate change impacts and the ongoing development of the energy system?

III. How do inter-annual weather variations influence the cost-optimal capacity mix obtained from energy systems modeling, and to what extents do technologies recoup their investments based on the specific year that is utilized for generating the capacity mix?

1.2 Contribution of the thesis

Papers I and **II** are dedicated to exploring the competitiveness of hydrogen-fueled gas turbines and the concept of shifting electricity generation in time via hydrogen, including the production, intermediate storage, and reconversion of hydrogen. **Paper I** examines the potential timeline for hydrogen-fueled gas turbines to become competitive within the European energy system, employing a methodology that involves investments being made every decade from 2030 to 2050. **Paper II**, on the other hand, focuses exclusively on Year 2050, carrying out a more-detailed technical investigation of the value of flexible blending of hydrogen with biomethane.

Paper III delves into the intricate dynamics of hydrogen supply in a future energy system, particularly focusing on the temporal aspects of the cost dynamics of the supply of hydrogen. This paper evaluates how hydrogen demands with different characteristics, including different levels of flexibility with regards to hydrogen utilization, impact the system. In addition, **Paper III** studies the potential role of hydrogen production from steam methane reforming (SMR) with carbon capture and storage (CCS).

Paper IV focuses on hydropower in energy systems modeling. The main part of the paper focuses on how to represent reservoir hydropower more accurately in energy systems modeling, given that it is a technology that is exceedingly simplified in such models, leading to overestimations of its flexibility. **Paper IV** also evaluates the future role of Swedish hydropower, considering the impacts of both the expected climate change and the ongoing development of the energy system.

In **Paper V,** the impacts of inter-annual variations are studied with regards to how these variations impact the economic performances of different technologies, i.e., the abilities of technologies to recover their annualized investment costs. **Paper V** further highlights how the value of shifting electricity via hydrogen and batteries depends on the wind profiles, as well as the values of high-cost fuels to balance inter-annual variations with low frequency.

1.3 Structure of the thesis

With the five appended papers forming the foundation of the research, this thesis synthesizes and contextualizes the overall findings within a broader framework. Chapter 2 provides an overview of key concepts and definitions, along with a review of the relevant research in the literature. Chapter 3 provides an introduction to the overarching methodological considerations, a description of the models used in this work, and an overview of the associated assumptions and input data. The main results of the work are presented in Chapter 4, and the overall work is further discussed in Chapter 5. Finally, Chapter 6 provides some concluding remarks and considerations for future work.

2 Background

This chapter provides an overview of the fundamental aspects of this work. Section 2.1 categorizes the variations from VRE generation and presents flexibility options to manage these variations, while Section 2.2 summarizes related work from the literature on hydrogen-fueled gas turbines, hydropower in energy systems modeling, and modeling of inter-annual variations.

2.1 Approaches, technologies, and strategies to manage VRE variations

Historically, the primary source of variations in the electricity system has been the electricity demand, characterized by one or two daily peaks and seasonal variations due to either heating demand or cooling demand, depending on the climate zone. To tackle these variations, technologies with different cost structures have been applied to carry out different roles in the system. Base-load technologies, characterized by high investment costs and low operational costs, create a low levelized cost of electricity when operated with a high-capacity factor. Conversely, peak-load technologies, which have low investment costs but high operational costs (primarily due to fuel costs), result in reasonable electricity costs when their capacity factor is kept low. However, when VRE generation is introduced, technologies such as wind and solar power with no or low variable costs are positioned early in the merit order, and consequently, the resulting load to be supplied by conventional technologies is changed. This new load, called the net-load, is calculated by subtracting the VRE generation from the original load. Thus, as the share of electricity supplied by VRE technologies increases, understanding the variations originating from VRE technologies becomes increasingly important.

The variability of wind and solar power has been studied extensively, and a review on the subject has been compiled by Widén et al. [20]. Examples of the ways in which wind and solar generation fluctuate are visualized in Figure 1, showing three 2-week periods during different parts of the year for southern Sweden (SE3). As observed, solar power generation exhibits both diurnal and seasonal variations, with the latter depending on the latitudinal position. The seasonal variations due to being located at a higher latitude affect both the amplitude and duration of solar power generation, influenced by the angle of the incoming sunlight and the number of daylight hours, respectively (*cf.* panels d and e in Figure 1). In addition, the cloud coverage and temperature cause the power production profile to deviate from the theoretical level of production under clear sky conditions, which is known for any given location. The variations in wind power generation are more arbitrary in terms of their characteristics, with variations on a timescale that ranges from hours to several days, as displayed in panels a–c in Figure 1. However, due to the non-linear shape of a wind turbine power curve, variations in wind speed can have significantly different impacts on the power output depending on the wind speed. Small variations in wind speed in the steep part of the power curve have a substantial impact on the power output, while for wind speeds above the rated power and below the cut-in level, the electric output level remains constant. Variations can, however, be reduced by geographic smoothing. Olauson and Bergkvist [21] have concluded that there is a low correlation for wind variations between neighboring countries on hourly to weekly timescales, whereas the seasonal correlation (timescales >4 months) is stronger. Details of how geographic smoothing is implemented in the modeling are presented in Section 0.

The seasonal variations in Europe have been quantified by Pryor et al. [22], and the monthly average The seasonal variations of wind power in Europe have been quantified by Pryor et al. [22]. The monthly average capacity factor ranges from 35% during the period of December–February to below 20% in the period of June–August. Inter-annual variations are also more pronounced for wind power than for solar power [23], and the standard deviation of wind power generation in the Nordic and Baltic countries has, for example, been found to be in the range of 8%–12% [22]. Furthermore, inter-decadal variations in wind speeds have been identified, showing, for example, a decline in the average wind speeds in Western Europe during the period of 2012–2020, a trend that is opposite to that seen in the two decades preceding this period [24].

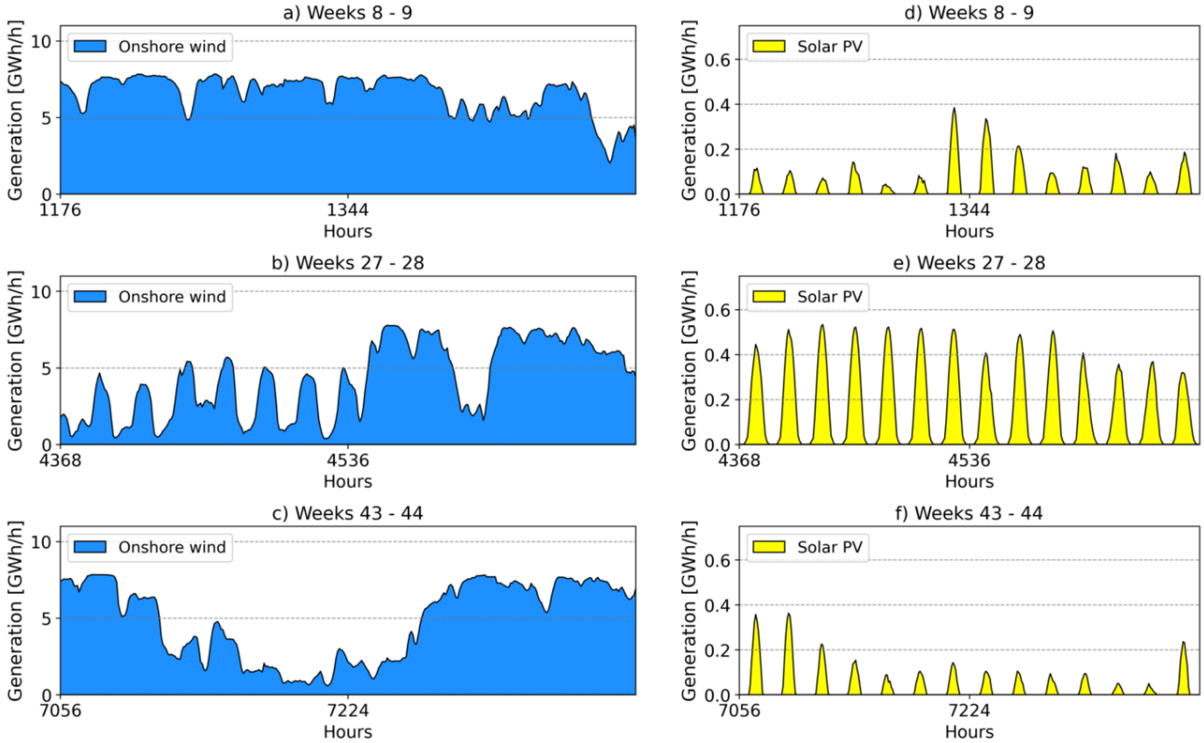

Figure 1: Wind and solar production levels for three 2-week periods in southern Sweden (SE3).

The ability to manage variations implies that various kinds of flexibility are available within a system. As shown above, variations can be fundamentally different depending on the conditions. Thus, different flexibility options must be considered to manage different variations. Based on the approaches, technologies and strategies suggested in [25], Johansson and Göransson [26] have concluded that the cost-optimal alternatives to manage variations depend on the conditions for VRE generation, and furthermore that all types of variations are present in all electricity systems, albeit to different degrees, indicating that a combination of strategies is required to minimize the total system cost.

In an advancement to categorize variation management strategies (VMS), Göransson [27] has suggested the following strategies: *peaking*, *shifting*, and *complementing*. Peaking strategies apply to variations with a low number of high-amplitude occurrences which means that low investment costs for charging, discharging, and storage is critical. However, low investment costs are typically accompanied by high operational costs, resulting in high costs for electricity during discharging or a low value of the electricity during charging. Suitable technologies to manage these variations include open-cycle gas turbines. Shifting strategies focus on mitigating on short timescales variations that have high amplitude and that occur frequently. Thus, these strategies are associated with low costs for charging and discharging capacities and a low operational cost. However, as these traits are typically associated with a high cost or a limited ability to store energy, these strategies are mainly applied for shifting electricity production during shorter periods, e.g., via the charging and discharging of batteries. Complementing strategies address less-frequent variations on longer timescales and are, thus, associated with a low cost for energy storage. Given the lower amplitude of such variations, higher costs associated with charging and discharging power are acceptable. Examples of applications that embody these characteristics include flexible hydrogen production and storage, as well as thermal energy storage, both of which offer more-cost-effective energy storage solutions compared to batteries.

The underlying options for the VMS proposed in [27] are summarized in a review published by Lund et al. [28]. These options encompass traditional flexibility measures, such as grid extensions and flexible thermal generation, as well as more advanced measures, which include demand-side management and coupling of existing and emerging sectors. The most-prominent flexibility measures are detailed in the following subsections.

2.1.1 Grid infrastructure

Sufficient transmission capacity is essential for robust power system operation and provides vital flexibility already in the current electricity system. Considering future systems and the integration of high shares of VRE generation, several studies have emphasized the value of an expansion of the transmission system. Reichenberg et al. [29] have demonstrated that wind and solar power, when combined with power transmission and battery storage, can efficiently achieve VRE integration levels of 85%–98% before the integration costs escalate significantly. This finding also underscores the challenges involved in covering the remaining fraction of the energy demand without incorporating flexible generation technologies. In a study conducted by Tröndle et al. [30], it was concluded that electricity trading not only provides flexibility but also facilitates the transfer of VRE resources between regions with different VRE conditions. Similar conclusions have been drawn by Walter and Göransson [31], who have demonstrated that when transmission costs are low, transmission capacity primarily enables transfer of the wind power resource. Conversely, when transmission costs are high, transmission capacity primarily facilitates wind power integration by reducing variability through geographic smoothing. Schlachtberger et al. [32] have found that a cost-optimal expansion of transmission capacity favors wind power generation. In contrast, a constrained expansion favors solar power and investments in battery capacity and increases the total cost of meeting the demand for electricity in a European context.

2.1.2 Supply-side flexibility

Supply-side flexibility refers to measures or technologies that enable adjustments to the output of power generation so as to maintain the supply-demand balance. Historically, the base-load, intermediate-load, and peak-load technology categories have aligned well with demand variations due to their distinct techno-economic characteristics. However, as pointed out by Schlachtberger et al. [33], traditional base-load generation is phased out at approximately 50% VRE penetration. Beyond this point, more-flexible peak-load generation, such as that provided by gas turbines, becomes the dominant dispatchable technology. When entering this regime in energy systems modeling, it is important to represent accurately the cycling properties of thermal units, especially intermediate-load generation [34]. These properties pertain not only to technical aspects but also to cost considerations, as plants can be designed to be more flexible, albeit at a higher cost. An example of this has been presented by Guandalini et al. [35], showing that the part-load efficiency of a gas turbine power plant improves with increasing number of gas turbine units. However, this improvement comes at an increased cost due to economies of scale. Another option could be to operate power plants flexibly while accepting increased maintenance costs as a penalty, due to the greater wear and tear on the equipment. Flexibility could also be attained in the form of products supplied. The operational patterns of combined heat and power (CHP) plants under future market conditions have been studied by Beiron et al. [36][37]. They have concluded that product flexibility and thermal flexibility are more valuable for the plant than operational flexibility (ramp rate). However, since CHP plants are dimensioned based on the heating demand, the flexibility that they provide will have a limited impact on the electricity system. [38]. Hydropower is another technology that could provide flexible generation to the system. However, as hydropower is thoroughly discussed in Section 3.3.2, it will not be elaborated upon in detail here.

2.1.3 Energy storage

Energy storage is employed to shift the supply of electricity (or any other energy carriers) in time, thereby allowing for temporary mismatches between the supply and demand to be managed. Various technologies are available for shifting electricity generation in time, including pumped hydro, compressed air, hydrogen, batteries, flywheels, and supercapacitors [28], each with distinct characteristics that determine their specific applications. One critical aspect to consider is the ratio of the energy storage capacity to the output power capacity. A higher energy storage capacity enables the system to respond to longer mismatches between the supply and demand, while a higher output power capacity allows for balancing mismatches with higher amplitudes. Investment cost and round-trip efficiency are obviously also important factors, and since no storage system can simultaneously provide a low-cost, high-energy density, high efficiency setup with a long lifetime, suitable storage technologies must be selected on a case-by-case basis [39]. Although all the aforementioned technologies shift electricity generation over time, distinctions can be made based on the services that they provide. Technologies with a high cost per unit of energy stored, such as flywheels and supercapacitors, and to some extent batteries, primarily offer grid-stabilizing services. In contrast, technologies with a low cost per unit of energy stored, such as pumped hydro, compressed air, hydrogen, and batteries, primarily facilitate shifting electricity generation through energy arbitrage. In this work, only the latter type of energy storage is considered.

2.1.4 Sector couplings and demand-side management

Sector coupling refers to the expansion of the electricity system to supply the energy demands in sectors historically served by other energy sources. Examples of these sectors include heating, transport, and specific industrial processes. An important aspect of some of these new demands is that they require energy in forms other than electricity, such as hot water for heating and hydrogen for industrial processes, and these alternative energy carriers offer the benefit of significantly lower storage costs. The concept of sector coupling and its impact on the net-load duration curve are described in a previous publication [40].

Investment in heat pumps and/or electric boilers in combination with heat storage allows the heating sector to utilize low-cost electricity during low-net-load events. This has been investigated previously [42]–[44], demonstrating dynamic heat production using CHP plants during higher net-load periods and using heat pumps and electric boilers during periods of low net-load. In addition, space heating offers a level of demand-side management through load shifting, as the heating demand does not need to be met instantly due to the thermal inertia of the buildings. However, owing to the relatively large thermal losses in buildings, thermal inertia can handle relatively short variations, whereas dedicated heat storage solutions, such as hot-water tanks, can provide heat storage over several days [44].

Hydrogen utilizations in the steel-making process [45], fertilizer production [46], and plastic recycling [46] are examples of sector coupling within industrial processes. Toktarova et al. have studied how the European electricity system is affected by both an electrified steel-making process [47] and plastic recycling [48]. The results show that the additional electricity demand is met predominantly by VRE technologies, and to some extent by nuclear power. Moreover, the findings reveal that it is cost-competitive to invest in overcapacity of electrolyzers, components of the steel-making process, and in both hydrogen storage and intermediate storage units for hot briquetted iron, such that steel production can adjust to the variations of VRE generation.

The ongoing direct electrification of the transport sector poses both challenges and opportunities for the system. If charging is conducted in a simplified manner, such as direct charging upon arrival, this could increase the variability of the electricity demand and exert a negative impact on the system. However, smart charging and the possibility for electric vehicles (EVs) to also discharge electricity to the grid, so-called vehicle-to-grid (V2G), may be important in terms of flexibility [49], creating an economic value for the system [50]. The use of EVs to manage variations in an electricity system has been studied by Taljegård et al. [51]. The results show that V2G stimulates investments in solar power in all the studied regions, except Sweden. Furthermore, full electrification of the road transport sector, including trucks and buses, would reduce the need for investments in peak power by at least 50% in all the studied regions, as compared with a scenario without EVs or with direct charging upon arrival, provided that an optimal charging strategy and V2G are implemented for passenger vehicles.

In recent studies that have considered larger geographic scopes, multiple sectors, and various energy storage alternatives, the significance of each individual flexibility option diminishes [14][52]. However, with different conditions in different countries, the different options have varying importance. This is shown in the work by Göransson [27], which reveals how different flexibility options stepwise reduces the net-load to zero.

2.1.5 Electricity market design

Although energy system flexibility is often perceived as a technological issue, poor market design can limit access to technical flexibility within the energy system [53]. In the review carried out by Lund et al. [28], both the temporal and spatial resolutions emerge as increasingly important aspects when designing the market. However, another critical aspect is how well support schemes, which in recent times have been aimed mainly at VRE generation, incentivize flexibility. Both feed-in tariffs and conventional contracts for differences (CfDs) have been shown to shield VRE producers from market signals [54][55], thereby encouraging power generation even during periods of excess production. With respect to the development of CfDs, which are regarded as an important part of the future EU power market [56], several improvements have been suggested and implemented since CfDs were first adopted in the UK in Year 2014 [57]. Essentially, CfDs aim to reduce the risks associated with fluctuating revenue flows for the producer. This risk can be attributed to both electricity price variations and variations in production volumes. While conventional CfDs mitigate exclusively the risk of price volatility, the 'financial' CfD suggested by Schlecht et al. [55] mitigates both price and volume risks by incorporating aspects related to forward contracts. The financial CfD further incentivizes the production of high-value electricity, for example through the alternative design of wind turbines, as discussed below. In the reform of the EU electricity market design [56], the emphasis is on providing power providers with stable revenues and shielding consumers from price volatility. There is, however, a paradox linked to the shielding of consumers from price volatility, as it may reduce the incentives for demand-side flexibility. This is an important aspect to bear in mind when designing the electricity market.

2.1.6 Design of VRE technologies

An additional option not addressed in the review of Lund et al. [28] is the design of VRE technologies to reduce variability. Hirth [58] has demonstrated that the value of wind power decreases by 20%–50% when wind power supplies 30% of the demand, and a similar decline in value is seen for solar power at just 15% market penetration. The reason for this decline in value is that the installed capacity has a similar production profile, leading to self-cannibalization when excessive generation occurs simultaneously. However, as noted by the author, the absence of flexibility provided by reservoir hydropower and an elastic demand function may lead to an overestimation of the decrease in the value factor for wind and solar power. By designing wind turbines in a different way, production can be optimized, thereby increasing the value of the produced electricity. In a study conducted by Hirth and Müller [59], conventional wind turbines are compared with turbines that are designed for lower wind speeds, in that they feature larger rotors relative to the generator, resulting in a lower specific power. These low-specific-power turbines also have an increased hub height. The results show that the value of wind power increases by 15% when turbines are specifically designed for low-wind-speed conditions. On the same topic, Hodel et al. [60] have investigated the interplay that occurs between adapted wind turbine designs and other flexibility measures, such as batteries and flexible hydrogen production. They have concluded that adapted wind turbines remain competitive even when other flexibility measures are available, and that it is more cost-effective to alter the specific power rather than increase the hub height. Regarding solar power, while single- or dual-axis tracking systems can increase output levels, they also increase both the investment and maintenance costs. A simpler solution is to orient the solar panels towards the west or east, which lowers the total production level but increases the value of the electricity produced.

2.2 Work related to the appended papers

In the following subsections, the relevant research found in the literature regarding the main topics of this thesis is summarized. Section 2.2.1 provides an overview of the research that has been conducted on the use of hydrogen to shift electricity generation in time, Section 2.2.2 focuses on the modeling of hydropower, and Section 2.2.3 presents studies regarding inter-annual variations in energy systems modeling.

2.2.1 Using hydrogen to shift electricity generation in time

In a review published by Apostolou and Enevoldsen [61], they state that there have been numerous scientific studies of wind-hydrogen systems during the past 20 years. While some of the earlier studies explored the conversion of hydrogen back into electricity, the majority have focused solely on demand-side management of the electrolysis process. Furthermore, most of the early studies investigated the impact of a given hydrogen storage system on the operation of a given electricity system, thereby neglecting the interdependencies between investments in different technologies.

In terms of using hydrogen to shift electricity generation in time, i.e., through the application of electrolyzers, hydrogen storage, and reconversion technologies to convert hydrogen back to electricity, fuel cells (FC) have featured commonly as a reconversion technology in the literature, e.g., Ferrero et al. [62], Fang et al. [63], and Ishaq et al. [64]. Pathways for the reconversion of hydrogen-utilizing technologies other than FC have been examined by, for example, Welder et al. [65]. Their findings indicated a preference for combined cycle gas turbines (CCGT) over open cycle gas turbines (OCGT), FC, and gas engines. However, since the reconversion technologies were evaluated in separate model runs, the study conducted by Welder et al. [65] does not address how these different reconversion technologies, given their distinct technical and economic characteristics, potentially complement one another within the modeled energy system. The reconversion of hydrogen in CCGT has also been included in the work conducted by Jülch et al. [66], who studied the levelized cost of storage (LCOS), as well as the reconversion of pure hydrogen in CCGT, they evaluated synthetic natural gas use in CCGT, 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 CCGT fueled with synthetic natural gas (SNG). However, in similarity to the work of Welder et al. [65], Jülch and colleagues modeled the different options in separate model runs, which meant that the interactions between the different technologies were not captured. Cloete at al. [67] have investigated the utilization factors of different technologies in a future energy system in Germany, in which hydrogen is used both for industrial processes and as energy storage within the electricity system. They have concluded that independently of how hydrogen is produced and where the hydrogen production is located in relation to the electricity generation and demand centers, various technologies will experience low utilization factors, and thus erode the cost savings from other benefits of a certain scenario. Their work included hydrogen-fueled gas turbines, although, similar to both the Welder et al. and Jülch et al. studies, no analyses of either the installed capacity or the operation of these hydrogen-fueled gas turbines were presented.

In considering the most-important technical aspects and challenges associated with utilizing hydrogen as a fuel in gas turbines, Zhou et al. [68] have provided a comprehensive overview. A major challenge, as emphasized by Zhou and colleagues, is the combustion of hydrogen. Several research groups have studied the impact of hydrogen on flame stability, highlighting the critical importance of this factor. Liu et al. [69] have concluded that hydrogen-enriched methane significantly affects flashback limits, which occur when the flame speed exceeds the fuel injection velocity, causing the flame to move upstream into the burner. Moreover, An et al. [70] have identified flame blow-out as a risk during the transitions between flame shapes. Furthermore, Li et al. [71] have investigated the flame stability of hydrogen-enriched syngas, discovering that flame stability decreases at a concentration of 50 vol.-% hydrogen.

Regarding the impact on power output during hydrogen blend-in, Ciani et al. [72] have demonstrated that hydrogen at 50 vol.-% can be mixed with methane without derating the power output. In a separate study, Bothien et al. [73] have validated these findings in a test facility and concluded that stable combustion can be achieved with up to 70 vol.-% hydrogen using staged combustion techniques, with only minor reductions in power output anticipated at hydrogen levels exceeding 70 vol.-%. Magnusson et al. [74] have reported similar outcomes in a full-engine test with 60 vol.-% hydrogen, maintaining stable combustion and nitrogen oxide (NOx) emissions at less than 25 parts per million (ppm). Furthermore, a report from a gas turbine manufacturer association [75] has indicated that mixing ratios of 60 vol.-% hydrogen are currently feasible in most of their gas turbines. Some suppliers, such as Siemens [76] and Kawasaki [77], claim to achieve higher mixing ratios, with Kawasaki asserting full fuel flexibility, meaning that they have the ability to mix hydrogen and methane across the full range from 0% to 100% hydrogen.

Gas turbines are renowned for their operational flexibility, as well as their fuel flexibility, as described by both Campbell et al. [78] and Huth and Heilos [79]. This fuel flexibility encompasses a wide range of fuel options, from pure methane to by-product gases from refineries (primarily composed of propane and butane), gases with high inert gas contents (N_2, CO_2), syngas containing 25%–50% H_2 and 35%–65% CO, and liquid fuels such as bio-ethanol [80] and bio-diesel [81]. Finally, González Álvarez et al. [82] have investigated the impacts of various hydrogen-based fuels derived from biowaste as potential alternatives to natural gas. They have concluded that all the hydrogen-based biofuels examined exhibit higher turbine efficiencies compared to natural gas. Notably, a mixture that contained 93.5% hydrogen and 6.5% CO_2 demonstrated lower combustor outlet temperatures and higher efficiency than natural gas, while maintaining similar aerodynamic properties.

In summary, there is growing interest among gas turbine suppliers to utilize hydrogen in gas turbines as a means to reduce CO_2 emissions. Furthermore, there is a significant body of work in the literature addressing the combustion process of hydrogen in gas turbines and the associated challenges. However, although some energy system studies include the option to reconvert hydrogen in gas turbines, none of the studies to date have explored comprehensively the investments and operation of these hydrogen-fueled gas turbines or assessed the system value that can be attained by deploying a hydrogen pathway to shift electricity generation in time. The pathway for shifting electricity generation over time via hydrogen is examined in **Papers I–III**, which evaluate whether hydrogen-fueled gas turbines can provide system value despite the low round-trip efficiency, a concern that is frequently highlighted in this context.

2.2.2 Hydropower in energy systems modeling

Being a dispatchable *and* flexible carbon-free generator, reservoir hydropower is anticipated to provide increasing value to the system as the share of intermittent generation increases [83]. However, the flexibility of hydropower is constrained by several factors, including the allocation of plants and reservoirs along river systems, the characteristics of the reservoirs, and the delays caused by connecting waterways within a river system [84]. Another important aspect is the impact of environmental permits, which impose restrictions on minimum and maximum water levels and water flows. Technical considerations include head-dependent generation and limitations on discharge flow changes due to the risks of pressure waves and cavitation. Furthermore, since the head[3] varies with the water levels both upstream and downstream of a hydropower plant – which in turn are affected by both the generation level and water inflow rate – hydropower generation constitutes a non-linear system.

Several studies have included all or some of the abovementioned hydropower characteristics in detailed hydropower models [85]–[90]. Due to the complex nature of hydropower, these studies have applied models that are non-linear, contain integer variables or are stochastic. However, due to computational limitations, such implementations are not suitable for energy systems models that include energy storage, electricity trade between regions, and demands that are flexible in time, and ones that have a high temporal resolution (in general, at least 1 year with hourly time resolution). Thus, in energy systems models, hydropower is commonly represented by aggregating the turbine and reservoir capacities into a single turbine and reservoir capacity per geographic region, a minimum and maximum generation level, and a time-resolved water inflow. An additional factor is that these models are usually solved with perfect foresight, such that future inflows can be valued already in the first time-step of the modeled period. This implementation is commonly found in the literature in relation to sophisticated energy systems models [83], [91]–[95]. The downside of this hydropower implementation is that it tends to overestimate the flexibility of hydropower, as concluded in [84] and discussed in [83].

There have been some attempts in the literature to include hydropower with a higher level of technical detail in energy systems models. Ramírez-Sagner and Muñoz [96] have compared the system impacts of linear and non-linear implementations of head-dependency, albeit with a low temporal resolution and omitting energy storage, transmission between nodes, and flexible demands. They have concluded that a linear implementation underestimates investments in dispatchable technologies, and correspondingly overestimates investments in variable generation technologies, as compared with the results obtained for non-linear implementation of head-dependency. Stevanato et al. [97] have used two soft-linked models to allow for non-linear head-dependency, evaporation losses, and cascade effects along a river, albeit without capacity investment decisions and with a relatively limited number of nodes (7). Liu et al. [98] have applied a method that captures the cascade effects along rivers in a Chinese electricity system, including both energy storage and trade between the 31 nodes modeled. However, as the hydropower was not evaluated in detail, it is difficult to assess the benefits of the applied method,

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[3] The height difference between the inlet and outlet, corresponding to the potential energy converted to power in the turbine.

considering both the hydropower dispatch and the impacts on investment decisions in other technologies.

In contrast to the detailed hydropower models described in [85]–[90], Ek Fälth et al. [84] have developed a linear hydropower model with a high level of accuracy compared to the full non-linear model that was developed in parallel. This linear model could potentially be implemented directly in energy systems models, although more importantly, it has been used in a comprehensive analysis of the ability of Swedish hydropower to sustain generation at high levels during longer periods with energy droughts, e.g., during low-wind periods [99]. The evaluation concludes that Swedish hydropower can sustain 67%–92% of its installed capacity for 3 weeks, depending on the time of year, with the higher values being related to the spring flooding. These results, along with losses due to high, sustained generation, are included in the Extended hydropower equivalent in **Paper IV**, a study that aimed to improve the representation of reservoir hydropower in energy systems modeling and to evaluate the future role of Swedish hydropower.

2.2.3 Modeling of inter-annual weather variations

Historically, energy systems modeling has typically incorporated meteorologic data for only a single year. These data, comprising precipitation, temperature, and capacity factors for wind and solar power, are usually chosen from a representative year, such as 2012 [100], for which the annual generation levels of wind, solar, and hydropower correspond to the expected average production levels over a longer time period. However, in recent years, concerns have been raised with respect to inter-annual variations, leading to an increased frequency of multi-year modeling. From the studies that have included multi-year modeling, the following conclusions can be drawn: i) wind power exhibits larger inter-annual variations compared to solar power [23][101]; ii) larger wind turbines are more severely impacted by multi-decadal wind variations than smaller turbines [101]; iii) long-duration storage (>10 hours) plays an important role in balancing inter-annual variations [102][103]; iv) operational costs may increase when the dispatch year differs from the year for which the system was designed [103]; and v) during the transition to a net-zero carbon emissions system, CO_2 emissions may fluctuate as fossil-fueled power plants are the marginal producers that balance the inter-annual variations in VRE generation. This is an important consideration when setting decarbonization targets on a year-by-year basis [100].

Incorporating multiple years into energy system models renders them complex and mathematically challenging. This complexity is particularly pronounced when also including a high temporal resolution to capture accurately the patterns of production from VRE and flexibility measures. In addition, ensuring a sufficiently broad geographic scope with electricity trade between regions to facilitate geographic smoothing of VRE variations increases the mathematical and computational burdens. Thus, various methods have been applied to study the effects of inter-annual variations in energy systems. One such method is time-series analysis, as applied in previous studies [23][104]. Another common approach is to exclude the investment decision and focus solely on optimizing the dispatch for a given capacity mix, as seen in various studies [100][102][105].

Considering studies that have included the optimization of both investments and dispatch, Ruhnau and Qvist [106] have investigated the German electricity system using 35 years of meteorologic data. One of their main findings is that a 'normal year' requires only half as much storage capacity as the entire 35-year period. However, representing Germany as a single region without cross-border trade with neighboring countries excludes the benefits of geographic smoothing. Zeyringer et al. [107] have applied a method with two soft-linked models to investigate the British electricity system over 11 meteorologic years. They conclude that reinforcement of the transmission system consistently leads to a reduction of the system cost, and that flexible generation capacity and energy storage in general are deployed close to demand centers. However, due to the separation of investment decisions and dispatch optimization, the investments do not recover their costs, neither during individual years nor over the full 10-year period. Ullmark et al. [108] have proposed a method to select a limited number of meteorologic years and assigns weights to these years so as to represent the most-important events during the 39 years included. The results show that the method can represent the net-load variability of multiple decades using data from only a few years. Moreover, the results indicate that high-net-load events with low frequency are effectively covered by investments in gas turbine capacity and long-term biomethane storage capacity.

Hilbers et al. [109] and Grochowicz et al. [110] both propose novel approaches to ease the computational burden associated with modeling future energy systems over several decades. Hilbers et al. suggest reducing the number of timesteps by selecting them based on their importance, such as the net-load level. Their study concludes that this method outperforms other options in reducing computational costs. However, because it does not maintain consecutive order of timesteps, it fails to accurately model long-term storage. In contrast, Grochowicz et al. apply a novel method exploring near-optimal solution spaces, enabling their model to run for 41 meteorological years with one node per country in Europe. This approach yields robust solutions for all years, with costs less than 5% higher than the most expensive year's solution. Their results also favor onshore wind power over offshore wind power and identify Year 1985 and Year 1987 as the most-challenging years with a narrow, near-optimal feasible solution space.

It is clear from this brief summary that multiple approaches exist to address the computational challenges associated with multi-year modeling, taking into account the specific research question investigated. In **Paper V**, another method is proposed with the aim of evaluating the economic performances of technologies during years other than the one upon which the capacity mix was based.

3 Method

This chapter presents the method used for the linear techno-economic optimization models applied in this work. Section 3.1 begins by describing some methodologic considerations and the rationale behind the chosen method. Section 3.2 provides an overview of the two models used, while Section 3.3 offers detailed insights into the modeling of hydrogen-fueled gas turbines and hydropower. Finally, Section 3.4 gives an overview of other assumptions made and the input data.

3.1 Methodologic considerations with energy systems modeling

Energy systems modeling, which is a broad term that is subject to context, is a research field with multiple methodologic alternatives depending on the research focus, as discussed previously [111]. In this thesis, the research is focused on the interplay between supply and demand in a future European energy system that has an assumed high level of electrification. Thus, instead of applying a general equilibrium model with the energy sector included as a part of the overall economy, a partial equilibrium model is applied to model the energy sector in isolation without endogenous interactions with other sectors within the economy. The argument for using a partial equilibrium model is that the model can contain a higher level of detail regarding the technical, spatial, and temporal aspects, features that are critical when specifically evaluating the interplay between the supply and demand of electricity. The absence of interactions with adjacent sectors does, however, come with some disadvantages. One particular disadvantage relates to the use of biomass for power production, which in a partial equilibrium model must be limited exogenously, while a general equilibrium model would allocate the biomass resource to sectors endogenously, considering, for example, land use competition between forestry, agriculture, and dedicated energy crops [112].

Another methodological alternative involves deciding whether to use simulation models or optimization models. These two model archetypes have been described and compared previously [113], whereby optimization models are described as *prescriptive*, seeking to find the best solution (e.g., capacity mix and dispatch of both generation and storage technologies) to a problem relative to the decision criteria, for example, to minimize the total system cost. Simulation models are instead described as *descriptive*, in that they use different scenarios to evaluate the impacts on selected parameters, such as costs, emissions, and energy supply. Simulation models do not include decision variables, which means that the capacity mix is defined exogenously, and the dispatch is defined by rules that specify the technology priority, e.g., according to the operational costs. When focusing on the interplay between supply and demand, applying a simulation model with prescribed rules for technologies would make little sense, so optimization models are applied in all of the appended papers.

Another trade-off that must be considered is the balance between accurate representation of the technologies and system aspects, such as spatial and temporal resolution, and flexibility measures to manage VRE variations. One option is to model each power plant (or wind park, for example) individually, i.e., using a unit commitment model. With this approach, techno-economic aspects such as efficiency and specific investment cost may differ depending on, for example, plant size, such that the cost-optimal dispatch will be better refined. However, this approach entails a mixed-integer mathematical formulation, creating a significantly more-complex mathematical problem to be resolved. To investigate the interplay between supply and demand in future energy systems, this work instead applies linearized investments, i.e., each technology is aggregated to a single unit per region. The benefit of this implementation is a simplified mathematical problem, allowing for a larger spatial scope, higher temporal resolution, and more flexibility options to manage VRE variations.

not the only ones that need to be taken into account when working with energy systems modeling. This section does not aim to provide a comprehensive overview of all aspects of modeling, but rather to highlight some of the important and overarching considerations. Detailed descriptions of the models used are presented in the subsequent sections, while other aspects of the modeling are discussed in Chapter 5.

3.2 Linear optimization modeling

The models employed in the appended papers are linear techno-economic optimization models that are designed to minimize the total cost of an energy system, including the electricity, heating, and industrial hydrogen demands. The models account for both the investment decisions and operational dispatch of generation technologies, electricity transmission technologies, and energy storage technologies. The models encompass both the historical electricity demand and new demands arising from an electrified transport sector and various industrial processes that are either directly electrified or indirectly electrified through hydrogen. Moreover, the models account for district heating demand in addition to electricity demands. Two distinct models have been utilized throughout this work. In **Paper I**, the ELIN-EPOD model is applied, which is further described in Section 3.2.1. Conversely, **Papers II–V** employ the Multinode model, which is described in Section 3.2.2.

The two models differ mainly with respect to their investment horizons and whether they consider existing capacity, whereas they are very similar regarding equation structure and have the same objective function, to minimize the total system cost, as displayed in Equation (1)[4]. The costs considered are investment cost, C_p^{inv}, fixed and variable operational costs, C_p^{fixOM} and C_p^{OPEX} (including fuel cost), respectively, part-load cost, C_p^{part}, and start-up cost, C_p^{start}. Since the investment cost is included in the objective function, there will be hours during which the investment cost sets the marginal cost of electricity. Thus, all the technologies will always recover at least their annualized cost, including also the operational costs. The recovery of investments is considered in all of the appended papers, although it is examined in greater detail in **Paper V**.

$$\min \sum_{r \in R} \Bigg(\sum_{p \in P} i_{r,p} \cdot C_p^{inv} \cdot a_p + \sum_{p \in P} (i_{r,p} + \mathrm{E}_{r,p}) \cdot C_p^{fixOM} + \sum_{t,p \in T,P^{gen}} g_{r,t,p} \cdot C_p^{OPEX} + \sum_{t,p \in T,P^{gen}} \left(g_{r,t,p}^{active} - g_{r,t,p}\right) \cdot C_p^{part} + \sum_{t,p \in T,P^{gen}} g_{r,t,p}^{start} \cdot C_p^{start} + \sum_{r',b \in \mathrm{R},B} i_{r,r',b}^{trans} \cdot C_{b,r,r'}^{trans} \Bigg) \qquad (1)$$

[4]**Variables**: $i_{r,p}$, investments in region *r* for technology *p*; $g_{r,t,p}$, generation in region *r* during timestep *t* for technology *p*; $g_{r,t,p}^{active}$, capacity ready for operation in region *r* during timestep *t*; and $g_{r,t,p}^{start}$, capacity starting from cold in region *r* during timestep *t*. **Parameters**: $\mathrm{E}_{r,p}$, existing capacity in region *r* for technology *p;* and a_p, annuity factor for technology *p*.

3.2.1 The ELIN-EPOD model

In **Paper I**, 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. This method is applied to investigate when in time the hydrogen-fueled gas turbines become competitive and, thereby, provide system value. The existing capacity is retrieved from the Chalmers Energy Infrastructure databases [114], which entail almost full coverage of power plants with a rated electric capacity of >10 MW. This model is divided into two parts: the long-term electricity investment model ELIN; and the operational, electric power dispatch model EPOD (Figure 2). 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 [115] is employed. The ELIN model was originally developed by Odenberger et al. [116], and further developed by Göransson et al. [117]. The EPOD model was originally developed by Unger et al. [118], and further developed by Göransson et al. [117] and Goop et al. [119].

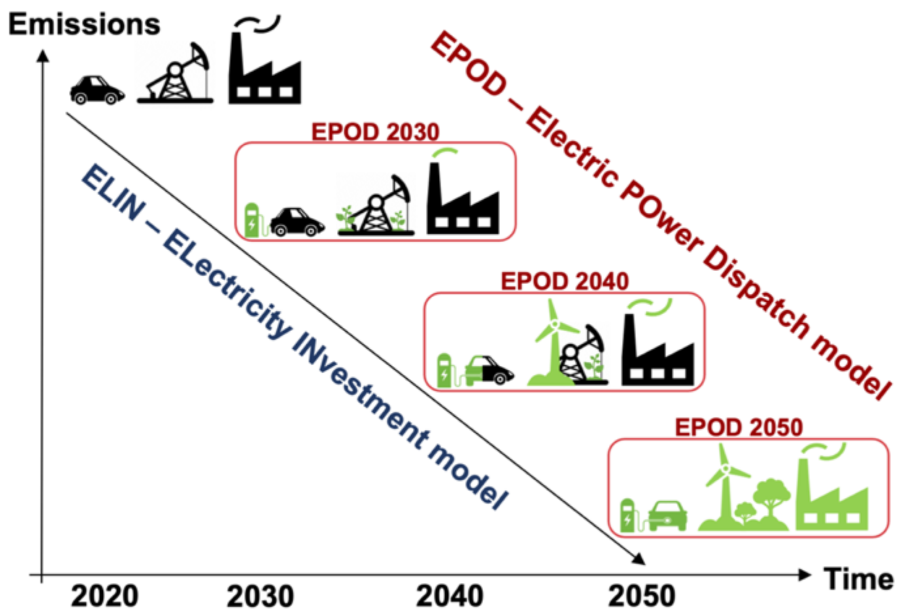

Figure 2: Visualization of the ELIN-EPOD model used to model the transition process of an energy system.

3.2.2 The Multinode model

The Multinode model is employed to study the interplays between generation technologies, storage technologies, and flexible demands in a future European energy system without direct carbon emissions from the sectors included. In addition, a greenfield approach is utilized, disregarding all existing capacities, with the exceptions of hydropower and transmission lines that are likely to remain operational for an extended period, as well as nuclear power plants with an expected lifetime extending beyond Year 2050. Thus, the projected technology costs for Year 2050 are used, as obtained from the Danish Energy Agency [120] and the International Energy Agency [121]. The model was originally formulated by Göransson et al. [122], and subsequently refined by Johansson et al. [123], Ullmark et al. [124], and Toktarova et al. [125].

The model is visualized in Figure 3, displaying the different demands included and the technologies that are available for investments (for a detailed description, see Section 2.1 in **Paper V**). The system displayed in Figure 3 is represented in each of the regions included in the geographic scope modeled (further described in Section 3.4.3) and these regions are connected with transmission capacity. The transmission capacity is represented by the net-transfer capacity (NTC), i.e., the transmission capacity that can be guaranteed at all times, disregarding the possibility of malfunctions. On the right-hand side of Figure 3, the aspects of the system that have been subjected to evaluation are highlighted. These include industrial production flexibility, indirect electrification of the transport sector, with or without the possibility to shift electricity generation via hydrogen, and the cost sensitivities of electrolyzers and hydrogen storage.

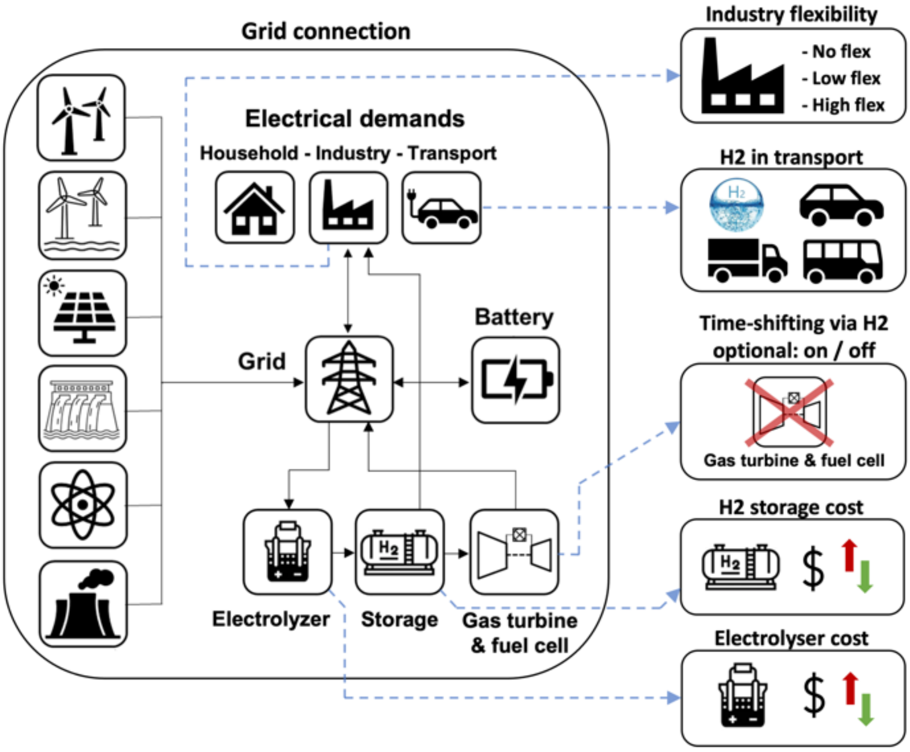

Figure 3: A visualization of the Multinode model showing the demands included, the technologies available for investments, and some of the aspects investigated during the work highlighted on the right-hand side of the figure.

3.3 Technologies in focus

As mentioned in the previous section, the models permit a wide array of technologies. Since hydrogen-fueled gas turbines and hydropower play central roles in the appended papers, these two technologies are discussed in detail in the following subsections.

3.3.1 Hydrogen-fueled gas turbines

The investment options for hydrogen-fueled gas turbines, both OCGT and CCGT, include mixing ratios of 30, 50, 77 and 100 vol.-% of hydrogen in biomethane. Regarding the mixing ratio, it should be noted that the volumetric mixing ratio deviates significantly from the corresponding energy share from hydrogen, as shown in columns 1 and 2 in Table 1. The investment cost for hydrogen-fueled gas turbines is assumed to be higher than that for conventional gas turbines and, furthermore, it is assumed to increase with the allowed upper mixing rate of hydrogen, as shown in the right-most column in Table 1. Although the cost increase for hydrogen-compatible gas turbines has been discussed with an industrial partner, there is some uncertainty because there are no[5] commercially available hydrogen-fueled gas turbines and the experience gained from real-life operation of hydrogen-fueled gas turbines is limited. Thus, a sensitivity study of the investment cost of hydrogen-fueled gas turbines was conducted in **Paper II**.

Table 1: A summary of the mixing ratios of hydrogen in biomethane that have been included in the work, together with the assumed additional investment cost to allow for hydrogen blend-in.

Upper mixing rate of H_2 [vol.-%]	Upper mixing rate of H_2 [energy-%], $\gamma_p^{H2,up}$	H_2GT[6] investment cost [% of ref. CAPEX]
30	11	101
50	23	103
77	50	105
100	100	115

The different options for hydrogen-fueled gas turbines are included in the set P^{H2GT}. Regarding the mixing of hydrogen, two options have been studied. *Flexible mixing* allows hydrogen to supply any fraction of the energy input required in a given timestep, ranging from zero to the upper mixing limit $\gamma_p^{H2,up}$, as shown in Table 1. The flexible mixing is controlled by Equations (2a-b)[7]. With *Fixed mixing*, Equation (2b) is replaced by Equation (2c), ensuring that the share of energy from hydrogen is exactly the upper mixing limit set by the investment decision.

$$g_{r,t,p} \cdot \frac{1}{\eta_p} \leq e_{r,t,p}^{H2} + e_{r,t,p}^{biomethane} \qquad (2a)$$

$$e_{r,t,p}^{H2} \leq \gamma_p^{H2,up} \cdot g_{r,t,p} \cdot \frac{1}{\eta_p} \qquad (2b)$$

$$e_{r,t,p}^{H2} = \gamma_p^{H2,up} \cdot g_{r,t,p} \cdot \frac{1}{\eta_p} \qquad (2c)$$

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

[5]Some gas turbine suppliers claim that their gas turbines can handle up to 75 vol.-% of hydrogen; however, as competition is severe, the costs have not been disclosed.
[6]Hydrogen-fueled gas turbines.
[7]**Variables**: $g_{r,t,p}$, generation in region *r* during timestep *t* for technology *p*; $e_{r,t,p}^{H2}$, the energy supplied from hydrogen in region *r* during timestep *t* for technology *p*; and $e_{r,t,p}^{biomethane}$, the energy supplied from biomethane in region *r* during timestep *t* for technology *p*. **Parameters**: η_p, electrical efficiency for technology *p*; and $\gamma_p^{H2,up}$, upper hydrogen mixing rate for technology *p*.

3.3.2 Reservoir hydropower

In energy systems modeling, reservoir hydropower is typically represented using so-called *hydropower equivalents*. An equivalent consists of a set of constraints that define how hydropower can operate. Since hydropower is often mathematically complex to model with a high level of accuracy, the equivalents used in energy systems modeling are greatly simplified. A common feature of the equivalents used in energy systems modeling is that hydropower is represented by a single turbine and reservoir capacity per region, thereby ignoring the dependencies that exist between power stations within river systems. Furthermore, the generation levels and storage capacities are often constrained only by the upper and lower levels. Consequently, generation is primarily limited by access to water, which is typically modeled as a time-resolved inflow of water (energy).

In **Paper IV**, two alternative hydropower equivalents are evaluated with the ambition to limit the otherwise overestimated flexibility of hydropower. For the equivalent that is termed *Extended*, additional constraints are introduced, explicitly to capture physical limitations. These limitations take into account: local water shortages in the parts of a river that restrict sustained weekly generation; losses due to spillage past smaller power stations when weekly generation remains high; and the minimum diurnal generation to prevent flooding smaller reservoirs during extended periods of low hydropower generation, such as those caused by prolonged periods of high-level wind power generation. The second equivalent, named *Bi-level*, implicitly incorporates the aforementioned limitations, albeit without the explicit constraints found in the *Extended* equivalent. Instead, it narrows the range expressed by the maximum and minimum generation levels and applies different upper and lower levels of generation during different parts of the year. This is accomplished by solving a bi-level optimization problem, which involves two levels of optimization. The lower-level optimization problem is to maximize the profit in a detailed hydropower model, which is subjected to an electricity price profile. The upper-level optimization problem is then to minimize the hourly difference in electricity generation between the detailed model and the equivalent model, such that the maximum and minimum levels of generation during different parts of the year can be determined. Further details can be found in Section 2.1 of **Paper IV**.

3.4 Assumptions and input data

The following subsections lists the assumptions made regarding new demands, weather data, and other factors such as the geographic scope and how biofuels are managed in the model.

3.4.1 New demands

The electricity demand in the model is divided into three categories: traditional, transport, and industry. The ‘traditional’ electricity demand refers to the historical demand, and the annual consumption level is obtained from Eurostat [126] and subjected to an hourly demand profile obtained from the European Network of Transmission System Operators (ENTSO-E) [127]. In **Papers I–III**, the traditional electricity demand is sourced from Year 2012, whereas **Paper V** utilizes historical data spanning the period of 2010–2019. However, in **Paper IV**, since statistics were unavailable for Year 1991 and Year 1992, a synthetic ‘traditional’ electricity demand was generated using the tool developed by Mattson et al. [128].

The future electricity demand for transportation is based on the work carried out by Taljegård et al. [129]. Thus, for Year 2050, all road transport units [electric vehicles (EV), light trucks (LT), heavy trucks (HT), and buses] are assumed to be electrified. The charging of EVs can to some extent be optimized by allocating the charging to low-cost hours (in contrast to direct charging upon arrival), thereby providing a system service. The share of EVs that is subjected to an optimized charging strategy is set at 30%. There is also an option that allows indirect electrification of transportation via hydrogen. In this case, a certain share of each vehicle category is indirectly electrified *via* hydrogen (EV, 12%; LT, 19%; HT, 28%; buses, 27%), according to the European Union Hydrogen Roadmap [130]. Assumptions regarding annual driving demands, hourly driving patterns, and electricity consumption per kilometer are all obtained from [129] and summarized in Appendix C of **Paper III**.

Considering the industrial demands, the steel, cement, and ammonia production processes are included, all of which are assumed to be fully electrified by Year 2050. The steelmaking process is assumed to be electrified using hydrogen direct reduction of iron ore and electric arc furnaces for the production of crude steel, which according to Fischedick et al. [131] represents the most-attractive route for future steelmaking from both the economic and environmental perspectives. For cement production, it is assumed that a plasma burner will replace the current combustion process. In the case of ammonia production, the shift to electrified production involves replacing the hydrogen produced from natural gas with hydrogen produced *via* electrolysis. The electricity and hydrogen demands per ton of each commodity (steel, cement, ammonia) are summarized in **Paper III**, with the future quantities of these commodities assumed to remain at current levels. In **Paper IV**, additional electricity demands are assumed specifically for Sweden, taking into account planned battery factories and potential thermochemical recycling of plastics (through the use of hydrogen).

3.4.2 Weather data

The data on wind power and solar PV potentials and generation profiles are acquired using the tool developed by Mattson et al. [128]. The potentials for wind power and solar PV are given in terms of maximum installed capacity using typical power densities (W/m^2) for solar and wind farms. The suitable land area is calculated by removing pixels where large-scale wind and solar plants cannot be located, e.g., due to protected areas, unsuitable land cover or too-high population density. The assumed area available for wind and solar power is then assumed to be a certain fraction of the total suitable land area, in the range of 4%–8%.

Both onshore and offshore wind power are divided into a number of wind classes based on the 40-year average wind speeds taken from the Global Wind Atlas version 3.0 [132], where all onshore pixels, for example with average wind speeds in the range of 2–5 m/s, belong to onshore Wind class 1. Hourly wind speeds taken from ERA5 [133] are then used to generate hourly production profiles for the corresponding wind classes. To generate the production profiles, which translate wind speeds into hourly wind power output, a power curve for wind farms rather than individual wind turbines is applied. This approach introduces a smoothing effect between wind speed variations and power output. Furthermore, since the hourly wind speed represents an average of all pixels within a wind class, a regional geographic smoothing effect is incorporated into the profiles used in the model.

In **Paper IV**, the technical resolution of onshore wind power is improved. For onshore wind classes with low average wind speeds, we assume a wind power technology with a low specific power (SP), i.e., a large rotor and a small generator, yielding higher electricity production at lower wind speeds, although at a higher specific investment cost. These wind turbines have an SP of 100 W/m^2 (sweep area) and a tower height of 150 m, while wind turbines in wind classes with higher average wind speeds have an SP of 300 W/m^2 and a tower height of 100 m. In addition to the higher investment cost for SP100, larger rotors also yield wind turbines that have to be placed further apart, which means that the potential for installed capacity is reduced. For reference, offshore wind power has an SP of 200 W/m^2 and a tower height of 150 m for all offshore wind classes. The assumptions regarding wind power are based on the results presented by Hodel et al. [60].

3.4.3 Other assumptions

Throughout the current work, various geographic scopes are studied. The primary reason for this approach is to examine how VRE resources in different regions influence factors such as the competitiveness of hydrogen-fueled gas turbines. In general, the geographic scopes are designed to include one focus region and several boundary regions, which facilitate the import and export of electricity to and from the focus region. An example of this, taken from **Paper III**, is shown in Figure 4.

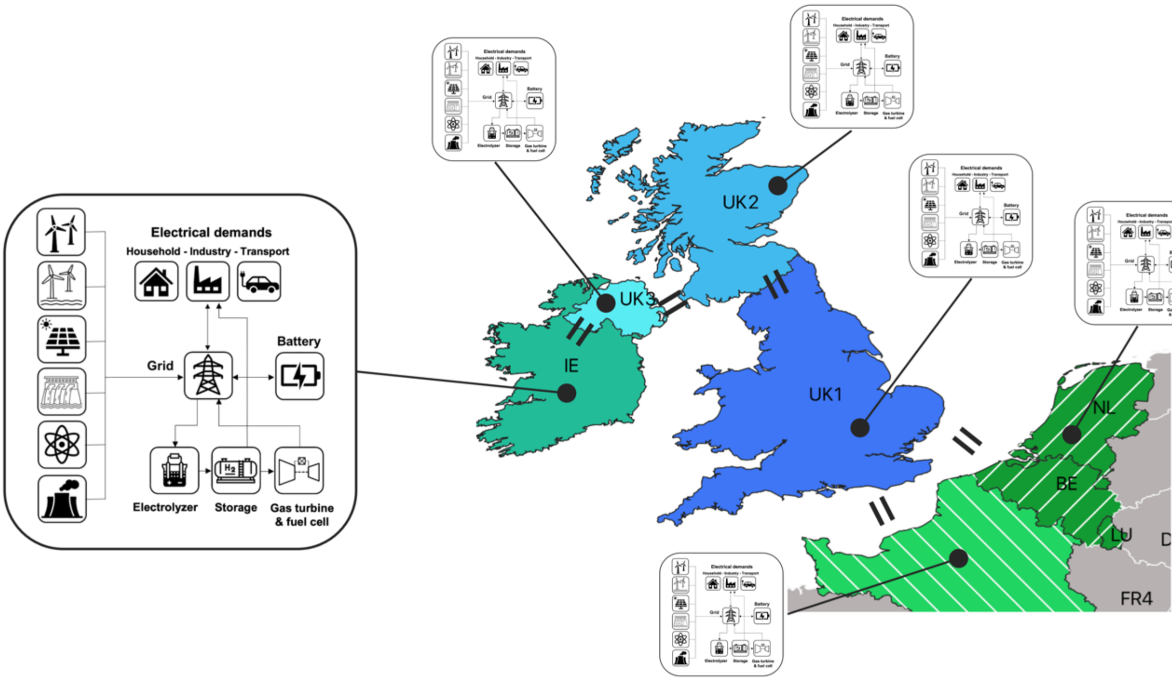

Figure 4: Example of one of the geographic scopes studied. Each colored region attains its own capacity mix, and neighboring regions are connected with transmission capacity.

With regards to biomass, biogenic fuels can be used for a set of different technologies in the model. Solid biomass can be used in either condensing steam cycles or in CHP plants. Biomethane is also available and can be used in gas turbines with or without a CHP configuration. Biomethane is assumed to be produced via the gasification of solid biomass. The gasification process is, however, not explicitly modeled. Instead, a conversion efficiency of 70% is assumed, along with an additional 20 €/MWh in running costs for the gasification process [134]. Thus, for an assumed solid biomass cost of 40 €/MWh, the cost of biomethane becomes 77 €/MWh.

Another potential application of biogenic fuels is in combination with CCS, thereby creating negative emissions, in a process that is commonly referred to as BECCS (Bioenergy with Carbon Capture and Storage). Allowing for negative emissions via BECCS might enable the use of a limited amount of fossil fuels, such as natural gas in gas turbines. However, in this work, it is assumed that BECCS is only used to compensate for residual emissions in hard-to-abate sectors, such as aviation and agriculture. Since electricity generation is not considered to be a hard-to-abate sector, BECCS is not included. This assumption is reinforced by the European Union Taxonomy [135], which mandates zero emissions from power production by Year 2050.

4 Main results

This chapter is divided into three main sections. Section 4.1 describes a comprehensive analysis of the utilization of hydrogen within the energy system, while Section 4.2 elucidates the contribution of hydropower in a future Swedish energy system, and Section 4.3 summarizes the findings related to inter-annual variations. To provide an introduction to the interplay that occurs between the generation technologies, storage technologies, and new demands, a summary of these aspects is presented below.

When modeling future energy systems from a strictly techno-economic perspective, the results typically favor VRE technologies owing to their low costs, particularly when adopting a greenfield approach, i.e., disregarding the current system composition. Consequently, regions that have good wind conditions attract substantial investments in wind power capacity, and correspondingly, regions with favorable solar conditions receive significant investments in solar PV capacity. This implies that the most-cost-effective options to manage the resulting variations will vary across regions. Figure 5 illustrates the modeled supply and demand profiles over a 400-hour period for the UK and Spain, two countries that are characterized by fundamentally different conditions for VRE. In the UK, where variations are predominantly driven by wind power, hydrogen-fueled gas turbines in combination with flexible hydrogen production for industrial demands play an important role in managing these variations. This is because wind variations are of long duration but occur at low frequency, such that large volumes of energy are shifted for relatively long periods, leading to less-costly, albeit less-energy-efficient, storage technology being the most cost-efficient option. In Spain, electricity generation is dominated by solar

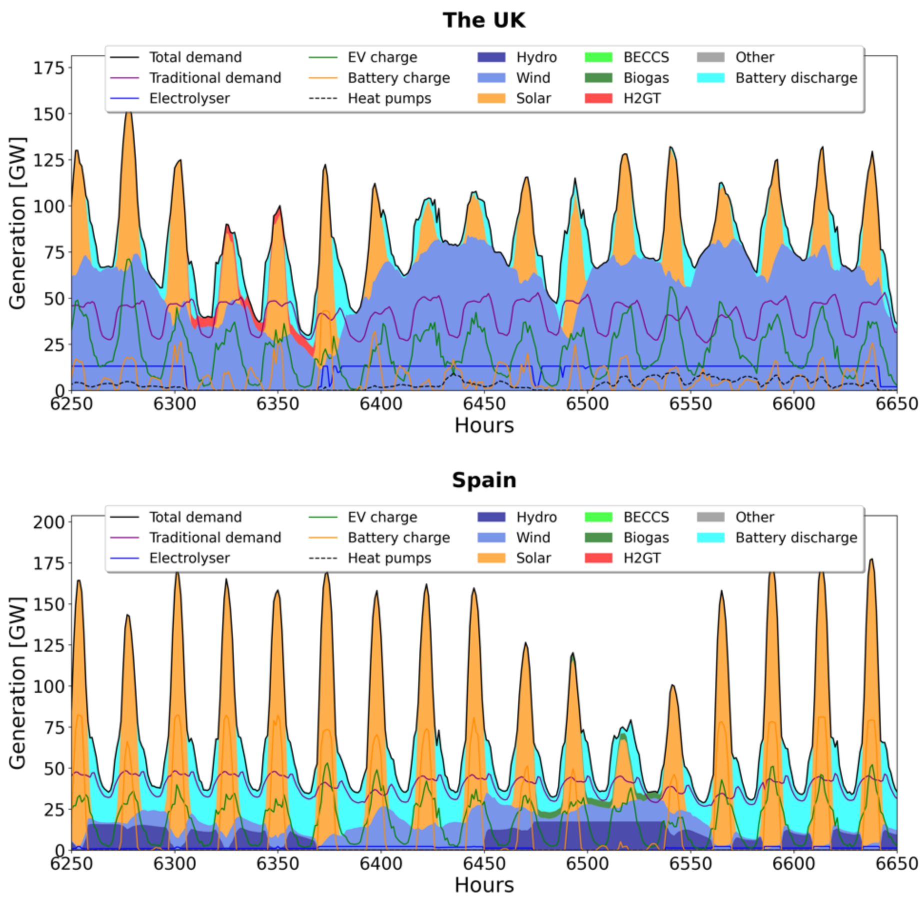

Figure 5: Characteristics of energy systems based on either wind power (the UK) or solar power (Spain), as obtained from ***Paper III****.*

power, which means that the variations are short in duration and occur at high frequency. Consequently, managing these variations primarily entails shifting electricity generation in time through the use of batteries. Yet, as depicted in Figure 5, despite the fundamental disparity in VRE conditions between the two countries, the two capacity mixes include both wind power and solar power. Furthermore, batteries emerge as a cost-competitive option also in the wind-dominated UK, albeit with only 8% of electricity passing through batteries, as compared with 23% in Spain.

As the share of VRE generation increases, it can be expected that the marginal cost of electricity will become more volatile relative to historical wholesale prices for electricity. Figure 6a displays the annual average electricity costs and the volatility index values[8] [136] for both the historical costs and future estimates of costs for electricity in Sweden, the UK, and Spain. Figure 6b displays the electricity cost duration for selected years and scenarios in Figure 6a. The future marginal electricity costs consider two scenarios, each based on specific assumptions regarding the Swedish electricity system. In the 2050 Wind scenario, a total of 22 GW of offshore wind power is enforced in southern Sweden, and in the 2050 Nuclear scenario, a total of 14 GW of nuclear capacity is enforced in the same region. While caution should be exercised when comparing historical and modeled values, it is apparent that the annual average electricity costs remain at levels similar to the historical costs for the three countries, with lower electricity costs in Sweden compared with the UK and Spain.

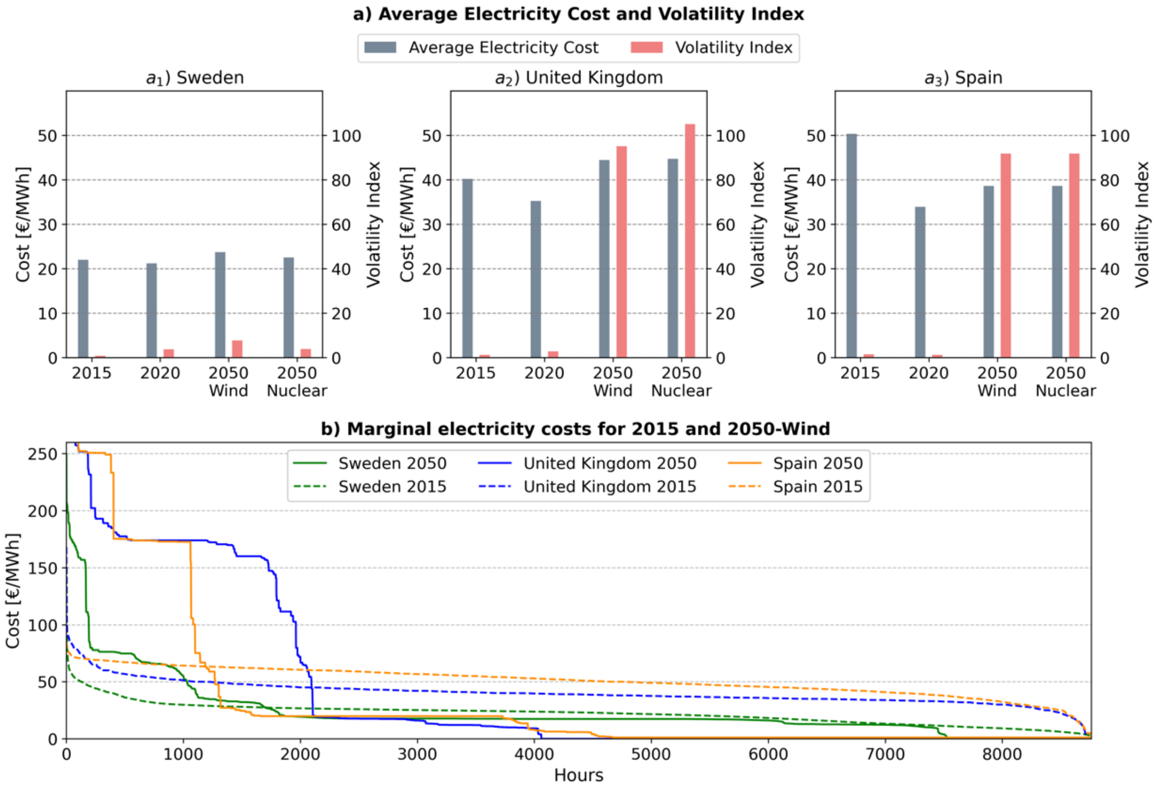

*Figure 6: Historical and future wholesale electricity prices/costs and volatility index values for Sweden (SE3), the UK (UK1), and Spain (ES2), using data obtained from ENTSO-E and **Paper IV**, respectively.*

[8] $I_v = \frac{\int_{t_1}^{t_2} (p_t - p^{average})^2 dt}{100(t_2 - t_1)}$, p_t is the electricity price at time t, and $p^{average}$ is the average electricity price.

Considering the volatility index values, significant disparities are evident between the historical and future electricity costs for the UK and Spain, while the electricity costs exhibit considerably less volatility for Sweden. As illustrated in Figure 6b, the increased values for the volatility index in the UK and Spain stem from a substantial proportion of the hours being characterized by either a zero marginal electricity cost or exceedingly high values, and only a low number of hours during which the electricity cost is at moderate levels. The low volatility index score for Sweden can be primarily attributed to two key factors. First, the large capacity of reservoir hydropower in the Swedish system plays a pivotal role. This flexible technology can balance variations spanning from minutes to weeks, as well as across seasons. Consequently, it facilitates the integration of considerable volumes of wind power without causing significant fluctuations in the marginal cost of electricity. Second, Sweden is assumed to have a substantial industrial hydrogen demand relative to other demands. Thus, wind variations can be balanced with flexible hydrogen production that is facilitated by an over-dimensioned electrolyzer capacity and investments in hydrogen storage capacity.

4.1 The value of hydrogen in future energy systems

The utilization of hydrogen has the potential to confer dual advantages in an energy system that is dominated by VRE generation. One of these advantages entails shifting electricity generation in time, whereby low-cost electricity can be absorbed through hydrogen production, subsequent storage of hydrogen, followed by conversion back to electricity during periods when electricity generation is scarce. The significance and system implications of this process are delineated in Section 4.1.1, with particular emphasis on the UK, given its favorable wind conditions and constrained transmission capacity to neighboring countries owing to its geographic insularity.

As already mentioned, a secondary advantage of hydrogen lies in its flexible production to meet industrial demands, such as in the steelmaking process or for ammonia production. The dynamics of supplying industrial hydrogen demands in a future energy system dominated by VRE are examined in Section 4.1.2. Special attention is paid to exploring how the attributes of the hydrogen demand influence both the system dynamics and the associated cost of hydrogen.

4.1.1 Shifting electricity generation in time via hydrogen

Regarding the transition towards a future decarbonized energy system, it is concluded in **Paper I** that hydrogen-fueled gas turbines become competitive primarily when emissions are constrained to very low levels, meaning that the share of VRE is high and the use of natural gas is limited. In addition, **Paper I** finds that industrial hydrogen demands reduce the necessity to shift electricity generation in time via hydrogen, as flexible hydrogen production also serves to balance variations, with the electrolyzers acting as an 'inverted' peak technology. Furthermore, the utilization of bi-directional charging of EVs, known as vehicle-to-grid or V2G, is found to have a detrimental impact on the competitiveness of hydrogen-fueled gas turbines. However, it is important to note that the use of V2G incurs no additional cost in the modeling, so the impact is likely overestimated.

Since it is concluded that the time-shifting of electricity generation via hydrogen will not be a competitive hydrogen pathway until the European energy system reaches very low carbon emission levels, the remainder of this section focuses on the role and value of this hydrogen pathway in a fully decarbonized energy system, i.e., a system that is compliant with the European Union's ambitions for Year 2050.

To complement the evaluation of hydrogen-fueled gas turbines described in **Papers I–III**, and to analyze further the implications for the system of shifting electricity generation in time via hydrogen, additional model runs have been conducted using the Multinode model. The geographic scope mirrors that used in **Paper III** (see Figure 4), where the British Isles are partitioned into four regions, and two regions in continental Europe are incorporated to facilitate trade. In this complementary study, three distinct scenarios are investigated: flexible mixing of hydrogen in gas turbines; fixed mixing of hydrogen in gas turbines; and without any option for investments in hydrogen-fueled gas turbines. The resulting electricity supply across the entire geographic scope is portrayed in Figure 7a-d, each panel having a distinct biomass cost. Notably, the cost of biomass exerts a significant influence on the total system cost, such that an increase in the biomass cost correlates with a concurrent increase in system value linked to allowing for hydrogen-fueled gas turbines. Certainly, the paramount advantage in relation to the total system cost arises from including hydrogen-fueled gas turbines. Nevertheless, flexible mixing provides an additional advantage, a facet that will be examined in detail later. A final observation is that despite the lower overall system cost, there is a cumulative increase in electricity generation when hydrogen-fueled gas turbines are allowed. This phenomenon is attributed to the unavoidable losses inherent to hydrogen production and reconversion processes.

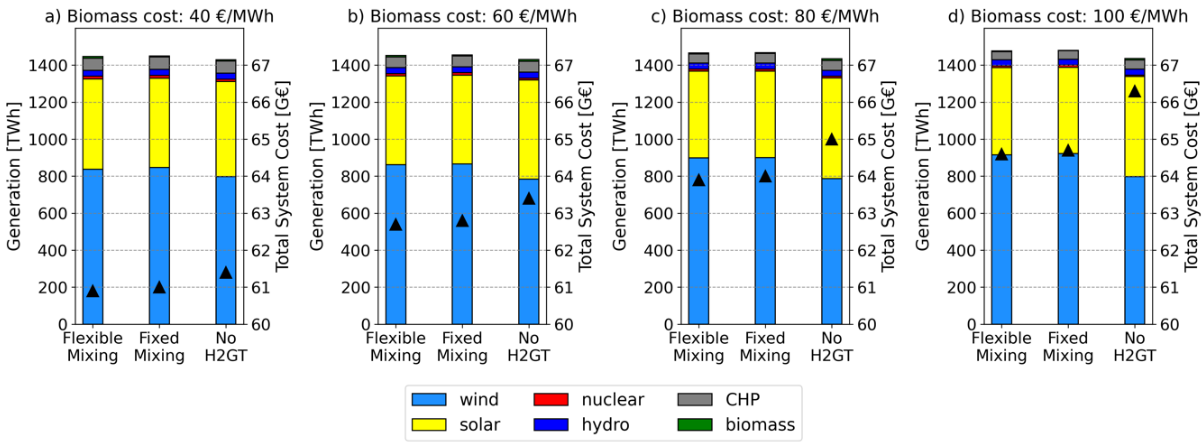

Figure 7: Total electricity supply levels and total system costs for different biomass costs. The results are generated by the Multinode model using the geographic scope displayed in Figure 4.

As depicted in Figure 7, allowing for investments in hydrogen-fueled gas turbines adds value to the system, implicitly suggesting that such investments are made. When assessing the competitiveness of a technology or process for energy storage, in addition to energy efficiency and cost, three key variation characteristics must be considered. The amplitude of the electricity cost variations must be sufficiently large enough to offset the energy loss incurred during a charge-discharge cycle, and the frequency and duration of the variations must be of sufficient magnitude that the annualized investment cost is recovered. All of these aspects are comprehensively captured in the energy systems model applied. Therefore, when investments are made, the technology or process is cost-competitive, as explained in Section 3.2.

For the electricity system context considered here (i.e., the UK, with very good wind conditions and mediocre conditions for solar PV), a consequence of allowing for hydrogen-fueled gas turbines is a transition from solar generation towards a higher proportion of wind power generation. This transition is evident in Figure 7. To elucidate this impact, Figure 8 illustrates the effects on generation from wind and solar power, and on investments in battery storage capacity. Relative to the scenario without hydrogen-fueled gas turbines, the generation from wind power exhibits an increase in the range of 5%–15%, contingent upon biomass cost, when allowing for hydrogen-fueled gas turbines. This uptick in wind power generation is accompanied by a corresponding percentage decline in solar PV generation. However, with wind power constituting a larger share of the generation mix, the total level of generation is increased, as previously mentioned. Considering batteries, the installed storage capacity experiences a reduction in the range of 16%–25%, dependent upon biomass cost, when hydrogen-fueled gas turbines are allowed. This reduction translates to 128–245 GWh of battery storage capacity, which is equivalent to the battery capacity of approximately 1.9–3.6 million electric vehicles, assuming that each vehicle has a battery capacity of 68 kWh.

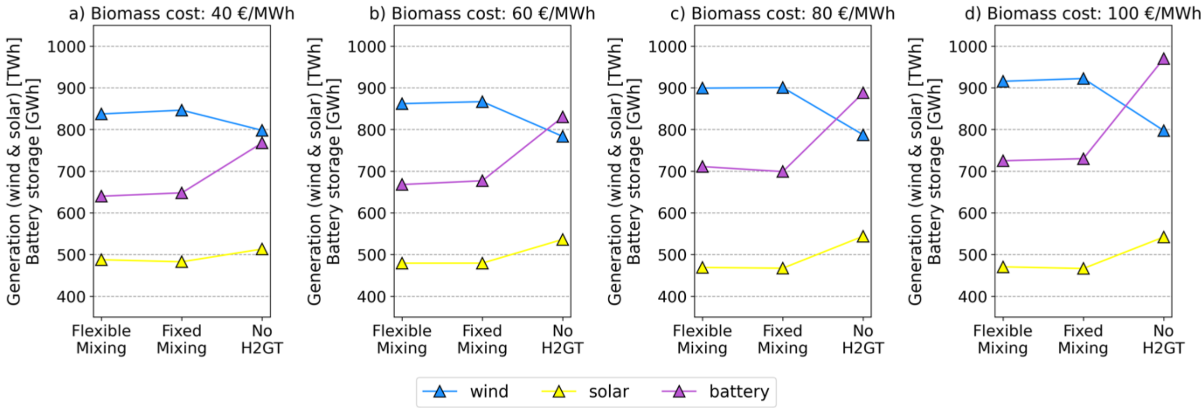

Figure 8: Generation supplied from wind and solar power, and installed battery storage capacity for different assumptions related to biomass cost and options for the conversion of hydrogen back to electricity. The results are generated by the Multinode model using the geographic scope displayed in Figure 4.

Figure 9 presents the investments in both open-cycle and combined-cycle gas turbines[9] fueled either exclusively with biomethane (green) or with varying levels of hydrogen blended with biomethane. In scenarios in which hydrogen-fueled gas turbines are not allowed, the distribution of total gas turbine capacity transitions from predominantly OCGT when biomass costs are low, to an even distribution of OCGT and CCGT when solid biomass costs[10] reach or exceed 80 €/MWh. At this threshold, investments in fuel cells also become viable. In the scenario without hydrogen-fueled gas turbines, the proportion of electricity supplied by biogenic fuels gradually diminishes with increasing biomass costs, steadily declining from 4.3% to 2.5% of the total electricity demand. When factoring in hydrogen-fueled gas turbines, the bulk of investments is allocated to options that are capable of utilizing 100% hydrogen; particularly for the lower spectrum of biomass costs, investments primarily favor the CCGT configuration. For higher biomass costs, investments are also directed toward OCGT configurations, considering the two options that utilize 100% and 30% hydrogen (by volume). Gas turbines with a 30% hydrogen blend-in constitute a compromise between reducing the utilization of biomethane and incurring a lower investment cost, as compared with achieving 100% hydrogen capability. By incorporating hydrogen-fueled gas turbines, the share of final electricity consumption supplied by hydrogen demonstrates steady growth as biomass costs increase, with consequent alleviation of the dependence upon the limited biomass resource.

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[9]OCGT, Open Cycle Gas Turbine; CCGT, Combined Cycle Gas Turbine

[10]The relationship between solid biomass cost and biomethane cost is a gasification efficiency of 70% and an additional 20 €/MWh in the operational cost of the gasification plant, as described in Section 3.4.3. Solid biomass costs of 40, 60, 80, and 100 €/MWh translate to biomethane costs of 77, 106, 134, and 163 €/MWh, respectively.

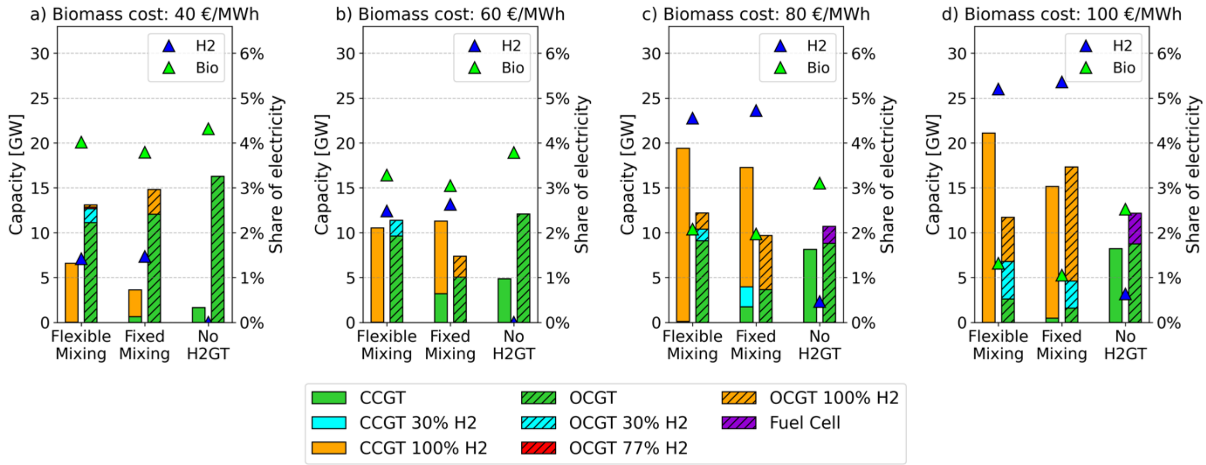

Figure 9: Installed capacities of different gas turbine configurations and shares of electricity supplied by biogenic fuels and hydrogen for different assumptions regarding the biomass cost in the UK1 region. The results are generated by the Multinode model using the geographic scope displayed in Figure 4.

Figure 10 displays the operation of the installed gas turbine and fuel cell capacities (as depicted in Figure 9). Each panel includes the sorted generation of all configurations for the respective scenarios and biomass cost. In these panels, the blue and green fields indicate the utilization of hydrogen and biomethane as fuels, respectively. The different shades of blue and green denote the different technology configurations shown in Figure 9. For instance, in Figure 10c$_1$, the two green fields display the operation of 1.7 GW of CCGT and 16 GW of OCGT, fueled exclusively with biomethane. In contrast, the two blue fields in Figure 10b$_1$ display the operation of 3 GW of CCGT and 2.8 GW of OCGT, fueled with 100% hydrogen. In Figure 10a$_{1\text{-}4}$, hydrogen can be mixed flexibly with biomethane, a feature that is particularly evident for the CCGT configuration with up to 100% hydrogen blend-in, which is the configuration that generates the major share of the electricity from gas turbines in the scenario that allows for flexible mixing. For configurations with a blend-in of 30 vol.-% hydrogen, it should be emphasized that this corresponds to only 11% of the energy. Thus, it can be difficult to distinguish in Figure 10, especially as these configurations tend to attract relatively small investments. Considering the installed capacity and its operation, it can be concluded that: i) CCGTs receive significantly larger investments when hydrogen-fueled gas turbines are allowed, particularly when flexible mixing is assumed; and ii) the main fuel in this configuration is hydrogen. For OCGTs, the results show that there is a consistent requirement for OCGTs that are fueled exclusively with biomethane, and furthermore that OCGTs fueled with up to 100% hydrogen provide more full-load hours than their counterparts fueled exclusively with biomethane.

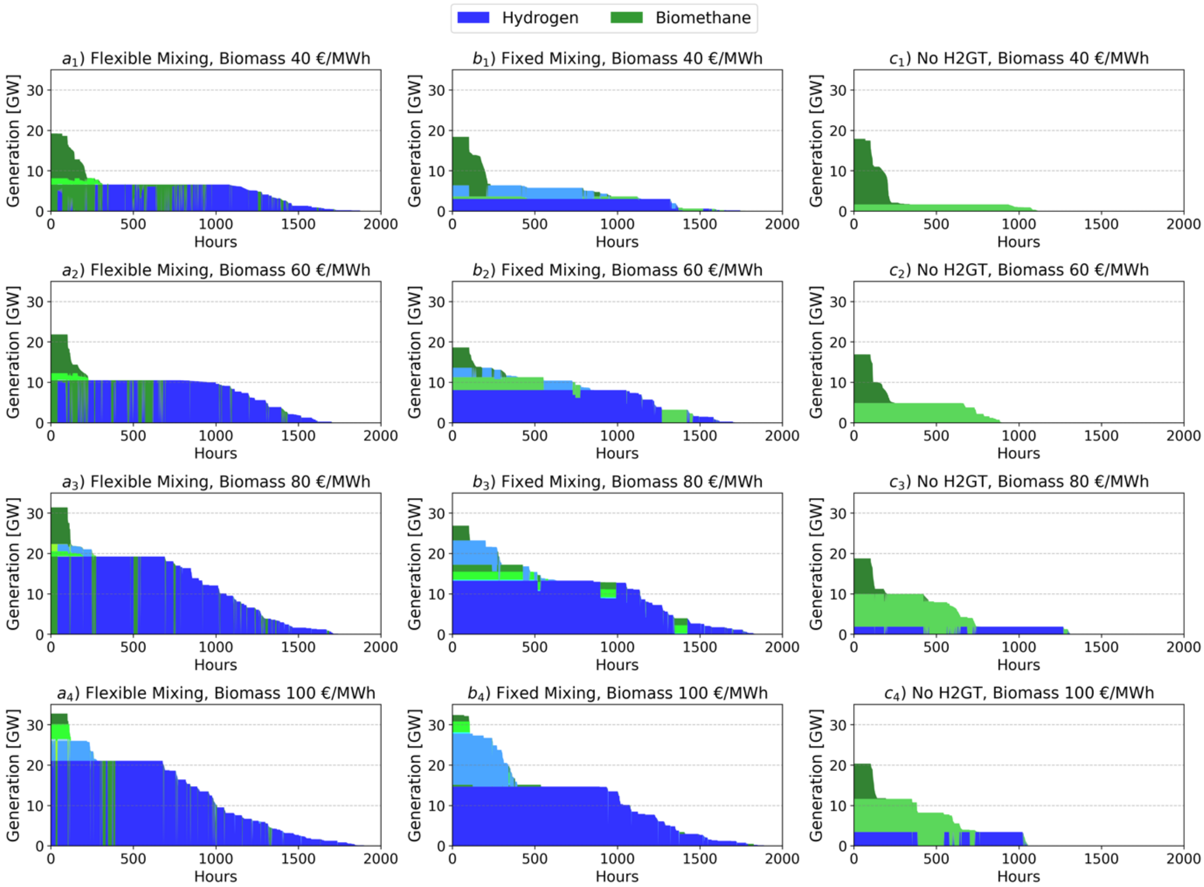

Figure 10: Sorted generation of the gas turbine and fuel cell capacities displayed in Figure 9. The green and blue fields indicate the utilization of hydrogen or biomethane as fuels, respectively, and the different shades of blue and green denote the different technology configurations depicted in Figure 9.

The results shown in Figure 10 clearly indicate that allowing for hydrogen-fueled gas turbines leads to increased electricity generation from gas turbines, with a significant portion of the fuel used being hydrogen. This increased generation is attributed to a shift in the equilibrium point for investments, which influences the interplay between generation and storage technologies. As shown in Table 2, the total curtailment of electricity decreases significantly when hydrogen-fueled gas turbines are allowed, despite the overall increase in electricity generation (Figure 7). Allowing for hydrogen-fueled gas turbines reduces the cost of shifting electricity generation in time via hydrogen, as compared with using fuel cells for the conversion of hydrogen back to electricity. Consequently, with substantial volumes of zero-cost electricity becoming available instead of being curtailed, the new equilibrium-point favors wind power, hydrogen storage, and gas turbines over solar PV and batteries.

Table 2: Summary of the curtailment of electricity generation observed in the 12 scenarios modeled with consideration to the biomass cost and options for reconversion of hydrogen. The values consider the total curtailment in all the regions included (Figure 4) in the modeling.

Biomass cost [€/MWh]	Flexible Mixing	Fixed Mixing	No H_2GT
40	7.5%	7.4%	9.6%
60	8.2%	8.2%	11.1%
80	8.8%	8.6%	12.1%
100	9.1%	8.9%	12.8%

The role of gas turbines in the modeled system is further illustrated in Figure 11, where the net-load, calculated by subtracting the VRE generation from the inflexible electricity demand, is progressively reduced by accounting for the different flexibility options to manage variations. While the *y*-axis in Figure 11 displays the duration of events, the *x*-axis shows the amplitude of an event, where positive values indicate a power deficit, and negative values indicate an excess of power. The coloration further indicates the frequency of an event. By comparing with the previous panel in Figure 11, the impacts of including different flexibility options can be identified. The inclusion of trade manages the frequent and short-duration electricity deficits seen in panel a), resulting in frequent and short-duration events with excess electricity in panel b). With minimal base-load operation in the system, batteries and electric vehicle charging in panel d) reduce the majority of the shorter-duration events with high amplitudes of excess electricity. When flexible hydrogen and heat production are considered, all events with excess electricity are eliminated, as shown in panel e). The remaining deficits are managed by CCGT and OCGT. CCGTs manage events that range in duration from a few hours to several days (up to 100 hours), while OCGTs primarily cover positive net-load events of around 40 hours in duration.

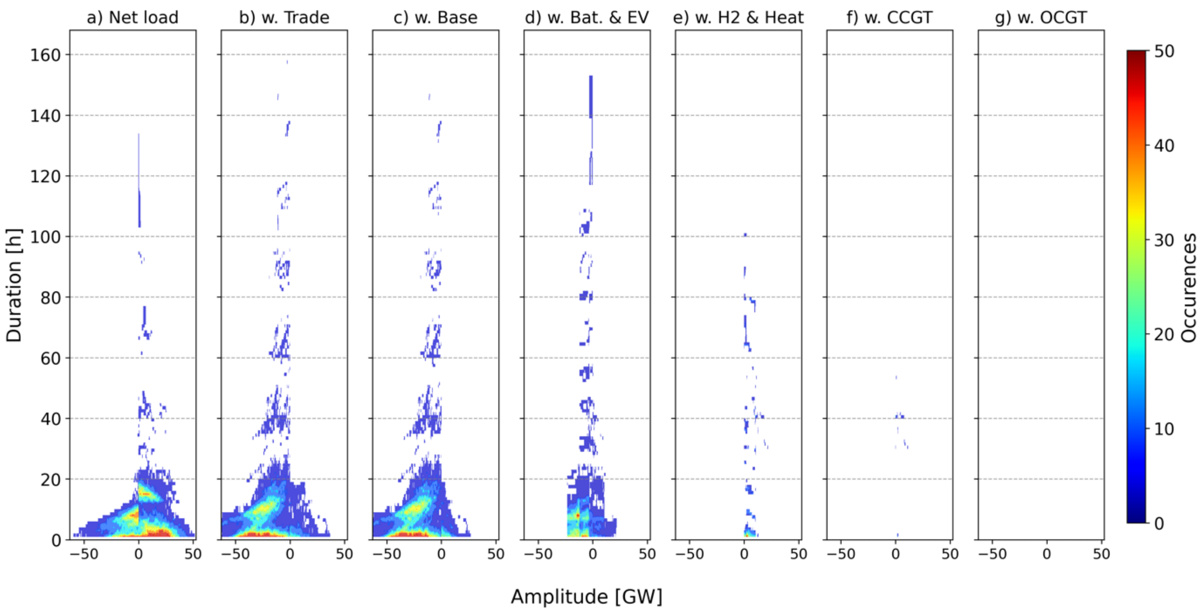

Figure 11: Impacts on the net-load in the UK1 region a) of: b) trade; c) trade and base-load; d) trade, base-load, and batteries and EV charging; e) trade, base-load, batteries and EV charging, and flexible production of hydrogen and heat; f) trade, base-load, batteries and EV charging, flexible production of hydrogen and heat, and CCGT; and g) trade, base-load, batteries and EV charging, flexible production of hydrogen and heat, CCGT, and OCGT. The results are taken from the scenario using flexible mixing of hydrogen in gas turbines and a biomass cost of 60 €/MWh.

In terms of categorizing hydrogen-fueled gas turbines within the scheme suggested by Göransson [27], OCGTs, with their low-frequent operation, low investment cost, and high operational cost, clearly fit within the Peaking strategy. Considering CCGTs, variations that occur on both shorter and longer timescales are managed, and with the relatively low cost of hydrogen storage and higher reconversion efficiency, the CCGT technology encompasses aspects described by both the Peaking and Complementing strategies. Common to both OCGTs and CCGTs in the future energy systems investigated is a low capacity factor, or low number of full-load hours, compared with historical benchmarks. Traditionally, OCGTs have operated with capacity factors of around 10%, and CCGTs with capacity factors between 50% and 60% [137]. However, in the modeling, when applying flexible mixing of hydrogen in gas turbines, these values are reduced to 2% for OCGTs and 12%–16% for CCGTs, with the upper end of this range being associated with lower biomass costs. Comparable values are observed when a fixed mixing of hydrogen is applied. However, in the absence of hydrogen blend-in, capacity factors are generally lower, as illustrated in Figure 10. Both OCGTs and CCGTs offer levels of dispatchability and flexibility that few other technologies can match at a similarly low investment cost. Nevertheless, the introduction of new generation technologies such as wind and solar power, competing technologies like batteries, flexible demands, and an assumed higher fuel cost have collectively reduced the operating space for these technologies. OCGTs, in particular, are likely to be outcompeted by batteries with respect to handling intra-day variations, resulting in fewer and somewhat longer consecutive operation periods compared with the historical patterns. The high efficiency of CCGTs relative to their investment cost is a crucial determinant of their ability to shift electricity generation in time via hydrogen, events that in general have a duration of several days. However, with capacity becoming available, CCGTs are also used to address imbalances of shorter duration. Referring back to Figure 6, the increased marginal cost of electricity during hours with a positive net-load, and consequently the higher electricity price variability, is driven by the high operational costs and reduced capacity factor for gas turbines.

Further exploring the operation of hydrogen-fueled gas turbines and the hydrogen cost at which they operate, Figure 12 showcases the results from **Paper II** for the UK1 region, illustrating the outcomes across three distinct levels of biomass costs. The left panels display the chronological operation of a CCGT with flexible mixing of up to 100% hydrogen, while the right panels show the operational costs relative to the electricity cost when in operation. This highlights instances in which a gross margin is generated and when the gas turbine operates at zero profit. Furthermore, both the left and right panels include the marginal cost of hydrogen on the secondary *y*-axis, making it possible to identify the marginal cost at which hydrogen is reconverted to electricity, essentially indicating the willingness to pay for hydrogen in this particular application. The willingness to pay for hydrogen increases with the cost of biomass, rising from 2.5 €/kg_{H2} to 4.5 €/kg_{H2} as the biomass cost increases from 40 €/MWh to 80 €/MWh. However, the absolute numbers for willingness to pay should be approached with caution. Alternatively, the willingness to pay could be defined relative to the average cost of hydrogen, which is slightly more than 1 €/kg_{H2}. This yields a willingness to pay that is 2–4-times the average cost of hydrogen for the specific scenarios portrayed in Figure 12. Considering the gross margin, i.e., when the income exceeds the operational costs and the investment cost is recuperated, the majority is generated during the 400–500 hours with the highest marginal electricity cost, while the CCGT is in operation for around 2,000 hours. This means that there are many hours during which the CCGT operates without generating a gross margin. Moreover, for higher biomass costs, there is a substantial number of hours during which the CCGT operates on hydrogen at a cost below 1 €/kg_{H2}, equivalent to a fuel cost of 30 €/MWh, which is significantly lower than the assumed cost of biomethane.

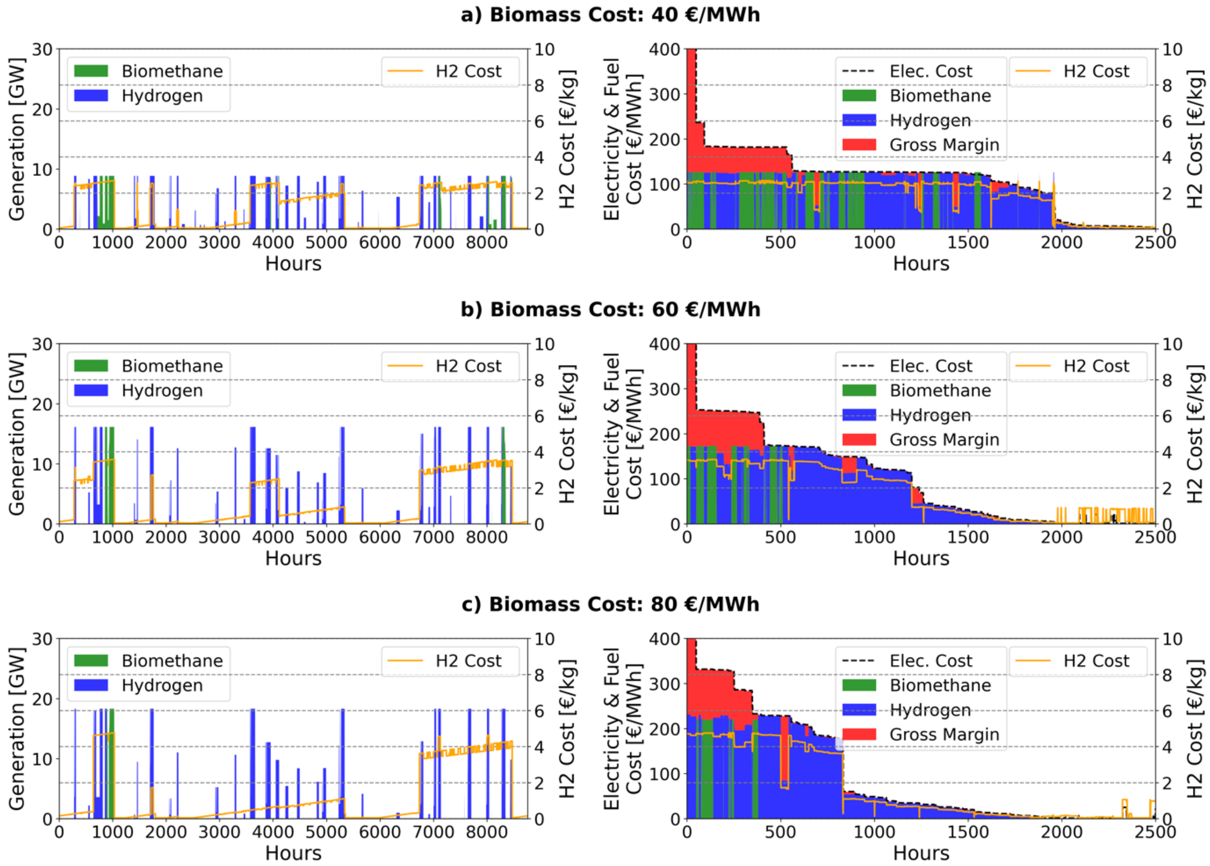

*Figure 12: The left panels illustrate the chronological operations of a CCGT with flexible mixing of up to 100% hydrogen, while the right panels depict the operational costs and gross margins, with each row having different assumptions regarding biomass costs. Results are obtained from **Paper II** using the Multinode model.*

4.1.2 The cost dynamics in the hydrogen supply

To elucidate the cost dynamics linked to the hydrogen supply in future energy systems, **Paper III** examines the supply of hydrogen demands with different characteristics and varying levels of flexibility. This study was designed to complement existing research that calculates the cost of hydrogen without integrating a comprehensive system perspective. Another part of the motivation for this study was the perceived notion that hydrogen production in future energy systems will occur exclusively during periods with surplus VRE generation, i.e., when the marginal cost of electricity is low. Assuming a constant industrial hydrogen demand, there is indeed a correlation between hydrogen production and low marginal electricity cost, as illustrated for southern Germany in Figure 13a. Nonetheless, owing to the cost of investments in electrolyzers and hydrogen storage capacity, there are periods during which hydrogen is produced despite the marginal cost of electricity being high, i.e., it would be too costly to avoid these periods through additional investments in electrolyzers and energy storage capacity. Furthermore, there are periods during which the marginal cost of electricity is low, even without hydrogen production being at full capacity. One such event occurs between timesteps 3,100 and 3,500 and is explained as follows: i) the electrolyzer is not required to be operated at full capacity to fill the storage before the electricity cost increases, and it is not cost-beneficial to invest in a larger hydrogen storage; and ii) the hydrogen demand is assumed to be fixed, and thus the system cannot make use of additional low-marginal-cost hydrogen during this period. Assuming instead a hydrogen demand that is flexible in time, as displayed in Figure 13b, the level of hydrogen production during the same period (timesteps 3,100–3,500) is close to being maximized, and the investments in both electrolyzers and hydrogen storage capacity are lower compared with the results shown in Figure 13a. Although the flexible hydrogen demand presented in Figure 13b may seem appealing, it is modeled assuming 50% overcapacity within the industry that utilizes hydrogen, an assumption that is not justifiable for capital-intensive process industries such as the steelmaking industry. However, since this study aims to assess exclusively the system impacts of various hydrogen demands, the actual downstream process is not taken into consideration.

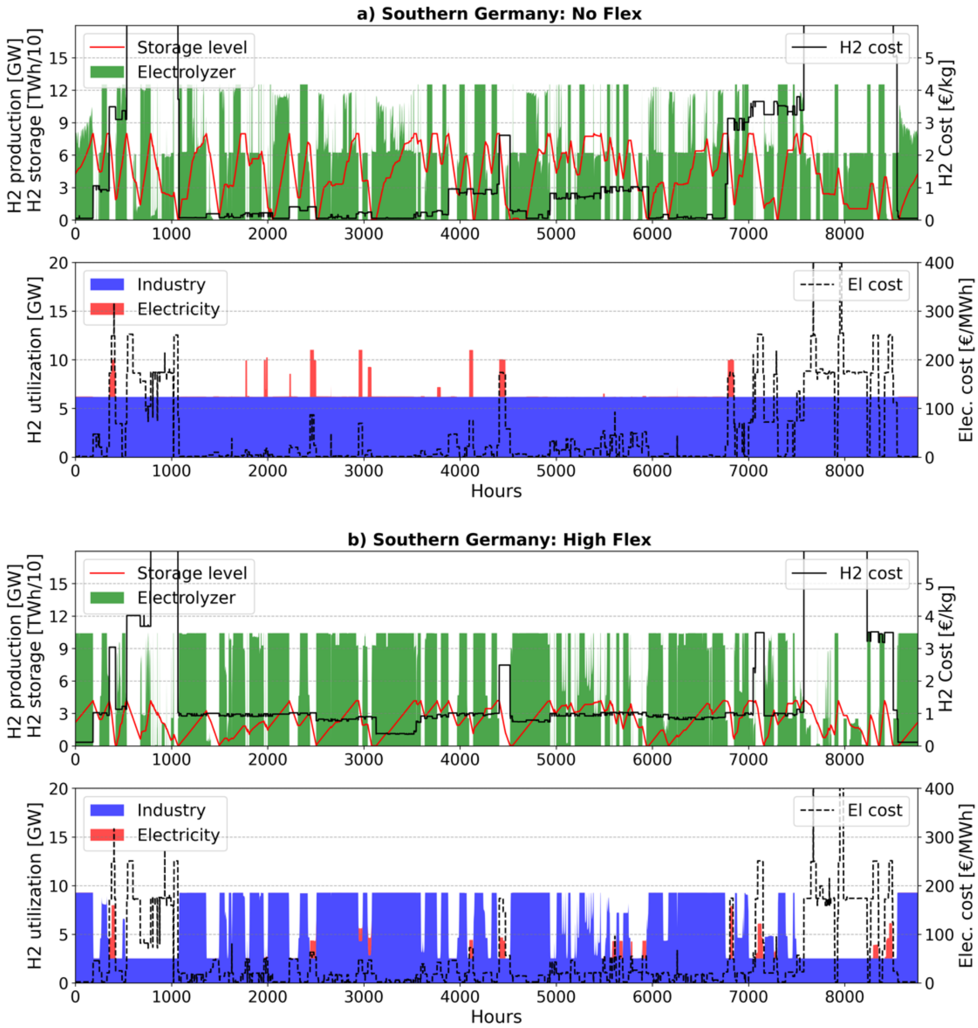

*Figure 13: The production and utilization levels of hydrogen in southern Germany for two scenarios with different levels of flexibility in industry: a) with no flexibility; and b) with high-level flexibility. The results are obtained from **Paper III** using the Multinode model.*

Complementing the two scenarios in Figure 13 with a scenario that assumes a 15% overcapacity for industries that utilize hydrogen (Low Flex), Figure 14 displays the hydrogen production levels sorted according to the marginal costs of hydrogen. Assuming a constant industrial hydrogen demand (No Flex), the electrolyzer never operates at full capacity during the 2,000 hours with the lowest marginal cost of hydrogen. However, a considerable amount of hydrogen is produced at a marginal production cost greater than 6 €/kg_{H2}. For the hydrogen demands that are flexible in time, hydrogen production is to a greater extent shifted to hours with a lower marginal production cost, and the average cost of hydrogen is decreased by 32% and 34% going from a constant hydrogen demand to a low or high level of flexibility, respectively. Consequently, as overcapacity in the range of 15% to 50% yields diminishing returns with respect to the average hydrogen cost, it can be concluded that with a modest overcapacity within the industrial process, a moderate reduction in the cost of hydrogen can be achieved.

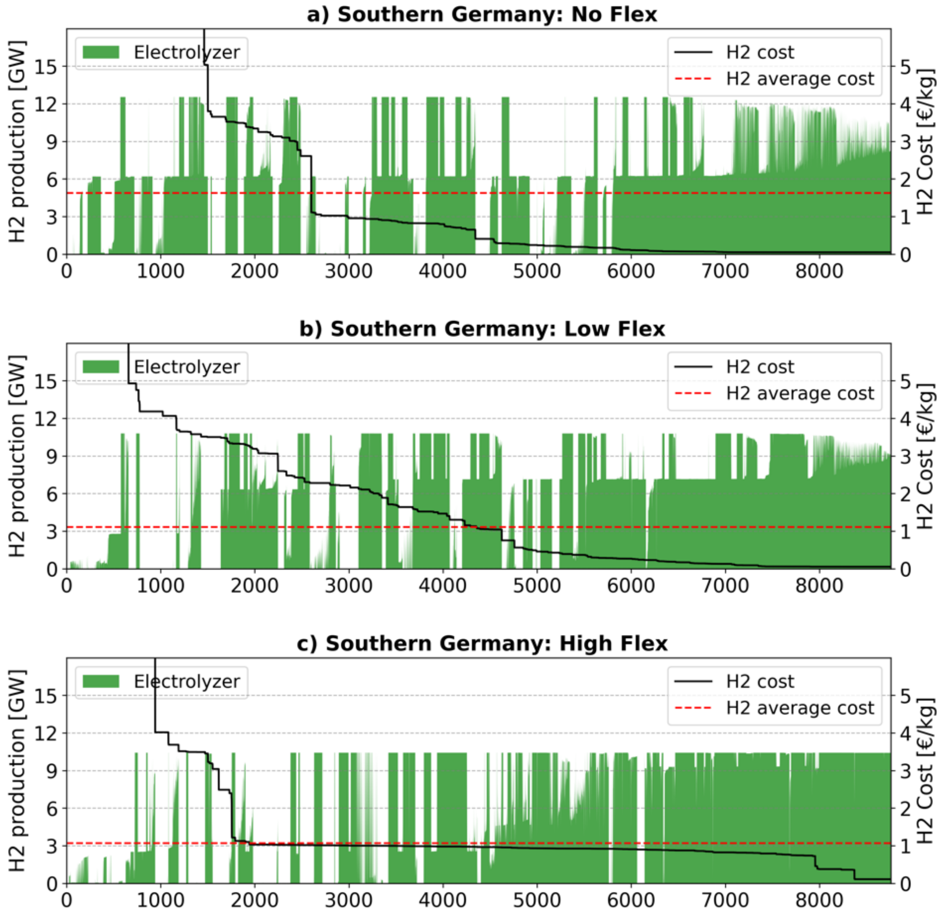

Figure 14: Cost durations for hydrogen and the corresponding hydrogen production levels in southern Germany for the scenarios with: a) no flexibility; b) low-level flexibility; and c) high-level flexibility. The results are obtained from ***Paper III*** *using the Multinode model.*

4.2 Hydropower in energy systems modeling

For certain countries, reservoir hydropower offers significant value to the system. With an anticipated growth in both the electricity demand and the share of VRE, the value of a dispatchable *and* flexible carbon-free generator, such as reservoir hydropower, can be expected to increase even further. However, there are limitations linked to the extent to which hydropower can be flexible. Moreover, in energy systems modeling, the flexibility of hydropower tends to be overestimated due to an exceedingly simplified implementation, leading to underestimations of investments in other dispatchable technologies. In **Paper IV,** three hydropower equivalents are evaluated with the ambition to improve the representation of hydropower in energy systems modeling. Section 4.2.1 offers a synopsis of the findings derived from **Paper IV** concerning hydropower representation in energy systems modeling. Using Sweden and Swedish hydropower as a case study, **Paper IV** explores the role of Swedish hydropower in a future energy system; the findings for which are summarized in Section 4.2.2.

4.2.1 Improving hydropower representation in energy systems modeling

The three hydropower equivalents evaluated are referred to as *Simple*, *Bi-level*, and *Extended*, and are described in detail in **Paper IV**. Figure 15 illustrates the generation-duration curves for hydropower in the four Swedish regions, with each panel displaying the three hydropower equivalents and the generation from a detailed hydropower model (Detailed model 1) for comparison. As detailed hydropower models are designed to maximize the revenue relative to a given electricity price profile, any part-load operation is a consequence of constrained flexibility of the hydropower. However, in energy systems models, including the Multinode model used in **Paper IV**, hydropower can affect the marginal cost of electricity, which means that part-load operation of hydropower can be motivated also for economic reasons.

The Simple equivalent has no constraints that limit flexibility, so part-load operation is only motivated if the operation is constrained by the water level in the reservoir or if the marginal value of water is equivalent to the the marginal cost of electricity, i.e., hydropower acting as a price-setter. In Figure 15, the Simple equivalent yields the lowest share of part-load hours, showing a characteristic behavior in region SE4, with generation either at the maximum or minimum level. This characteristic behavior does, however, decline progressively as one moves northwards, with the northern-most region SE1 having around 2,000 hours of part-load operation. In the absence of any constraint limiting the ability to shift large volumes of water in time, the Simple equivalent clearly overestimates the flexibility of hydropower. An example of this is the potential to allocate generation to periods when, for instance, wind generation is low, and correspondingly avoiding generation during periods of high wind generation. Consequently, there is an underestimation of the number of hours with a marginal electricity cost equal to zero. Furthermore, the overestimated flexibility leads to small variations in the marginal value of additional water, which can be interpreted as a possibility to distribute the hydropower resource freely over the hours of the year. In region SE1, the value of additional water remains constant throughout the year, as depicted in Figure 6 in **Paper IV**.

By incorporating additional constraints that limit the flexibility of the hydropower equivalents i.e., the Bi-level and Extended equivalents, the resulting operation is closer to the generation obtained from the detailed model. For the Bi-level equivalent, the stepwise decreases in the levels of generation, which are particularly prominent for region SE3, result from having different maximum and minimum operation levels for different periods of the year. A consequence of imposing part-load operation through minimum and maximum generation levels is, however, that the marginal value of water is zero for significant periods of the year (as depicted in Figure 6 in **Paper IV**). This means that hydropower production cannot increase even with additional water during these periods. Consequently, the Bi-level implementation emerges as the least flexible of the three evaluated, leading also to the largest proportion of hours with marginal electricity cost equal to zero.

In the Extended equivalent, part-load operation arises due to limited sustained generation and minimum diurnal generation. These factors reflect the impacts of local water scarcity in the river system during periods with strong incentives for hydropower generation and the need to prevent flooding of smaller reservoirs during extended periods with low marginal electricity costs. Considering the marginal value of water, similar trends are observed between the Extended and Bi-level equivalents, albeit without the extended periods of zero values seen in the Extended equivalent. This indicates that the constraints incorporated into this implementation limit flexibility, although they are not sufficient to drive the marginal value of additional water to zero, and consequently, the number of hours with a marginal cost of electricity equal to zero is intermediate to the numbers of hours for the Simple and Bi-level equivalents.

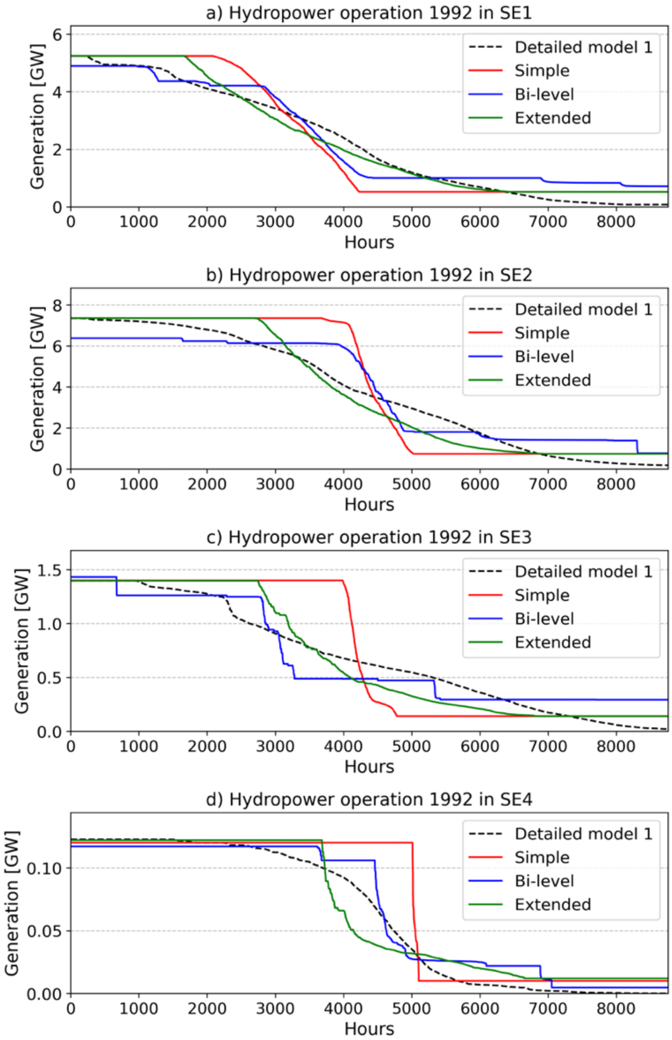

*Figure 15: Generation durations of hydropower in the four Swedish regions for the three hydropower equivalents evaluated with Detailed model 1 as reference. The results are obtained from **Paper IV** using the Multinode model.*

With the anticipation that wind power will cater to a significant portion of the electricity demand in a future Northern European electricity system [10][11], net-load variations with durations that range from days to weeks are expected to be introduced to the system [138]. Thus, the ability of hydropower to respond to net-load variations in the range of several days to weeks in accordance with the relevant technical limitations is of particular relevance. Figure 16 displays the hydropower operation in region SE2 during one of the few long periods with low-level wind generation, resulting in high electricity costs and exerting a high level of stress on the hydropower generation. While the Simple equivalent operates continuously at the installed capacity for almost 4 weeks, the Bi-level equivalent operates continuously at its maximum allowed generation level during the same period, and the Extended equivalent has a more-dynamic generation profile that is similar to the detailed model. The problem with equivalents that allow hydropower to operate at maximum capacity for long periods, e.g., several weeks, is that such operation is not feasible in reality, which means that unrealistic modeling results are generated [84].

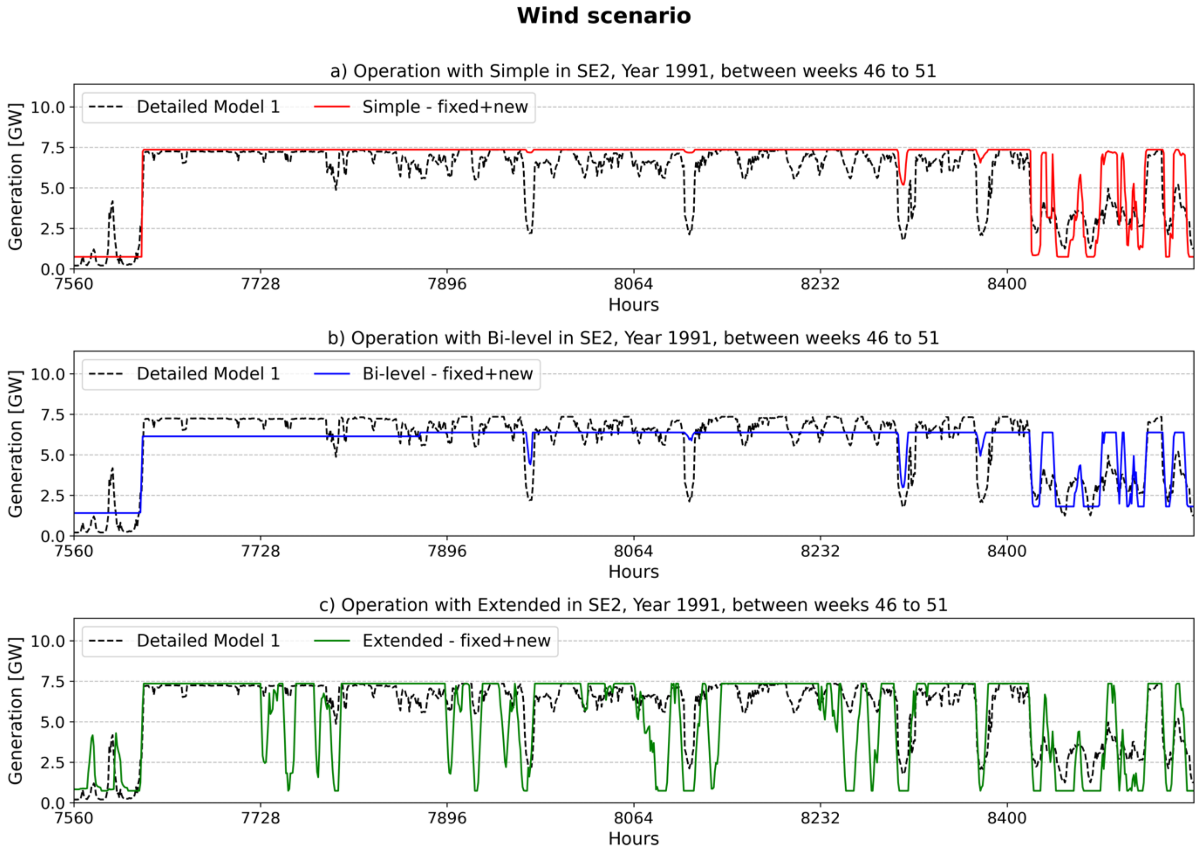

*Figure 16: A 6-week period with high levels of hydropower generation at the end of Year 1991 for the Simple (a), Bi-level (b), and Extended (c) equivalents, with the corresponding generation from Detailed model 1 as reference. The results are obtained from **Paper IV** using the Multinode model.*

Instead of a period with a high residual load, Figure 17 depicts a 6-week period that is characterized by prolonged intervals of low residual load and low marginal electricity costs, resulting in hydropower generation at low levels. Both the Simple and Bi-level equivalents attain generation profiles that are characterized by extended periods of constant generation at minimum (albeit different) levels, giving a result which is quite different from that provided by the detailed model. Conversely, the Extended equivalent demonstrates a profile that closely resembles that of the detailed model. The reason for the similarities between the detailed model and the Extended equivalent is the constraint imposed on minimum diurnal generation. The generation profile observed in the detailed model is a consequence of limited reservoir capacity in certain segments of the river system, resulting in the forced discharge of water during periods of excessive inflow and when the water levels are too high. As the detailed model is formulated to maximize profit from hydropower, the discharge is concentrated to instances when the electricity price is the most beneficial, while being only marginally different to the electricity price in adjacent hours. The behavior observed in the detailed model could be perceived as an artifact of the model, as it might not accurately represent the dispatch scheduling in reality. However, from a system perspective, what matters is the total energy dispatch within each 24-hour period rather than the specific profile, i.e., that the water (energy) is discharged and, therefore, cannot be shifted to other periods of the year, an aspect that is captured also in the Bi-level equivalent with an increased minimum generation.

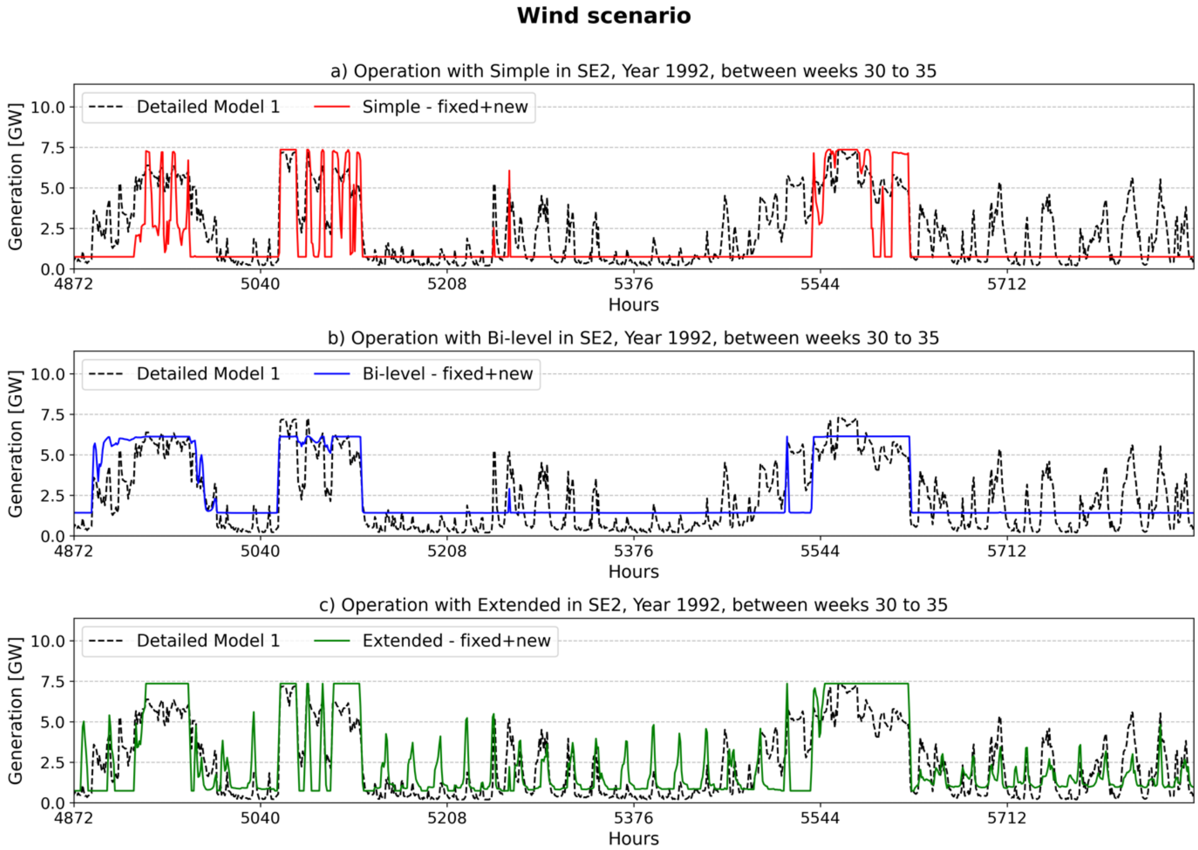

*Figure 17: A 6-week period with low levels of hydropower generation in the middle of Year 1992 for the Simple (a), Bi-level (b), and Extended (c) equivalents, with the corresponding generation from Detailed Model 1 as reference. The results are obtained from **Paper IV** using the Multinode model.*

The results shown in Figure 16 and Figure 17 are for a model setup that allows for unlimited investments in transmission capacity. An unlimited expansion of grid capacity allows for a more-accurate evaluation of the additional hydropower constraint, as the impacts derived from potential transmission bottlenecks are reduced. However, when transmission expansion is instead fixed according to forecasts made by the ENTSO-E [139], the outcomes diverge, particularly for the Simple equivalent, for which the number of hours in part-load operation increases significantly. In contrast, the impacts of not allowing for new transmission capacity for the two hydropower equivalents, Bi-level and Extended, are limited, suggesting that the dispatch is more-severely limited by internal hydropower constraints than by limited transmission capacity to neighboring regions.

4.2.2 The future role of Swedish hydropower

To assess the role of Swedish hydropower in a future energy system that is compliant with the European Union´s ambition to achieve net-zero greenhouse gas emissions by Year 2050 [3], this section commences with an analysis of recent developments. Figure 18 shows the historical operation of Swedish hydropower, comparing Years 2019 and 2020. Up to Year 2019, the production pattern and the southbound transmission flows were closely tied to the intra-day variations in southern Sweden, where a significant portion of the hydropower generation is directed. The intra-day pattern is displayed in Figure 18a [140], where the red area represents the frequent occurrences of hydropower operation at 6–8 GW during consecutive periods of 15–20 hours. However, as shown in Figure 18b, this pattern diminishes from Year 2020, as well as thereafter (data not shown).

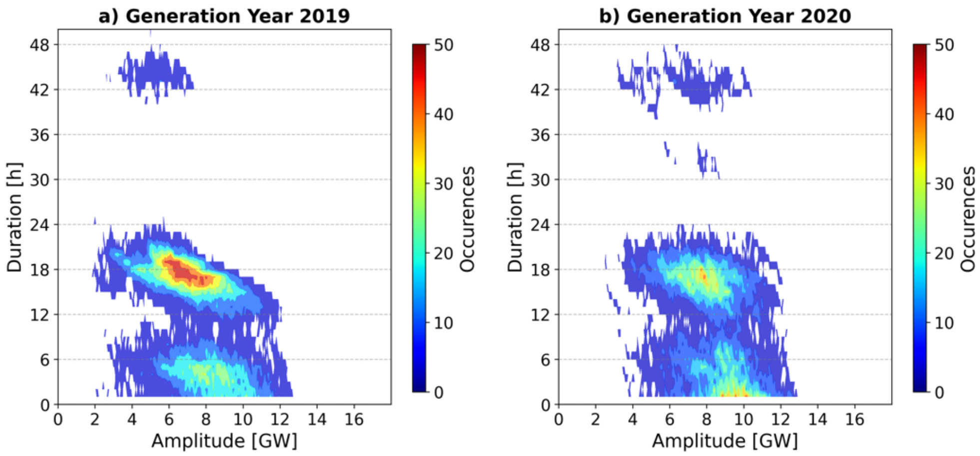

Figure 18: Hydropower generation levels for Year 2019 (a) and Year 2020 (b). Statistical data from the Swedish Transmission System Operator, SvK.

The weaker relationship between hydropower and intra-day variations can be attributed to the expansion of wind power and the emergence of a more-constrained southbound transmission capacity between regions SE2 and SE3. This is illustrated in Figure 19 using data from the Swedish Energy Agency [141] and ENTSO-E [142]. Until Year 2019, wind power accounted for a small fraction of the electricity generation and was fairly evenly distributed between the northern and southern regions of Sweden [141]. However, there was a significant increase in wind power generation in Year 2020, largely due to favorable wind conditions and partly due to an increase in the installed wind power capacity. Since Year 2020, wind power has continued to expand, primarily in the northern regions [141]. Consequently, increased wind power generation in northern Sweden has led to higher southbound transmission flows, and due to limited transmission capacity, this has caused shifts in hydropower operation patterns.

The future role of Swedish hydropower is evaluated for four future scenarios that are concerned with the potential development of the Swedish electricity system. The first scenario, which is named *Wind*, includes enforced investments in a total of 22 GW offshore wind power (16 GW in SE3, 6 GW in SE4), while also assuming that existing nuclear power plants are retired due to reaching end of lifetime. This scenario is designed to be challenging in that it considers the requirement for flexibility while remaining feasible (at the beginning of Year 2024, projects corresponding to 35 GW of offshore wind power were awaiting decisions by the Government of Sweden [143]). It is also the scenario used for the evaluation of hydropower equivalents in Section 4.2.1. The second scenario, *Cost Optimal*, does not enforce any specific type of investments, although it does include a lifetime extension of 5 GW of the existing nuclear capacity in region SE3. The scenario termed *Nuclear* includes enforced investments in 9 GW of nuclear power (8 GW in SE3 and 1 GW SE4), in addition to a lifetime extension of 5 GW of the existing nuclear power in region SE3. The *Wind No Flex* scenario, while less plausible, serves as a stress test for the system. In this scenario, 22 GW of offshore wind power are enforced, in similarity to the *Wind* scenario, whereas no investments in either hydrogen or heat storage are allowed in any of the modeled regions.

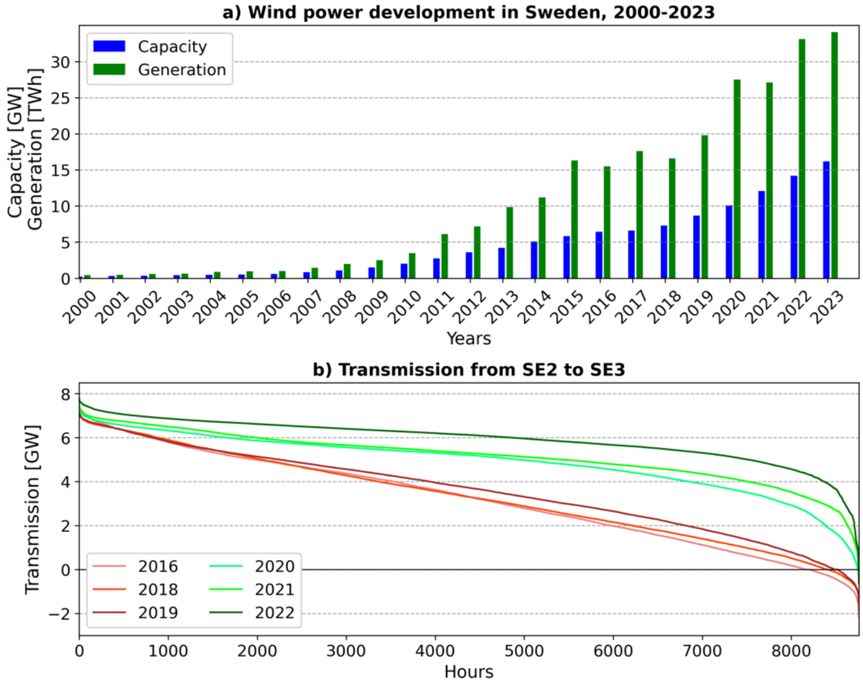

Figure 19: a) Wind power development for the period of 2000–2022, considering both the installed capacity and generated electricity based on statistics provided by the Swedish Energy Agency. b) Patterns of electricity transmission from region SE2 to region SE3 for 6 years according to the ENTSO-E data.

Using the Extended hydropower equivalent, as described in **Paper IV**, while assuming that the expansion of transmission capacity is fixed according to the study carried out by ENTSO-E [139], the projected future operation of hydropower, as given by the Multinode model, is shown in Figure 20. The hydropower generation patterns generally exhibit similarities across all the investigated scenarios. However, there are trends towards more-frequent operation during periods of 12–15 hours for the *Nuclear* scenario (Figure 20c) and less-frequent 1-hour segments for the *Wind No Flex* scenario (Figure 20d). When comparing these results with the historical dispatch patterns shown in Figure 18, it becomes evident that the trend of a weaker correlation between hydropower generation and intra-day load variations persists and becomes stronger in the future energy systems modeled. This suggests that hydropower primarily complements wind power rather than balancing the demand.

The limited variability of hydropower operation among the investigated scenarios can be attributed to the overall similarities in the total electricity generation mixes for northern Europe across the investigated scenarios, as depicted in Figure 21a. Despite differences in generation mixes within Sweden (Figure 21b), the broader regional context appears to exert greater influence on hydropower operation patterns. This implies that the development of the Swedish electricity system has only a marginal impact on the dispatch of Swedish hydropower. Instead, generation from sources such as wind power located outside of Sweden is likely to dominate the overall variations, and subsequently influence the dispatch of Swedish hydropower. This is further supported by the resulting marginal electricity costs in the four Swedish regions for the four scenarios (Figure 10 in **Paper IV**). The marginal electricity cost appears to be similar for the *Wind*, *Cost Optimal*, and *Nuclear* scenarios. However, there are slightly larger differences observed for the *Wind No Flex* scenario, in which neither hydrogen nor heat storage units are allowed. In this scenario, the overall level of generation is higher (as depicted in Figure 21a), and curtailment becomes a significant aspect of managing variable generation. Nevertheless, this scenario seems rather unlikely.

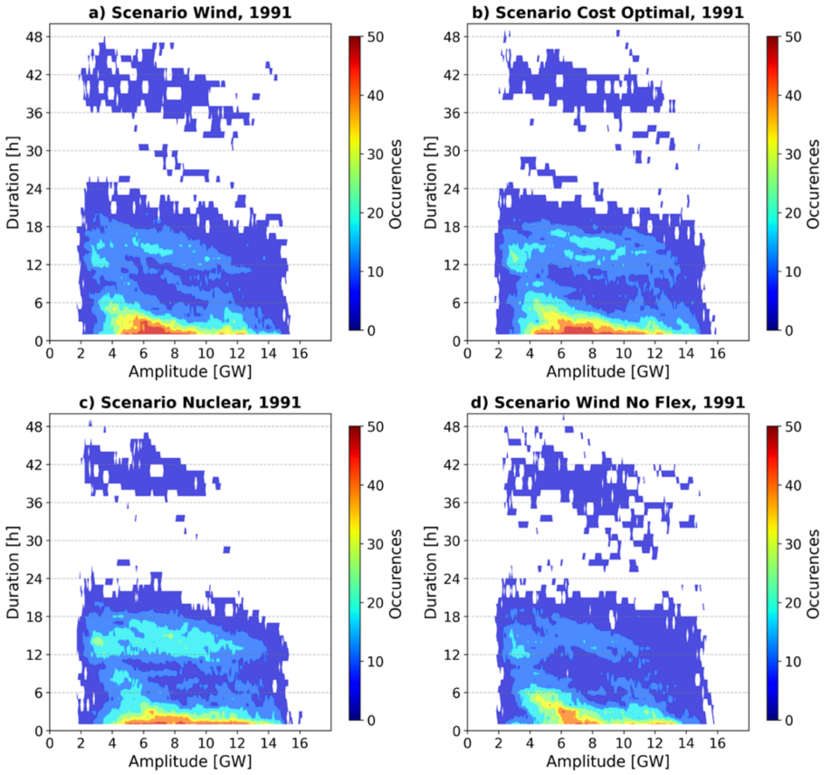

*Figure 20: Hydropower generation during meteorological Year 1991 for four future scenarios that consider the development of the Swedish electricity system. The results are obtained from **Paper IV** using the Multinode model.*

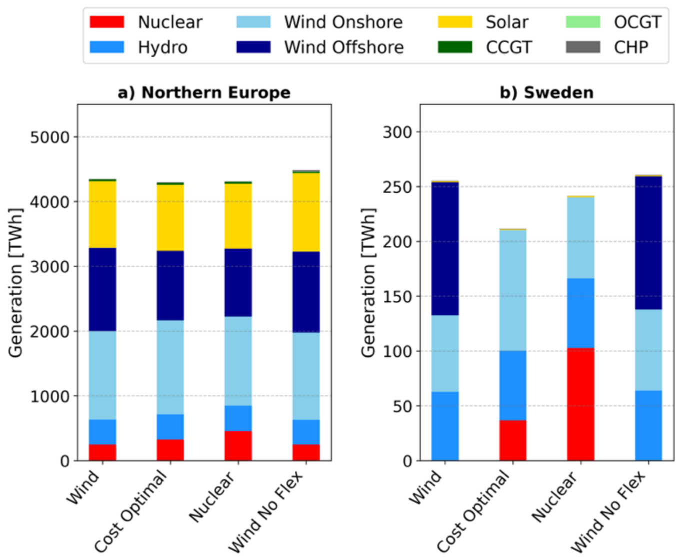

*Figure 21: Electricity generation mixes in a) northern Europe, and b) Sweden for the different future scenarios modeled. The results are obtained from **Paper IV** using the Multinode model.*

4.3 Inter-annual variations

Regarding the study of inter-annual variations, Section 4.3.1 presents the results as to how these variations impact the cost-optimal capacity mix for the ten meteorological years studied. Furthermore, as described in **Paper V**, each of these ten capacity mixes is supplemented with additional capacity, to ensure feasibility for all 10 years. Since the supplemented capacity mixes are no longer cost-optimal, their economic performances must be investigated, the results of which are summarized in Section 4.3.2.

4.3.1 The impacts on cost-optimal capacity mixes

The generation and storage capacity mixes for the ten meteorological years modeled are displayed in Figure 22 for the UK1 region; these capacities align with the results presented by Zeyringer et al. [144] and the UK Department for Business, Energy, and Industrial Strategy [145]. With conservative assumptions made regarding the potentials of onshore wind power and solar PV, these resources are fully exploited for all the years modeled. Consequently, inter-annual variations in wind power capacity factors are compensated with different investments in offshore wind power. An alternative to offshore wind power is nuclear power, which is a technology with the potential to satisfy a significant share of electricity demand. However, the installed nuclear capacity remains constant at 3.2 GW for all the years modeled. This capacity represents the Hinkley Point C nuclear power plant, which is currently under construction and is assumed to be operational until and beyond Year 2050. Thus, despite the variable nature of wind power, the model deems offshore wind to be a more-cost-competitive option than new nuclear power. The weak competitiveness of nuclear power is related to its requirement for a high number of full-load hours to achieve a competitive levelized cost of electricity. With the levelized cost of electricity from wind and solar power being lower than that from nuclear power, nuclear power is in this study penalized with respect to both frequent cycling, which is related to additional costs, and low numbers of full-load hours (ranging from 3,600–6,100 for the Hinkley Point C capacity). These two factors make nuclear power a less-competitive option.

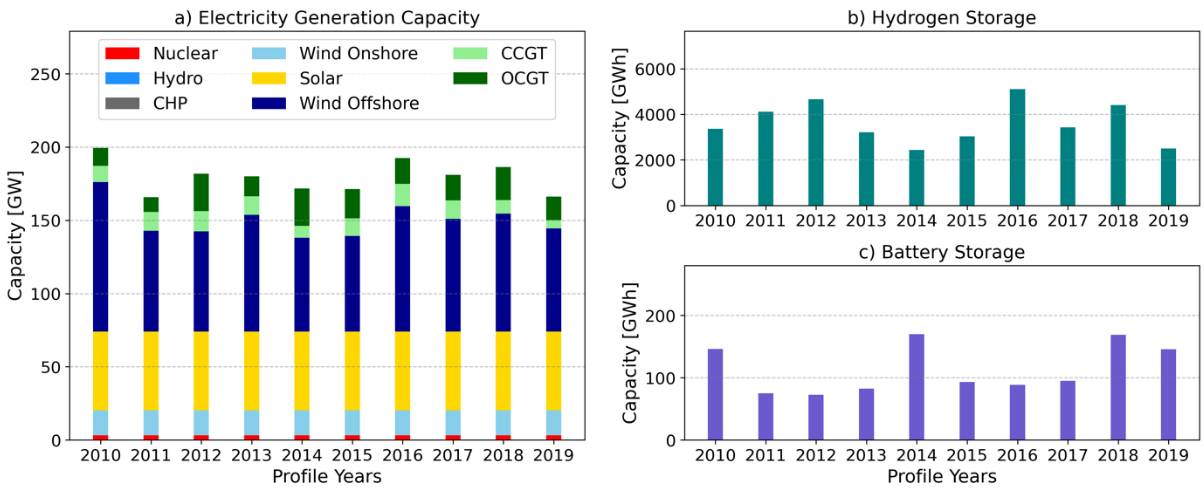

*Figure 22: Installed capacities in the UK1 region for the ten individually modeled years, showing the: a) electricity generation capacity; b) hydrogen storage capacity (salt cavern); and c) battery capacity. The results are obtained from **Paper IV** using the Multinode model.*

The differences in generation capacity, as well as in hydrogen storage and battery storage capacity between the modeled years are attributed primarily to the variations in wind power generation. The generation profiles for wind power, including both onshore and offshore wind power, are displayed in Figure 23 for four of the modeled years, revealing considerable differences between the years. For those years with a clear decrease in wind generation during the summer, e.g., Year 2014, investments in battery capacity increase as the variations that occur during this period are dominated by generation from solar PV, i.e., variations characterized by a high amplitude and high frequency, and thus there is a greater value associated with balancing these variations with batteries. For years in which there is a more evenly distributed wind generation, i.e., neither long periods with high and continuous wind generation, such as at the end of Year 2015, nor long periods with very low levels of wind generation, such as during the summer of Year 2014, hydrogen storage instead becomes the more-competitive storage technology.

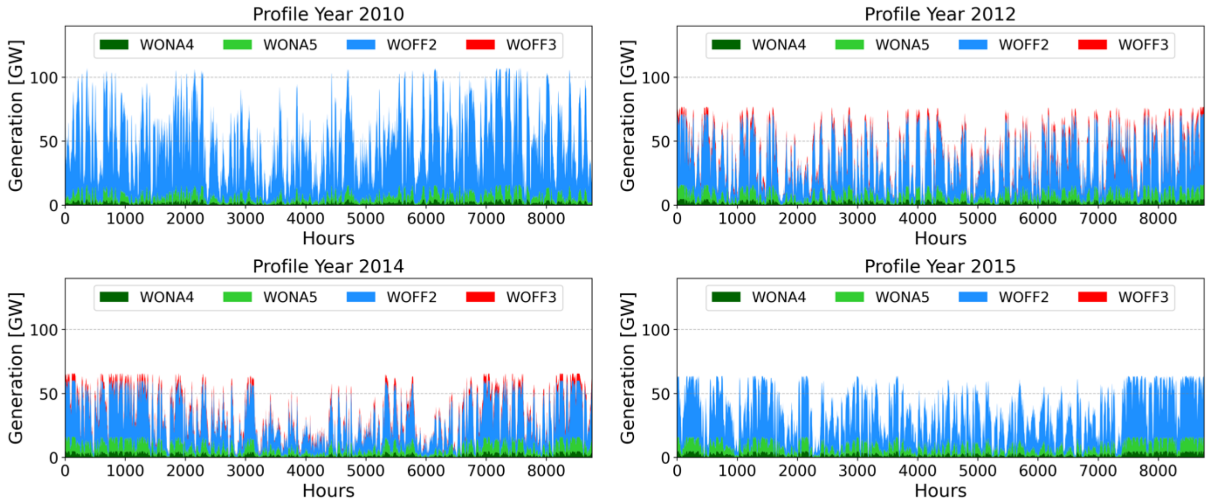

Figure 23: Wind generation levels for the different wind classes in the UK1 region for four of the modeled years.

To connect this section back to Section 4.1.1 and the concept of utilizing hydrogen to shift electricity generation in time, Figure 24a displays the extent to which hydrogen is used for electricity production relative to how much hydrogen is used for industrial purposes, where the latter is provided exogenously to the model. The amount of hydrogen that is used to shift electricity generation in time varies significantly, and as was discussed in the previous passage, this is due to the characteristics of the generation profiles of wind power. Furthermore, Figure 24a shows that there is no correlation between the annual capacity factor for wind power and the amount of hydrogen used to shift electricity generation in time. For example, Years 2010 and 2015 have the lowest and highest capacity factors for wind power, respectively, yet the same amount of hydrogen is used to shift electricity generation in time. Moreover, while Year 2012 and Year 2014 have very similar capacity factors, there is a substantial difference in the use of hydrogen for electricity production in these years.

Without any additional gas turbine capacity to ensure feasibility over all 10 years, the specific gas turbine investments for the different years modeled are visualized in Figure 24b. The configurations available in this stage are: OCGTs and CCGTs that are exclusively fueled with biomethane; or a configuration that allows for flexible mixing of hydrogen in biomethane. As illustrated in Figure 24b, there are significant disparities in the installed capacities of OCGTs and CCGTs across the different years, with certain years exhibiting a total gas turbine capacity that is nearly double that of other years, comparing for example, Year 2010 and 2012. When supplementary capacity is added, only OCGTs that are fueled with biomethane are allowed.

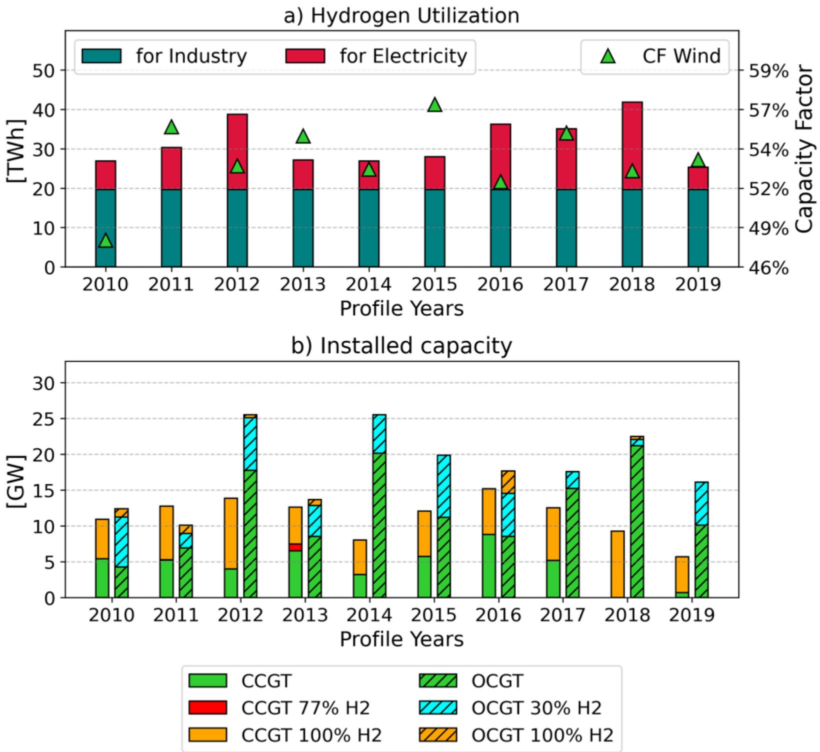

*Figure 24: Results for ten meteorological years considering: a) the distributions of hydrogen utilization for industrial and time-shifting purposes and wind power capacity factors; and b) the installed gas turbine capacities assuming flexible mixing of hydrogen. The results are obtained from **Paper V** using the Multinode model.*

4.3.2 The abilities of technologies to recuperate their costs

After the capacity mixes in Figure 22 are supplemented with additional peak capacity, ensuring feasibility for all 10 years, the economic performance of each technology is evaluated. This assessment is necessary because the capacity mixes are no longer cost-optimal (i.e., the investments are not the result of a single 10-year model run). Therefore, it is essential to determine the extent to which the technologies cover their own costs, specifically by calculating the revenue-to-cost ratio (annual revenue divided by the annualized cost). The annual revenue-to-cost ratios shown in Figure 25 are for the capacity mixes originating from Years 2010 and 2018, as shown in Figure 22. The capacity mix based on Year 2010 has the lowest recovery rates, primarily due to the low capacity factor for wind power in

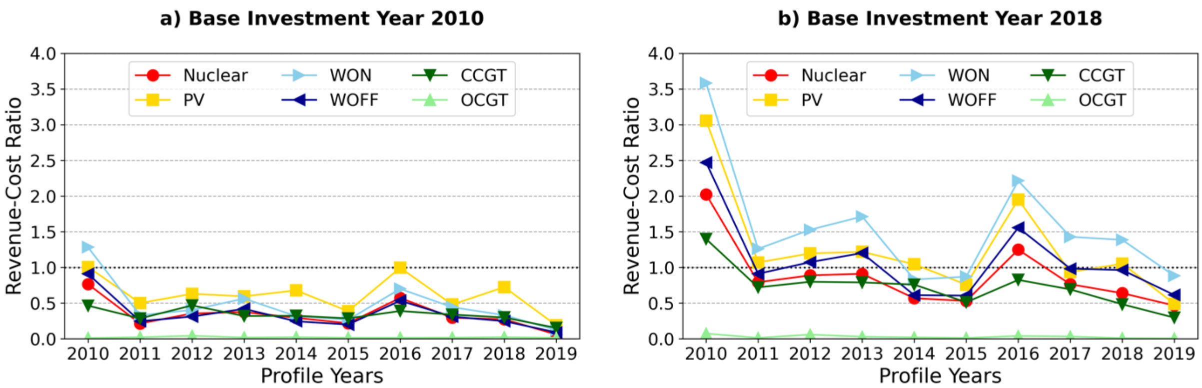

*Figure 25: Annual and average revenue-to-cost ratios for capacity mixes based on (a) Year 2010 and (b) Year 2018, with the capacity mixes including also additional capacity to ensure feasibility for all 10 years. The results are obtained from **Paper V** using the Multinode model.*

that year (see Figure 24a). The low capacity factor for wind power in Year 2010 results in larger investments in wind power, resulting in a surplus of electricity generation during the other years with normal and high capacity factors, with the surplus leading to a lower marginal cost for electricity, making it difficult for all the technologies to recover their costs. When investments are instead based on Year 2018, less wind capacity is installed, resulting in generally higher electricity costs but with the consequence that most of the technologies recover their costs over the 10-year period. The exceptions to this are nuclear power, CCGT, and OCGT, with revenue-to-cost ratios of 0.88, 0.73, and 0.02, respectively, over the 10-year period. It should be noted that since the model used is not an electricity market model, the revenue-to-cost ratio should be regarded simply as an indicator of economic performance rather than an absolute predictor. The overall poor economic performance of OCGT is clearly due to the additional capacity that is needed for this technology to ensure feasibility. One could argue that some of this additional capacity could instead be allocated as reserve capacity, such that it would not be required to recover its cost in the energy-only market, which is the one represented in the model.

Figure 26 provides an overview of the economic performances of all ten capacity mixes over the 10-year period. Categorizing the economic performances, some capacity mixes exhibit poor recovery rates (Years 2010, 2013, and 2016), some attain excessive recovery rates (Years 2014, 2015, and 2019), and others have more-moderate recovery rates (Years 2011, 2012, 2017, and 2018). A common factor for the capacity mixes with poor recovery rates is an unbalanced generation mix with very high production from VRE, leading to low utilization of high-cost biogenic fuels, which supply only around 1% of the electricity demand. Conversely, capacity mixes with excessive recovery rates exhibit high levels of utilization of biogenic fuels, supplying around 5% of all the electricity, due to insufficient generation from other technologies. The more-well-balanced capacity mixes with moderate recovery rates have 2.6%–3.5% of their electricity supplied by biogenic fuels. Clearly, it is important to have a balanced capacity and generation mix that can reliably supply the demand at all times and that remains economically sustainable over time, considering the varying conditions for VRE generation across different years. However, as demonstrated in Figure 9, biogenic fuels are utilized even when associated with very high costs, and their utilization significantly impacts the marginal cost of electricity, thereby affecting the revenues earned by other technologies operating during those hours.

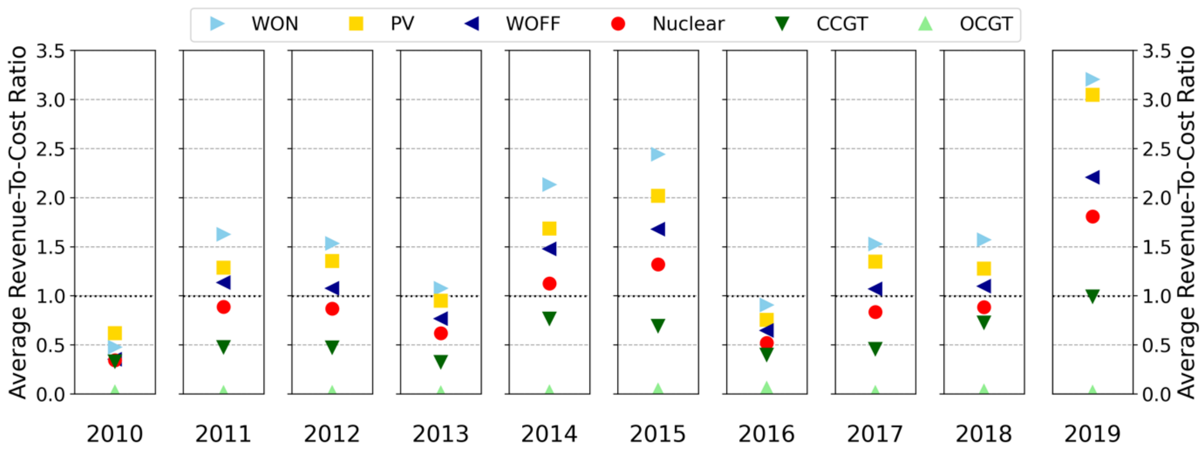

*Figure 26: The 10-year average revenue-to-cost ratios (per technology) for capacity mixes based on each of the 10 years, with the capacity mixes including also additional capacity to ensure feasibility for all 10 years. The results are obtained from **Paper V** using the Multinode model.*

Irrespective of the amounts of biogenic fuels that could be sustainably and cost-competitively supplied, large variations in the utilization of fuels for dispatchable technologies between different meteorological years are identified in **Paper V**. This is illustrated in Figure 27, and from the supply-chain perspective, it is clearly problematic with a tripling of the demand once a decade (or even less frequently). Yet, due to the high investment costs linked to processes that produce biofuels, such as biomethane or methanol, compared to the cost of storing these fuels, a rational solution could be to produce continuously slightly more biofuels than are required for 'normal' years, thereby buffering the fuels in storage units for the years with energy deficits. While biomethane could be stored in existing natural gas storage systems (existing and planned natural gas storage facilities in the UK have a combined capacity of 53.2 TWh [146]) at low cost, methanol could be stored essentially anywhere in above-ground cisterns at very low cost, and they could be used as buffer fuels for the most-infrequent energy deficits. **Paper V** concludes that the utilization of fuels such as biomethane, methanol, and biodiesel, or even fossil equivalents, is likely to be a cost-competitive option for balancing inter-annual variations with low recurrence. This is because these fuels, besides being storable at a reasonable cost, can be utilized in gas turbines, which have a low investment cost and, therefore, do not significantly impact the total system cost. The same conclusion has been reached by Ullmark et al. [108], i.e., that gas turbines with low investment cost and fueled with biomethane are the most-cost-optimal strategy to balance inter-annual variations with low recurrence. However, the question as to who should bear the cost for both inter-annual energy storage and generation capacity with a very low utilization rate remains unanswered and is outside the scope of this work.

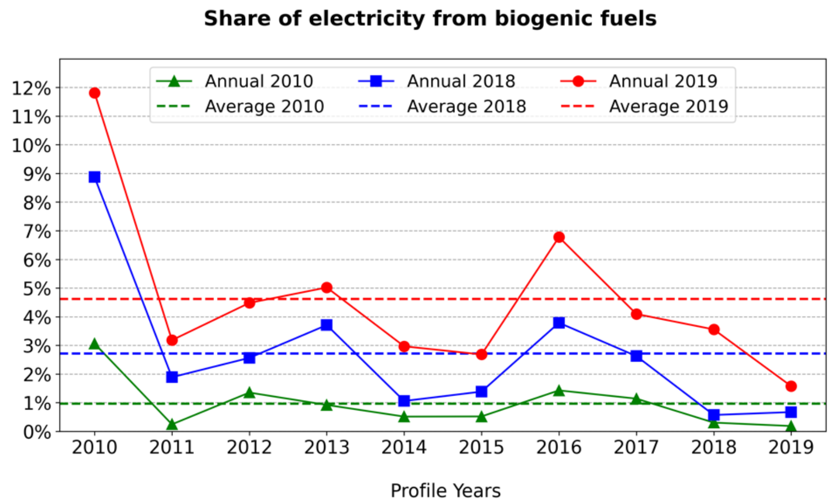

*Figure 27: Annual and 10-year average shares of electricity originating from biogenic fuels for capacity mixes based on Years 2010, 2018, and 2019. The results are obtained from **Paper V** using the Multinode model.*

5 Discussion

This section discusses the key topics related to the work presented in the previous sections. Section 5.1 focuses on the main results attained within the scope of the work, Section 5.2 centers around the development of large-scale hydrogen demands, Section 5.3 describes the applied methods in **Paper I** and **Paper V**, Section 5.4 considers the limitations of the modeling approach, and Section 5.5 focuses on the development of nuclear power and biomass availability.

5.1 Discussion of results

One of the main focuses of this work has been to evaluate the potential system value of shifting electricity generation in time via hydrogen, including production, storage, and conversion of hydrogen back to electricity. However, this hydrogen pathway has been criticized and regarded with some skepticism due to its low round-trip efficiency and significant inherent losses. Unquestionably, a round-trip efficiency in the range of 20%–40% is not desirable. However, the critique implies that the poor round-trip efficiency in itself disqualifies the process, without considering the alternatives and the system value that this hydrogen pathway could provide. If the alternative is to curtail electricity, the loss would amount to 100%, and balancing all variations with, for example, batteries would incur significant costs. Given the assumptions and simplifications inherent to energy systems modeling, this work demonstrates that in systems dominated by wind power, the time-shifting of electricity generation via hydrogen does provide a system value, and that is true despite the low round-trip efficiency of this hydrogen pathway.

The initial goal of this work was to evaluate the competitiveness of hydrogen-fueled gas turbines, and as such, this technology has received considerable attention throughout the work. Regarding the conversion of hydrogen back to electricity, the results indicate that gas turbines have a competitive edge over fuel cells, given the assumptions of cost, efficiency, and fuel flexibility. However, it is important to emphasize that the specific technology used for the reconversion of hydrogen is not the main finding. Rather, the main takeaway message is that for a technology that can provide dispatchable generation with similar investment cost, efficiency, and fuel capabilities as those assumed for gas turbines, the proposed hydrogen pathway provides a positive system value by supplying electricity during high-net-load events. Thus, if another technology with similar or better properties was to emerge, it could also provide the aforementioned system services. Furthermore, it must be emphasized that gas turbines with modern combustion systems are not yet capable of 100% hydrogen combustion, nor are they capable of flexible mixing across the full range, as is assumed in the present work. Therefore, significant challenges remain for gas turbine manufacturers.

Considering the implementation of the hydrogen pathway for shifting electricity generation in time, it is likely to be one of the last hydrogen applications to be adopted. As concluded in **Paper I**, critical aspects are that VRE generation constitutes a major share of the electricity supply and that the carbon emissions budget must be constrained to very low levels. This is because gas turbines can be expected to provide only a minor share of the total electricity demand, offering primarily flexible and dispatchable power. Thus, natural gas-fired gas turbines could provide the balancing service with a limited impact on the total carbon budget for many years to come. While industries such as steelmaking and ammonia production are likely to adopt hydrogen before it is used for the decarbonization of peak power, such development could influence the competitiveness of, for example, hydrogen-fueled gas turbines in both positive and negative ways. On the positive side, large-scale investments in hydrogen infrastructure could reduce the cost of key components, something which would benefit all types of hydrogen applications. However, with large-scale hydrogen demands, electrolyzers can function as an ‘inverted peak technology’, reducing its operation when electricity generation is scarce – provided that there is either hydrogen storage or flexibility within the industrial production process. The impact of flexible hydrogen production is, however, limited and primarily determined by the hydrogen demand rather than the size of the net-load, as long as the cost of electrolyzers remains high. Consequently, it is unlikely that flexible hydrogen production would fully replace the role of hydrogen-fueled gas turbines, or any other similar technology.

As there are periods with elevated electricity costs, to a great extent caused by the high-cost fuels used in gas turbines, another aspect that could reduce the competitiveness of gas turbines is demand-side flexibility in households. This is a flexibility option that is not included in the modeling performed in this work, although as concluded by Nyholm et al. [157], space heating of single-family dwellings typically has the ability to shift the heating demand in the range of 3–6 hours due to the thermal inertia of buildings. Thus, small-scale heat pumps with smart control systems could provide such demand-side flexibility if electricity price variations offer sufficient incentives. In relation to the results obtained in the present work, household demand-side flexibility would primarily influence the operation of CCGTs during events of low duration (visualized in the lower part of panel e in Figure 11).

The characteristics of gas turbines, including flexible and dispatchable generation capabilities combined with low investment costs, make this technology a cost-effective option for balancing variations that have low occurrence rates. The low-occurrence variations include both shorter fluctuations within years and longer periods of very low frequency, such as consecutive weeks once a decade or even less frequently. However, the infrequent operation of gas turbines poses a problem due to the variable and unpredictable revenue flow. This financial uncertainty exposes operators to significant risk, which may act as a disincentive for the capacity investments needed to ensure system functionality. To mitigate the financial risks linked to capital-intensive investments, such as those in wind power or nuclear power, different types of contracts have been designed. An example is the contract-for-difference (CfD), which initially included a direct subsidy to the operator, although as wind power and solar power have become cost-competitive in their own right, CfDs have been further developed to mitigate instead the financial risks associated with variable revenues without distorting the dispatch, investment, and repowering decisions [55]. However, CfDs are not suitable for low-capital intensive technologies with high variable costs, which means that other kinds of contracts must be designed. While it is important to ensure system functionality and mitigate the financial risk for operators, these contracts must be designed such that they do not interfere with the energy-only market, thereby avoiding the distortion of incentives for other flexibility options. One such contract is the so-called *capacity mechanism*, or *strategic reserve*, which is procured for a certain number of years through an auction, where the winning bids receive compensation according to the terms of the agreement. The strategic reserve, which is activated by the transmission system operator (TSO), exclusively affects the spot market electricity price during the hours of activation, imposing a ceiling price currently set at 4,000 €/MWh (in Sweden). Consequently, the influence on other flexibility options remains minimal. However, future capacity mechanism contracts may need to be developed to consider also the capacities and fuels that are required only once a decade, or even less frequently, as inter-annual variations will become more pronounced in a weather-dependent energy system.

Considering the inter-annual variations of wind- and hydro-based energy systems, statistics on water inflows in the Swedish hydropower system between Year 1963 and Year 2019 show that annual variations can range from 45 TWh to 80 TWh [158], corresponding to 73% and 130% relative to the mean inflow of 61.5 TWh. Although some years exhibit significant differences, such as between 2001 and 2002, with Year 2002 having an inflow that is 23 TWh less than that in Year 2001, the standard deviation is 8.5 TWh (13.8%). While the inter-annual variations in water inflow can be partially balanced by reservoir storage capacity, there will still be year-to-year variations in hydropower generation. Given the likelihood that wind power will constitute a considerable part of the Swedish electricity system, there is a risk that some years will experience deficits in both wind power and hydropower generation. With the standard deviation in wind power generation being around 10% for Sweden [22], and with a system that has 75–190 TWh of wind power generation (Figure 21b), the standard deviation would be 7.5–19.0 TWh for wind power generation. Thus, there is a risk that wind and hydro-based energy systems are exposed to considerable inter-annual variations in electricity generation. However, the probability of these two technologies generating at low levels in the same year will determine the preferable alternative to manage these variations, an analysis that is beyond the scope of this work.

Considering the cost of electricity in the modeled future energy systems, the results in Figure 6 show that while the average cost of electricity remains at similar levels as the historical wholesale prices, the volatility increases dramatically in some of the regions modeled. The highly fluctuating electricity costs reflect the balance between supply and demand and the cost required to meet the demand at any given timepoint. However, these fluctuations also enable various flexibility measures to recover their costs. If such variations were not expected, investments to balance the variations between the supply and demand would not be made. There is plenty of statistical evidence and an understanding of the variations that can be expected, and there are multiple options to balance these imbalances, as described in Section 0. However, if there is uncertainty as to whether these variations will occur, for instance due to political interference with how the electricity system should be designed, this uncertainty risks undermining investments in solutions designed to balance these variations.

5.2 Assumptions on industrial hydrogen demands

In this work, it has been assumed that steelmaking and ammonia production are indirectly electrified via the use of hydrogen, and that the historical production quantities of steel and ammonia are maintained in the future system that is modeled. Under these exogenous assumptions regarding hydrogen demand, combined with endogenous hydrogen generation for energy storage, the total hydrogen production amounts to 240 TWh_{H2} within the north-western European scope modeled in **Paper IV**. This hydrogen demand is considerably lower compared to other studies [94][156] and aligns with the European Commission's communicated milestone for Year 2030 [147], even though the modeled year is Year 2050. However, instead of assigning a general and unspecified hydrogen demand based on a general assumption that such demand will materialize, the presented work implements well-defined hydrogen demands in processes that are likely to transition to a hydrogen-based production, such as in steelmaking and ammonia production. A potential drawback of assuming a lower overall hydrogen demand is that it leads to a lower electricity demand, which would result in a significantly different system composition compared to a scenario with higher hydrogen demand. For example, one conjecture is that a higher hydrogen demand could necessitate larger investments in nuclear power due to limited potential for VRE resources. However, as concluded by Walter et al. [94], VRE resources are sufficient to supply a hydrogen demand as high as 2,500 TWh_{H2} when nuclear is excluded, and even if nuclear generation increases with an increasing hydrogen demand, the majority of electricity would still be supplied by VRE resources.

Considering the milestones outlined in the hydrogen strategy communicated by the European Commission [147], the objective of the first phase is to install 6 GW of electrolyzer capacity and produce 33 TWh_{H2} (1 Mt) of clean hydrogen annually by Year 2024. In the second phase, the ambition is to have 40 GW of installed electrolyzer capacity and an annual production of 333 TWh_{H2} (10 Mt) of clean hydrogen by Year 2030, in addition to an equal amount of imported hydrogen. However, by the end of Year 2022, the aggregate electrolyzer capacity in the EU-27, EFTA[11], and the UK amounted to only 174 MW [148]. Short-term estimates for Year 2023 have ranged from a minimum of 191 MW to an optimistic 500 MW [149], and by the end of Year 2025, 1,371 MW of electrolyzer capacity could be installed, assuming that all the planned projects adhere to their timelines. Thus, despite the ambitious plans for a rapid expansion of clean hydrogen production, the implementation currently falls short of expectations.

The cost situation is clearly an explanation for the slow implementation, and although the cost of electrolyzers has declined by 90% since the beginning of the millennium [150], the costs still remain high. Moreover, contrary to an expected gradual decline, the costs for electrolyzers have, in fact, increased in recent years [151]. These increases can to a large extent be attributed to inflation, which has driven up the costs of materials, utilities, and labor. In addition, recent projects have been larger than previous ones, leading to additional costs related to grid integration [151]. Another aspect that is holding investments back is the delay in announced subsidies reaching developers [151][152]. For example, the second auction of green hydrogen subsidies for a total of €2.2 billion has been delayed until the autumn of Year 2024, as the European Commission first wishes to evaluate the first auction of €800 million that was finalized in the beginning of Year 2024 [153]. In this first auction, 132 bids were received, with developers applying for more than 8 GW of electrolyzer capacity, although only a small fraction of the bids will receive funding [154]. Thus, although the Phase 1 objectives of the European Hydrogen Strategy [147] have not been met, interest among developers remains high, and with subsidies pending, investment decisions critical to driving down the costs could soon be realized.

In the longer perspective, the production of clean hydrogen may require electricity volumes comparable to the current EU electricity consumption of around 2,800 TWh [155]. A study conducted by Lux and Pfluger [156] has revealed that a European hydrogen demand of 1,400 TWh_{H2} would be cost-optimally supplied by 615 GW of electrolyzer capacity. Similarly, Walter et al. [94] have shown that 250–450 GW of electrolyzer capacity are required to supply 1,500 TWh_{H2} of hydrogen. The range given by Walter et al. [94] reflects different assumptions regarding flexibility options, where for example, the electrolyzer capacity of 250 GW assumes no hydrogen storage, such that hydrogen would be produced at a constant rate, i.e., a capacity factor of 100%. The 450 GW are derived from a scenario in which the hydrogen demand is flexible in time, and thus large quantities of hydrogen can be produced when VRE generation is high. This scenario leads to a lower utilization rate of the electrolyzer with a capacity factor of 54%. In the study carried out by Lux and Pfluger, the hydrogen demand is flexible regarding both time and location, leading to an even higher electrolyzer capacity (615 GW) with a capacity factor of 38%. To summarize, if 1,400–1,500 TWh_{H2} of hydrogen are to be produced via electrolysis, not only will the electricity demand increase by over 70%, but hundreds of gigawatts of electrolyzer capacity will also be needed, given that the capacity factor likely will be well below 100%. The latter aspect is important to keep in mind because the objectives of 6 GW and 40 GW and the related production goals in the European Hydrogen Strategy [147] seem to assume a capacity factor of 100%.

5.3 Methodologic reflections

The method used in **Paper I** applies a model package that consists of two soft-linked models, where the bulk investments are made in the ELIN investment model, and the detailed dispatch is modeled in

[11]European Free Trade Association (EFTA), including Norway and Switzerland (Iceland and Lichtenstein not considered).

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 that uses representative days is applied. This method has good accuracy in terms of capturing the bulk investments in electricity generation, although it has 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. Furthermore, due to the representation of time, 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 that enable the possibility to blend in different shares of hydrogen. This means that the additional investments made in EPOD are made in an already existing energy system. This, in combination with fixed mixing ratios of hydrogen in gas turbines, means that a low mixing ratio (30 vol.-%) of hydrogen is the most-commonly made investment among the investment options for hydrogen-fueled gas turbines examined in **Paper I**. Consider instead **Papers II**, **III**, and **V** (hydrogen-fueled gas turbines are not included in **Paper IV**), all 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 most-common hydrogen blend-in level in gas turbines is 100 vol.-%, regardless of whether the hydrogen mixing is fixed or flexible. Thus, it can be concluded that the optimal mixing ratio of hydrogen in hydrogen-compatible gas turbines is affected by the selected method, although that the total installed gas turbine capacity is similar for both methods.

The approach used in **Papers II**, **III**, and **V** models a hypothetical system with a perfect equilibrium between the included technologies, excluding any impacts from lock-in effects from previous investments or bridging technologies. In such a system, gas turbines with high mixing ratios are considered more competitive than they would be in a system with a legacy of former decisions. It could be argued that, while the overall system in general develops slowly, gas turbines can be put in place relatively fast, and thus that the approach in **Paper I**, with the resulting low mixing ratio, is more likely. In reality, however, the practical aspects of having access to hydrogen could also be a factor to consider, i.e., that different sites may have different access to hydrogen, and it could also be the case that the hydrogen mixing capability of a gas turbine is increased over time as the system and technologies develops. Related to technology development, another aspect to consider is the technical capability of gas turbines to combust hydrogen, which has not yet reached the levels and flexibility assumed in this work.

A greenfield approach can of course be questioned in a more general sense, as investments in reality always are made in the context of an existing system. However, as the modeled year in **Papers II–V** 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 economically feasible when there is a higher cost attached to emissions allowances. Instead, the results in **Papers II–V** should be regarded as indicators of how future energy systems could be designed, particularly highlighting the interplay between generation and storage technologies, as well as flexible demands for energy.

In **Paper V**, the objective was to examine the impacts of inter-annual variations, primarily due to fluctuations in wind power generation, on the operation and revenue of technologies, and to investigate the consequences of having energy systems which are not perfectly adapted to the weather conditions of the investigated year, as opposed to the optimal systems typically produced by capacity expansion models. In addition, emphasis was also placed on maintaining a high level of detail, including factors such as endogenous investments with optimized dispatch, a sufficiently large spatial scope to account for geographic smoothing and trade to manage variations, and hourly time resolution. Thus, while the study highlights the effects of exposing a fixed capacity mix to different weather conditions, it does not provide a comparison of individual years and an optimal 10-year model run. Another aspect worth mentioning is the assumption that 100% of the revenue collected by generation technologies over the 10-year period is derived from the hourly marginal cost of electricity, which serves as a proxy for the wholesale spot market price. This assumption is somewhat problematic because, in reality, a significant portion of electricity is traded on futures and forward markets several years before production. These markets allow producers and consumers to hedge against price uncertainty, which is not accounted for when assuming that all revenue is derived solely from the spot market prices. However, the same assumption is, in fact, also employed in models run for a single year, where it is implicitly assumed that all years of a technology's lifetime will be identical.

5.4 Limitations

An aspect that is commonly raised as a limitation of linear optimization models is that the problem is solved with perfect foresight. This means the solution is deterministic, relying on full transparency of all inputs for the decision-making process. The problem with this approach is that the marginal value of, for example, energy storage is based on perfect information, allowing for investments, charging, and discharging to be made optimally. In reality, however, the marginal value of storage can be under- or over-estimated for any given period, depending on the forecasts available at a given moment. For energy storage over relatively short periods, considering, for example, the charging and discharging of batteries to manage solar PV variations, this may not pose a major problem. However, for energy storage over longer periods, such as those related to shifting electricity generation in time via hydrogen, forecasting will be much more difficult. Estimating the value of stored energy over longer timeframes in a climate of some uncertainty is a practice that is already employed in managing resources such as hydropower. However, when the uncertainty extends to additional dimensions of the system, the complexity and level of uncertainty increase further. In reality, uncertainty implies risk, and with risks comes the need for risk mitigation, which invariably incurs additional costs. Additional costs due to risk mitigation would likely render a technology such as hydrogen-fueled gas turbines less competitive, i.e., the investments attained with perfect foresight likely are overestimated. However, to mitigate the risk of being unable to meet the demand at all times, gas turbines – with their low investment costs – are a plausible technology for addressing this risk. Thus, models that apply perfect foresight may underestimate the total installed gas turbine capacity needed to ensure the functionality of an energy system. In general, models with perfect foresight might not be suitable for making forecasts of detailed aspects of future energy systems. Nevertheless, they can be informative when studying the interplay between technologies.

Another methodologic aspect that that may influence the results is the lack of price elasticity in the different demands included in the model. For some of the modeled scenarios, the model includes flexible production of the commodity within industrial processes, in addition to the flexibility provided by, for example, hydrogen storage, albeit with an unchanged annual demand. Furthermore, even though the hydrogen demand for time-shifting electricity generation is endogenous and therefore flexible, the vast majority of the electricity demand is fixed, considering both the annual demand and the hourly profile. In reality, this demand would likely be influenced by high electricity costs, leading to a shifted or decreased demand. Such electricity price elasticity was identified in Sweden (and possibly also in other countries) during the winter period of Years 2022 and 2023 as a consequence of the electricity price crisis following the Russian invasion of Ukraine. According to the Swedish TSO, Svenska

Kraftnät, electricity consumption decreased by 10.2% and 8.1% in the Swedish price areas of SE4 and SE3, respectively, far exceeding the EU ambitions to reduce consumption by 5% [159]. Such price elasticity would most likely impact the competitiveness and operation of gas turbines in the model.

The representation of the electrical grid is another critical aspect to consider when evaluating the results of this work. Each of the modeled regions is connected with a simplified representation of the transmission grid, such that electricity can be sent from one region to another without impacting the flows between any other regions. This representation is known as a pipe-flow model, which is one of the less-sophisticated methods for modeling a transmission grid. In reality, power flow in a transmission grid depends on several factors. For instance, the power flow between two points (A and B) is influenced by the voltage angles at each end of the transmission line. Moreover, when power is transmitted from point A to point B, it can also affect neighboring points (C and others), with power distribution across different paths being influenced by cable resistance levels and voltage angles at various nodes (previously referred to as *regions*). Thus, the actual power flow distribution in a grid is more complex than what a simple pipe-flow model can capture. Furthermore, the individual regions are modeled with the copper-plate assumption, i.e., that power can flow unconstrained from any generation site to any demand site within the region. This simplification has two implications. First, bottlenecks in the distribution grid are omitted, which means that the cost-optimal capacity mix does not reflect these constraints. Second, there is the cost of expanding the transmission system connecting the regions. While these investments do incur costs, the model does not account for the local distribution grid. Consequently, investments needed to reinforce that part of the grid are not considered, and thus, the cost of expanding the transmission grid is underestimated.

Although the transition from the current system to a decarbonized system was modeled in **Paper I**, a limitation of this work as a whole is that it does not reflect the feasibility of achieving the resulting energy systems within the desired timeframe. While the physical potential to supply the assumed future demands mainly with wind and solar power exists, and the available flexibility measures have the potential to integrate such generation, a number of aspects may impact the system development in other directions. As described by Cherp et al. [160], after achieving its maximum growth rate, factors that risk stalling the expansion of VRE generation include a decreasing marginal value of generation, challenges with grid and system integration, geophysical constraints, and a lack of social acceptance, as well as countervailing political resistance. As further concluded by Cherp et al., to limit the increase in the global average temperature to 1.5°C or 2°C above pre-industrial levels, the expansion of VRE must either match or surpass the highest expansion rates recorded in any country up and until Year 2018. The method employed effectively captures the techno-economic aspects of market saturation for various technologies, specifically identifying the cost-optimal capacity mix for a given system. However, while social acceptance and political opinions can to some extent be represented through exogenous assumptions – such as those concerning onshore wind potential and mandated nuclear power expansion – the dynamic interplay between system development and social acceptance, as well as political direction, is not captured.

5.5 Nuclear power development and the use of biomass for electricity production

One technology that has not attracted much investment throughout this work is nuclear power, which is a model outcome that has occasionally been criticized. With the objective to minimize the total system cost given a number of constraints, assumptions regarding technology costs naturally have potent impacts on the modeling outcome. The investment and variable costs of nuclear power used in **Papers I–III** were retrieved from the IEA World Energy Outlook (2021). However, after consultation with experts in the field of nuclear power, the costs were adjusted in **Papers IV–V** to be lower than those provided by the IEA [161], even though this adjustment had only a weak impact on the results. The investments in nuclear power that have been attained are primarily in regions at the boundary of the modeled geographic scope, where access to trade is reduced, or in southern Germany, where the VRE potential is limited and electricity demands are high, assuming current industrial activity. However, in the case of Germany, the last nuclear reactors were decommissioned in Year 2023 as a result of political decisions [162], and consequently, nuclear power has not been considered in the modeling for Germany.

The weak competitiveness of nuclear power, as previously mentioned, is due to its requirement for a high number of full-load hours to achieve a competitive levelized cost of electricity. With the levelized cost of electricity for wind and solar power being lower than that of nuclear power, nuclear power is in this work penalized in terms of both frequent cycling, which incurs additional costs, and low numbers of full-load hours. The headwind for nuclear is, however, not only observed in the modeling conducted within this work, but also by the nuclear industry [163]. For the 18 reactors that were connected to the grid between Year 2020 and Year 2022 globally, the mean construction time was 7.9 years, which on average is 3.1 years longer than the expected construction time, with delays leading to significantly increased costs. Yet, projects such as Vogtle-3 and 4 in the United States, Hinkley Point C in the UK, and Flamanville 3 in France, which are not included in this summary as they were commissioned after Year 2022, have notably exceeded both their time plans and budgets. For example, the construction of the Vogtle reactors started in Year 2013 and commissioning was planned for Year 2018. However, when it was finally commissioned in Year 2023, the total cost of $15,766 per kW was approximately 2.5-times the expected cost. Similarly, the cost for the Hinkley Point C project is expected to be approximately double that initially expected and the project is delayed by several years (Hinkley Point C had not been commissioned at the time of completion of this thesis).

Considering new technologies that could reduce the cost of nuclear power, small modular reactors (SMRs) have garnered attention in recent years. However, the World Nuclear Industry Status Report [163] concludes that there have been no significant advances lately. In the Western world, no SMR units are under construction, and no design has been fully certified for construction. The most-advanced project in the United States was terminated in November 2023 due to a 75% increase in estimated costs.

In contrast to nuclear power, biomass is an energy source that is utilized in all of the scenarios and geographic scopes modeled. With the assumption that biomass and the downstream biofuels are carbon dioxide-neutral – an assumption that can certainly be debated – the model attributes a very high system value to these fuels. This value is illustrated in Figure 9 and Figure 10, where biofuels are utilized despite their very high associated costs. However, since biomass can provide significant value also in other sectors, e.g., as biofuels in hard-to-abate sectors such as aviation and heavy transport, it has been the intention to avoid overestimating the use of biomass within the modeled systems. This exogenous interference is the result of working with a partial equilibrium model, as described in Section 0. The use of biomass has been limited either by applying strict limits to the share of electricity that can originate from biomass, and/or applying high costs for biomass. In a study carried out by Millinger et al. [164], the biomass availability in relation to biomass cost is displayed, showing that domestic (European) biomass products can be supplied at a cost of 10–20 €/MWh, while larger volumes of imported biomass can be supplied at a cost of 54 €/MWh. The cost ranges applied in this thesis are 40–100 €/MWh solid biomass, and as previously mentioned, 77–163 €/MWh for biomethane. Thus, the costs applied are clearly at the higher end of the spectrum.

With these assumptions, the overall share of electricity originating from biomass, across all scenarios modeled, is in the range of 0.8%–2.9%. However, certain subregions may not use any biofuels at all. In **Paper IV**, which encompasses the largest geographic scope among all the appended papers, 58 TWh/a of solid biomass and 172 TWh/a of biomethane are utilized. These levels are notably lower than the 2,000 TWh of biomass used in Year 2021 [165][166]. It is, however, important to note that the modeling did not include Spain, Italy, and eastern Europe; the level of biomass usage would have been higher if all the countries had been modeled. The most-common biofuel used in the model is biomethane, which is employed in gas turbines to address the residual electricity deficit that other flexibility measures cannot balance cost-effectively. Wood chips are used to a lesser extent than biomethane, and then almost exclusively in CHP plants, supplying both electricity and heat demands.

In summary, this work can only evaluate the role and value of biomass within the modeled electricity systems based on the exogenous assumptions made regarding the availability and cost of biomass. Whether the quantities of biomass utilized in the modeled systems are optimal, or even reasonable, in the broader perspective is beyond the scope of this work. However, it is acknowledged that biomass is a limited resource with strong potential in many sectors. Therefore, biomass should be used where it creates the highest value, whether that is in carbon sequestration, replacing fuels in hard-to-abate sectors or serving as the final piece of the puzzle for the electricity system.

6 Conclusions and future work

As mentioned in the *Introduction* section of this thesis, the already-existing technologies constitute the available options in the transition to a decarbonized electricity system, notwithstanding that these technologies can be developed further, and in some cases, take on new roles. In this work, gas turbines and hydropower have been the technologies in focus, and presented below is a summary of the main conclusions of this work. Finally, Section 6.1 provides some suggestions for future work.

With wind and solar power anticipated to supply a major share of future electricity demands and with the emergence of new, flexible industrial demands, the role of gas turbines is expected to evolve. Given the high cost of non-fossil fuels for flexible and dispatchable technologies and new characteristics being introduced to the net-load variations, both OCGT and CCGT are expected to operate with significantly fewer full-load hours in future energy systems. Yet, with their low investment costs and relatively high efficiency levels, gas turbines offer a unique strategy to address low-occurrence variations. This includes managing both shorter fluctuations within years and extended periods of very low generation, such as consecutive weeks of scarce VRE generation, which occur once a decade or even less frequently.

A specific application of gas turbines that has been investigated relates to the reconversion of hydrogen to electricity. Shifting electricity generation in time through hydrogen production, subsequent storage of hydrogen, and conversion back to electricity – primarily via hydrogen-fueled gas turbines in this work – offers a way to increase the value of electricity by shifting it from periods of abundant generation to periods of scarce generation. This hydrogen pathway is identified as particularly competitive in wind-dominated regions, despite the lower production cost of hydrogen in solar-dominated regions. The crucial parameter is the residual load profile, which in wind-dominated regions is characterized by longer and more irregular variations compared to the highly recurrent patterns in solar-dominated regions – variations that can generally be balanced cost-effectively with batteries. It is important to emphasize that shifting electricity generation in time via hydrogen to manage high-net-load events remains competitive despite the low round-trip efficiency, an aspect that is sometimes cited as a considerable drawback of this hydrogen pathway. This work demonstrates that by incorporating hydrogen-fueled gas turbines – or any other technology with similar cost characteristics and fuel mixing capabilities – the total system cost can be decreased while the share of electricity that is curtailed is also reduced.

In relation to hydropower, this work compares and evaluates three hydropower implementations in the Multinode energy systems model. The aim of this part of the work was to enhance the representation of the physical limitations of hydropower, so as to avoid overestimating the operational flexibility of hydropower. One of the implementations incorporates constraints related to physical aspects, such as not having water in the right parts of a river system to facilitate sustained generation at high levels, losses due to spillage in bottlenecks, and the dispatch of water to avoid flooding of smaller reservoirs during periods with a low marginal cost for electricity. Collectively, these constraints reduce the overestimated flexibility of hydropower in energy systems modeling, thereby influencing investments in both generation and storage technologies. Similar system impacts are observed when applying a narrower operational span for hydropower. However, since part-load operation was mathematically enforced with varying minimum and maximum generation levels throughout the year, there are concerns regarding the impact on the marginal values of water and electricity. A hydropower implementation that better represents the physical limitations of hydropower is particularly important in those cases in which the hydropower system constitutes a larger part of the generation mix and has a complex structure, as is the case for the Swedish hydropower system. An enhanced representation of the physical limitations of hydropower is also important when grid expansion is an option in the model, as constrained grid capacity can inhibit the flexibility of hydropower.

Regarding the role of hydropower in a future Swedish electricity system, the main conclusion drawn is that the trend of a weaker correlation between hydropower generation and intra-day load variations is preserved and strengthened in the modeled future energy systems. This suggests that hydropower will primarily act to complement wind power rather than balance the demand. Consequently, the value of operating hydropower at high and low levels for periods ranging from several days to a couple of weeks will be higher in future electricity systems, highlighting the importance of accounting for internal hydropower limitations when including hydropower in energy systems modeling. In addition, the development of the Swedish electricity system has a limited impact on the dispatch of Swedish hydropower. This is because variations outside of Sweden are dominated by wind power, and due to the interconnected transmission capacity, Swedish hydropower is exposed to these variations regardless of the system that is built within Sweden.

Concerning inter-annual variations, primarily driven by fluctuations in wind power generation, it is crucial to distinguish between annual capacity factors and the hourly generation profile. While variations in the annual capacity factors primarily influence investments in the amount of wind power (given that nuclear power is not a competitive technology under the assumptions applied in this work), variations within the generation profile mainly affect investments in different storage technologies. During years or extended periods with low levels of wind generation, fuels such as biomethane, methanol, biodiesel, or even fossil equivalents are likely to be cost-competitive options for balancing inter-annual variations with low recurrence. These fuels are not only storable at a reasonable cost but can also be used in gas turbines, which have low investment costs and, thus, do not significantly influence the total system cost.

6.1 Suggested future work

Listed below are some suggested topics for future work related to the research presented in this thesis. These topics encompass additional technical features of hydrogen-fueled gas turbines, an improved representation of the grid, managing variations that have very low recurrence, socio-technical and institutional barriers that hinder the transition, and finally, the behavioral aspects of actors within the developing energy system.

- The hydrogen-fueled gas turbines modeled in this work exclusively produce electricity. However, to add another layer of flexibility, combined heat and power plants could also be considered for the reconversion of hydrogen. Allowing for such configurations would enable an interplay between different energy carriers and storage technologies, potentially providing additional value to an energy system with multifaceted energy needs.

- The grid representation in the presented models offers significant opportunities for improvements. The pipe-flow and copper-plate assumptions most likely overestimate the ability to transmit electricity across regions and countries. Therefore, an important improvement would be to increase the spatial resolution and apply, for example, a linearized alternating current (AC) power flow representation instead. However, due to computational limitations, such a development of the model would likely impose constraints on other aspects of the model, such as the spatial scope. Consequently, adequately representing trade with neighboring countries needs to be more thoroughly studied. An increased spatial resolution would also enable a better representation of hydropower. This improvement would involve moving from aggregated rivers per price area to representing rivers using a number of segments, or even individual power stations.

- With wind power likely to represent a significant element in a future northern European energy system, managing inter-annual variations in general, and variations with very low recurrence in particular, poses new challenges for system operators. In particular, inter-annual variations in countries with large shares of both wind power and hydropower, such as those in the Nordic energy system, may create especially difficult problems due to the considerable inter-annual variations linked to both of these technologies. Long-term energy storage together with low-cost reconversion technologies appears to be a feasible solution, although further investigations are needed to define how such investments can be incentivized. In addition to mechanisms on the supply side, the impact of more-profound, albeit low-recurrence, demand-side flexibility should be investigated as a complementary approach.

- The type of techno-economic models used in this work identifies cost-optimal capacity mixes under given constraints on demand and emissions. However, concerning the transition from the current to a future system, these models do not adequately reflect the relevant socio-technical and institutional drivers and barriers. In addition, these models fail to clarify whether it is feasible to build the needed infrastructure within the required timeframe, given the social, economic, and institutional realities and potential disruptions. Therefore, in addition to models that merely depict end-state systems, it is crucial to define realistic storylines with near-term steps and critical midway stages, in order to inform scientists, authorities, industry, and the public about feasible pathways for achieving low-carbon energy systems.

- Another aspect of the long-term development of the energy system is the interactions that occur between market actors, considering both supply-side and demand-side participants, and especially how these interactions are affected by the method that is applied. In a study carried out by Fischer and Toffolo [167], it has been concluded that the optimal solution obtained by minimizing the total system cost differs from the solution obtained by instead maximizing the profit for the actors, while obtaining the same overall objective. Thus, there may be a need for alternative methods when evaluating the transition of the energy system, particularly regarding how the timing of the supply and demand will influence the long-term development of the system. A final aspect related to how different actors behave involves the discount rates for technologies. In the presented work, a uniform discount rate of 5% has been applied to all technologies. However, in reality, there are clear indications that different technologies employ varying discount rates [168]. The varying discount rates reflect the risk levels associated with different technologies. For example, offshore wind power, which is considered a higher risk than solar power, typically has a higher discount rate.

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