Master thesis:

Exploring the optimum infrastructure for expected green hydrogen demand in 2030 in Sweden

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Abstract

The ambition to move away from fossil fuels in order to mitigate global warming and reduce dependency on Russian gas and oil is increasing the momentum behind the development of a hydrogen-based economy in Europe. Sweden is ambitiously working towards a carbon-neutral society and has several large-scale green hydrogen projects on the agenda in the coming years. Sweden currently has no infrastructure in place for transporting hydrogen across the country, and the question arises whether this investment is necessary for developing their hydrogen economy. There is also uncertainty regarding the most cost-efficient locations for electrolysers and the resources for its electricity input. The EnergyHub model is run to explore two hydrogen demand scenarios for 2030, resulting in the most cost-effective configuration and performance of hydrogen and electricity infrastructure throughout the country. The results show that the built-out of hydrogen pipelines is more economical than re-enforcing the electricity grid, in combination with hydrogen production in areas with cost-beneficial electricity. Hydrogen storage is located near production and transported to the demand areas when needed. Electricity is mostly produced in the same area as the electricity demand, in combination with large storage facilities to balance fluctuating production and demand.

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CAPEX	Capital expenditure
CF	Capacity factor
CO_2	Carbon dioxide
ESM	Energy system model
EU	European Union
GHG	Greenhouse gas
H_2	Hydrogen
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
OPEX	Operational expenditure
SE1 to SE4	Swedish energy bidding zone 1 to 4
WT	Wind turbine

1. Introduction

1.1 The relevance of a hydrogen future

As climate change is increasingly threatening Earth's ecosystems and societies, urgent action is required. Limiting the – still increasing – global temperature to 1.5 °C with respect to pre-industrial levels is necessary to combat the devastating effects of global warming (Intergovernmental Panel on Climate Change, 2022). According to the International Energy Agency (IEA), the energy sector accounts for approximately two thirds of global greenhouse gas emissions (2021). Within this sector, about 80% of the supply is generated by conventional fossil fuels. In efforts to reduce carbon emissions resulting from fossil fuel use, a shift is occurring towards renewable energy resources, such as wind energy and solar power. Their intermittent nature of energy generation can cause problems with matching supply and demand. Flexibility and storage methods are needed in an energy system that is becoming increasingly volatile, which is where hydrogen could become relevant (Mikovits et al., 2021). Recent studies showed the potential of hydrogen as storage medium to balance the supply and demand in an electricity system primarily depending on intermittent resources (Weimann et al., 2021). Furthermore, hydrogen can be an excellent agent for reducing CO_2 emissions in hard-to-abate industries, serving as an environmentally friendly alternative feedstock and potentially replacing fossil fuels in manufacturing processes (Öhman et al., 2022).

The importance of moving away from fossil fuels is currently extra highlighted in the context of the global energy crisis. The European Union (EU) desires to reduce its enduring reliance on Russian oil and gas regarding the invasion in Ukraine (Knodt & Kemmerzell, 2022). The current context is characterised by dealing with high energy prices and concerns over energy security. EU leaders agreed to phase out their dependence of Russian oil and gas as quickly as possible and stress the importance to accelerate the energy transition by substituting fossil fuels (European Commission, 2022).

In relation to these factors, the momentum for developing hydrogen economies is currently at an all-time high. The European Council speaks about creating an EU-wide hydrogen backbone in the near future (European Commission, 2022). Numerous pilot projects to demonstrate the uses of hydrogen have been established, such as the first ever hydrogen-powered trains in Germany (International Energy Agency & Clean Energy Ministerial, 2022).

In essence, the growing concerns regarding the negative effects of global warming in combination with the current energy crisis necessitate a shift away from fossil fuels and the development of innovative energy solutions, such as the integration of hydrogen in energy systems.

1.2 Hydrogen relevance in Sweden

This research is limited to the context of Sweden and its potential hydrogen economy by 2030. This context is interesting and relevant due to several reasons.

First of all, Sweden has potential to be at the forefront of accelerating the transition towards a fossil-free society. The country expresses great ambitions towards climate goals, having a national target of becoming net-zero by 2045, which is 5 years ahead of the EU plans. Sweden put clear milestones for carbon mitigation in their climate act, such as the transport sector reducing its carbon emissions with 70% by 2030 (Klimat politiska rådet, 2022).

In addition to the government's ambitions, many Swedish companies show voluntary efforts in sustainable practises to become a carbon-neutral society. Thus, innovation and climate action are happening at the niche as well as regime level in Sweden (Nurdiawati & Urban, 2022).

Furthermore, Sweden recognizes the importance of hydrogen in becoming a carbon-free society. The national strategy for fossil free competitiveness by Fossil Free Sweden, an initiative by the Swedish government, emphasizes hydrogen as an important tool for achieving its climate goals (Fossil Fritt Sverige, 2021). Their focus is on expanding in *green* hydrogen, as this form of hydrogen comes with zero emissions. The cost of renewable electricity, needed for electrolysis, is expected to continue to fall globally, which also benefits a focus on green hydrogen rather than grey (Fossil Fritt Sverige, 2021). Currently, Sweden's energy mix is already low in carbon emissions, having a significant share of hydropower for flexibility and nuclear power for baseload, as well as an abundant amount of biofuels. The theoretical framework elaborates on this. In practice, several pilots of hydrogen projects have been established, such as the recent installation of five hydrogen refuelling stations (Tang et al., 2022) and the H_2 Green Steel project in the North of Sweden (R. R. Wang et al., 2021).

All in all, Sweden has interesting features to investigate the prospects and obstacles associated with a shift towards a green hydrogen economy.

1.3 Research gap

A growing body of academic research is exploring the opportunities and barriers of a hydrogen-based economy (Mikovits et al., 2021).

At a global level, various dimensions of a hydrogen economy are being assessed, with Hauglustaine et al. (2022) investigating the potential of a hydrogen economy to drive the global temperature down and assessing the climatic impact on a worldwide level. Oliveira et al. (2021) conducted a system-level analysis to investigate the different stages of implementation that a transition towards a global hydrogen-based economy would require.

In addition to global investigations into a hydrogen economy, many researchers have explored the role of hydrogen in European context. Genovese et al. (2023) presents a high-level study in which the role of hydrogen is examined in several sectors, in reference to European scenarios. Falcone et al. (2021) zoomed in on the link between a hydrogen-based economy and the Sustainable Development Goals and presents policy insights. Van der Spek et al. (2022) considered the technological, business and legal side of a hydrogen-based economy in Europe.

Regarding hydrogen developments in Sweden, some studies focus on deep diving into case studies and specific sectors to investigate technical and economic processes. For instance, Tang et al. (2021) zoomed in on the techno-economic feasibility of a hydrogen plant powered by nuclear energy, to fulfil hydrogen demand in Sweden. Janke et al. (2020) focused on the agricultural sector in Sweden and assessed the potential of demand-driven small-scale hydrogen production. Nurdiawati & Urban (2022) concentrated their research on the refinery sector in Sweden and assessed its niche developments in carbon abatement technologies. Andersson & Grönkvist (2021) conducted a comparison of hydrogen storage technologies in Sweden, considering cost-effectiveness. These studies lack a high-level perspective, as to how such hydrogen storage or plants would be integrated in the system as a whole and the effects of this. Nonetheless, these studies are useful for understanding the context and current stage of hydrogen-based developments, as well as enhance data collection for this study. For instance, the research on carbon abatement technologies in the refinery sector provides context that green hydrogen is a viable option that is being worked towards in reality, but still holds a lot of uncertainties regarding its future pathway (Nudriawati & Urban, 2022). The research paper by Tang et al. (2021) enables several insights and resources on Swedish electricity prices and understanding the dynamics between hydrogen prices and the marginal cost curve of the electricity that is used in the system.

Other studies adapt a high-level perspective, each with its own area of focus, applied to Sweden. Karakaya et al. (2018) investigated the potential for the heavy industries in Sweden and the rest of Europe to transition towards a hydrogen-based future, using a multi-level perspective and a technical innovation system approach, where Sweden leads as an example. This study focuses on the policy and industry commitments, rather than technological or economic feasibility, which facilitates comprehension on the potential and developments of using green hydrogen large-scale, affirming the relevance of this thesis. Mikovits et al. (2021) evaluated different scenarios for testing the flexibility of hydrogen production with different weather regimes using a dispatch model in Sweden. Insights from this study are taken regarding electrolyser performance in combination with hydrogen production. Refuelling stations with corresponding levelized cost of hydrogen (LCOH) in a system analysis framework is the focus of a study by Tang et al. (2022), which enhances comprehension on the variation of LCOH within one energy system.

This thesis project focuses on a high-level analysis of several hydrogen infrastructure alternatives, serving the demand for green hydrogen and electricity in Sweden for 2030. The analysis of different hydrogen infrastructure configurations in Sweden considering multiple spatial, economic and technical factors has not been investigated yet on country level.

1.4 Problem definition and research question

The 'strategy for fossil free competitiveness' by the government initiative Fossil Free Sweden (2021) stresses that infrastructure development throughout the country is required for hydrogen development. The best system-level approach to meeting hydrogen demand in the country while balancing the electricity needed for other electrification needs remains unclear. The European Hydrogen Backbone vision, written by Amber Grid et al. (2022), presents a vision of the desired hydrogen infrastructure in European countries. They note that due to the lack of natural gas pipelines in Sweden, the conversion of existing pipelines to hydrogen is not an option. Therefore, if hydrogen pipelines are to be established, they must be built from scratch, which is a more costly investment compared to utilising existing natural gas pipelines. Thus, careful consideration must be given to the costs and benefits of such an investment in hydrogen pipelines, more so than in other EU countries, where a gas pipeline network is present.

Sweden has the potential to produce hydrogen sustainably through renewable energy sources, but this may require expanding the electricity transmission network to transport the electricity to the hydrogen production plants. As the country increases its use of renewable electricity and electrification in other sectors as well, the demand for electricity is already rising, making it important to weigh the trade-offs of further electrification and its effects on the transmission network (Government offices of Sweden: Ministry of Infrastructure, 2022).

To sum up the problem, as stated in the report from Fossil Free Sweden, quote, "the question concerns whether large-scale hydrogen production is more cost-effective in a location with good access to electricity, including distribution of gas over longer distances, in comparison with decentralised production at a location where the electricity grid may instead need to be reinforced" (Fossil Fritt Sverige, 2021).

The governmental reports highlight the relevance of the timeframe for future scenarios up until 2050, but clearer goals and data availability are given for the year 2030. Considering the relevance of the latter year and reduced level of uncertainty compared to the distant future, this thesis focuses on the year 2030.

Ramboll, working towards a fossil-free Sweden, is interested in identifying future hydrogen-related projects to offer their consulting services to the appropriate stakeholders, making this an important issue for the company.

The above-described leads to the following research question and sub questions:

What infrastructure design choices can contribute most cost-effectively towards fulfilling several hydrogen demand scenarios of Sweden, in the year 2030?

1. *What is the expected hydrogen and electricity demand in Sweden for 2030 and what are the expected associated costs for production, transport and storage for 2030?*

2. *How does the optimal configuration and utilisation of technologies and infrastructure differ between the distinct hydrogen demand scenarios for Sweden?*

3. *What drives the discrepancies and similarities between the outcomes of the analysed scenarios?*

2. Research outline and scope

In this section, the outline of the research and its scope will briefly be elaborated upon.

2.1 Research outline

To answer the research question including the sub questions, an analysis will be made by modelling the national energy system of Sweden.

The first section presents the theoretical framework in which the purpose of a hydrogen economy in Sweden is explained. It also provides details on the current state of hydrogen and electricity demand and production in the country. Thus, the Swedish energy mix and production technologies employed for generating electricity is illustrated. The Swedish electricity network is also succinctly elaborated upon in this section, for comprehending the division of Sweden into different zones. These zones will later be used to aggregate data in the energy system model. The theoretical framework also elaborates upon energy system modelling and mentions the particular energy system model (ESM) tool that is used for this research.

In the methodology section, that follows the theoretical framework, the usage of the ESM 'EnergyHub' is explained in depth, as well as the data collection. The latter is required for gathering input data for the model and creating scenarios to be analysed. After the energy system is built in EnergyHub, the model is run and evaluated on its performance, to see whether all technologies function and no errors arise. Then, the scenarios will be simulated and optimised in the model and its outcomes analysed to answer the research question. An outline of the steps to be undertaken in this research is shown in Figure 1.

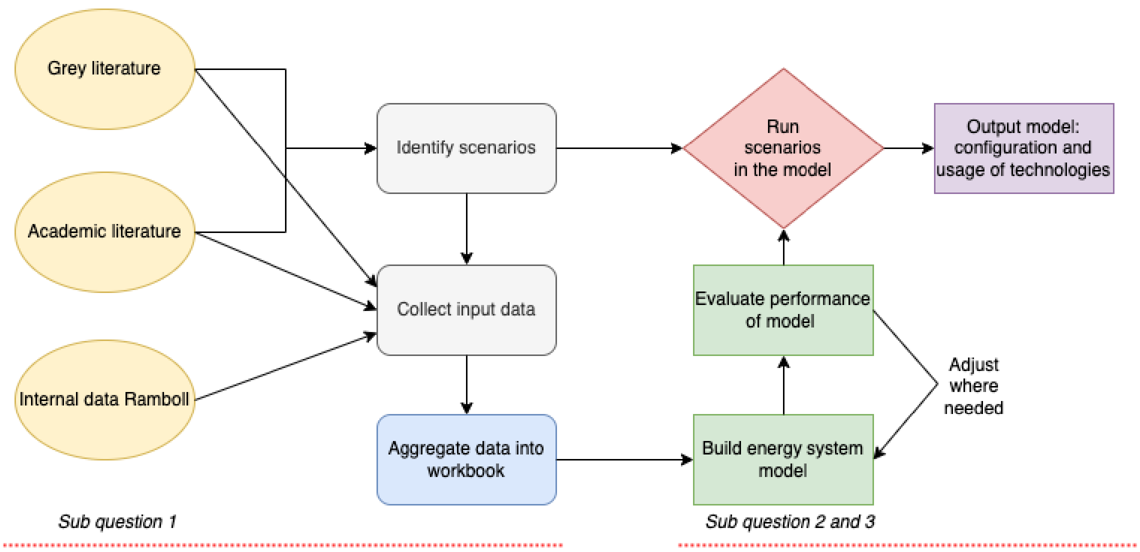


Figure 1: Schematic overview of the research outline

2.2 Research scope

The primary focus of this research is green hydrogen, leaving other production methods of hydrogen, such as grey, blue, and other forms, outside the scope. The decision to focus on green hydrogen is due to Sweden's significant potential for renewable energy sources, which supports the development of green hydrogen. Additionally, the Swedish government's climate goals and strategies prioritise reducing carbon emissions, which is not achievable when hydrogen is produced using fossil fuels (Klimat politiska rådet, 2022). Further elaboration on the different methods of hydrogen production and the significance of their colour codes is provided in the Theoretical Framework section of this study.

Green hydrogen refers to hydrogen being produced by several renewable electricity sources. However, in this research only wind energy, hydropower and nuclear energy is considered relevant. Excluding solar energy as a potential renewable energy source for hydrogen production is based on its limited contribution to the energy mix in the country, and internal communication within Ramboll indicating that it has less potential compared to wind parks. Given the substantial share of nuclear energy in Sweden's energy mix and it being emission-free as well, it cannot be overlooked in the context of this research, despite the fact that hydrogen production using nuclear energy is typically classified as 'pink' rather than 'green' (Swedish Energy Agency, 2022). Therefore, a more technically accurate term in this research would be ‘carbon-free hydrogen,’ but for the sake of simplicity, it will be referred to as ‘green hydrogen’ nonetheless. Consequently, the construction of new nuclear plants is scoped out in this research, avoiding new greenhouse gas (GHG) into the system.

Green hydrogen is produced by a process called electrolysis, which is explained more thoroughly in the theoretical framework. The type of electrolyser used in this research is proton exchange membranes (PEM), which has a higher efficiency than the alkaline electrolyser and has more flexible ramping capabilities. According to Mikovits et al. (2021), it can be assumed that this type of electrolyser will be more developed and commercialised in the near future than alkaline electrolysers.

This research considers only hydrogen and electricity as energy carriers, excluding fossil fuels. Fossil fuels have a small share in the Swedish energy mix and are expected to decrease further by 2030 (Swedish Energy Agency, 2022). Moreover, this study aims to assess the potential of an energy system without the use of fossil fuels.

In light of the projected expansion of transmission capacities by 2030, as outlined in the ten-year development plan of the European Network of Transmission System Operators for Electricity, the import and export of electricity with neighbouring countries is taken into account in this study (ENTSO-E, 2022b). However, the future potential of importing and/or exporting hydrogen with neighbouring countries is scoped out of this research, as many uncertainties regarding the price of hydrogen in neighbouring countries and transmission capacities prevents robust modelling. Additionally, it seems most likely that Sweden's heavy industries will consume most of the green hydrogen produced in the country, and therefore improbable that Sweden will become a hydrogen trader, according to the report of Fossil Free Sweden (Fossil Fritt Sverige, 2021).

Regarding the set-up of the model, as mentioned before, Sweden will be divided into 4 energy zones, according to the electricity bidding zones in the country. Energy transmission between these zones will be modelled as either hydrogen pipelines or electricity grid. Other ways of transporting hydrogen are left out of the scope, as hydrogen pipelines are expected to be the most cost-efficient mode of transport for hydrogen in Europe (Amber Grid et al., 2022).

3. Theoretical Framework

3.1 Introduction to hydrogen

3.1.1 The use and production of hydrogen

Hydrogen is a useful energy carrier, that can be transported, stored, converted into electricity but also used as fuel (Rosen & Koohi-Fayegh, 2016). Considering recent developments of the global energy system, hydrogen has gained increasing momentum due to its diverse range of applications. Many countries are transitioning to an energy system that places greater emphasis on renewable energy sources, as a means of enhancing sustainability.

Today's interest in hydrogen aligns with these ambitions, as there is no release of greenhouse gases when utilised as a fuel (International Energy Agency & Clean Energy Ministerial, 2022). It is a promising replacement fuel for fossil fuels, especially in sectors that are not electrified easily, such as heavy industries and some transportation sectors. Moreover, hydrogen can also be used as a storage medium, to increase flexibility and reliability of an energy system heavily dependent on renewables (Rosen & Koohi-Fayegh, 2016). In this case, it is important to distinguish the different routes of producing hydrogen, as this determines how environmentally friendly the hydrogen is.

The different production routes have been colour-coded, as a means to identify the greenhouse gas impact. The most prevalent colours of hydrogen are grey, blue and green. Hydrogen derived from fossil fuels is referred to as grey or blue, the latter indicating usage of carbon capture and storage. Green hydrogen is defined as being produced from renewable energy sources (Tang et al., 2022). The process that is used to create green hydrogen is called electrolysis. This involves dissociation of water molecules into hydrogen and oxygen gas, using electricity generated by renewables, if it is to be defined as 'green' hydrogen. Equation (1) shows the chemical reaction of this process (Shen et al., 2011).

$$H_2O\ (l) \rightarrow H_2(g) + \frac{1}{2}O_2(g) \tag{1}$$

3.1.2 Global interest in a hydrogen economy

Over the past years, momentum has been increasing for the development of hydrogen. In 2021, global hydrogen demand reached 91 million tonnes (Mt) which contains an energy content of about 2.5% of global final energy consumption (International Energy Agency & Clean Energy Ministerial, 2022). Prior to this momentum, grey hydrogen was already widely used in industries and refinery.

However, there is a notable shift towards green hydrogen, as key new applications are making strides and the focus is moving away from grey hydrogen. It should be noted that the production of environmentally friendly hydrogen is still in its early stages, as the current volume of low-emission hydrogen production amounts to only about 1 Mt. According to data of the International Energy Agency (IEA), which monitors all hydrogen projects in the pipeline, the potential production volume of low-emission hydrogen could increase up to 16-24 Mt per year if all the planned projects are realised (International Energy Agency & Clean Energy Ministerial, 2022).

The current elevated prices of fossil fuels also promote the development of hydrogen. Analysis by the IEA, Clean Energy Ministerial and the Hydrogen Council showed that renewable hydrogen is already cost-competitive with fossil fuels in many regions, particularly where renewable energy resources are abundantly available (Hydrogen Council, 2020; International Energy Agency & Clean Energy Ministerial, 2022). To enhance future development, it is necessary to create a market, make substantial investments and provide policy recommendations (Hydrogen Council, 2020).

3.2 Hydrogen in Sweden

Similar to the global trend, the main usage of hydrogen in Sweden is currently in the chemical and refinery sector. Production and use of hydrogen in Sweden is estimated to be around 180,000 tonnes of hydrogen per year nowadays, of which the share of low-carbon hydrogen is almost neglectable, accounting for less than 3% (Wråke et al., 2021). However, Sweden is making efforts to innovate and invest time and money into green hydrogen initiatives, in response to the need to transition from grey to green hydrogen.

One of the major industrial projects on green hydrogen that is currently being realised is the HYBRIT initiative. This project investigates the potential for fossil-free steel and iron production, using hydrogen (Pei et al., 2020). Several other initiatives and partnerships have been announced in Sweden in recent years and more are expected. According to Fossil Free Sweden, Sweden can reduce up to 30% of its national carbon emissions if all today's known hydrogen projects are realised (Fossil Fritt Sverige, 2021).

The schematic image in Figure 2, created by Fossil Free Sweden, illustrates the current location of hydrogen production and usage. The vast majority of hydrogen is consumed locally near production sites, as no hydrogen infrastructure is in place currently throughout the country.

Figure 2: Schematic image of Sweden's hydrogen production and use locations (Fossil Fritt Sverige, 2021)

In Sweden, hydrogen pipelines are mainly limited to a few local pipelines in industrial areas. As a result, most hydrogen is currently distributed via road transport, using compressed hydrogen. As regards storage facilities for hydrogen, Sweden only has a few small to medium sized sites (Fossil Fritt Sverige, 2021). However, Scandinavia is found to have favourable geological structures for large underground hydrogen storage in rock caverns (Małachowska et al., 2022). Other large-scale hydrogen storage options, such as abandoned mines and depleted oil fields, are less feasible in Sweden as the mines are still operational and the country lacks significant oil reserves (Foh et al., 1979).

3.3 High-voltage electricity network and bidding zones in Sweden

The expected development of green hydrogen generates a considerable increase in demand for green electricity, which could create significant pressure on the electricity grid (Wråke et al., 2021). The Swedish electricity grid is operated and maintained by Svenska Kraftnät. The transmission network consists of 17,000 km of power lines and about 200 substations and switching stations (Svenska Kraftnät, 2020). A visualisation by Svenska Kraftnät of the Swedish electricity network is shown in Figure 3. As can be seen, Sweden has connections with the following countries: Norway, Finland, Lithuania, Denmark, Germany and Poland, which are all taken into consideration in the constructed ESM.

Figure 3: Visualisation of the Swedish electricity transmission network (Svenska Kraftnät, 2020b)

Sweden has 4 electricity bidding areas (elområde) introduced in 2011, starting with Luleå SE1 in the North and Malmö SE4 in the South. The price of electricity in each bidding area in Sweden is determined by the supply and demand of electricity, as well as the transmission capacity between the different areas. The North of Sweden typically experiences an overproduction of electricity, while the South has a high demand, which leads to the transportation of electricity from the North to the South (Svenska Kraftnät, 2021b). Figure 4, by Svenska Kraftnät, shows the electricity bidding zones for Sweden. The bidding zones will be used in the ESM and referred to as '(energy) zones' or '(energy) nodes'. The approach of using these existing bidding zones in system modelling has also been employed in previous research that examined Sweden in a similar context (Olauson & Bergkvist, 2015).

Figure 4: Visualisation of Sweden's electricity bidding zones (Svenska Kraftnät, 2020a)

3.4 Electricity demand and production in Sweden

Sweden's total annual electricity demand is currently 136TWh, with SE3 accounting for the majority with 63%. 8% of the electricity demand is allocated to SE1, and SE2 and SE4 account for 11% and 18%, respectively (Mimer | Svenska Kraftnät, 2022). This variation can be explained by the fact that SE1 and SE2 are less densely populated areas in the North of the country, while SE3 includes major cities like Stockholm and Gothenburg, being the largest and second largest city of Sweden. SE4 is a smaller region in size and includes only one major city, namely Malmö, which explains its lower demand compared to SE3.

Even though Sweden's electricity consumption per capita is larger than compared to that of The Netherlands as an example, they manage to keep their total annual CO_2 emissions low, being 32 Mt compared to 130 Mt in The Netherlands. To illustrate, Sweden has a population size of 10 million, while The Netherlands has a population size of 17.5 million with an annual electricity demand of 116 TWh (*Sweden - Countries & Regions - IEA*, 2023; *The Netherlands - Countries & Regions - IEA*, 2023). An important reason for this difference in emissions is that Sweden's electricity is mostly generated by renewable resources. Figure 5 shows the composition of the sources that generate Sweden's electricity. The electricity mix is dominated by GHG-free resources, such as nuclear and hydropower. These are mainly complemented by renewable sources like wind energy, which has been upcoming since the 2000s approximately, and biofuels (Swedish Energy Agency, 2022).

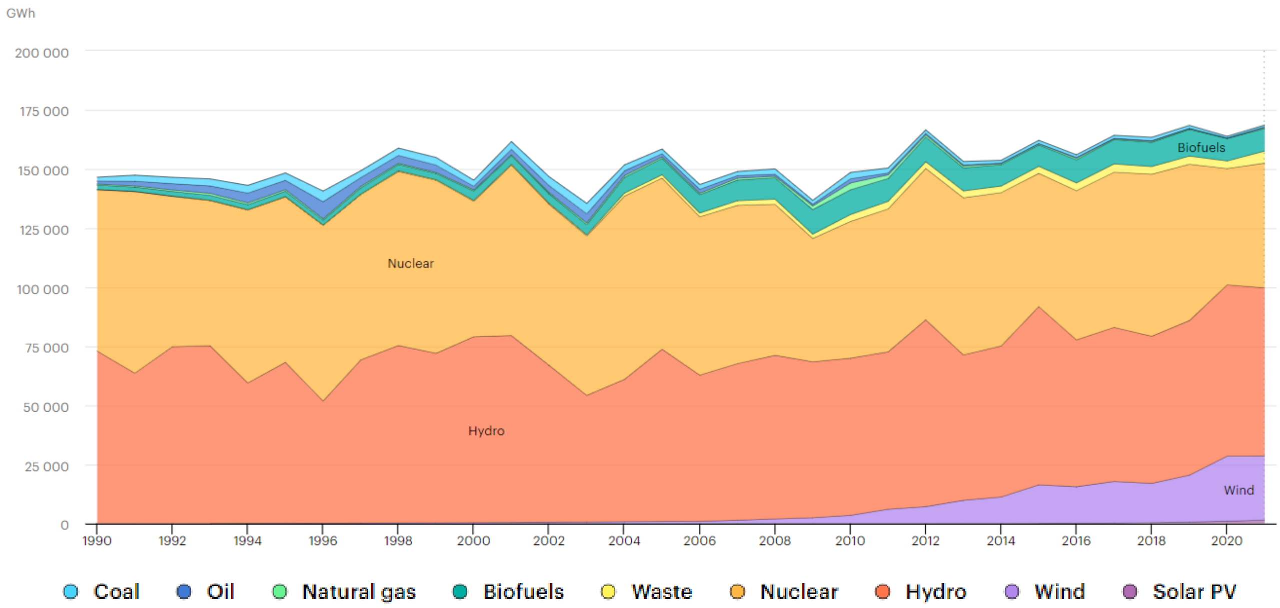


Figure 5: Electricity generation by source, Sweden 1990, 2021 (IEA, 2023)

Figure 6 shows a graph of the installed capacity of each of the energy sources used in Sweden over the years. As seen in the Figure, hydropower has been playing a large role in the energy mix since the 1980s and wind energy has been increasing rapidly over the last years. Nuclear power has been fluctuating and solar power has been on the rise, but still has a low total installed capacity.

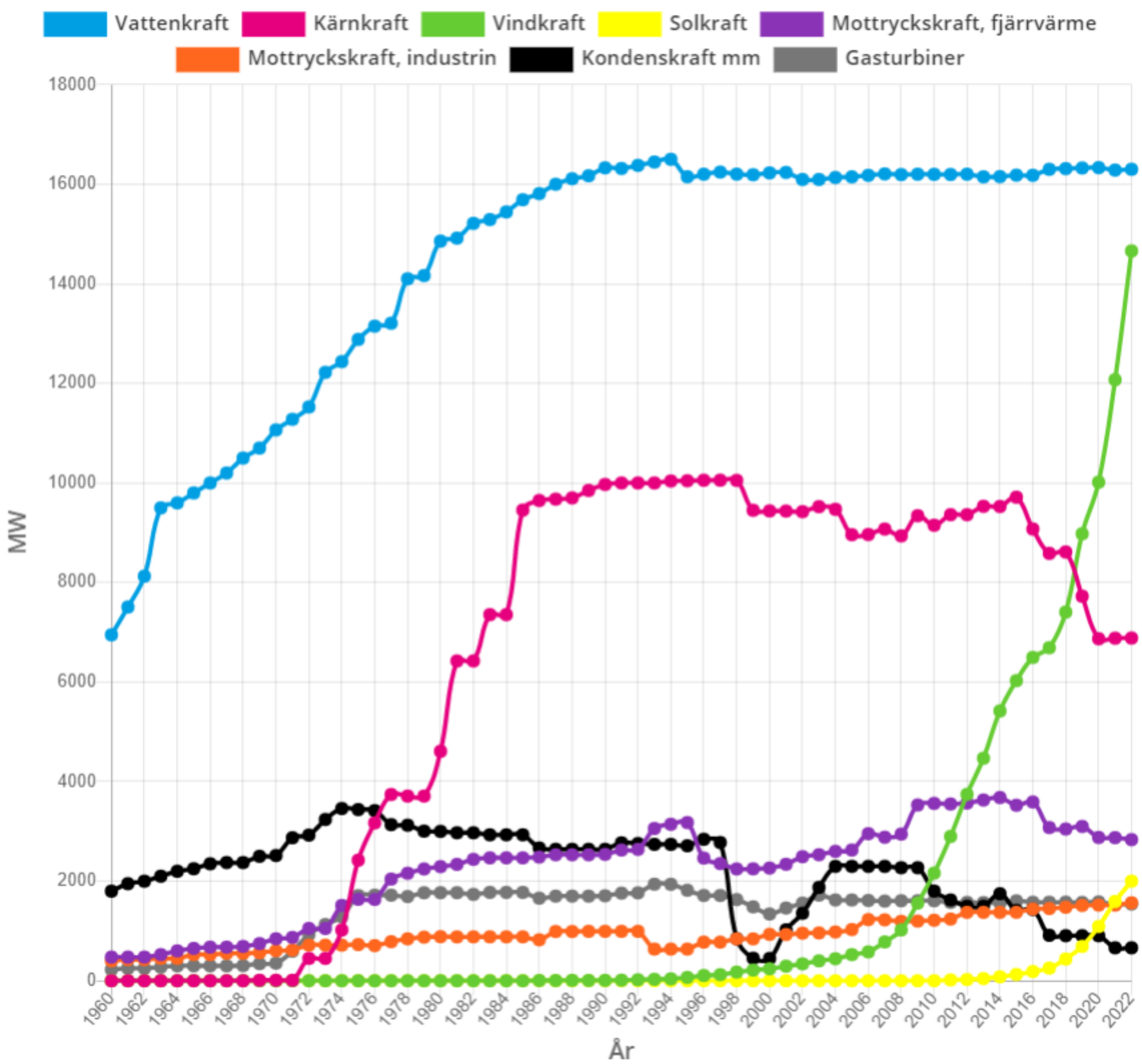


*Figure 6: Installed capacity of energy sources in Sweden over time (*Energy Year - Annual Statistics - Energiföretagen Sverige, n.d.) *Vattenkraft = hydropower, Kärnkraft = nuclear power, Vindkraft = wind power, Solfkraft = solar power, Mottryckskraft, fjärrvärme = steam turbine, district heating. Mottryckskraft, industrin = steam turbine, industrial. Kondenskraft = condensing power. Gasturbiner = gas turbines. År = Year.*

Sweden's primary fossil-free energy resources include nuclear power, hydropower and, more recently, wind energy.

Nuclear power generates approximately 40% of Sweden's electricity and serves as a stable baseload. As can be seen in Figure 6, the installed capacity fluctuated over the years, due to evolving government regulations, after a period of rapid growth in the 1980s. Currently, 6 nuclear reactors are in operation, divided over 3 locations which are all in SE3: Oskarshamn, Forsmark and Ringhals (Figure 7, Nuclear Energy in Sweden - World Nuclear Association, n.d.). There are ongoing discussions in the government about removing the current cap on nuclear power generation, which suggests a potential expansion in the future. However, this matter is still under consideration and no definitive decisions have been made. Consequently, also taking into consideration the construction time of build-out, it is assumed for this study that at least until 2030, no further expansion of nuclear power will occur. As for the existing reactors, they are all planned to be in use at least until 2040 (Uniper Energy, 2022).

*Figure 7: Location of nuclear reactors currently in operation (Stockholm is shown as reference, there is no nuclear reactor in Stockholm) (*Nuclear Energy in Sweden - World Nuclear Association*, n.d.)*

In accordance with Figure 6, the installed capacity of hydropower has remained stable over the last years. It is an important balancing resource for energy production in Sweden. Most hydropower plants are adapted to local conditions in the respective rivers, which have seasonal variability in their availability of water. The majority of these hydropower plants are relatively small in size; however, the aggregate number of plants totals around 2000. The four largest hydropower plants are located in the rivers Umeälven, Ångermanälven, Faxälven and Indalsälven, which are all located in SE1 and SE2, and account for a total of 60 percent of all hydropower production in the country. Pumped storage hydro is only used to a very limited extent in Sweden (Karin Byman, 2016).

Wind energy in Sweden has seen significant growth since the 2000s, due to the country's expansive uninhabited lands and favourable wind conditions. As a result, wind power is high on the political agenda of Sweden. Currently, Sweden exhibits an installed capacity of approximately 15 GW, see the green line in Figure 6. The vast majority of installed capacity is located in SE2. SE3 and SE1 show similar numbers, followed by the least installed capacity in SE4 (Swedish Wind Energy Association - Svensk Vindenergi, 2021b). Exact numbers can be found in the Appendix in Table 18.

Regarding offshore wind, Sweden is far behind compared to other European countries such as The Netherlands, Finland and Norway. However, there are ambitious targets and prospects for the advancement of offshore wind energy, as it is recognised as an essential component in the future energy mix (Klimat politiska rådet, 2022; THEMA Consulting Group, 2021). It is especially significant considering Sweden's aspirations for green hydrogen production, as more renewable electricity is needed and offshore wind has great potential to contribute to this. The government has demonstrated a strong commitment to enhance the offshore wind industry by recently granting permits for two offshore wind farms, namely Kattegatt Syd and Galene, with a combined capacity of 1.6 GW. Unfortunately, the Galene project did not receive a permit for the entire wind farm, which would be 1.7 GW(Buljan, 2023). The government has expressed optimism that the Galene project still has a high likelihood of obtaining its full permit in the future. Currently, there is a substantial pipeline of projects amounting to an impressive total of 15 GW, that will potentially be operational before 2030 (*Sweden: Making up Lost Ground on Offshore Wind | WindEurope*, 2022). Given the uncertainties surrounding permitting and construction timelines for these wind farms, it is unrealistic to assume that the complete pipeline is realised before 2030. Therefore, this study considers that a prudent 5 GW of these projects will successfully be implemented before 2030, located in the sea area connected to SE4.

3.5 Energy system modelling

Energy system modelling has been a widely used tool since the 1970s. It is concerned with several purposes, such as comprehending present and future demand-supply interactions, analyse energy-economy interactions and understanding the interplay in an energy supply system with a given level of demand forecast (Bhattacharyya & Timilsina, 2010). Energy system models are also considered a fundamental tool for analysing the impact of climate policies and targets on an energy system including the need for future infrastructure (Müller, 2022). Energy system models often apply techniques such as mathematical programming, in particular linear programming, which is also used in this research. Energy system models rely heavily on their input data, key assumptions, and established boundaries to effectively define and analyse the energy system, making them a critical asset in the study of energy systems. Some models require enormous databases and have high technical detail which results in complex computations, whereas other models are more specific to a certain area and require less data and complexity (Bhattacharyya & Timilsina, 2010). To reduce computing time and decrease workload of gathering extensive databases, energy system models can be spatially aggregated. Creating aggregated zones in an energy system model means that energy supply and demand profiles of several geographical areas are summed together in one energy node (Cao et al., 2018).

The ESM that is applied in this research is the EnergyHub model described by Gabrielli et al. (2018), and elaborated upon by Weimann et al. (2021). This model allows for aggregating demand, production and storage for several energy carriers into nodes whilst also modelling transport networks, which are capabilities needed to conduct this research. The model is written in Python script and the optimisation is solved using the commercially available Gurobi solver. The EnergyHub model employed in this research is sourced internally from the research group at Utrecht University, which is another rationale of employing this model for the research.

4. Methodology

In this section, the methodology for conducting the research is explained. First, the energy system modelling is elaborated upon, followed by the data collection for the model. Lastly, the scenario analysis that is executed with the model is explained.

4.1 Energy Hub Model

4.1.1 Overview of the model and its capabilities

The EnergyHub model, in its direct adoption from the research group at Utrecht University, possesses a multitude of capabilities. It allows for constructing an energy system consisting of several nodes, with each node including various technologies and demand inputs. It includes the mathematical framework of several technologies of which only the data inputs must be tailored to accurately reflect the situation in Sweden. The aforementioned applies similarly to the transmission technologies between the energy nodes.

The EnergyHub model distinguishes between technologies and networks that are modelled as ‘existing’ or ‘new’. Technologies that are currently not existing in the Swedish system are modelled as ‘new technologies’, meaning that the EnergyHub model decides on the installed capacity, subject to a given limit. Other technologies are modelled as ‘existing technologies’, represented with real-life quantities. Considering the pre-existing nature, the model assumes that the CAPEX has already been accounted for and therefore sets it to zero. The fixed installed capacity of these technologies will not be changed by the optimisation.

The technologies for this research that require data adjustment are wind turbines, electrolysers, hydrogen storage, batteries, electricity cables and hydrogen pipelines. However, considering the energy system of Sweden and the scope of this research, the inclusion of nuclear power and hydropower deem necessary. Therefore, the model's capabilities are extended by implementing custom modelling approaches for these two technologies, as elaborated upon in the following section.

The EnergyHub model aims to minimise overall total system costs of the constructed ESM, while adhering to specific constraints and allowing for various decision variables, which relate to the energy technologies represented in the system. While the installed capacities of existing technologies in the Swedish energy system, such as nuclear powerplants and hydropower, are predetermined and fixed, the model allows for decision-making on new technologies such as additional wind capacity, electrolysers and transmission capacities. An overview of the model formulation is given in Figure 8.

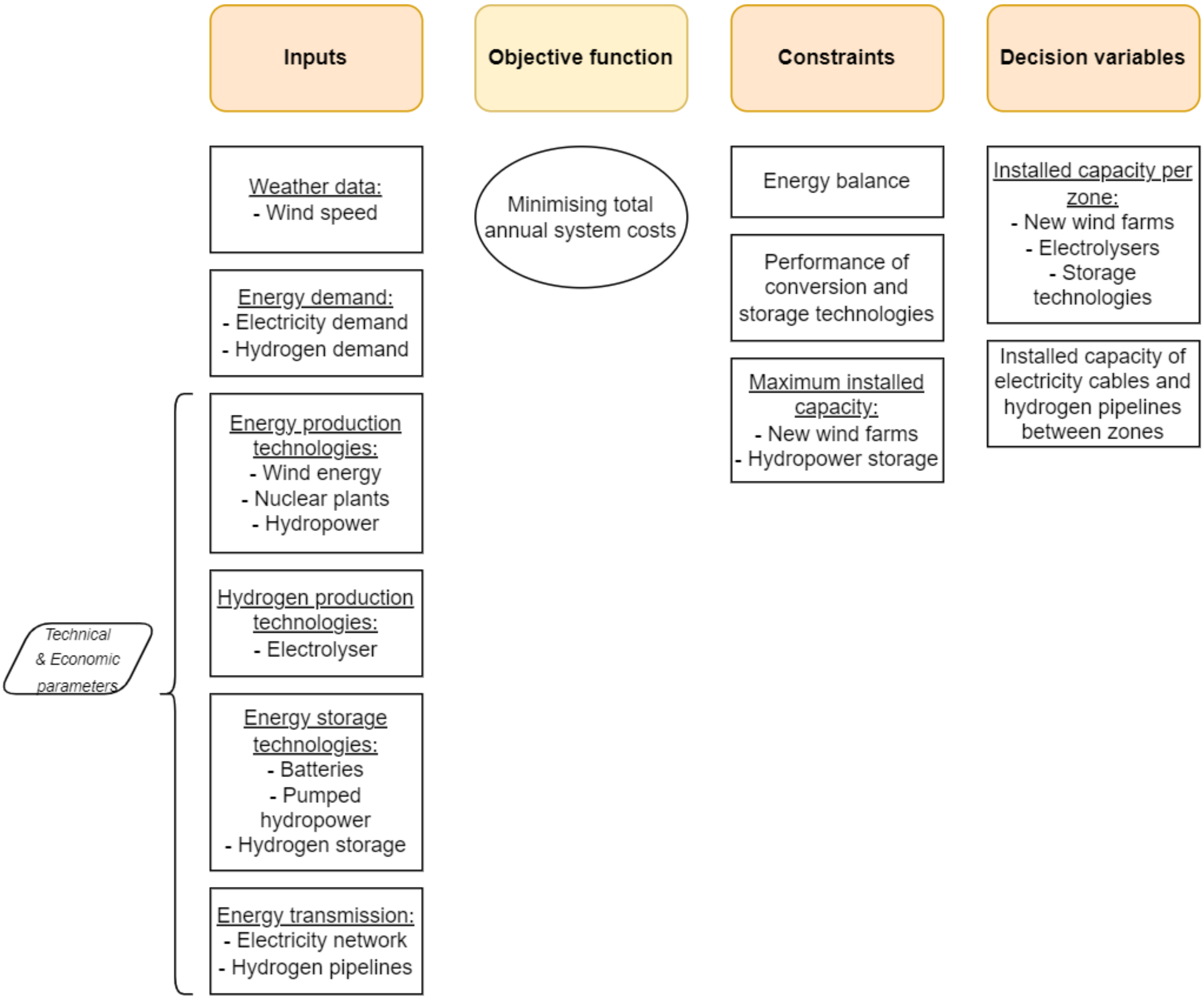


Figure 8: Overview of the energy system model, based on the EnergyHub model from Gabrielli et al. (2018)

Figure 9 visualises the ESM of a node within Sweden, showcasing all included technologies and their interactions. It is important to note that not all technologies will be available in each energy node, flow of hydrogen and electricity is possible between the nodes, and that imports and exports of electricity to surrounding countries are available in all nodes. For existing technologies, the data collection results define whether a technology is present in an energy node and for new technologies the EnergyHub model decides the installed capacity per energy node, aiming to minimise overall system costs.

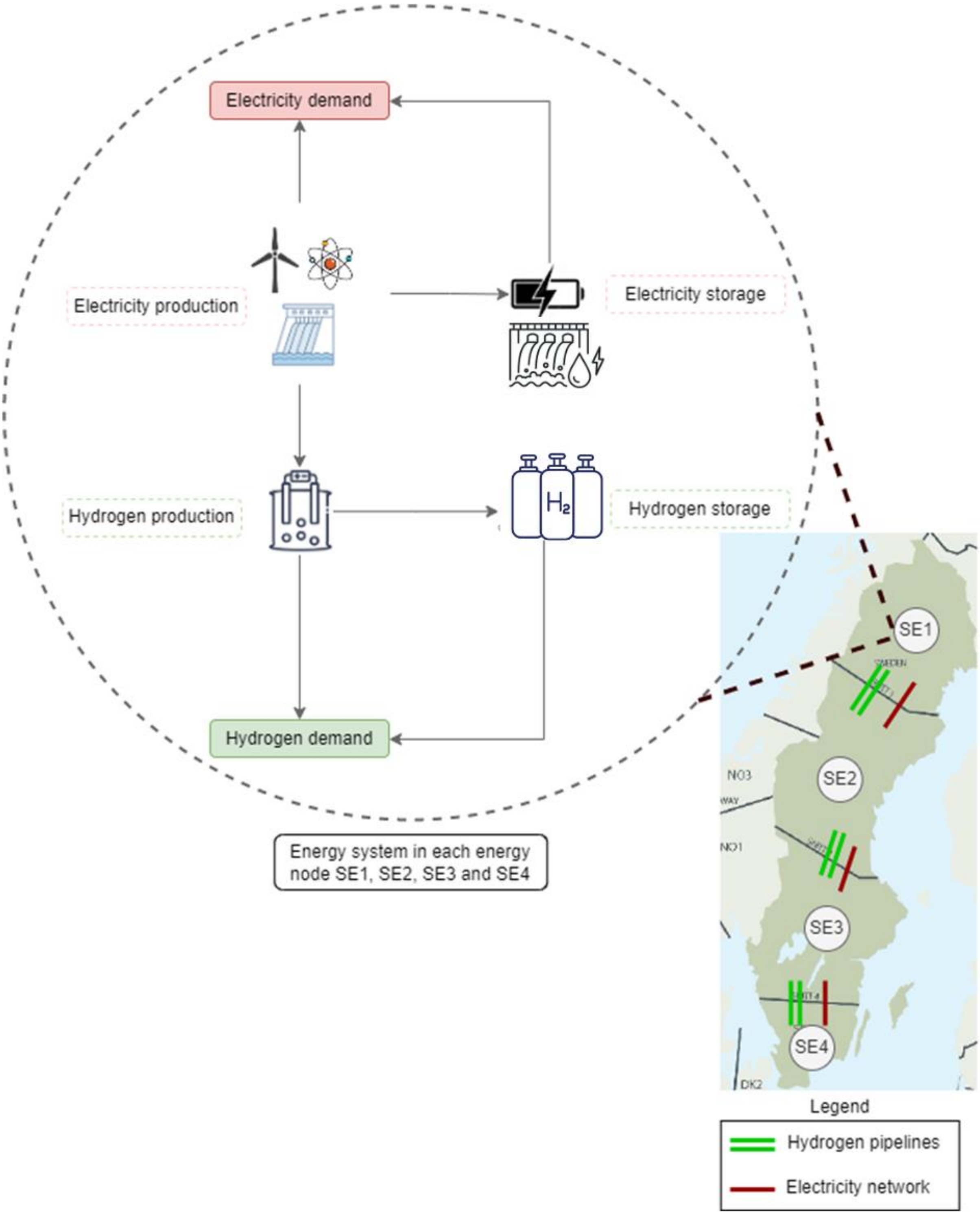


Figure 9: Schematic overview of the energy system model within the nodes of Sweden illustrating all the included technologies and their interactions: imports and exports to neighbouring countries are not represented but are included in the framework

4.1.2 Adding technologies to the model

Renewable energy production technologies in Sweden that are investigated and considered in this research are wind energy, nuclear power and hydropower, as elaborated upon in the Research Scope section. The current state of each of these technologies is studied and incorporated into the model as 'existing technologies', while wind energy is also allowed to expand, which is modelled as 'new technology'.

4.1.2.1 Production technologies

To generate production profiles or onshore wind energy, for 'new' as well as 'existing', the model obtains weather data from the JRC PVGIS dataset. This is a publicly available database providing various meteorological data for solar and wind energy systems (Joint Research Centre (JRC), 2022). The model extracts the wind data for a full year using a function that utilises an API to extract relevant climate data from given coordinates. The coordinates for the middle of each energy zone (SE1, SE2, SE3, and SE4) are determined using an empirical approach. The middle coordinates are used for retrieving weather data that provides a reasonable estimation of the wind speeds of each energy zone. Google Maps is visually examined to identify approximate locations that are perceived to represent the central points within each zone (*Google Maps*, n.d.). These identified locations are then taken as the specified longitude and latitude, as shown in Table 1. This approach is justified based on the consideration of practical constraints and research objectives. Given the aggregated nature of the energy zones and the focus on broader wind patterns within the zones, a high degree of precision in the coordinates seems unnecessary. This methodology offers a practical and efficient solution within the research scope.

Table 1: Latitude and longitude for the middle of each of the Swedish energy zones

	Latitude	Longitude
SE1	66.67	20.45
SE2	63.37	16.06
SE3	59.01	14.91
SE4	56.63	14.21

The current installed capacities of existing wind turbines in each energy zone are retrieved in the data collection section. New turbines are not subject to a maximum installed capacity size, due to the expected need for a substantial increase in wind turbines, considering the heightened electricity and hydrogen demand for 2030. Additionally, the other production technologies are restricted from expanding within the model, making wind energy the sole technology capable of accommodating this increase.

The integration of offshore wind energy is implemented using a distinct approach compared to the integration of onshore wind turbines. This is done to reduce extra complexity and computation time of the model. First, wind energy production profiles are generated by Renewables.ninja. This is an online software tool that generates hourly wind energy profiles using weather data from MERRA-2, while the specific parameters required for the offshore wind parks, such as installed capacity and turbine type, must be provided (*Renewables.Ninja*, n.d.). For this study, the largest available offshore wind turbine listed in the Renewables.ninja database is selected, which is the Vestas V 164 9500 with a rated power output of 9.5 MW (Vestas: V164-9.5 MW, n.d.) A total installed capacity of 5 GW is used for this case, based on offshore wind projects currently in the pipeline as elaborated upon in the Theoretical framework. The geographical location pinned on the map of Renewables.ninja is the Kattegatt sea area. Then, the generated electricity profile is imported into the EnergyHub model at zone SE4, where the Kattegatt sea area is located.

Nuclear power is supposed to serve as a base load for the energy system with a constant power output, considering the inflexibility of ramping the respective power source up and down (Macedo et al., 2021). To reflect this in the EnergyHub model, the annual production of nuclear power is added to the model similarly as offshore wind energy; as a 'production profile'. A limitation to this method is the absence of added costs to the electricity production profile of nuclear power in the model, which leads to an incomplete portrayal of the actual costs associated with this energy source. However, the inclusion of nuclear power as a costless, constant baseload in the model is justified, as the model's primary purpose is to optimise the configuration and placement of energy and hydrogen technologies across zones, rather than to provide precise numerical values of total energy system costs. The same applies to the supply of offshore wind in the scenario where this is considered.

For hydropower, an hourly production profile is generated which is thereafter included in the model as 'import'. The hourly production profile is generated using data on the installed capacity of hydropower in each bidding zone in Sweden and monthly capacity factors of the resource (Karin Byman, 2016; Tang et al., 2021). These reflect the fluctuation of the availability of hydropower throughout the year. This results in a production profile for each of the 4 zones, with an electricity production that remains constant in the same month but fluctuates throughout the year. The generated production profiles are incorporated into the model with the 'import' function and 'hydropower' is added as a conversion technology with 100% efficiency, since the conversion of hydropower to electricity is already reflected in the production profiles. The technology 'hydropower' is modelled as 'existing' technology, which means the model is given the installed capacity. By modelling hydropower as a technology with the production profiles as 'imported' input, the model gains a degree of freedom that it would not have if it were modelled solely as a production profile, as is the case with nuclear power.

4.1.2.2 Storage technologies

Hydrogen storage as well as batteries and pumped hydropower are modelled as 'new technologies'. For hydrogen storage and batteries, no constraints are imposed regarding maximum installed size. This decision allows for flexibility in system configurations and accommodates the anticipated growth in electricity and hydrogen demand and variable production technologies, ensuring the model can find efficient solutions in light of evolving energy needs. For pumped hydropower, a constraint is set on the maximum installed capacity to maintain alignment with the real-world Swedish energy system. The maximum capacity is defined as the current installed hydropower level in Sweden, considering that pumped hydropower storage cannot exceed the existing hydropower capacity due to its conversion into pumped storage. Section 4.1.3 elaborates on the mathematical foundation behind the storage modelling. In principle, the storage technologies in this model are dependent on the following parameters: charging efficiency, discharging efficiency, self-discharging coefficient, maximal charging and discharging capacity.

4.1.2.3 Transport technologies

Considering that Sweden currently does not have a hydrogen pipeline network in place, hydrogen pipelines in the model are modelled as 'new technologies' (Fossil Fritt Sverige, 2021). For electricity Sweden has a network in place with a certain transmission capacity between the energy zones (Svenska Kraftnät, 2021a). However, in the model the cables are also modelled as ‘new technologies’, as this enhances a transparent computation of the trade-off between newly built hydrogen pipelines and/or transmission network. In the discussion section, the model’s decisions on transmission are compared to Svenska Kraftnät’s documentation. The modelled distance of the network between the energy zones is approximated as the geographical distance between the midpoint of each zone.

Transmission connections with neighbouring countries are modelled with a limit to transmission capacity and a price. The data collection section provides elaboration on the methodology used to establish these limits and prices, as well as the sources from which the relevant data is obtained.

4.1.3 Mathematical formulation

The model used in this research is built upon work by Gabrielli et al., (2018) and Weimann et al., (2021). The mathematical framework shown in this section is adapted from those works and a more detailed description can be found in those papers. Table 2 shows an overview of all terms and subscripts used in the following equations.

Table 2: Overview of all terms and subscripts used in the mathematical formulation of the model

Indices	
i	Technology
k	Energy carrier
n	Node
t	Time
Sets	
M	Set of all technologies
$\mathcal{N}$	Set of all nodes
Objective function	
x_c	Total annual cost of system
J_c	Annual capital cost
J_o	Annual operation cost
J_m	Annual maintenance cost
Decision variables	
S	Installed size
P	Power output
F	Consumed energy
F^{min}	Minimum energy input
F^{max}	Maximum energy input
E	Energy content
E^{in}	Energy input
E^{out}	Energy output
U	Generated electricity
ξ	Flow of energy carrier
I	Energy imports
Data inputs & constraints	
λ	Variable cost coefficient
μ	Fixed cost coefficient
p_e	Costs of electricity
S^{min}	Minimum size

S^{max}	Maximum size
a	Annuity factor
ψ	Maintenance cost fraction
τ	Number of time intervals to completely (dis)charge a storage medium
$\Pi\&\Delta$	Self-discharge coefficients
g	Influence of ambient temperature
T^{amb}	Ambient temperature
η^{in}	Charging efficiency
η^{out}	Discharging efficiency
L	End-user demand
D	Distance between nodes
α	Connectivity between nodes

4.1.3.1 Objective function

The objective function of the model is to minimise overall system costs, x_c, shown in equation (2). The overall system costs consist of the annual capital costs, J_c, the annual operational costs, J_o, and the annual maintenance costs, J_m.

$$x_c = J_c + J_o + J_m \tag{2}$$

The annual capital costs are determined by summing the fixed cost coefficient for each technology, μ_i, with the variable cost coefficient for each technology, λ_i, multiplied by the installed size of each technology. To account for the annuity, this is multiplied with an annuity factor specific for each technology, a_i. This is shown in equation (3).

$$J_c = \sum_{n \in \mathcal{N}} \sum_{i \in M} (\lambda_i S_{i,n} + \mu_i) a_i \tag{3}$$

The annual operational costs are calculated by multiplying the costs of electricity for each technology, $p_{e,i}$, with the generated electricity for each node during the year, $U_{n,t}$, as depicted in equation (4).

$$J_o = \sum_{n \in \mathcal{N}} \sum_{i \in M} \sum_{t \in T} p_{e,i} \, U_{n,t} \tag{4}$$

Annual maintenance cost is depicted as a fraction of the concerning technology, ψ_i, of the annual capital costs, in equation (5).

$$J_m = \sum_{n \in \mathcal{N}} \sum_{i \in M} \psi_i J_{c,n,i} \tag{5}$$

4.1.3.2 Constraints

The constraints are divided into two categories, namely the performance of conversion and storage technologies and the energy balances.

Performance of conversion and storage technologies:
The size of all technologies in each node, $S_{i,n}$, is constrained between the maximum and minimum installed size, as shown in equation (6).

$$S_i^{min} \leq S_{i,n} \leq S_i^{max} \tag{6}$$

Likewise, the consumed energy for these technologies is constrained by minimum and maximum values, which are a function of the installed size of the technology at the respective node.

$$F_i^{min}(S_{i,n}) \leq F_{t,i,n} \leq F_i^{max}(S_{i,n}) \tag{7}$$

Storage technologies are modelled as shown in equation (8). The energy content of a storage medium at a given time in a certain node, $E_{t,i,n}$, is determined by self-discharging coefficients Δ and Π, if applicable the influence of the ambient temperature, g, and the in- and output efficiencies, η^{in} and η^{out} respectively.

$$E_{t,i,n} = E_{t-1,i,n}(1-\Delta) - \Pi S_{i,n} g_{t,i,n}(T^{amb}) + \eta^{in} E_{t,i,n}^{in} - \frac{1}{\eta^{out}} E_{t,i,n}^{out} \tag{8}$$

Size and periodicity constraints must be fulfilled in storage technologies, as shown in equation (9) and (10). The energy content of a certain storage technology in a node at a given time, $E_{t,i,n}$, cannot be smaller than zero and larger than the installed size of the technology at a node, $S_{i,n}$.

$$0 \leq E_{t,i,n} \leq S_{i,n} \tag{9}$$

The energy content of the storage medium at timestep 0 must be the same as T, the last timestep of the run, to depict a realistic year where periodicity is considered. To illustrate, the stored energy in a storage medium in timestep 0 is equal to the amount in the final timestep of the simulation, which is 8760 in this case.

$$E_0 = E_T \tag{10}$$

The maximum charging and discharging rate is limited as depicted in equation (11) and (12), where P^{in} is the power input, the charging rate, and P^{out} the power output, the discharging rate. τ_i^{in} is the number of time intervals it takes to completely charge the storage technology, whereas τ_i^{out} is the number of time intervals it takes to completely discharge the storage technology.

$$P_{t,i,n}^{in} \leq \frac{S_{i,n}}{\tau_i^{in}} \tag{11}$$

$$P_{t,i,n}^{out} \leq \frac{S_{i,n}}{\tau_i^{out}} \tag{12}$$

Energy balances

The energy balance can be formulated as in equation (13). At each node in the energy system, the equation calculates the energy balance by summing various components, which all adds up to zero in the end. For each node n in the set N, the equation evaluates the following expression for each technology i in the set M. The consumed energy F, is subtracted from the power output, P. This is then summed with the energy imports, I, to the respective node, and the end-users demand, L, is subtracted. This energy balance equation ensures that the sum of these components over all nodes in N is equal to zero, indicating that the total energy supplied matches the total energy demanded within the system.

$$\sum_{n\in\mathcal{N}}\left[\sum_{i\in\mathcal{M}}(P_{k,n,i,t} - F_{k,n,i,t}) + I_{k,n,t} - L_{k,n,t}\right] = 0 \tag{13}$$

Transport networks

The transport networks are designed as a second linear program to minimise the needed networks, x_{NW}, as given in equation (14). The total distance of transmission across the network, D, is summed with the decision variable ξ, the flow of the respective energy carrier, for all combinations of n, m, and t, excluding cases where n and m are the same node.

$$x_{NW} = \sum_{\substack{m\in\mathcal{N}\\ m\neq n}}\sum_{\substack{n\in\mathcal{N}\\ n\neq m}}\left(D_{k,n,m}\sum_{t\in T}\xi_{k,n,m,t}\right) \tag{14}$$

This linear program is subject to the constraints as shown in equation (15), (16) and (17). Equation (15) ensures that the energy balance is maintained at each node of the transport network. The sum of the energy flow through the network, ξ, the power output, consumed energy, imports, and losses over all technologies i in M at each node n and time t should equal zero.

$$\xi_{k,n,m,t,in} - \xi_{k,n,m,t,out} + \sum_{i\in\mathcal{M}}\left(P_{k,n,i,t} - F_{k,n,i,t}\right) + I_{k,n,t} - L_{k,n,t} = 0 \tag{15}$$

The constraint in equation (16) shows that the energy flow through the transport network must always be greater than or equal to zero, for all nodes and every timestep.

$$\xi_{n,m,t} \geq 0 \ \forall\ (n,m) \in \mathcal{N}, t \in T \tag{16}$$

This constraint shows that the flow of the energy carrier is zero when the connectivity between the nodes, $\alpha_{n,m}$, is zero and applies for all equations that contain the energy flow, such as (14) and (15).

$$\xi_{k,n,m,t} = 0\ \forall\ \alpha_{n,m} = 0 \tag{17}$$

4.2 Data collection

4.2.1 Input data for the EnergyHub model

Data from reliable resources is needed to serve as an input for the EnergyHub model, to depict an energy system as close as possible to reality. First, information is collected on the production, demand and storage of electricity and green hydrogen in the Swedish energy system as it is now, as well as projected values for 2030 where necessary.

Resources and databases that are investigated are including but not limited to: International Renewable Energy Agency (IRENA), International Energy Agency (IEA), Swedish Energy Agency, governmental reports from Fossil Fritt Sverige, Klimat Politiska Rådet and the European Commission. Furthermore, Ramboll has internal databases and insights from which information is utilised. Numerical values of the data collection with corresponding references can be found in the Appendix section.

4.2.2 Technical parameters

4.2.2.1 Production

To model the wind energy, data is needed on the current installed capacity of wind turbines in each zone. Additionally, the technical performance indicators of the average wind turbine in Sweden currently as well as projected values for 2030 are retrieved, as depicted in Table 3. The EnergyHub model includes a database of multiple manufacturers of wind turbines and its power curves, and the power curve is retrieved from the turbines with similar rated power as is found in data collection regarding Swedish turbines. To enhance the robustness and reliability of the model, the power curve is constructed as an average across multiple turbines rather than relying solely on the capabilities of a single turbine. This ensures a more comprehensive representation of the overall wind energy system, accounting for the varying characteristics and performance of different turbine models. The constructed power curves can be found in the Appendix (Figure 32).

The technologies for nuclear power and hydropower are not represented in the EnergyHub model by default and are therefore included in a different way, as explained before. Data needed to be retrieved for this is shown in Table 4.

The annual electricity generation from nuclear power in 2022 is retrieved from the annual statistics from Energiföretagen and then divided by the number of hours in a year to retrieve the hourly electricity production (*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.). This results in 5696 MWh/h, all generated in SE3 as all plants are located there.

To produce green hydrogen in the model, electrolysers are considered. Two types of electrolysers are most commercialised: the Alkaline and PEM electrolyser. Given that the projected efficiency and costs for the PEM electrolyser are more advantageous than those of the Alkaline electrolyser, this research focuses on the former (Brynolf et al., 2018).

Table 3 shows the technical parameters and its units that are retrieved to fit the EnergyHub model. Some parameters are marked with '*(z.s.)*', which stands for 'zone specific', meaning that the value can vary between each zone. Others are assumed to be similar throughout the zones as they are considered independent from their geographical location.

Table 3:Technical parameters and units for production technologies to fit the EnergyHub model

	Technical parameter	Unit
Existing technology: Wind energy	Installed wind capacity *(z.s.)*	#Turbines
	Rated power	MW
	Hub height	m
	Lifetime wind turbine	Years
New technology: Wind energy	Rated power	MW
	Hub height	m
	Lifetime wind turbine	Years
New technology: Electrolyser	Efficiency electrolyser	%
	Lifetime electrolyser	Years

Table 4: Technical parameters and units for nuclear power and hydropower to use for the EnergyHub model

	Technical parameter	Unit
Nuclear power	Installed nuclear capacity *(z.s.)*	MW
	Generated electricity in 2022	MWh
Hydropower	Installed hydropower capacity *(z.s.)*	MW
	Seasonal capacity factor hydropower	%
	Lifetime hydropower plant	Years

The exact numbers for each energy node including references can be found in the Appendix (Table 18, Table 19 and Table 20).

4.2.2.2 Demand

The hydrogen and electricity demand for 2030 are defined and used as input parameters rather than decision variables for the model, as commonly done in ESMs as described by Agnolucci & Mcdowall (2013). Given that the future hydrogen and electricity demand is very uncertain and there is a lack of available reports or literature forecasting electricity and hydrogen demand per electricity bidding zone in Sweden, a methodology has been adopted to estimate the demand per zone for this research. Historically, various methods have been exploited to optimise the forecasting of energy demands, from dynamic equations in engineering methods to AI-based methods. Forecasts should however always be taken with a degree of uncertainty, since it is merely impossible to accurately predict the future (Bedi & Toshniwal, 2019).

4.2.2.2.1 Electricity demand

The total electricity demand for 2030 consists of two components: the electricity demand for creating hydrogen through electrolysers and the electricity demand for all remaining sectors. To prevent double counting in the model, the electricity demand that will serve as an input parameter to the model is excluding the electricity needed for the electrolysers. The latter is calculated by the model when hydrogen demand is given as an input. To ensure that the ESM runs with an hourly time resolution, the electricity demand for 2030 must be defined accordingly.

The proposed method to define the hourly electricity demand profile for 2030 is based on existing demand forecast models that are dependent on historical data as described by Bedi & Toshniwal (2019). Data from the year 2021 is taken from Mimer, which is a website that holds data from Svenska Kraftnät on the production and consumption patterns of electricity for each electricity bidding zone separately (*Mimer | Svenska Kraftnät*, 2022). It is assumed that the hourly demand curve of 2030 will be similar to that of 2021, and that demand will increase in all bidding zones at the same rate, as there is no information that indicates otherwise. This assumption simplifies the modelling of the electricity system, as it avoids the need for detailed regional forecasts of electricity demand, which can be uncertain and time-consuming to collect. The national electricity demand forecast being 160 TWh, which is used as a base for scenario A, is taken from a report from Energimyndigheten; Sweden's largest government financier of energy research. Further elaboration on the scenarios is found in section 4.3. The national electricity demand in this report is forecasted under the scenario that Sweden will be electrified, due to drivers as ambitious climate targets.

The forecasted electricity demand per bidding zone is obtained by identifying a multiplication factor, which is calculated by dividing the total demand for 2030 by the total demand of 2021. The multiplication factor is then applied to the hourly data per bidding zone from 2021 to get hourly profiles per bidding zone for 2030.

4.2.2.2.2 Hydrogen demand

Forecasting future hydrogen demand is even more volatile than forecasting electricity demand since hydrogen is a relatively novel energy carrier and lacks historical data to draw upon. Therefore, a different approach is pursued to determine the hydrogen demand per energy zone as opposed to the methodology employed for determining electricity demand per zone.

Several reports have attempted to speculate on the hydrogen demand for Sweden in 2030, but there is limited relevant data, especially on the predicted demand for each energy zone separately. Government initiative Fossil Fritt Sverige estimated the national hydrogen demand for 2030 to be 12 TWh (Fossil Fritt Sverige, 2021). This number is based on assumptions about recently announced projects in Sweden that aim to use hydrogen. To explore multiple scenarios and consider the uncertainty of future hydrogen demand, a second scenario is considered where the demand of 12 TWh is increased by 50%, as further outlined in section 4.3.

Since the energy system model of Sweden is divided into four energy nodes, it is necessary to obtain information regarding the hydrogen demand specific to each of these regions, for which information could not be found in databases and reports. Consequently, a methodology has been developed whereby assumptions are made regarding the proportionate distribution of hydrogen demand across the various zones, thus allowing for the identification of the requisite numbers. Agnolucci & Mcdowall (2013) describe a comparable method, wherein each geographical zone is assigned a score to determine the anticipated deployment of hydrogen. However, since the national demand has already been established by report findings, each energy zone is assigned a share of the total amount of hydrogen to be deployed, based on various factors such as the number of facilities currently using hydrogen, the number of facilities in heavy industries, and publicly announced green hydrogen projects. This is done as follows.

First, the current use of hydrogen in Sweden is identified, using data from the Fuel Cells and Hydrogen Observatory (*Hydrogen Supply Capacity | FCHObservatory*, n.d.). Figure 10 shows the geographic distribution of existing hydrogen production sites. Since currently hydrogen production and use are mostly co-located in Sweden, it is assumed that the present hydrogen demand is similarly located (Fossil Fritt Sverige, 2021).

*Figure 10: Map of current hydrogen production facilities in Sweden (*Hydrogen Supply Capacity | FCHObservatory*, n.d.)*

The FCH Observatory also indicates what sectors currently constitute the majority of the hydrogen demand in Sweden. About three quarters of Sweden's current hydrogen use is directed towards refineries, followed by a much lower number for methanol and other chemical industries (*Hydrogen Supply Capacity | FCHObservatory*, n.d.). Therefore, the refineries and their location in Sweden are identified and appear to be on the same location as the hydrogen production sites (*Refineries Map - Concawe*, n.d.). Therefore, it is assumed that these already benefit from the hydrogen facilities and are not included in the Table to avoid double counting of the facilities. Next to these industries, Sweden has disclosed specific intentions of employing hydrogen in the steel industry. Therefore, the locations of steel factories in Sweden were identified, despite their current non-usage of hydrogen. It is assumed that steel factories will shift towards green hydrogen in the future. Lastly, three large scale green hydrogen projects that have been announced for the near future were identified. All identified facilities and projects are aggregated and allocated to their corresponding energy zone, as shown in Table 5.

Table 5: Share of hydrogen demand for each energy zone in Sweden by 2030, based on current hydrogen use, potential industries for hydrogen use and large announced projects

	SE1	SE2	SE3	SE4	Reference
Current facilities that use hydrogen	0	0	8	2	(*Hydrogen Supply Capacity | FCHObservatory*, n.d.)
Existing steel industry facilities	1	0	10	2	(*Companies and Plants - Jernkontoret*, n.d.)
Announced green hydrogen projects	3	0	0	0	1. HYBRIT: (Pei et al., 2020) 2. Green Wolverine: (GrupoFertiberia, 2021) 3. H2 Green Steel: (*H2 Green Steel*, n.d.)
Total number	4	0	18	4	
Share of total	15%	0%	69%	15%	

The national hydrogen demand is allocated to each zone accordingly to the shares identified in Table 5. The hydrogen demand is assumed to remain constant on an hourly basis throughout the year as its main application is in heavy industries which usually comes with constant demand. Therefore, these values are divided by 8760 hours to obtain hourly profiles for the year 2030 to serve as an input for the model, as shown in Equation (18). The results are shown in the Appendix (Table 21 and Table 22).

$$\text{Hourly hydrogen demand} = \frac{\text{National hydrogen demand} * \text{Share of total hydrogen demand}}{8760\,hours} \tag{18}$$

4.2.2.3 Storage

To incorporate electricity as well as hydrogen storage into the energy system model, it is necessary to gather data on their technical performances. Various types of storage exist, but for the sake of simplicity this research considers two types of electricity storage and one type of hydrogen storage.

For electricity storage, lithium-ion batteries and existing hydropower converted into pumped hydropower storage are considered as they appear to be suitable for grid-level energy storage systems (Chen et al., 2020; Karin Byman, 2016).

Due to numerous uncertainties and unknowns regarding hydrogen storage in Sweden, it is emphasised that further research on this topic is necessary (Johansson et al., 2018). Several reports and academic papers suggest that lined rock caverns hold potential for hydrogen storage in Sweden (International Energy Agency & Clean Energy Ministerial, 2022; Hopper et al., 2017). However, the exact locations, capacity and costs of these future storages remain unclear. Therefore, this research uses hydrogen pressurised tanks as a storage medium for hydrogen. This is currently the most common and state-of-the-art hydrogen storage technology. It is important to note that these pressurised tanks are not designed for large-scale, long-term storage, so the model will not reflect reality considering this aspect (Danish Energy Agency, 2018). However, considering the lack of data for implementing lined rock-caverns into the model, the former type of storage is incorporated to enable the model to enable insights into the amount of storage needed per zone.

It is assumed that the values of the technical performance parameters are equal across all energy zones. Table 6 shows the technical parameters for batteries as well as hydrogen storage. The numbers can be found in the Appendix (Table 23).

Table 6: Technical parameters and units for storage technologies to fit the EnergyHub model

Technical parameter	Unit
Maximum installed capacity *(z.s.) (only for pumped hydro)*	MWh
Lifetime	Years
Charging efficiency	%
Discharging efficiency	%
Self-Discharging coefficient independent of environment	% per hour
Self-Discharging coefficient dependent on environment	% per hour
Maximal charging capacity in one hour	% of storage capacity
Maximal discharging capacity in one hour	% of storage capacity

4.2.2.4 Transport

Technical data needed to model the transport infrastructure between the zones is retrieved to serve as input for the EnergyHub model, which is shown in Table 7. The numerical values and associated references can be found in the Appendix (Table 24 and Table 25). To model transmission capacity for imports and export with neighbouring countries, the transmission capacities of the countries that are connected to a particular node are summed. As a result, each node has one import and one export channel, subject to a limit which is the summation of the connected countries. Numerical values including sources can be found in the Appendix (Table 26).

Table 7: Technical parameters and units for transport technologies to fit the EnergyHub model

	Technical parameter	Unit
New technology: Electricity network	Network losses Lifetime	% per km and flow Years
New technology: Hydrogen pipelines	Network losses Minimum transport Lifetime	% per km and flow % of rated capacity Years
Electricity network as well as hydrogen pipelines	Distance between SE1 and SE2 Distance between SE2 and SE3 Distance between SE3 and SE4	Km Km Km

4.2.3 Economic parameters

The EnergyHub model is optimised for minimising the total system costs. Therefore, in addition to technical parameters, cost data on production, storage and transmission is collected to calibrate the model.

For all the production as well as storage technologies a discount rate of 4% is used, as this seems a feasible discount rate for technologies in an energy system in Europe (García-Gusano et al., 2016).

4.2.3.1 Production

The cost of a particular production technology is assumed to be approximately the same across all regions of Sweden. Therefore, there is no variance in cost data input for the different energy nodes. Economic parameters that are considered for the production technologies in this model are shown in Table 8. Numerical values can be found in the Appendix (Table 27). For existing wind energy, even though numerical values are retrieved, the costs are set to zero to ensure this is the first technology that the model deploys to cover demand.

Table 8: Economic parameters and units for production technologies to fit the EnergyHub model

	Economic parameter	Unit
Existing technology: Wind energy	CAPEX OPEX variable OPEX fixed	EUR/module EUR/MWh of total output % of annual CAPEX
Existing technology: Hydropower	CAPEX OPEX variable OPEX fixed	EUR/MW EUR/MWh of total output % of annual CAPEX
New technology: Wind energy	CAPEX OPEX variable OPEX fixed	EUR/module EUR/MWh of total output % of annual CAPEX
New technology: Electrolyser	CAPEX OPEX variable OPEX fixed	EUR/MW EUR/MWh of total output % of annual CAPEX

4.2.3.2 Storage

The cost parameters that are retrieved for storage technologies in this ESM are shown in Table 9. The values are considered uniform across all energy zones due to lack of data to make more accurate assumptions specific for each zone. For numerical values see Appendix (Table 28).

Table 9: Economic parameters and units for storage technologies to fit the EnergyHub model

	Economic parameter	Unit
New technology: Battery storage	CAPEX OPEX variable OPEX fixed	EUR/MWh EUR/MWh of total output % of annual CAPEX
New technology: Pumped hydropower	CAPEX OPEX variable OPEX fixed	EUR/MWh EUR/MWh of total output % of annual CAPEX
New technology: Hydrogen storage	CAPEX OPEX variable OPEX fixed	EUR/MWh EUR/MWh of total output % of annual CAPEX

4.2.3.3 Transport

Table 10 displays the cost parameters that are obtained for energy transport technologies to fit in the EnergyHub model. To represent electricity costs for importing and exporting with neighbouring countries, the price of electricity of all connected neighbouring countries with the particular node is averaged, as each node has only one import and export channel that goes outside country borders in this model. Numerical values including references are found in the Appendix (Table 29 and Table 30).

Table 10: Economic parameters and units for transport technologies to fit the EnergyHub model

	Economic parameter	Unit
New technology: Electricity network	CAPEX OPEX fixed	EUR/MW % of annual CAPEX
New technology: Hydrogen pipelines	CAPEX OPEX fixed	EUR/MW % of annual CAPEX

4.3 Scenario analysis

As elaborated on before, hydrogen demand for 2030 in Sweden is very uncertain and currently there are no numerical targets set by the government. Therefore, two scenarios are created and analysed with the EnergyHub model, as scenario-building can be useful for considering uncertainty and complexity (Amer et al., 2013). The scenarios are forecasting scenarios, as described by Wang et al. (2017), quote "Forecasting scenarios start with the existing situation and prognose different changes that would occur in the future". When two scenarios are considered, it is usually an optimistic and pessimistic scenario (Pillkahn, 2008). The optimistic scenario in this research refers to a well-developed hydrogen economy, while the pessimistic scenario assumes a significantly lower hydrogen demand. The identification of driving forces and effects within each scenario is necessary to ensure that the scenario presents a coherent narrative.

One of the main drivers behind Sweden's potential future hydrogen economy is their ambitious climate targets (Government offices of Sweden: Ministry of Infrastructure, 2022; Klimat politiska rådet, 2022; Regeringen: The Ministry of Infrastructure, 2020; Swedish Energy Agency, 2022). There is also a clear focus on supporting future hydrogen economies on a European level, which is considered a driver for Sweden's hydrogen economy as well (Amber Grid et al., 2022; International Energy Agency & Clean Energy Ministerial, 2022). However, given the novelty of hydrogen, and specifically green hydrogen, it remains unknown whether hydrogen economies will experience the expected acceleration. The climate targets of Sweden are a certainty, making the achievement of the goals a communal driver in both scenarios. The optimistic scenario assumes that the climate targets will be achieved through a strong emphasis on green hydrogen, while the pessimistic scenario predicts that hydrogen will be used to a lesser extent, although still present. In the pessimistic scenario, the climate targets will be met through increased electrification rates in combination with green hydrogen. Figure 11 shows scenario A and B with corresponding drivers and effects.

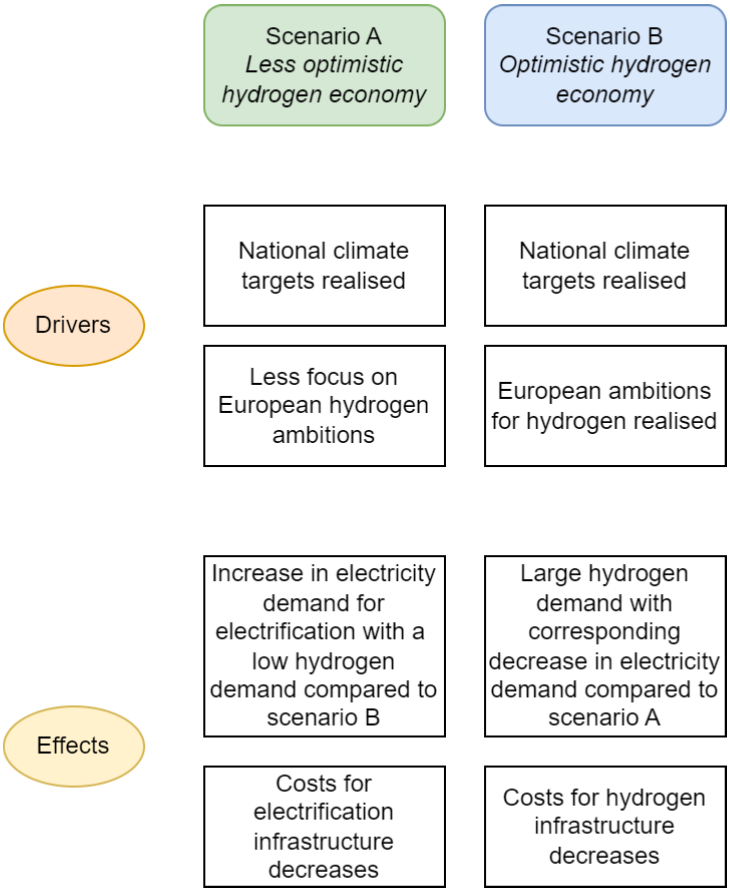


Figure 11: Schematic overview of scenario A and B with corresponding drivers and effects

To add more depth to the scenarios some parameter values are adjusted, next to the demand data input, as presented in Table 11. In the data collection, some technologies were already presented with an uncertainty range with a lower and upper limit for the predicted costs. Where this is the case, the lower limit is assumed for the decrease in costs, and the upper limit is used for increase in costs. This applied to the CAPEX of the electrolyser, the CAPEX for electricity transmission and the CAPEX for hydrogen pipelines. For the parameters where a range was not given in the reports, hence the CAPEX of hydrogen and battery storage, the decreased costs are calculated by subtracting 30% from the original value, and an increased price with 30% added. This results in large cost differences of each parameter between the different scenarios, which encapsulates the uncertainty surrounding the forecasted costs of the relevant infrastructure.

The electricity demand for scenario B is defined by subtracting the amount of electricity needed when producing the increased amount of hydrogen with a PEM electrolyser. This is based on the narrative that when hydrogen has a higher level of penetration in the energy system with the aim of decarbonising, less electrification is needed. Table 11 shows the values of the parameters in scenario A versus scenario B. References of these values can be found in the Appendix in several Tables. The EnergyHub model is used to apply the different effects of the scenarios and it is examined how the optimisation including the decision variables of the model differs between scenario A and B.

Table 11: Parameter values of scenario A versus scenario B

	Scenario A	Scenario B
Total annual hydrogen demand [TWh]	12	18
Total annual electricity demand [TWh]	160	151
CAPEX electrolyser [EUR/MW]	1 300 000	300 000
CAPEX hydrogen storage [EUR/MWh]	58 500	31 500
CAPEX battery [EUR/MWh]	435 400	808 600
CAPEX hydrogen pipelines [EUR/MWh]	1 700	700
CAPEX electricity cables [EUR/MWh]	2 500	3 100

5. Results

In this section, the results of the EnergyHub model are presented in order to answer the research question. First, the two scenarios' electricity and hydrogen demand are presented visually to enhance understanding of their distribution across different zones, identify seasonal patterns and observe disparities between the scenarios. To clarify, this is not an outcome of the EnergyHub model, but considered a result in this thesis as a part of the scenario development. Then, the model outcomes of installed capacity per zone for each technology are presented, as well as cost distribution visualisations. Furthermore, the ESM has not only determined the selection of technologies to be deployed in the energy zones, but also the degree of utilisation throughout the year, which is presented next. Lastly, to further comprehend the hourly dispatch of the system, typical day patterns are presented, of which one winter and one summer day.

5.1 Electricity and hydrogen demand

From Table 12, Figure 12 and Figure 13 it can be observed that the electricity as well as hydrogen demand is largest in SE3. SE2 has no hydrogen demand, whilst SE1 and SE4 have similar hydrogen demand. The electricity demand in zones SE1 and SE2 is of similar magnitude compared to the total, while SE4 demonstrates a slightly higher demand, but significantly less than SE3.

Table 12: Annual electricity and hydrogen demand in TWh per zone per scenario

	Electricity demand [TWh]		Hydrogen demand [TWh]	
	Scenario A	Scenario B	Scenario A	Scenario B
SE1	12.59	11.88	1.80	2.69
SE2	18.17	17.15	0.00	0.00
SE3	101.07	95.39	8.28	12.42
SE4	28.17	26.58	1.80	2.69
Total	160.00	151.00	12.00	18.00

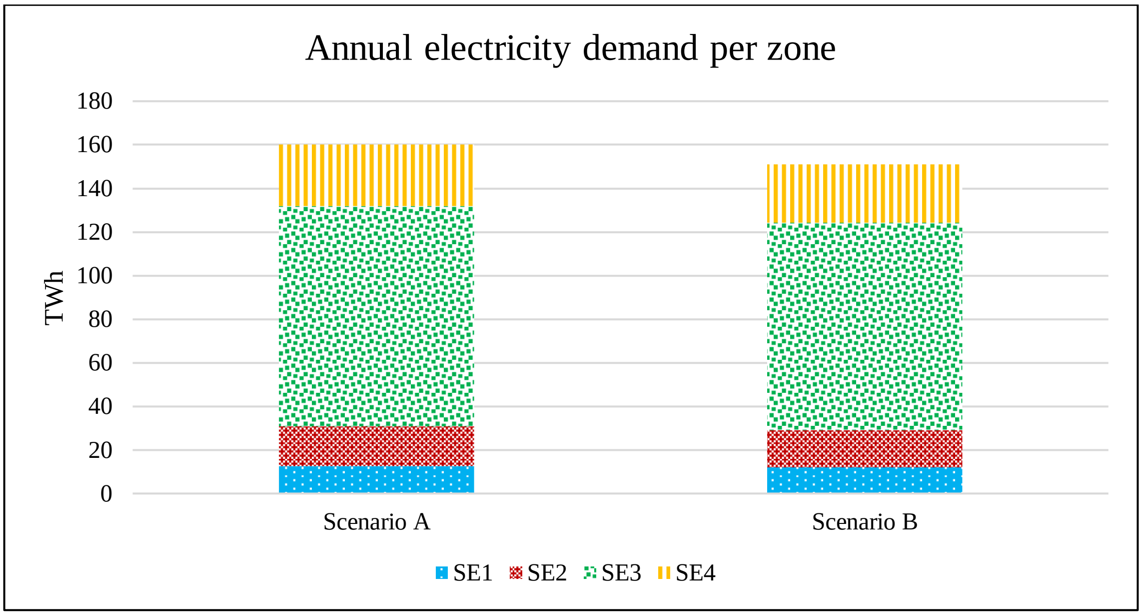


Figure 12: Annual electricity demand in TWh per zone per scenario

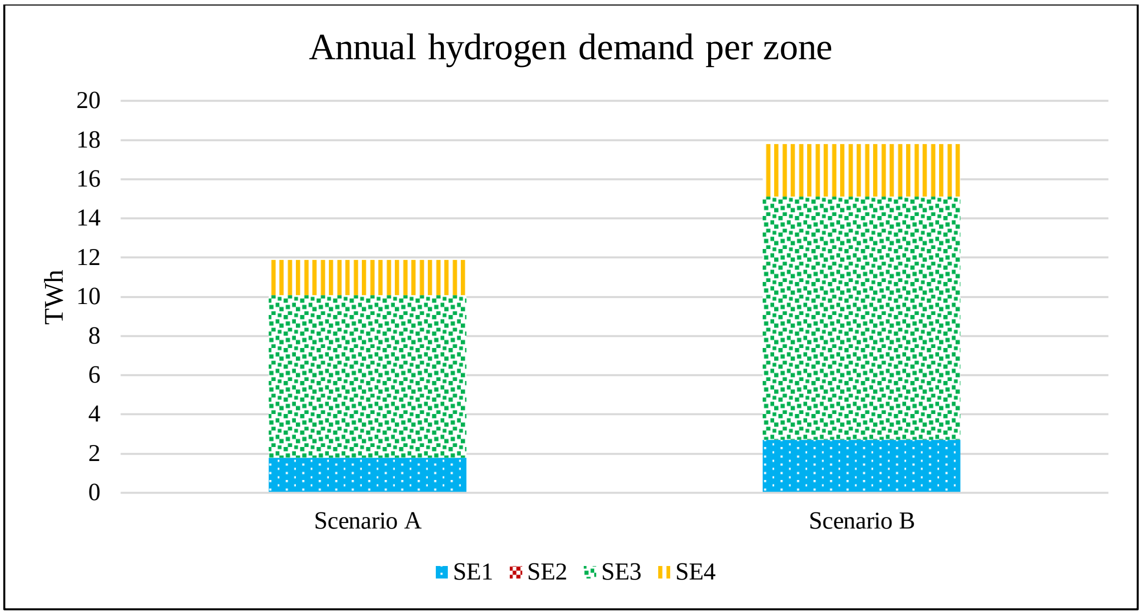


Figure 13: Annual hydrogen demand in TWh per zone per scenario

Figure 14 shows the hourly pattern of electricity demand during the year for each energy zone of scenario A. The pattern is the same in scenario B; hence, only scenario A is illustrated. Peak demand is observed in the beginning and end of the year, thus in the winter months. Lower demand is seen in the middle of the year when it is summer. Hydrogen demand is assumed to be constant throughout the year and therefore, no visual representation depicting its fluctuation over time is needed.

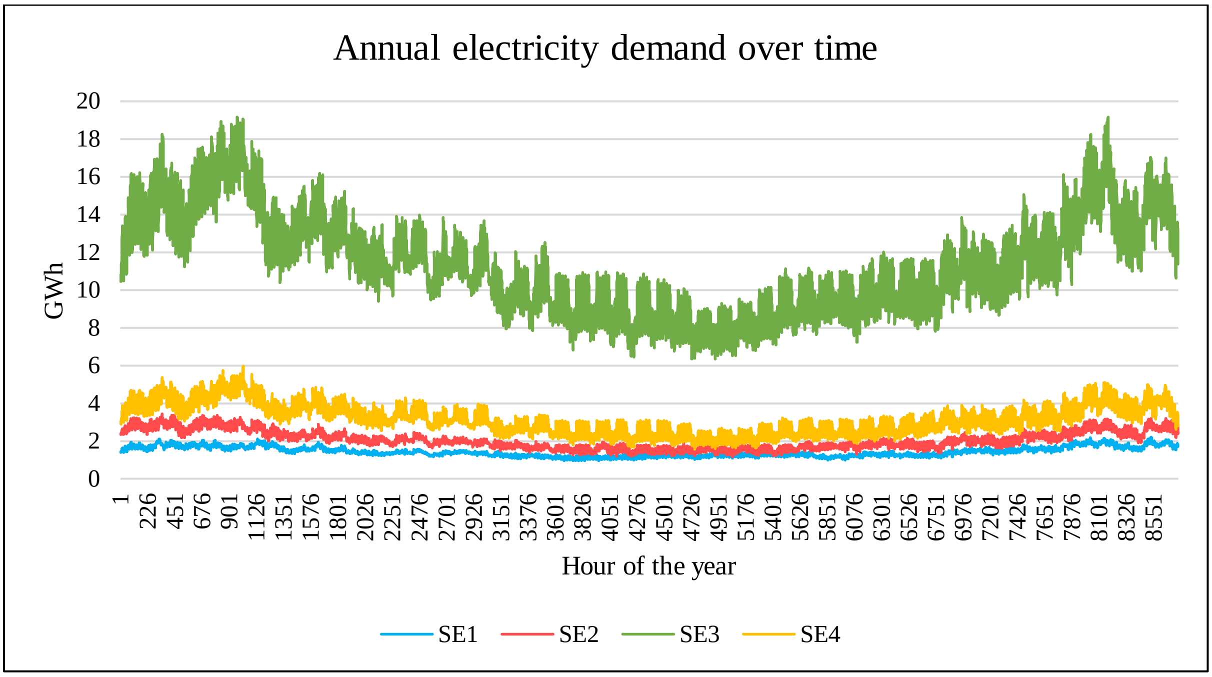


Figure 14: Annual electricity demand in GWh over time per zone scenario A

5.2 Installed capacity of technologies throughout the zones

In this section, the installed capacities for the technologies throughout the zones are represented, as well as visualisations of the cost distribution of the installed technologies.

5.2.1 Installed capacities of technologies

Table 13 shows the installed capacities for all technologies per zone per scenario, of which some are input data as indicated in the Table. The figures that follow visually present the technologies for which the capacity was determined by the model. Existing technologies such as hydropower and 5MW wind turbines are not presented graphically since the installed capacity was pre-determined and thus remain consistent across the scenarios.

Table 13 reveals that not all technologies are deployed in each zone for either scenario. Specifically, pumped hydropower storage is exclusively found in SE3 for both scenarios with an installed capacity of 1847 MW. This is the maximum capacity allowed for this technology in that zone. For both scenarios, battery storage is absent in SE1 and SE2, while it is present in SE3 and SE4 in scenario A and only SE3 for scenario B. Hydrogen storage is not present in SE1 in either scenario and is also absent in SE3 for scenario A. Moreover, 10 MW wind turbines are not installed in SE1 and SE2 in either of the scenarios. Lastly, electrolysers are deployed in all zones for both scenarios, with the largest installed capacity for scenario A in SE2, but in SE4 for scenario B.

Table 13: Installed capacity for each technology per zone

		Installed capacity	
Technology	Node	Scenario A	Scenario B
Electrolyser [MW] (model outcome)	SE1	33	124
	SE2	1331	1629
	SE3	788	1451
	SE4	225	2913
Hydropower [MW] (input data)	SE1	5132	5132
	SE2	7894	7894
	SE3	1847	1847
Pumped hydro storage [MWh] (model outcome)	SE1	0	0
	SE2	0	0
	SE3	1847	1847
Battery storage [MWh] (model outcome)	SE1	0	0
	SE2	0	0
	SE3	214267	135931
	SE4	1707	0
Hydrogen storage [MWh] (model outcome)	SE1	0	0
	SE2	1137	6200
	SE3	0	4793
	SE4	1847	43671
WT 10 MW [Number of Turbines] (model outcome)	SE1	0	0
	SE2	0	0
	SE3	13527	10868
	SE4	6913	7146

WT 5 MW [Number of Turbines] (input data)	SE1	446	446
	SE2	1101	1101
	SE3	605	605
	SE4	380	380
Electricity cables [MW] (model outcome)	SE1 – SE2	0	0
	SE2 – SE3	0	0
	SE3 – SE4	32490	43206
Hydrogen pipelines [MW] (model outcome)	SE1 – SE2	0	0
	SE2 – SE1	312	208
	SE2 – SE3	1505	1162
	SE3 – SE2	230	0
	SE3 – SE4	245	200
	SE4 – SE3	1292	23

Figure 15 shows the installed capacity of electrolysers for each zone per scenario. The distribution is rather different for the scenarios. In all zones, the installed capacity of electrolysers is larger for scenario B than for scenario A, which coincides with the larger hydrogen demand in scenario B. In scenario A, zone SE2 has the largest installed capacity for electrolysers, amounting to 1.63 GW, whereas in scenario B, zone SE4 surpasses it with an installed capacity of nearly 3 GW. To compare, the HYBRIT project, which is one of the promising large-scale green hydrogen projects in Sweden, plans to build a 500 MW electrolyser (*HYBRIT Demonstration - Hybrit*, 2023).

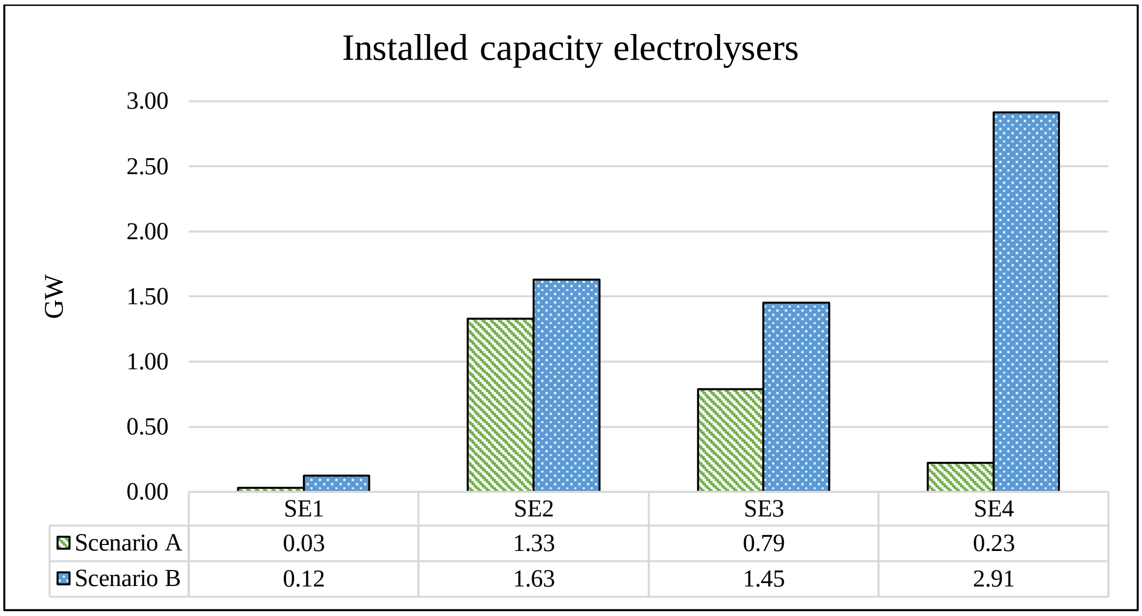
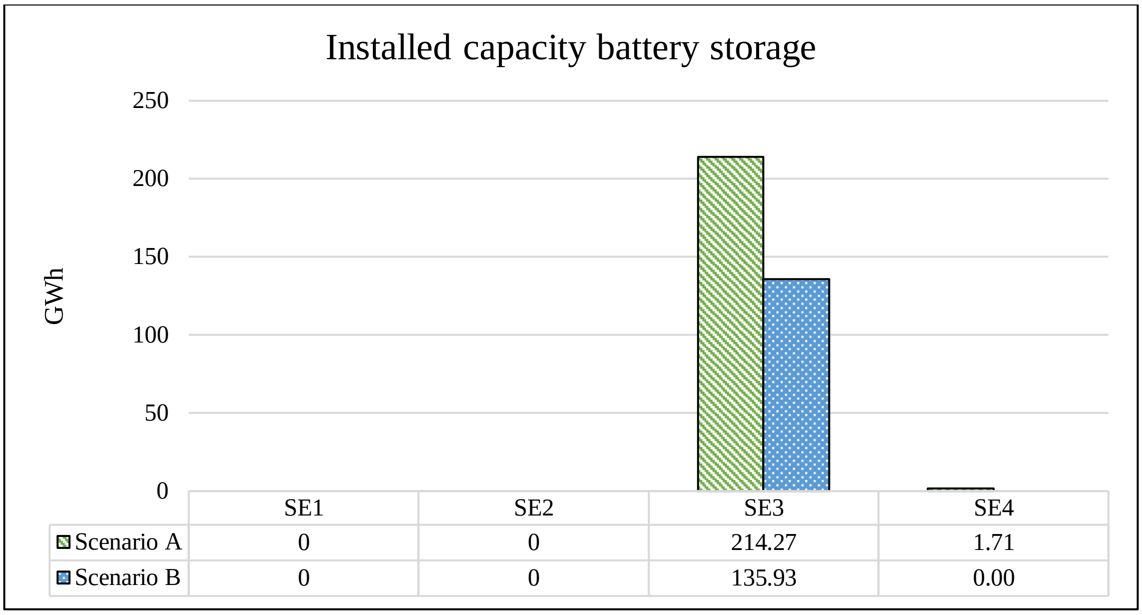


Figure 15: Installed capacity of electrolysers per zone and scenario

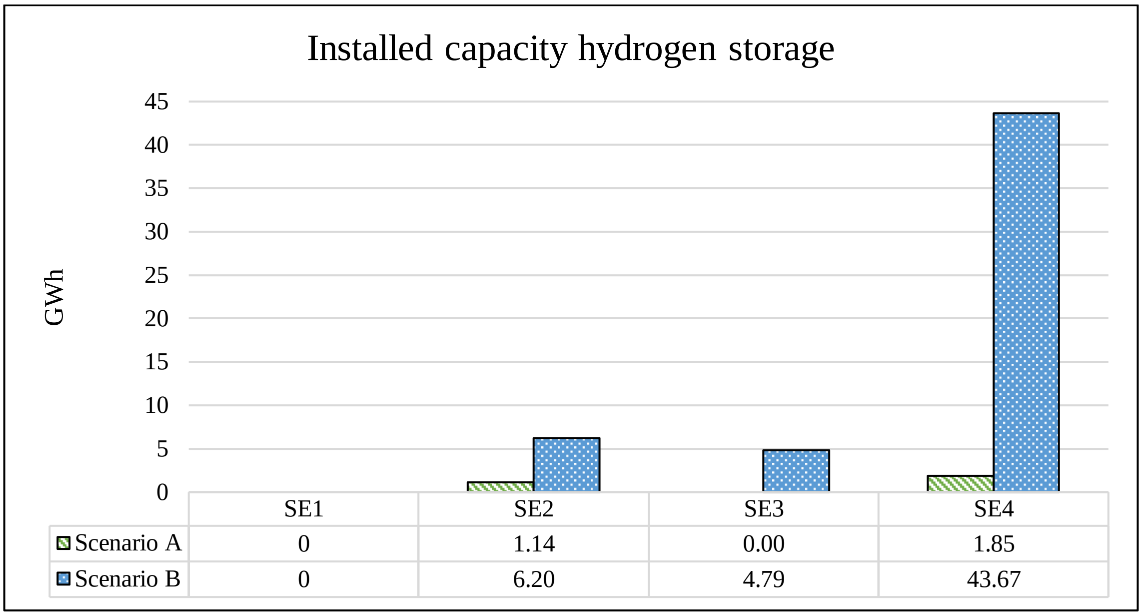
Figure 16 shows the installed capacity of battery storage, which is by far the largest in SE3 in both scenarios. In scenario B there is an installed capacity of 1.71 GWh in SE4 as well, but the remaining zones do not have any batteries installed. In scenario B, the deployment in SE3 exceeds 100 GWh whereas in scenario A it even surpasses 200 GWh. To compare, a grid-level state-of-the-art battery in Sweden that is under development in Uppsala is planned to have a delivery capacity of about 20 MWh (Smart City Sweden, 2022).



	SE1	SE2	SE3	SE4
Scenario A	0	0	214.27	1.71
Scenario B	0	0	135.93	0.00

Figure 16: Installed capacity battery storage per zone and scenario

The installed capacity of hydrogen storage is shown in Figure 17. It is clear that the largest amount of hydrogen storage is deployed in SE4 in scenario B, being 43.67 GWh. In terms of kilograms of hydrogen this equals approximately 1310 tonnes. To put into context, the current hydrogen production in Sweden amounts up to 180.000 tonnes per year (Fossil Fritt Sverige, 2021). In scenario B, SE2 and SE3 also deploy hydrogen storage, though significantly smaller than the storage in SE4. In scenario A, a similarly sized hydrogen storage is depicted in SE2 and SE4.



	SE1	SE2	SE3	SE4
Scenario A	0	1.14	0.00	1.85
Scenario B	0	6.20	4.79	43.67

Figure 17: Installed capacity hydrogen storage per zone and scenario

Figure 18 illustrates that for both scenarios, the highest number of newly built wind turbines of 10 MW is observed in SE3, with over 10,000 wind turbines installed. This number of turbines equals approximately 100 GW altogether. In comparison, Sweden currently employs approximately 15 GW of wind energy (*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.) In addition to SE3, SE4 also demonstrates a substantial number of newly built wind turbines in both scenarios, with approximately 7,000 wind turbines installed. This installation corresponds to an approximate capacity of 70 GW. Both SE1 and SE2 have no wind turbines in either scenario.

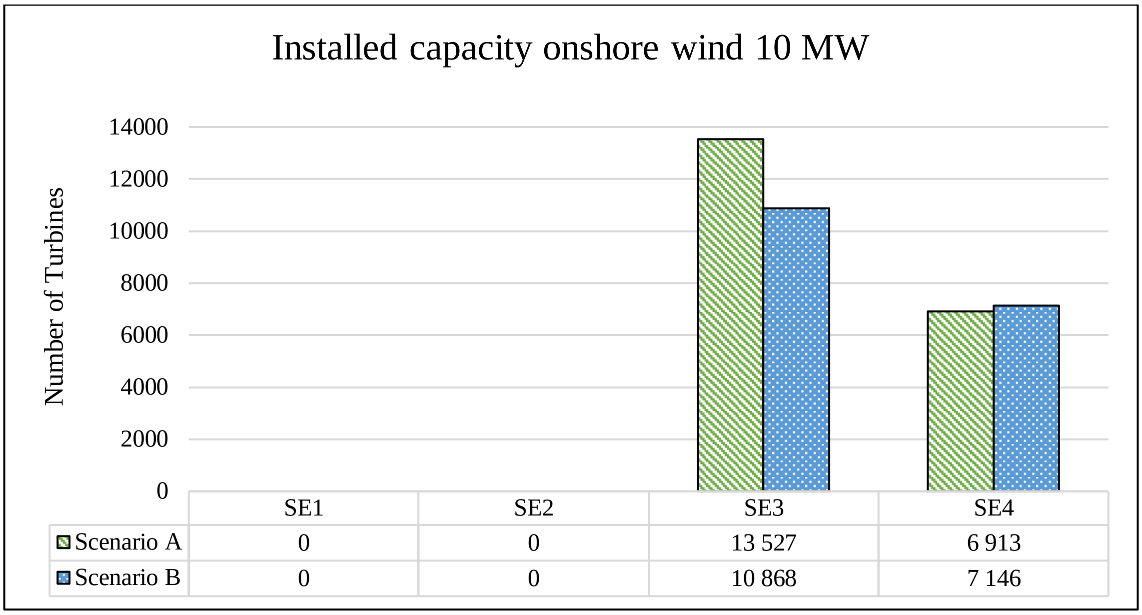


Figure 18: Installed capacity 10 MW turbines per zone and scenario

Figure 19 shows that the electricity transmission infrastructure is primarily deployed between zones SE3 and SE4 in both scenarios. Scenario A has the largest installed capacity, namely 43 GW. Comparing with real-life, the installed capacity of transmission between zone SE3 and SE4 is about an order of magnitude smaller (Svenska Kraftnät, 2021a). The transmission lines are bidirectional, in contrast to the hydrogen pipelines, that are depicted in Figure 20. Transmission connections between the zones and neighbouring countries are not demonstrated, as they are input data to the model, of which the values can be found in the Appendix in Table 26.

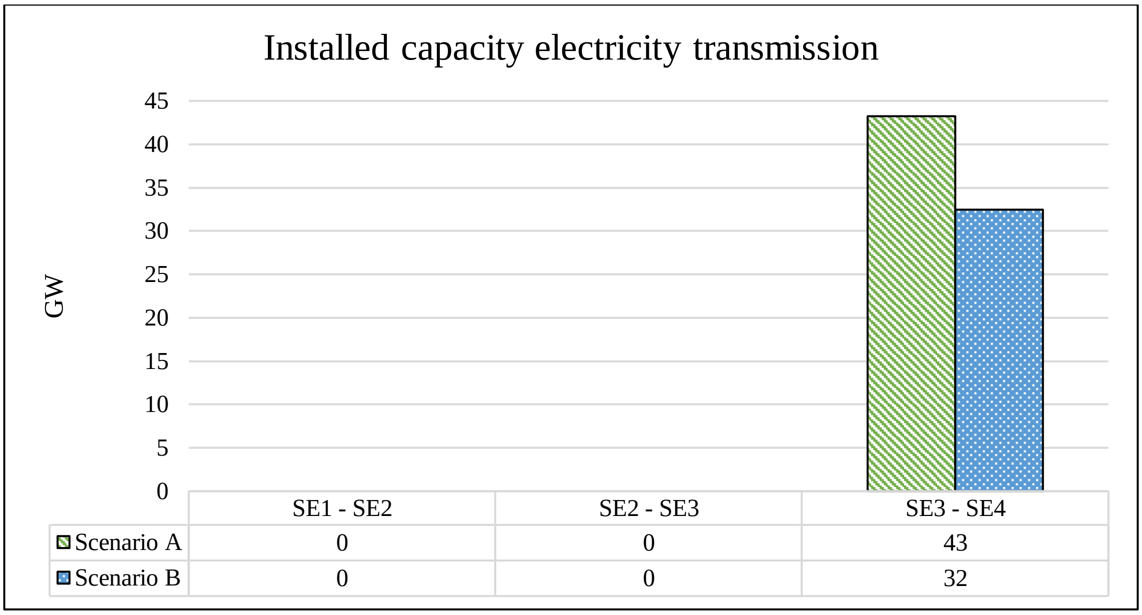
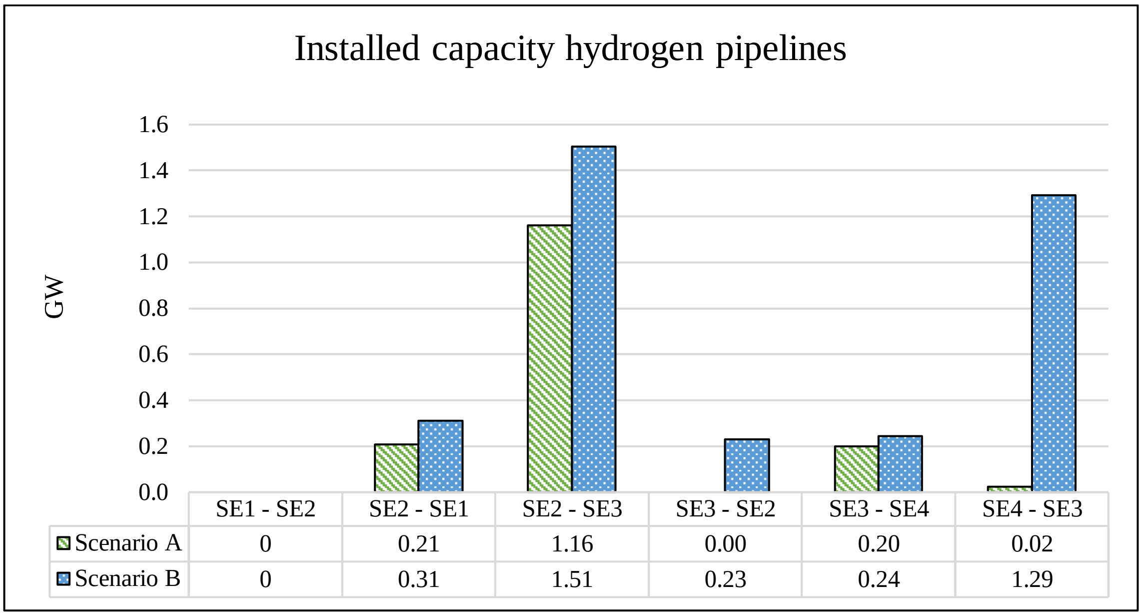


Figure 19: Installed capacity electricity transmission per zone and scenario

Figure 20 shows the installed capacity of hydrogen pipelines for each direction, zone and scenario. For scenario B, all hydrogen pipelines are larger than those of scenario A in the same zone. The largest installed capacity is observed in scenario B for the pipeline connecting SE2 to SE3, with a size of 1.51 GW. This is closely followed by the pipeline from SE4 to SE3 in scenario B, with a value of 1.29 GW. In scenario A, the largest installed capacity is observed from SE2 to SE3, with a size of 1.16 GW. In both scenarios, there is a relatively small pipeline that brings hydrogen from SE2 to SE1, but in none there are outgoing pipelines from SE1 to SE2.



	SE1 - SE2	SE2 - SE1	SE2 - SE3	SE3 - SE2	SE3 - SE4	SE4 - SE3
Scenario A	0	0.21	1.16	0.00	0.20	0.02
Scenario B	0	0.31	1.51	0.23	0.24	1.29

Figure 20: Installed capacity hydrogen pipelines per zone and scenario

5.2.2 Costs distribution

Figure 21 shows the distribution of all costs per technology of all zones summed. It can be seen that, similar for both scenarios, most of the system costs consist of the newly installed wind turbines, followed by the battery storage and electricity cables. Other technologies are a

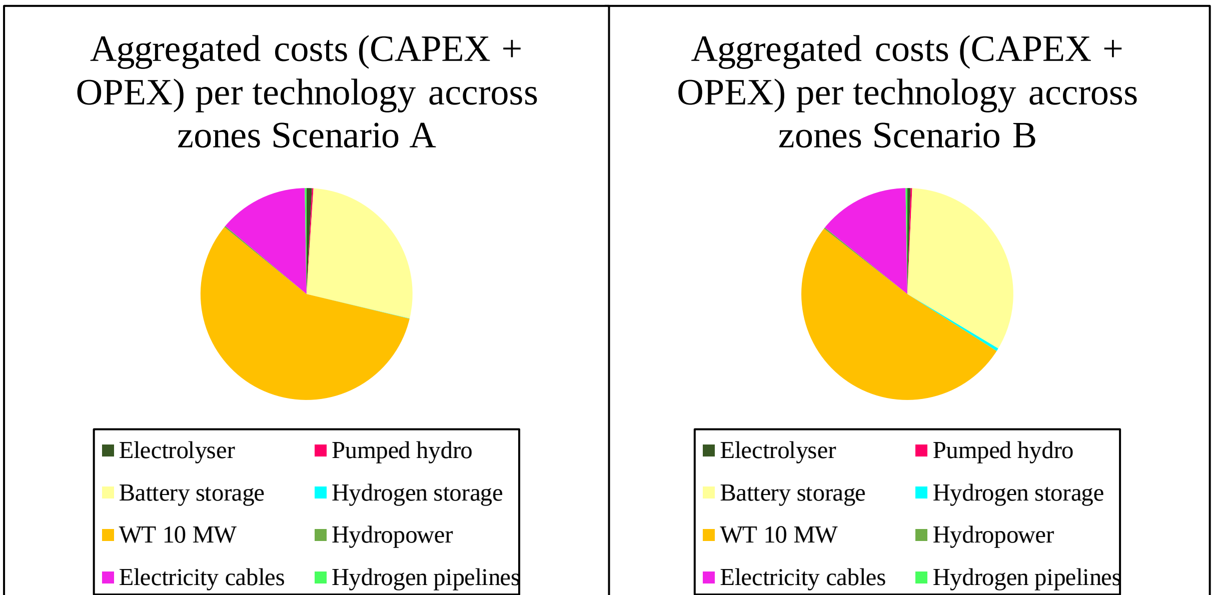


Figure 21: Share of each technology's costs of the total annuitised system costs

significantly smaller share of the total system costs. The total system costs for scenario A are approximately 17291 million Euros, and for scenario B 16780 million Euros, both annuitised.

In order to analyse the relative significance of the CAPEX and OPEX for the technologies, Figure 22 is shown. Similar pie charts were generated for each technology. However, these charts exhibited similar patterns in terms of the share of CAPEX and OPEX, rendering it redundant to display all of them. Consequently, only the pie chart for one technology, battery storage, is shown for both scenarios, which clearly demonstrates that investment costs outweigh operational costs across the technologies.

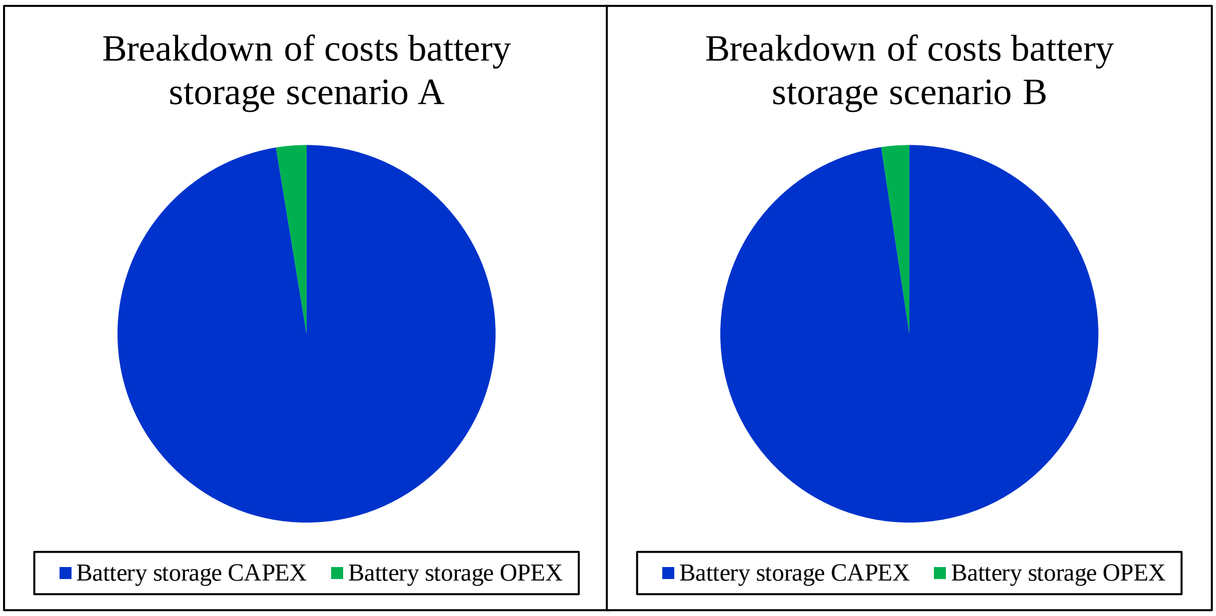


Figure 22: Share of OPEX and CAPEX of total batteries' costs

To be able to better understand the model's decisions regarding dynamics between the zones driven by costs, Table 14 provides the LCOE and LCOH for every zone, as well as for the country as a whole. It must be noted that the LCOH in this calculation does not directly include the LCOE of the electricity that is being used for electrolysis in that zone. Their indirect relation is explained by the following example; minimal hydrogen is produced when electricity prices are high, resulting in a larger LCOH as the costs of electrolysers outweigh the produced hydrogen in this situation.

It can be observed that the country-level LCOE in scenario B is higher, whereas this is the other way around for the LCOH. The LCOE is highest in zone SE3 for both scenarios, as well as the LCOH for scenario A. For scenario B however, the LCOE is highest in SE4. Real life electricity prices and LCOH are included in Table 14 as well to compare, taken from Nordpool, SCB: Statistics Sweden and the Fuel Cell Hydrogen Observatory (*Hydrogen Supply Capacity | FCHObservatory*, n.d.; Nordpool, 2023; SCB: Statistics Sweden, 2023).

Table 14: LCOE and LCOH per zone, for each scenario and real-life

	Scenario A	Scenario B	Real life 2022	Scenario A	Scenario B	Real life 2022
	LCOE [EUR/MWh]			LCOH [EUR/kg]		
SE1	0.71	0.71	59.06	0.43	0.16	-
SE2	0.68	0.67	61.95	0.28	0.06	-
SE3	125.51	140.24	129.21	0.79	0.25	-
SE4	68.89	67.36	152.10	0.75	0.43	-
Country	79.51	82.04	81.30	0.43	0.16	2.01

5.3 Annual utilisation of technologies

Section 5.2 provided insight in the decided installed capacities of technologies but lacked information about their performance. This section shows the allocation of generated electricity per production technology, displays capacity factors of the technologies, and showcase annual electricity and hydrogen balances per zone and scenario.

Table 15 and Figure 23 shows the contribution of each zone to the total annual electricity production. This could provide insights into the drivers behind the dynamics between the zones and understand how demand is being met. It can be observed that most electricity is generated in SE3 for both scenarios, even though it is a slightly smaller proportion in scenario B. SE1 and SE2 have the smallest role in providing electricity for both scenarios.

Table 15: Annually produced electricity per zone and scenario

	Annually produced electricity [TWh]	
	Scenario A	Scenario B
SE1	22.67	22.68
SE2	36.47	36.78
SE3	115.84	99.71
SE4	62.97	65.83

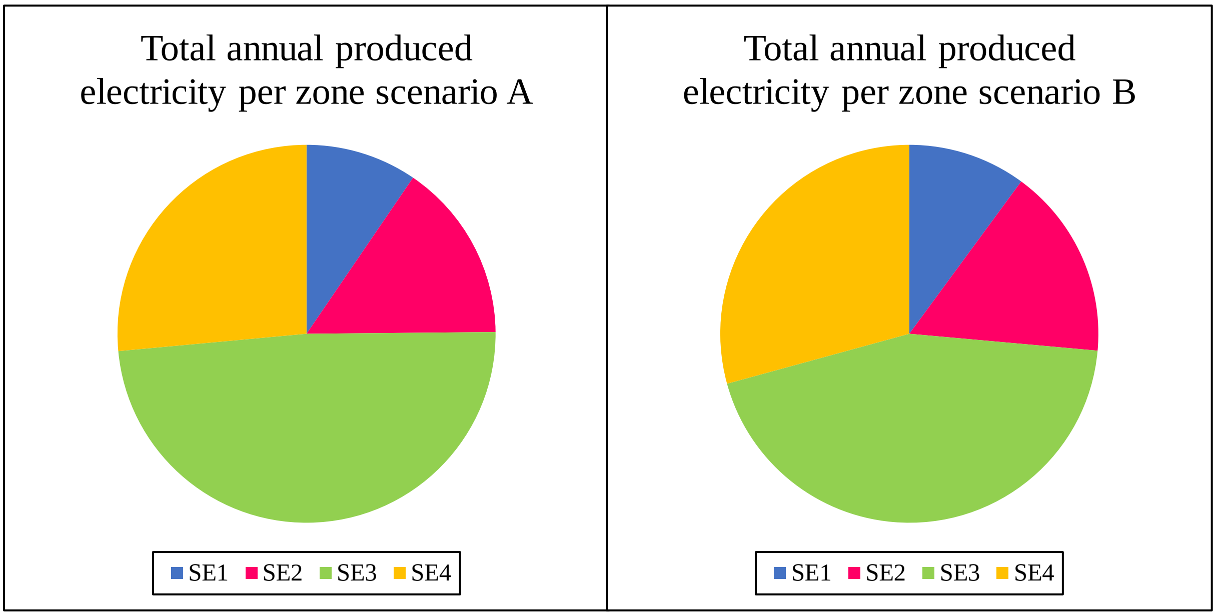


Figure 23: Share of each zone to the total annually produced electricity

Table 16 with corresponding Figure 14 show the annually produced electricity from each of the production technologies used in the scenarios. The allocation of generated electricity per source is similar in the scenarios. However, there are slight differences between scenario A and scenario B. In scenario A, a greater amount of electricity is produced by the 10 MW wind turbines, while in scenario B, the 5 MW turbines contribute more to the electricity generation. Additionally, scenario B exhibits slightly higher electricity generation from hydropower compared to scenario A, which is negligible.

Table 16: Annually produced electricity per technology and scenario

	Annually produced electricity [TWh]	
	Scenario A	Scenario B
Nuclear	49.90	49.90
Offshore wind	19.74	19.74
Onshore wind 10 MW	146.57	138.79
Onshore wind 5 MW	13.32	13.42
Hydropower	59.40	59.61

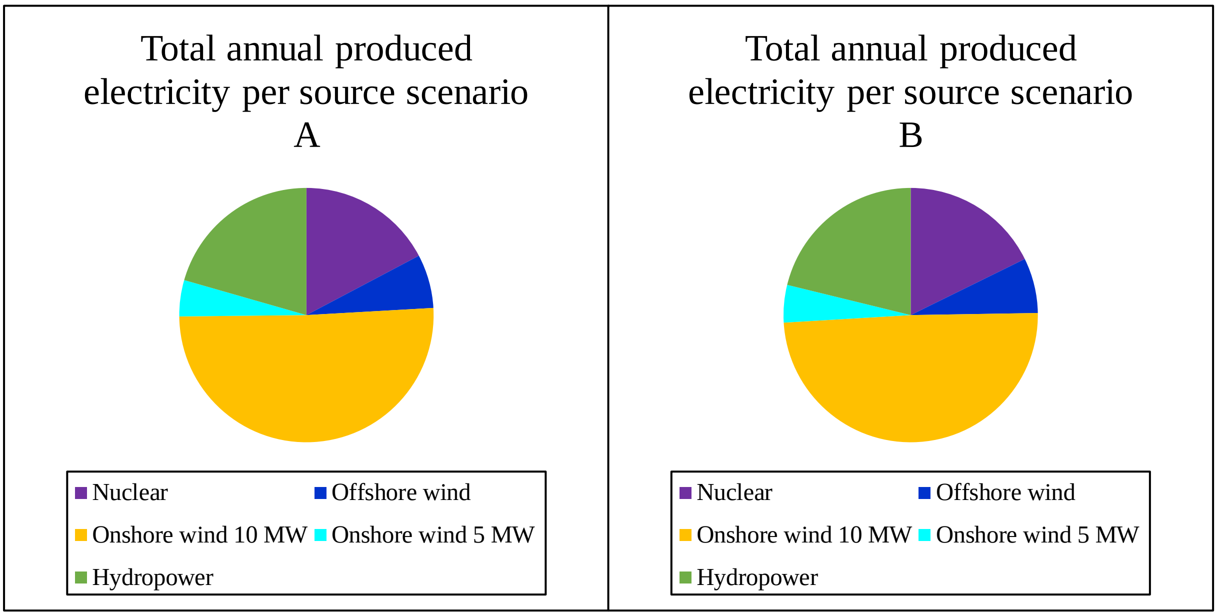


Figure 24: Share of each technology to the total annually produced electricity

The capacity factor (CF) for each technology per node, for both scenarios, is presented in Table 17. It can be observed that the CF remains relatively consistent across the scenarios for most technologies, such as hydropower and wind turbines. Hydropower has a CF that is close to the real averaged availability of hydropower in Sweden. The 5 MW turbines have a slightly higher CF in each zone compared to the 10 MW turbines, the largest being 17.12% in SE4, which is consistent for both scenarios. The wind turbines displaying the lowest CF are the 10 MW turbines in SE3 from scenario A, with a CF of 7.33%. Both the battery, pumped hydropower and hydrogen storage demonstrate significantly low CFs across all zones and scenarios. The CF for storage mediums are based on the electricity discharges, as shown in equation (19):

$$CF_{storage} = \frac{Total\ electricity/hydrogen\ discharged\ [MWh]}{Installed\ capacity\ [MW] * 8760\ [h]} * 100\% \tag{19}$$

This results in low CFs for storage, as the discharged energy is very low compared to the installed capacity, since the latter is designed to match peak demand in a fluctuating production pattern. The highest observation is a value of 2.8% which corresponds to the battery storage in SE4 under scenario A. Contrary, electrolysers show rather high CFs. When comparing each node respectively, scenario A results in larger CFs than scenario B. SE1 in scenario A shows the highest CF for electrolysers, which are only used for local demand, namely 68.20%. To compare SE1, in scenario B, the CF for electrolysers accounts for 43.36%.

Table 17: Capacity factor per technology, zone and scenario

Technology	Node	Capacity factor [%]	
		Scenario A	Scenario B
Electrolyser	SE1	68.20	43.36
	SE2	72.06	52.45
	SE3	37.07	26.45
	SE4	45.78	28.14
Hydropower	SE1	46.10	46.11
	SE2	45.15	45.45
	SE3	46.12	46.12
Pumped hydro storage	SE3	0.68	0.79
Battery storage	SE3	0.97	1.10
	SE4	2.80	-
Hydrogen storage	SE2	0.92	0.80
	SE3	-	0.84
	SE4	0.86	0.77
WT 10 MW	SE1	0.00	0.00
	SE2	0.00	0.00
	SE3	7.33	7.96
	SE4	9.86	10.06
WT 5 MW	SE1	9.99	10.00
	SE2	10.89	11.11
	SE3	12.33	12.33
	SE4	17.12	17.12

To provide insights in the dynamics and utilised technologies at each node to meet the electricity demand, a depiction of the averaged annual electricity demand balance is shown per zone and scenario in Figure 25. The corresponding values can be found in the Appendix in Table 31. The Figure reveals that the share of technologies used to meet demand in each node is similar for the scenarios. SE1 and SE2 exhibit low electricity demand, primarily fulfilled by hydropower, with a surplus that is exported to neighbouring countries. In SE2, there is additional electricity consumption attributed to the electrolyser, while some electricity is imported to meet the overall demand. In SE3, most electricity is generated by 10 MW wind turbines, followed by production from the nuclear power plant. A significantly smaller proportion is generated by 5 MW turbines, which is consistent in SE2 and SE4 as well. Moreover, a reduced portion of electricity is imported from external sources, obtained from battery storage or received from other nodes. Lastly, electricity is exported both outside the country and to other nodes, while the battery is also being charged. In SE4, the majority of electricity production relies on hydropower, supplemented by offshore wind energy, as well as imports and inflows from other nodes.

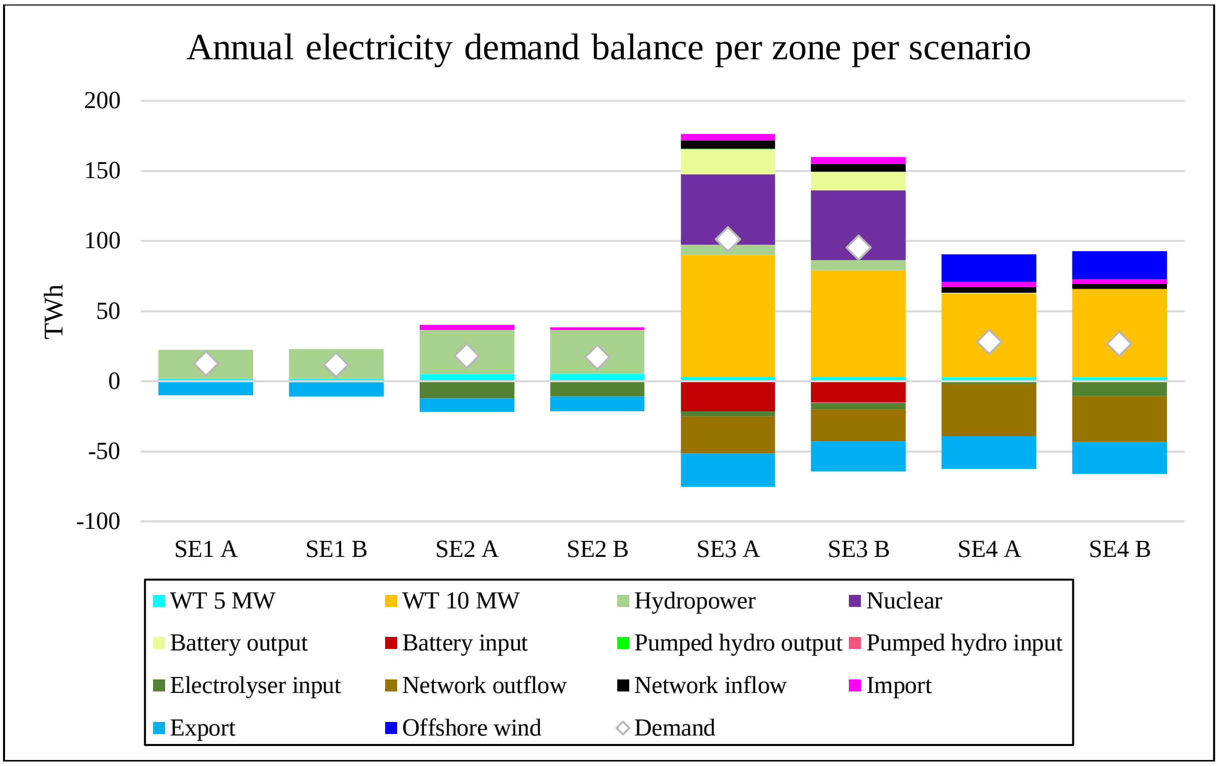


Figure 25: Annual electricity demand balance per zone per scenario. 'Export' & 'Import' refers to connections with neighbouring countries, while 'Network in/out- flow' refers to connections between the nodes.

Figure 26 shows insights into the utilisation of technologies for meeting the hydrogen demand per zone, for each scenario. The corresponding values can be found in the Appendix in Table 32. SE1, SE2 and SE3 show similarities, but SE4 differs significantly across the scenarios. In SE4, scenario B demonstrates a higher utilisation of the technologies compared to scenario A, even though the hydrogen demand in scenario B is not larger. A large amount of hydrogen is produced by electrolysers, which is both stored and withdrawn from the hydrogen storage. Furthermore, a significant volume of hydrogen is transported through pipelines to other nodes, and a much smaller share is imported. In the same zone for scenario A, there is only a small share of hydrogen produced by electrolysers and imported from other nodes. The storage is barely used. For SE3, in both scenarios most of the hydrogen is imported from other nodes, and a much smaller portion is exported. In addition, hydrogen production from electrolysers is also observed. SE2 exhibits a significant production of hydrogen from electrolysers and a large export in both scenarios. However, in scenario B, additional features are observed, including a small amount of hydrogen import, storage input, and storage output. The demand in both scenarios is zero for SE2, so the usages of the technologies is merely to provide hydrogen for other nodes. SE1 is similar for both scenarios, showcasing a very small production from electrolysers and a much larger import from other nodes.

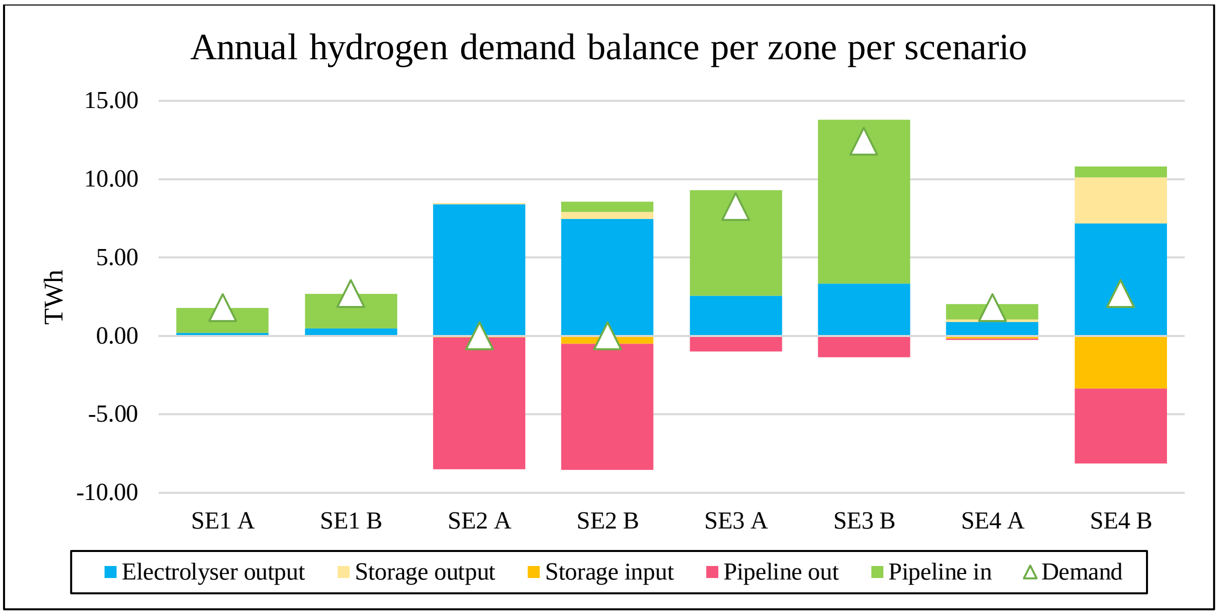


Figure 26: Annual hydrogen demand balance per zone per scenario. 'Pipeline in/out' refers to hydrogen connections between the nodes. No international import/export is depicted in this study.

5.4 Typical days dispatch electricity and hydrogen

This section showcases several dispatch figures of the electricity and hydrogen demand balance for a typical winter and summer day. This analysis provides valuable insights into the operational dynamics of different technologies on a daily basis, shedding light on how the energy system manages peak demand and periods of low demand.

5.4.1 Dispatch electricity demand

Figure 27 shows the dispatch of a typical winter and summer day for both scenarios, regarding electricity dispatch. The winter day with the highest demand of the year is shown, to observe how peak demand is handled by the ESM. The opposite counts for the summer day. Regarding the winter day, it can be observed that both scenarios show very similar patterns for this day with only minor deviations to be discerned. For instance, in hour 8 of scenario A negligibly small portion of the demand is met by battery output, whereas this is not the case in scenario B. Regarding the summer day, there is a notable difference between the scenarios around hour 19. Scenario A shows withdrawal of electricity from battery storage and a larger outflow of electricity between the nodes, whereas this is not observed in scenario B. Apart from this, the scenarios illustrate great resemblances for the typical summer day.

Overall, in both scenarios for all days, nuclear power and hydropower serve as a baseload, complemented by a large share of import for the winter day. On the summer day, imports are lacking but a higher proportion of electricity is withdrawn from storage to meet demand. Additionally, a large proportion is exported, whereas this is missing in winter. In both the winter and summer day, the 10 MW wind turbines provide a large share of electricity during the day. Another remarkable difference is the significant proportion of electricity being directed towards battery and pumped hydro storage on the winter day, which is absent on the summer day where surplus is exported, which could be due to seasonal price differences.

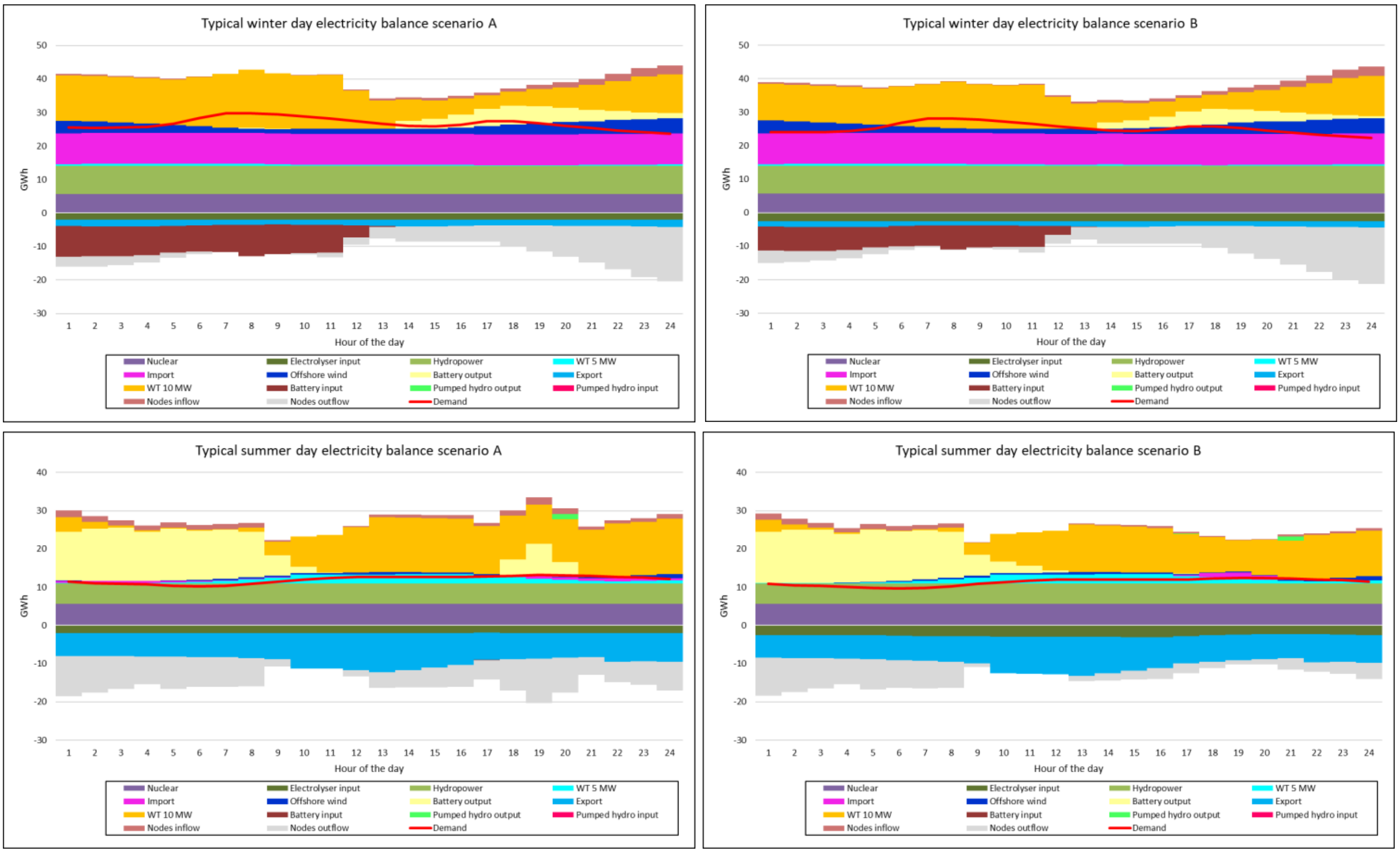


Figure 27: Hourly electricity dispatch of typical winter and summer day for both scenarios

5.4.2 Dispatch hydrogen demand

Figure 28 illustrates the dispatch for meeting the hydrogen demand on the same winter and summer day as for the electricity dispatch elaborated on in section 5.4.1. As hydrogen demand is constant throughout the year, it is apparent that the dispatch of typical days exhibits relatively stable patterns. It can be observed in Figure 27 displaying electricity dispatch that the input to electrolysers is consistent, which corresponds with Figure 28. A prominent difference arises between the two scenarios, namely that there is a notable higher utilisation rate of hydrogen storage in scenario B compared to scenario A in both days. Additionally, on the summer day, there are more significant fluctuations in electrolyser output, resulting in corresponding variations in storage utilisation and the flow of hydrogen between nodes.

The constancy observed in the hydrogen storage inputs, outputs, and flows on those typical days may be coincidental and not representative for the full year. To analyse the duration of consistency of hydrogen production and storage levels throughout different periods of the year, the annual balance of hydrogen storage levels is presented in Figure 28. For both scenarios, hydrogen storage levels in SE4 are showcased, given that this zone possesses the largest installed capacity amongst all nodes, making it particularly interesting for further investigation. The depicted Figure shows considerable fluctuation of storage levels throughout the year, characterised by steep slopes, which indicates that this consistent pattern could deviate substantially if a different typical day were selected for the analysis. It also denotes that hydrogen storage has a long-term characteristic, rather dan a daily cyclical fluctuation as battery shows.

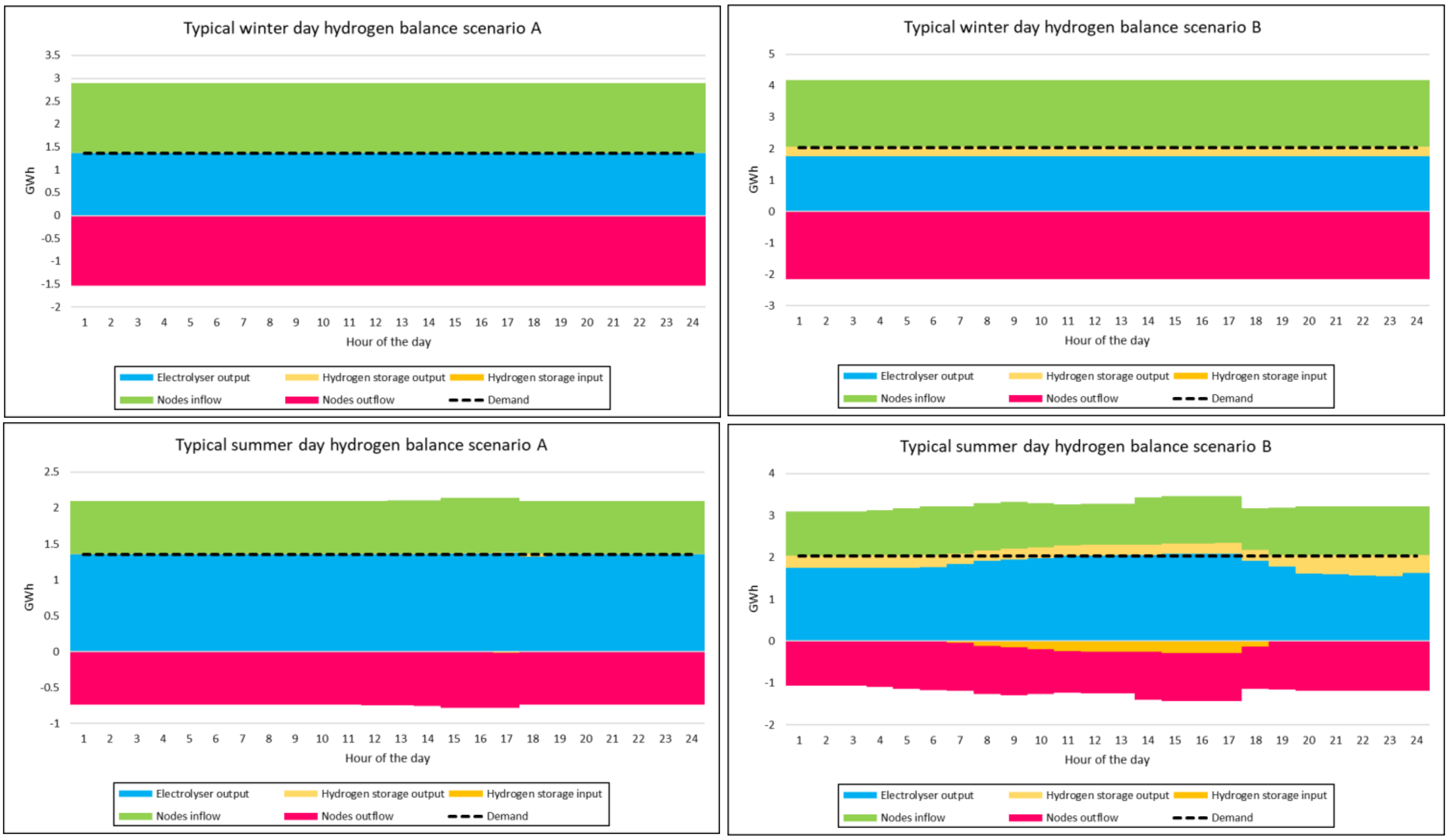


Figure 28: Hourly hydrogen dispatch of typical winter and summer day for both scenarios

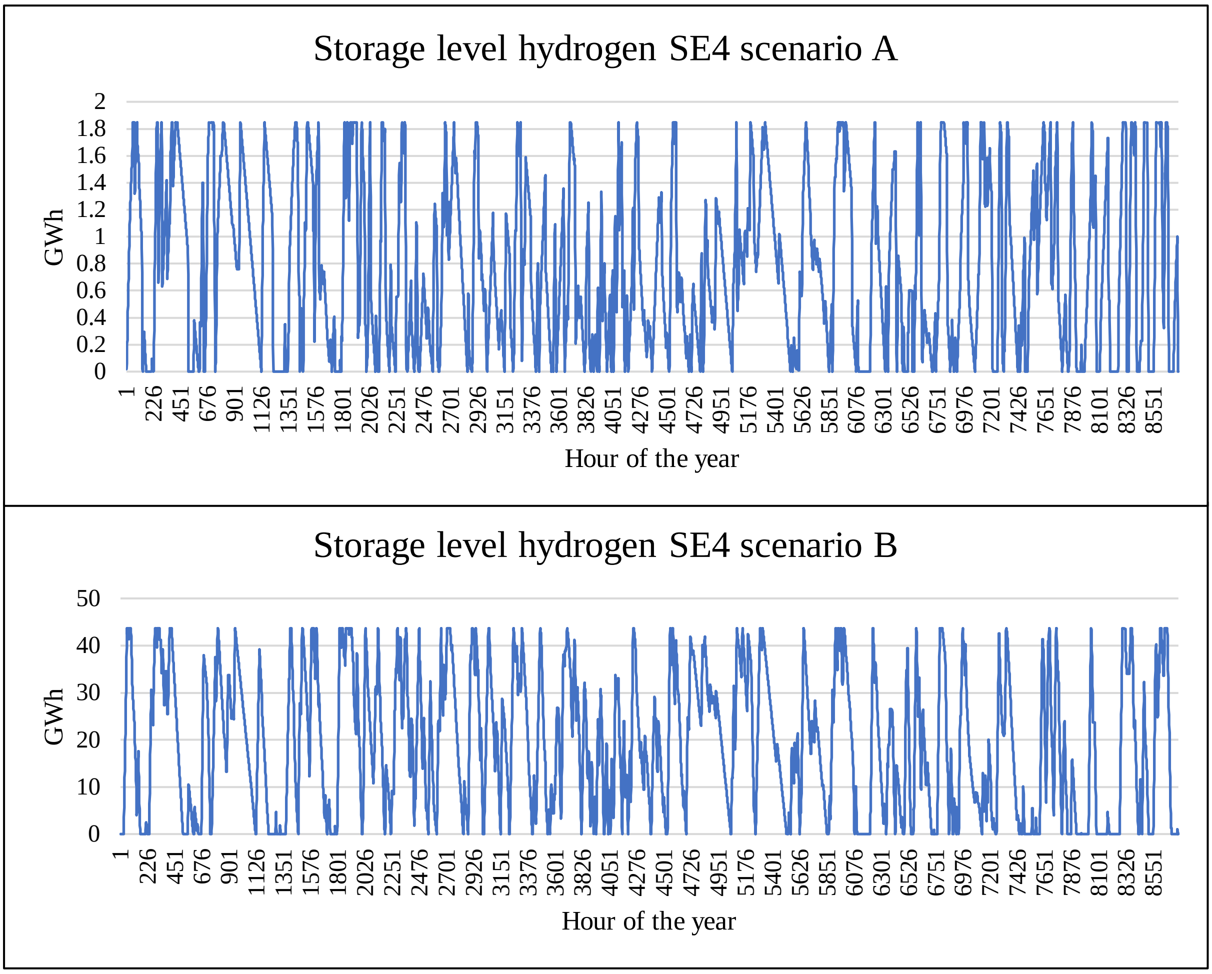


Figure 29: Annual storage levels hydrogen scenario A and B

5.5 Sensitivity analysis of results

In this section, the model's outcomes are tested on their sensitivity to various parameters. The analysis specifically examines the sensitivity of the sizes of installed technologies for the transportation and production of hydrogen, as well as the production and transportation of electricity that are decided by the model. Thus, the installed capacity of electrolysers, hydrogen pipelines, electricity cables and 10 MW wind turbines. These parameters are tested on their sensitivity for costs of electricity cables as well as costs of hydrogen pipelines. The independent variables are subjected to a deviation of ±30% from their original values. The model is run for one month instead of one year and only for scenario A, to reduce computational time.

Figure 30 shows the sensitivity of the total installed capacity of electricity transmission to the discussed variables. Due to the significant share of total system costs attributed to electricity cables in both scenarios, it is interesting to analyse the effect of the pricing of the energy transport technologies on the sizing of the cables. The Figure shows that the installed capacity is not sensitive to deviations in pricing of hydrogen pipelines. However, when lowering the price of electricity cables, the total installed capacity increases (the configuration between nodes remains the same). Similarly, when the price of cables is increased, the installed capacity decreases.

The sensitivity of electrolysers and hydrogen pipelines is an interesting analysis since the pricing of energy transport could enhance a shift in allocations of electrolysers to reduce transport costs. It also investigates the extent to which the built-out of hydrogen pipelines is attributed to the pipeline costs. No figures are provided for electrolysers and hydrogen pipelines as they show no sensitivity to the independent variables tested.

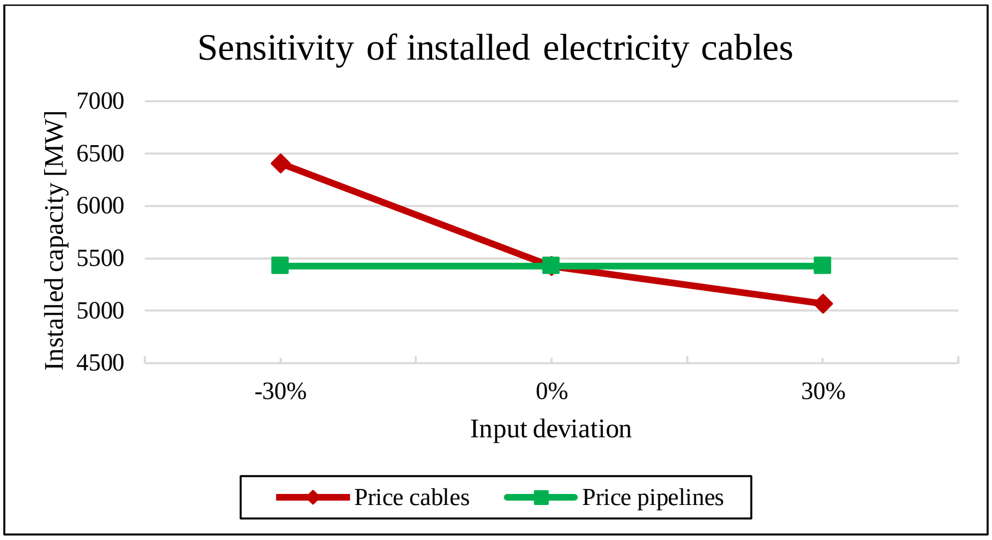


Figure 30: Sensitivity of installed electricity cables to the price of cables and the price of pipelines

For the wind turbines, it deems interesting to analyse the spatial distribution of newly built turbines, as the pricing of energy transport could influence the optimal localisation of electricity production technologies. For instance, higher cable prices may favour the development of generation capacity closer to the demand centres, in all runs the wind turbines are solely built in zone SE3 and SE4; therefore, the ratio between those zones is presented to display allocation differences. Figure 31 shows that the pricing of hydrogen pipelines does not affect the allocation of the wind turbines. It can also be observed that the allocation is sensitive to the pricing of electricity cables. Namely, lower costs result in a higher ratio, which indicates a relatively larger presence of wind turbines in zone SE4 compared to the scenario without cost deviations. Conversely, as cable costs increase, a noticeable shift is seen towards a greater construction of wind turbines in zone SE3. This shows that as costs of cables increase, a shift is observed from more wind turbines being built in zone SE3, which implies more self-reliance as response to the increased transmission costs.

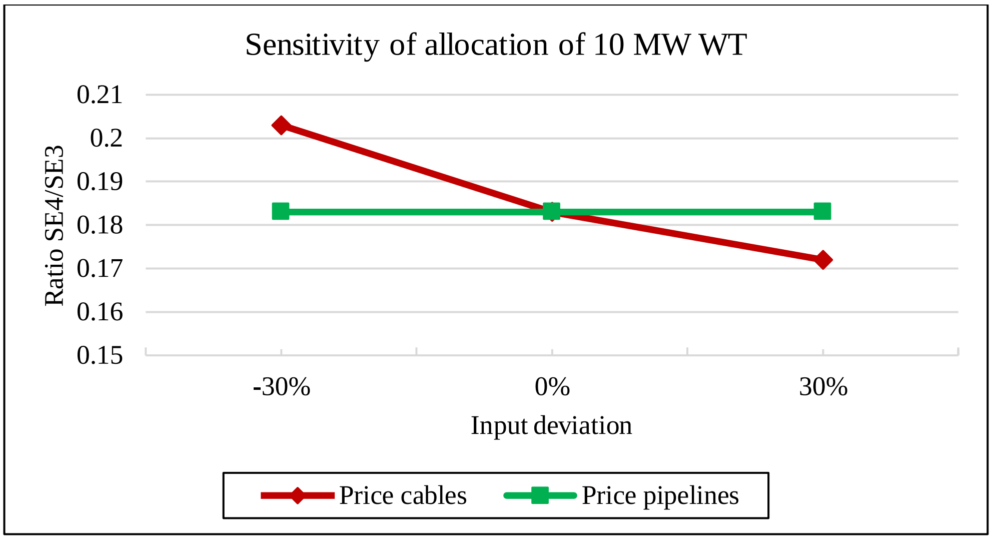


Figure 31: Sensitivity of spatial distribution of 10 MW turbines to the price of cables and the price of pipelines

6. Discussion and Analysis of results

This section presents a comprehensive analysis of the results shown in section 5, and discusses limitations encountered during the process, as well as recommendations for future studies to overcome these. Firstly, a critical review is given on the modelling process and underlying assumptions that may have influenced the model's outcomes. Following that, the findings of scenario A and B are thoroughly discussed, taking into account the realism of the outcomes. Further, a comparative analysis is performed between the two scenarios, to highlight their similarities and differences to answer the research question properly.

6.1 The modelling process and underlying assumptions

The EnergyHub model optimises for total system costs. Therefore, it is heavily dependent on the economic parameters that are assigned to the technologies. Taking into account the timeframe of this study, it needs to be recognised that there is always a degree of uncertainty when forecasting future scenarios. Adding to this, within the scope of this study, it is assumed that costs of technologies are uniform across all zones in Sweden, whereas this may not be true in reality. For instance, the construction and maintenance of wind turbines up North could potentially incur higher costs because of the cold temperatures that they need to be able to withstand. This nuance could influence the model's results and is therefore recommended to investigate further for future research.

Now, some assumptions surrounding hydrogen and electricity data inputs are considered more in depth, to provide better understanding of this study's outcomes and limitations.

For hydrogen, a large uncertainty lays in the predicted hydrogen demand for 2030 including the spatial distribution. The assumptions in this study on the distribution of hydrogen demand across zones were based on rough estimations, so an in-depth study on the future hydrogen demand in Sweden, both at the national and zonal levels, could give valuable insights. Other than that, a definition of Sweden's governmental hydrogen targets in the near future would greatly contribute to this analysis. Another issue is the ambiguity surrounding the economic and technical potential for lined rock cavern hydrogen storage. Sweden leans towards this storage method considering their geographical characteristics (Fossil Fritt Sverige, 2021), but no detailed information could be found regarding costs or feasibility. As a consequence, pressurised tanks are included in this study to facilitate the model's operation, but in reality, this is not considered viable on national scale. Thirdly, this study considers exclusively hydrogen pipelines between zones as they are generally regarded as most favourable and cost-efficient option in Europe (Amber Grid et al., 2022). However, seeing Sweden's current lack of piping infrastructure, the government might consider other transport options, such as road transport in compressed form as is the main mode of hydrogen transport currently (Fossil Fritt Sverige, 2021).

Considering electricity, the demand for 2030 is also subject to uncertainty, including the distribution of electricity usage between different zones. In this study, the demand pattern from 2021 is scaled up uniformly, assuming that this pattern is relatively the same in the future. However, it needs to be recognised that this pattern may change as circumstances evolve. Moreover, this research assumes all electricity to be generated by renewable technologies in 2030, without any injection of fossil fuels. However, Sweden is still in transition towards this goal, thus the true composition of their electricity mix by 2030 remains uncertain. A deviation in this could greatly influence the model's outcomes, as the spatial distribution and capacity of generation technologies and consequential need for transport infrastructure is dependent on these assumptions. The transport infrastructure itself was also not modelled completely corresponding with the real-life situation, as existing transmission networks were not modelled as data inputs but seen as decision variable for the model. Furthermore, the imports and exports of electricity with neighbouring countries are included with a simplified approach in this research and are recommended to be expanded in future research to depict a more complete picture of reality. If the costs and transmission capacities from different countries were not averaged, the model would have more degrees of freedom and might have taken different decisions.

A limitation of the EnergyHub model for the framework applied in this study is that some technologies were not included by default, such as hydropower, nuclear power and pumped hydropower storage. The approaches to include these in the current research are simplified in a way that was feasible within the time limits. It is recommended to add these technologies to the EnergyHub model in a more sophisticated way for future purposes, as this enhances the reliability and realism of the outcomes. Another difficulty was managing the computational time of the model runs. Especially scenario B, with the 50% H_2 demand increase, took approximately 10 hours to yield annual results compared to around 4 hours for scenario A. Occasionally, the outcome was that the model was infeasible, due to the imposed constraints combined with increasing the demand. The prolonged wait for results significantly delayed the following tasks. This implies that modelling a fully renewable system, where base load is already nearly cost-free and increase in demand needs to be met by fluctuating resources and storage, is a challenge to optimise mathematically.

6.2 Scenario A

In this part, the outcomes for scenario A are discussed more in-depth. First, a discussion on installed capacities of technologies that the model decided is provided, to offer valuable insights into their realism.

Starting with hydrogen, the ESM indicates a total installed capacity of 2.4 GW for electrolysers. This seems large initially, but if 5 large scale projects like HYBRIT, Green Wolverine and H_2 Green Steel are realized, there is potential to achieve this (GrupoFertiberia, 2021; *H2 Green Steel*, n.d.; *HYBRIT Demonstration - Hybrit*, 2023). Also, Fossil Fritt Sverige suggests a goal of 3 GW installed capacity of electrolysers for the government by 2030 which is in the same order of magnitude (2021). It is remarkable that SE2, despite having no hydrogen demand, boasts the highest installed capacity of electrolysers with 1.3 GW, as is visualised in Figure 15. This hydrogen is produced to provide for other zones, which causes the large pipeline capacity between zones SE2 and SE3, of 1.16 GW, as Figure 20 depicts. This dynamic aligns with the fact that SE2 has the lowest LCOH, so it is the most cost-efficient location to produce hydrogen. Regarding electrolysis, since SE2 lacks electricity transmission, all electricity required for this is locally generated. This is primarily done by hydropower sources, supplemented by existing 5 MW wind turbines, resulting in the lowest LCOE of all zones. The model's placement of electrolysers is driven by this cost-efficient electricity.

To accommodate the variability of renewable electricity generation technologies, hydrogen storage is necessary since hydrogen demand is assumed constant in this study. The country's total hydrogen storage capacity is determined to be approximately 3 GWh, with SE2 and SE4 containing the majority of storage facilities. This number is not that large compared to the total hydrogen demand, which indicates that most of the produced hydrogen is consumed directly and storage is cautiously being built, to prevent high costs. This means that electrolyser input of electricity needs to be constant, which could explain in turn the large capacities of the battery storage, to compensate the fluctuation of electricity generation. Remarkably, SE3, which exhibits the largest hydrogen demand, primarily relies on hydrogen imports from other nodes, complemented by direct utilisation from local electrolysers, instead of deploying more electrolysers in combination with H_2 storage in its own zone. This could be explained by the fact that hydrogen as well as electricity is more economical in other zones, as can be read from Table 14. Thus, it appears to be more cost-efficient to produce hydrogen with electricity from other zones and transport the hydrogen through pipelines, instead of using locally produced electricity, or transporting electricity to zone SE3 and perform electrolysis locally.

Shifting the focus to electricity, the model builds additional wind turbines in SE3 and SE4 to meet the demand. The total installed capacity of these wind turbines amounts to 204.4 GW, which implies an ambitious plan to achieve the construction of approximately 29.2 GW of wind turbines annually until 2030, when comparing to the built-out of 3 additional Gigawatts per year for 2022 in reality (*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.). However, if governmental permitting and business investments increases significantly, the rate of expansion may yield surprising outcomes. The model's emphasis on SE3 for wind turbine expansion aligns with the zone’s largest demand, followed by SE4 with a corresponding injection of wind turbines. The accompanying large capital expenditures, seen in Figure 21, could partly explain that the LCOE of these zones is significantly larger than the ones of the Northern zones, as Table 14 reveals. Nevertheless, the concentration of new wind turbines in SE3 and SE4 appears unrealistic considering Sweden's focus on less densely populated areas, which happen to be in the North, in contradiction with the model outcomes. In future studies, it is interesting to explore limitations on turbine construction for all zones to impose realistic constraints on the built-out for each zone and increase realism of the model’s outcomes. Factors such as population density in SE1 and SE2, the colder climates in SE1 and SE2 and considerations regarding indigenous lands and nature reserves should be taken into account.

Regarding electricity storage, the model indicates that the vast majority is located in SE3. This aligns with the high penetration rate of wind turbines in SE3, which inherently exhibits variability and necessitates storage solutions. The model decides to construct a large amount of battery in SE3 instead of adding pumped hydro storage to zones SE1 and SE2. This indicates that zone SE3 needs all electricity storage close to the demand, to compensate for its fluctuation. The lack of storage in SE4, whereas this zone also exhibits a high amount of wind energy, can be attributed to the substantially lower local demand, which is partially offset by the additional offshore wind generation which exhibits different fluctuation patterns, and the surplus electricity that is exported to zone SE3 instead of being stored locally. The reported capacity of 214.3 GWh for battery storage in SE3 may initially seem substantial when compared to state-of-the-art battery sizing where one large-scale battery system equals 20 MWh (Smart City Sweden, 2022). However, it is important to realise that when Sweden moves to a fully renewable energy system, storage solutions may inevitably need to attain these high numbers, and storage will be spread out throughout the country.

The model shows limited electricity transmission, only connecting zones SE3 and SE4, as Figure 19 shows. SE1 and SE2 function as autonomous zones meeting their electricity demand through hydropower and existing 5 MW wind turbines, as can be observed from the annual electricity demand balance depicted in Figure 25. The remaining electricity after local demand is met, is exported outside the country or used for electrolysis, rather than exporting to other zones. This diverges from reality, as these zones are interconnected with the rest of the country. To enhance the model’s depiction of reality, deeper investigation into the connections including prices to neighbouring countries is suggested, to eventually reflect a more complete picture of the real situation. It seems to be more economically viable to invest in cost-efficient hydrogen production in zone SE2 rather than providing cheap electricity for the rest of the country. The sizing of the transmission between the zones, amounting to 43 GW, appears unrealistic when comparing to current capacities. The model's decision is most likely based on the fact that electricity costs in SE4 are approximately twice as low as in SE3, and it pays off to install a large amount of transmission capacity, rather than building more wind turbines and producing the electricity locally in SE3. Limiting the interconnection capacity between the nodes could have yielded more realistic results.

When analysing the total system costs in Figure 21, it is obvious that the 10 MW wind turbines are the largest proportion. The dominance of these expenses could be explained by the model's limitation of only allowing the addition of 10 MW turbines as increase of electricity generation, meaning that the investment would simply be necessary. Furthermore, the model's inclusion of a large amount of battery storage capacity in SE3 addresses the variable nature of wind energy generation, so the allocated costs may be inevitable to maintain the hourly dispatch throughout the year. Regarding the LCOE of the zones, the expenses of 10 MW turbines in zones SE3 and SE4 could explain the substantially larger LCOE of those zones compared to Northern zones, where LCOE is extremely low due to (nearly) free technologies, as only OPEX is considered for existing technologies. Despite the discrepancy to real-life LCOEs, the country-level LCOE of the scenarios still approximates realistic costs. This could be explained by the fact that in this model, hydropower, existing wind and nuclear have less costs than reality, but wind energy has higher costs because of the large investment and relatively low CF, so this balances out against each other. The LCOH of 0.43 EUR/kg is significantly smaller compared to reality, which could be explained by the fact that hydrogen is currently produced in a different way, and the expected reduced costs for electrolysers by 2030 incorporated in the model.

Considering technology utilisation degree, it is noteworthy that approximately half of the total electricity is generated by the 10 MW wind turbines, while the contribution from existing 5 MW turbines is significantly smaller (Figure 24). Specifically, the annual electricity generation from the existing 5 MW turbines amounts to 13.31 TWh, whereas the actual electricity generation from wind turbines in Sweden was around 27 TWh in 2021 (*Sweden - Countries & Regions - IEA*, 2023). Examining the capacity factors of the turbines in Table 17, the highest value is observed for 5 MW turbines in SE4, reaching 17.12%. This relatively low capacity factor raises questions about the model's decision to heavily invest in the deployment of new 10 MW turbines when the existing 5 MW turbines are not performing well, especially considering the operational costs of the latter being set to zero, implying cost-free electricity production. To rule out weather conditions as the cause, model runs have been conducted with wind speeds from different locations, but no significant increase in capacity factor was observed. The need to compensate for the large fluctuation of electricity supply due to varying wind speeds could explain the extensive deployment of 10 MW turbines, given the constant hydrogen demand and the variable nature of electricity demand. The built-out of larger turbines is deemed more cost-effective than expanding storage capacities to address this variability. At the same time, the capacity factors for storage are extremely small, implying that the storage is overbuilt. Considering that this energy system consists merely of renewables, the model might lack the necessary flexibility to effectively balance electricity generation and demand fluctuations, leading to underutilisation of storage capacities. This is a questionable result, as the storage facilities are supposed to provide this flexibility for the system. Consequently, further investigation into enhancing the capacity factors of wind turbines and storage facilities is recommended, which was beyond the scope of this study due to time limitations.

Analyzing typical days, it becomes evident that during winter, the higher electricity demand leads to a substantial reliance on imports from surrounding countries. Additionally, batteries and outflow to other nodes play a crucial role in managing overproduction of wind energy. When wind energy production decreases in the second half of the day, withdrawal from storage compensates. In contrast, for a typical summer day that holds lower demand than the winter day, excess wind generation is exported to other countries, accompanied by outflow to other nodes. Moreover, storage plays a larger role on this typical summer day than the typical winter day. This could be explained by electricity being cheaper in summer, which is when hydropower is less available, as this resource is more expensive than nuclear power and existing wind turbines in this model.

In terms of hydrogen production, the input of electricity into the electrolysers remains relatively constant during these typical days, resulting in a stable dispatch for hydrogen storage and transport, as hydrogen demand remains constant. This could differ depending on the day, as can be assumed from the varying pattern in Figure 29. However, the charging and discharging rate is slower for hydrogen storage compared to batteries, so the pattern will not fluctuate as much in one day as is the case for the latter.

6.3 Scenario B

In this section, the results of scenario B are discussed. Some results display similarities with scenario A and entail a comparable explanation. Majorly different results are discussed in-depth, as is done in section 6.2. However, an elaborative explanation and validation for differences and similarities between the scenarios are discussed in the next section, 6.4.

Starting with the feasibility of installed sizes of electrolysers, the sum throughout the zones amounts to approximately 6 GW, which is about three times more than in scenario A. Considering the current announcements on green hydrogen projects that have been mentioned before, this number seems too ambitious to deploy for 2030. If hydrogen demand in Sweden reaches a demand of 18 TWh as is the case in scenario B, it is likely that this demand will partly be met by existing grey hydrogen. The largest installed capacity of electrolysers appears in SE4, which produces hydrogen partly for local use, but mostly to export to SE3, as can be concluded from Figure 26 and the pipeline capacity from SE4 to SE3. The hydrogen demand in SE3 is complemented by imports from SE2 and local production. It is remarkable that SE4 provides such a substantial amount of hydrogen to SE3, considering its relatively high LCOH. The high LCOH can be explained by the large size of hydrogen storage in SE4 which plays a role in the LCOH. Otherwise, it would be expected that the LCOH in SE4 is lower than in SE3, considering the lower electricity price. Comparing the LCOH of SE2 with SE4 from Table 14, it would be more economically viable to import from SE2, but since this is not the case, it must be technically infeasible to generate more hydrogen with the available electricity in SE2. This raises questions about the model's decision to abstain from wind turbine deployment in this zone, but apparently this is still the most cost-efficient option given the model's contextual constraints and data inputs.

The large production of hydrogen in SE4 corresponds with the large storage in this zone. The model decides that it is more cost-efficient to place storage facilities near production, rather than near demand. This could be reasoned by the pipeline capacity being a larger size, thus more costs, if it were to match a fluctuating hydrogen production, whereas this is not the case if the hydrogen is locally stored after production. Then, the export of hydrogen through pipelines needs to match demand, which is constant. Even though hydrogen production is relatively stable compared to electricity production, there is still some fluctuation between hours of the year, looking at Figure 29. It is important to consider that with increasing hydrogen usage in the future, the demand might not only be coming from heavy industries with constant load. Therefore, if hydrogen will be used for other purposes such as transport, it needs to be taken into consideration that the demand profile will be more fluctuating.

Looking into electricity production, the model decides on constructing 10 MW turbines in zones SE3 and SE4, amounting to approximately 180 GW. Even though this is slightly lower than in scenario A, it would still be an ambitious goal to achieve for 2030. Electricity storage is only present to a large extent in SE3, which can be reasoned similarly as in scenario A. When looking at the annual electricity demand balance per zone in Figure 25, as well as the hourly dispatch of a typical day in Figure 27, it can be observed that the patterns are very similar to scenario A, as well as the capacity factors of electricity related technologies, so the dynamics are driven by the same logic.

Moreover, considering economics, similar to scenario A, most budget is dedicated to building 10 MW turbines. The LCOE for each zone is comparable with scenario A, which can be explained by the same factors. The increase in LCOE of SE3 for scenario B can be attributed to the higher battery costs for scenario B compared to A. The LCOH has the highest value in SE4, because of the large addition of electrolysers, that have relatively low CF compared to the electrolysers in Northern zones, as well as the large amount of hydrogen storage. The decrease of CF from the electrolysers in the South could be justified by the penetration of wind energy with its fluctuating nature. The LCOH for the country is, just like scenario A, not comparable to the costs in reality for the same reasons.

6.4 Comparison of scenario A and scenario B

The analysis of both scenarios reveals that with a larger hydrogen demand for scenario B, the technologies for electricity production, storage and transportation show great similarities, including similar dynamics regarding electricity between the zones. This means that the increased need for electrolysis is not so large that it necessitates a major divergent allocation of electricity generation or storage compared to scenario A.

The main differences in the model’s outcomes of the scenarios lays in the configuration of the hydrogen infrastructure. It is remarkable that in both scenarios, the hydrogen demand in SE3 is not produced locally; neither with local electricity nor imported electricity. In scenario A, the major interconnection for hydrogen is from SE2 to SE3. With a 50% increase in hydrogen demand, this pipeline is not enough to supply SE3 with cost-efficient hydrogen. SE4 contains a major number of electrolysers to provide SE3 with its hydrogen demand, but does not require an increased amount of newly built wind turbines compared to scenario A. This could be understood through the trade-off between an enlarged hydrogen demand versus an increased electricity demand. Namely, in both scenarios, electricity production is similar in SE4, but in scenario A excess electricity is used for transporting directly to SE3 for its larger electricity demand, whereas in scenario B this is converted to hydrogen to be directed towards SE3, meeting its heightened hydrogen demand.

The sensitivity analysis in section 5.5 shows that the configuration of electrolysers and hydrogen pipelines is not sensitive to the costs of the pipelines or electricity cables. Even when the costs of pipelines and cables are approximately similar, the model does not adjust the configuration of these technologies, implying that these decisions are rather driven by technological feasibility and costs of other technologies, rather than their own costs. This would enhance the explanation that an increase of electrolysers is deployed in SE4 rather than SE2, despite the latter being more cost-efficient in terms of LCOH. An additional aspect to consider with regarding the model's decision on this matter, is the distance between zones SE2 and SE3 compared to the distance between SE3 and SE4. The latter is shorter, resulting in lower transportation costs, as they increase proportional to the number of kilometers. Consequently, the model prefers to construct additional wind turbines and electrolysers in SE4 for transportation to SE3, rather than executing this in SE2.

Moreover, the installed capacity of electricity cables and spatial allocation of 10 MW turbines does show sensitivity to the price of electricity, though not for hydrogen pipeline costs. With lowered costs, more electricity cables are installed, but the pipeline configuration remains the same. This shows again that the built-out of electricity-related technologies is driven by costs more strongly than for hydrogen-related technologies.

7. Conclusion

In order to answer the research question '*What infrastructure design choices can contribute most cost-effectively towards fulfilling several hydrogen demand scenarios of Sweden, in the year 2030?'*, the EnergyHub model is enriched and run with two hydrogen demand scenarios. In the first scenario, Sweden's electricity demand for 2030 is determined to be 160 TWh with a predicted hydrogen demand of 12 TWh, which represents the less optimistic hydrogen economy. The second, optimistic hydrogen scenario sees an increase of 50% for the hydrogen demand, with corresponding decrease in electricity demand since the large hydrogen utilisation compensates for part of the electrification. It is acknowledged that the demand forecasts are subjected to major uncertainties and require further investigation. Nonetheless, the results of the model runs offer insights into the possible configuration of hydrogen and electricity infrastructure for Sweden in 2030.

A major finding is that for both scenarios, since hydrogen production is expensive in SE3, its demand is met by importing hydrogen from other zones. The built-out of pipelines for transporting hydrogen, which is produced using local electricity, is preferred against enforcing the grid to transfer cost-efficient electricity to SE3 for local electrolysis. This is explained by the lower costs of hydrogen transport compared to electricity transmission, as well as the high LCOE for SE3, which would make the LCOH more expensive than when it is imported including the costs of built-out hydrogen pipelines. Moreover, the results reveal that if hydrogen needs to be transferred through zones, storage is best located by the source of generation, rather than near the demand-site. This minimises the corresponding pipeline costs, as they are then sized to the constant demand rather than the fluctuating production. It needs to be considered that this outcome can be different if hydrogen demand does not have a constant demand profile in the future, as is assumed regarding heavy industries in this study.

Thus, this research reveals that in order to meet hydrogen demand for 2030, expansion of hydrogen pipelines is preferred over re-enforcing the electricity grid. Even in scenario A, with a less optimistic hydrogen economy and increased emphasis on electrification, the model opts for hydrogen pipelines rather than electricity transmission to meet the projected hydrogen and electricity demand for 2030.

It is essential to acknowledge that green hydrogen cannot be produced cost-efficiently without considering the electricity mix that is used for electrolysis and its corresponding costs. In this research it is shown that, even though hydrogen demand is mainly located in SE3, the majority of this demand is met through imported hydrogen, driven by the lower costs of producing hydrogen in other zones, which is in turn driven by the decreased electricity costs in comparison to SE3.

Considering Sweden's announced green hydrogen projects in the Northern parts of the country, it is recommended to investigate how the electricity for electrolysis can be generated most cost-efficiently within the Northern zones locally, as this study shows this to be more economical than transporting electricity into the zone to facilitate electrolysis. However, the outcomes of this research do not show a built-out of additional wind turbines in the North, since the expansion of wind turbines in the Southern zones is not entirely subjected to realistic assumptions. The modelled offshore wind in SE4 also plays a role in this, and further investigation into the cost-efficiency of offshore wind generation in Southern zones in combination with local electrolysers is recommended.

Moreover, research into the limiting factors of wind energy deployment per zone is recommended, including offshore wind which is forecasted to be in the Southern areas. Adding to this, developing the EnergyHub with more accurate models of renewable energy technologies, that were simplified in this study due to time limits, is strongly advised to improve the depiction of reality.

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Appendix

Table 18: Values for technical parameters for existing wind energy

Parameter	Value	Unit	Reference
Installed wind capacity SE1	446	#Turbines	(Swedish Wind Energy Association - Svensk Vindenergi, 2021b)
	2230	MW	
Installed wind capacity SE2	1101	#Turbines	(Swedish Wind Energy Association - Svensk Vindenergi, 2021b)
	5509	MW	
Installed wind capacity SE3	605	#Turbines	(Swedish Wind Energy Association - Svensk Vindenergi, 2021b)
	3026	MW	
Installed wind capacity SE4	380	#Turbines	(Swedish Wind Energy Association - Svensk Vindenergi, 2021b)
	1902	MW	
Rated power wind turbine existing	5	MW	(Swedish Wind Energy Association - Svensk Vindenergi, 2021a)
Hub height wind turbine existing	150	m	
Lifetime wind turbine existing	27	Years	(Danish Energy Agency, 2023)
Rated power wind turbine new	10	MW	(Swedish Wind Energy Association - Svensk Vindenergi, 2021b)
Hub height wind turbine new	200	m	(Swedish Wind Energy Association - Svensk Vindenergi, 2021b)
Lifetime wind turbine new	30	Years	(Swedish Wind Energy Association - Svensk Vindenergi, 2021b)
Lifetime electrolyser	30	Years	(Hannemanns Allé & Møller Thomsen, 2020)
Efficiency electrolyser	69	%	(Hannemanns Allé & Møller Thomsen, 2020)

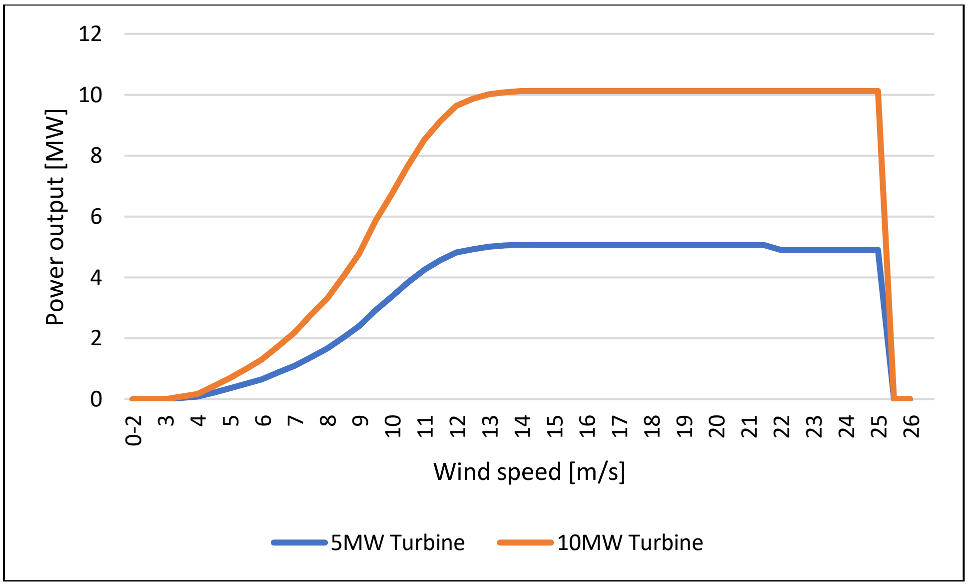

Figure 32: Constructed power curves wind turbines

Table 19: Values for technical parameters for modelling nuclear power

Parameter	Value	Unit	Reference
Installed nuclear capacity SE1	0	MW	(*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.)
Installed nuclear capacity SE2	0	MW	(*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.)
Installed nuclear capacity SE3	6682	MW	(*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.)
Installed nuclear capacity SE4	0	MW	(*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.)
Annual electricity production from nuclear power (2022)	49.9	TWh	(*Energy Year - Annual Statistics - Energiföretagen Sverige*, n.d.)

Table 20: Values for technical parameters for modelling hydropower

Parameter	Value	Unit	Reference
Installed hydropower capacity SE1	5132	MW	(Karin Byman, 2016)
Installed hydropower capacity SE2	7894	MW	(Karin Byman, 2016)
Installed hydropower capacity SE3	1847	MW	(Karin Byman, 2016)
Installed hydropower capacity SE4	0	MW	(Karin Byman, 2016)
Availability hydropower January	58.06	%	(Tang et al., 2021)
Availability hydropower February	55.2	%	(Tang et al., 2021)
Availability hydropower March	53.94	%	(Tang et al., 2021)
Availability hydropower April	44.6	%	(Tang et al., 2021)
Availability hydropower May	47.8	%	(Tang et al., 2021)
Availability hydropower June	37.01	%	(Tang et al., 2021)
Availability hydropower July	35.22	%	(Tang et al., 2021)
Availability hydropower August	37.68	%	(Tang et al., 2021)
Availability hydropower September	41.12	%	(Tang et al., 2021)
Availability hydropower October	41.05	%	(Tang et al., 2021)
Availability hydropower November	46.37	%	(Tang et al., 2021)
Availability hydropower December	48.27	%	(Tang et al., 2021)
Lifetime hydropowerplant	80	Years	(Nordic Energy Research. et al., 2013)

Table 21: Scenario A: hourly hydrogen demand with a national annual demand of 12TWh

	Share of total national hydrogen demand	Hourly hydrogen demand [MW]
SE1	15%	205
SE2	0%	0
SE3	69%	945
SE4	15%	205

Table 22: Scenario B: hourly hydrogen demand with a national annual demand of 18TWh (Scenario A+50%)

	Share of total national hydrogen demand	Hourly hydrogen demand [MW]
SE1	15%	307.5
SE2	0%	0
SE3	69%	1417.5
SE4	15%	307.5

Table 23: Values for technical parameters storage technologies

Parameter	Value	Unit	Reference
Lifetime battery	25	Years	(Danish Energy Agency, 2018)
Charging efficiency battery	98.5	%	(Danish Energy Agency, 2018)
Discharging efficiency battery	97.5	%	(Danish Energy Agency, 2018)
Self-Discharging coefficient battery	0.0042	% per hour	(Danish Energy Agency, 2018)
Maximal charging capacity in one hour battery	50	% of storage capacity	(Danish Energy Agency, 2018)
Maximal discharging capacity in one hour battery	300	% of storage capacity	(Danish Energy Agency, 2018)
Lifetime pumped hydropower storage	50	Years	(Danish Energy Agency, 2018)
Charging efficiency pumped hydropower storage	99	%	(Danish Energy Agency, 2018)
Discharging efficiency pumped hydropower storage	70	%	(Danish Energy Agency, 2018)
Self-Discharging coefficient pumped hydropower storage	0	%/period	(Danish Energy Agency, 2018)
Maximal charging capacity in one hour pumped hydropower storage	85.7	% of storage capacity	(Danish Energy Agency, 2018)
Maximal discharging capacity in one hour pumped hydropower storage	100	% of storage capacity	(Danish Energy Agency, 2018)
Lifetime hydrogen storage	30	Years	(Danish Energy Agency, 2018)
Charging efficiency hydrogen storage	89	%	(Danish Energy Agency, 2018)
Discharging efficiency hydrogen storage	100	%	(Danish Energy Agency, 2018)
Self-Discharging coefficient hydrogen storage	<1	%/period	(Danish Energy Agency, 2018)
Maximal charging capacity in one hour hydrogen storage	5.4	% of storage capacity	(Danish Energy Agency, 2018)
Maximal discharging capacity in one hour hydrogen storage	100	% of storage capacity	(Danish Energy Agency, 2018)

Table 24: Values for technical parameters transmission technologies

Parameter	Value	Unit	Reference
Network losses electricity cables	0.3	%	(Danish Energy Agency, 2021)
Lifetime electricity cables	40	Years	(Danish Energy Agency, 2021)
Energy losses hydrogen pipelines	0.0035	%	(Danish Energy Agency, 2021)
Minimum transport	0.1429	% of rated capacity	Default EnergyHub model
Lifetime hydrogen pipelines	50	Years	(Danish Energy Agency, 2021)

Table 25: Distances between each of the zones to fit the EnergyHub model transmission network

Parameter	Value	Unit	Reference
Distance between SE1 and SE2	455	Km	(Google Maps, 2023)
Distance between SE2 and SE3	516	Km	(Google Maps, 2023)
Distance between SE3 and SE4	279	Km	(Google Maps, 2023)

Table 26: Limit to electricity transmission capacities between each node and neighbouring countries

Parameter	Value	Unit	Reference
Import SE1	2700	MW	(ENTSO-E, 2022a)
Export SE1	2600	MW	(ENTSO-E, 2022a)
Import SE2	850	MW	(ENTSO-E, 2022a)
Export SE2	1300	MW	(ENTSO-E, 2022a)
Import SE3	4060	MW	(ENTSO-E, 2022a)
Export SE3	4010	MW	(ENTSO-E, 2022a)
Import SE4	4315	MW	(ENTSO-E, 2022a)
Export SE4	3915	MW	(ENTSO-E, 2022a)

Table 27: Values for economic parameters for production technologies

Parameter	Value	Unit	Reference
CAPEX existing wind energy	5600000	EUR/module	(Danish Energy Agency, 2023)
OPEX variable existing wind energy	1.5	EUR/MWh	(Danish Energy Agency, 2023)
OPEX fixed existing wind energy	1.25	% of total annual CAPEX	(Danish Energy Agency, 2023)
CAPEX hydropower	2261000	EUR/MW	(Nordic Energy Research. et al., 2013)
OPEX fixed hydropower	2.5	% of total annual CAPEX	(García-Gusano et al., 2016)
CAPEX new wind energy	10400000	EUR/Module	(Danish Energy Agency, 2023)
OPEX variable new wind energy	1.35	EUR/MWh	(Danish Energy Agency, 2023)
OPEX fixed new wind energy	1.21	% of total annual CAPEX	(Danish Energy Agency, 2023)
CAPEX electrolyser	300000-1300000	EUR/MW	(Hannemanns Allé & Møller Thomsen, 2020)
OPEX variable electrolyser	0	EUR/MWh	(Hannemanns Allé & Møller Thomsen, 2020)
OPEX fixed electrolyser	2	% of total annual CAPEX	(Hannemanns Allé & Møller Thomsen, 2020)

Table 28: Values for economic parameters for storage technologies

Parameter	Value	Unit	Reference
CAPEX battery	622000 (435400-808600)	EUR/MWh	(Danish Energy Agency, 2018)
OPEX variable battery	1.8	EUR/MWh	(Danish Energy Agency, 2018)
OPEX fixed battery	2.1	% of total annual CAPEX	(Danish Energy Agency, 2018)
CAPEX pumped hydro (pump part)	600000	EUR/MWh	(Danish Energy Agency, 2018)
OPEX fixed pumped hydro	1.5	% of total annual CAPEX	(Danish Energy Agency, 2018)
CAPEX hydrogen storage	45000 (31500-58500)	EUR/MWh	(Danish Energy Agency, 2018)
OPEX variable hydrogen storage	0	EUR/MWh	(Danish Energy Agency, 2018)
OPEX fixed hydrogen storage	1.1	% of total annual CAPEX	(Danish Energy Agency, 2018)

Table 29: Values for economic parameters for transport technologies

Parameter	Value	Unit	Reference
CAPEX electricity line	2500-3100	EUR/MW/km	(Danish Energy Agency, 2021)
OPEX fixed electricity line	0.6	% of total annual CAPEX	(Danish Energy Agency, 2021)
CAPEX hydrogen pipeline	700-1700	EUR/MW/km	(Danish Energy Agency, 2021)
OPEX fixed hydrogen pipeline	≈0	% of total annual CAPEX	(Danish Energy Agency, 2021)

Table 30: Averaged import and export prices of electricity of neighbouring countries connected to a particular zone

Parameter	Value	Unit	Reference
Import SE1	48.41	EUR/MWh	(Nordpool, 2023)
Export SE1	42.49	EUR/MWh	(Nordpool, 2023)
Import SE2	41.94	EUR/MWh	(Nordpool, 2023)
Export SE2	42.55	EUR/MWh	(Nordpool, 2023)
Import SE3	78.39	EUR/MWh	(Nordpool, 2023)
Export SE3	66.00	EUR/MWh	(Nordpool, 2023)
Import SE4	88.86	EUR/MWh	(Nordpool, 2023)
Export SE4	80.52	EUR/MWh	(Nordpool, 2023)

Table 31: Annual electricity demand balance per zone per scenario

TWh	SE1 A	SE1 B	SE2 A	SE2 B	SE3 A	SE3 B	SE 4A	SE4 B
WT 5 MW	1.95	1.95	5.25	5.36	3.27	3.27	2.85	2.85
WT 10 MW	0.00	0.00	0.00	0.00	86.87	75.81	59.70	62.98
Hydropower	20.72	20.72	31.22	31.42	7.46	7.46	0.00	0.00
Nuclear	0.00	0.00	0.00	0.00	49.90	49.90	0.00	0.00
Battery output	0.00	0.00	0.00	0.00	18.13	13.04	0.42	0.00
Battery input	0.00	0.00	0.00	0.00	-21.31	-15.08	-0.45	0.00
Pumped hydro output	0.00	0.00	0.00	0.00	0.11	0.13	0.00	0.00
Pumped hydro input	0.00	0.00	0.00	0.00	-0.16	-0.18	0.00	0.00
Electrolyser input	-0.28	-0.68	-12.18	-10.84	-3.71	-4.87	-1.31	-10.41
Network outflow	0.00	0.00	0.00	0.00	-26.55	-22.83	-37.65	-32.83
Network inflow	0.00	0.00	0.00	0.00	6.14	5.35	4.33	3.72
Import	0.00	0.00	3.70	1.79	4.51	5.02	3.54	3.37
Export	-9.80	-10.11	-9.66	-10.42	-23.57	-21.60	-22.99	-22.75
Offshore wind	0.00	0.00	0.00	0.00	0.00	0.00	19.74	19.74
Demand	12.59	11.88	18.17	17.15	101.07	95.39	28.17	26.58

Table 32: Annual hydrogen demand balance per zone per scenario

TWh	SE1 A	SE1 B	SE2 A	SE2 B	SE3 A	SE3 B	SE4 A	SE4 B
Electrolyser output	0.19	0.47	8.40	7.48	2.56	3.36	0.90	7.18
Storage output	0.00	0.00	0.09	0.43	0.00	0.00	0.14	2.95
Storage input	0.00	0.00	-0.10	-0.49	0.00	0.00	-0.16	-3.34
Pipeline out	0.00	0.00	-8.39	-8.06	-1.01	-1.34	-0.09	-4.78
Pipeline in	1.60	2.22	0.00	0.64	6.73	10.44	1.00	0.68
Demand	1.80	2.69	0.00	0.00	8.28	12.42	1.80	2.69