THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

Provision of electrolytic hydrogen for the electrification of industry in urban and regional energy systems

SOFIA ROSÉN

Department of Environmental and Energy Sciences

CHALMERS UNIVERSITY OF TECHNOLOGY

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SOFIA ROSÉN

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Department of Environmental and Energy Sciences
Chalmers University of Technology
SE-412 96 Gothenburg
Sweden
Telephone + 46 (0)31-772 1000

Cover: Watercolor painting by the author, illustrating a coastal urban area with hydrogen pipelines and off-shore wind power.

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SOFIA ROSÉN
Department of Environmental and Energy Sciences
Chalmers University of Technology

Abstract

This thesis investigates how urban and regional energy systems are impacted by large-scale industrial electrification supplied with electrolytically produced hydrogen. Three urban areas with hydrogen-intense industries are studied both as a separate energy system and as part of a Swedish region. The municipalities can be connected by investments in hydrogen pipelines, and for the regional scope, hydrogen can also be produced at sites other than the hydrogen demand nodes. Furthermore, three different ways to include gas dynamics when transporting hydrogen through pipelines in energy system optimisation models are evaluated in this thesis.

The future demand for electrolytically produced hydrogen is cost-efficiently met with investments in on-shore and off-shore wind power, over-sized electrolysers, and underground hydrogen storage units. Wind power is complemented with investments in solar PV power, combined heat and power plants, gas turbines, and electricity imports. For the geographical scope investigated, access to electricity import capacity reinforcements or investments in wind power are needed to meet the demand for electrolytic hydrogen in a cost-efficient manner. When neither of these technology options is available, the total system cost is 18% higher than if both are in place. Having access to either electricity import reinforcements or off-shore wind power increases the cost by about 4% compared to not having either option.

In the studied region, investments in pipelines remain cost-efficient under a wide range of assumptions. For the three municipalities, all of which have hydrogen-based industries, investments in pipelines result in more-centralised hydrogen production in the node with good availability of both electricity imports and off-shore wind power. For the regional energy system, investments in pipelines moves hydrogen production to sites with on-shore wind power, although the hydrogen demand node with strong access to both wind power and electricity imports continues to have the largest electrolyser capacity. The possibility to collaborate across the region through hydrogen pipelines reduces the total system cost by 21%, while having both pipelines and power line reinforcements reduces the cost by 23%, as compared to not allowing for either power line reinforcements or pipeline investments.

Including the gas dynamics in the energy system models results in a more-constrained flow of hydrogen, making the pipelines less flexible in terms of how fast the flow can be changed. Moreover, the impact of accounting for the gas dynamics in the energy system configuration is found to be dependent upon the roles of the pipelines. When pipelines provide a way to manage variable hydrogen production based on solar and wind power through rapid changes in the hydrogen flow between municipalities, accounting for the gas dynamics impacts investments in off-shore wind power and electrolysers. In addition, underground hydrogen storage units are distributed such that the municipalities become more self-sufficient. When pipelines primarily provide uni-directional bulk energy, including the gas dynamics in the modelling has a limited impact on production and storage technology investments, as well as pipeline capacities.

Keywords: *Industry electrification, hydrogen, hydrogen pipelines, regional energy systems, municipal energy systems, energy systems modelling*

List of publications

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

I. S. Rosén, L. Göransson, M. Taljegard, M. Lehtveer. (2024). Modeling of a "Hydrogen Valley" to investigate the impact of a regional pipeline for hydrogen supply. *Frontiers in Energy Research*, vol. 12, doi: 10.3389/fenrg.2024.1420224.

II. S. Rosén, L. Göransson, M. Taljegard, M. Lehtveer. (2026). Timely delivery of electricity for industrial hydrogen demands: path dependencies in the transition of urban energy systems. *International Journal of Hydrogen Energy*, vol. 218, doi: 10.1016/j.ijhydene.2026.153975

III. S. Rosén, P. Prianto, L. Göransson, M. Lehtveer, M. Taljegard, N. Mattsson, F. Johnsson. (2026). Electricity and hydrogen grids to facilitate future regional industrial electrification. *Manuscript.*

IV. S. Rosén, P. Sobha, C. Wallmark. Waste heat availability from hydrogen-based industries in district heating systems – a Swedish case study. (2025). *Energy Reports*, vol 14: 432-444, doi: 10.1016/j.egyr.2025.06.028

Sofia Rosén is the principal author of all four papers. Prof. Lisa Göransson, Dr. Maria Taljegard and Dr. Mariliis Lehtveer contributed with method development, discussions and editing to **Papers I**, **II** and **III**. In **Paper III**, Pandu Prianto is co-principal author and contributed equally, Dr. Niclas Mattsson contributed with method development and Prof. Filip Johnsson contributed with discussion and editing. Lic. Parvathy Sobha is co-principal author and contributed equally to **Paper IV.** Dr. Cecilia Wallmark contributed with discussions and editing to **Paper IV.**

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Sofia Rosén
Marstrand, 11th of October, 2026

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Abbreviations

CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage
COP	Coefficient of performance
CHP	Combined heat and power
EB	Electric boiler
EF	Energy flow
GIS	Geographic information system
HOB	Heat only boiler
HP	Heat pump
LRC	Lined rock cavern
LP	Linear programming
MIP	Mixed integer programming
OCGT	Open-cycle gas turbine
PEM	Proton exchange membrane
PV	Photovoltaic
RESYST	Regional Electricity SYSTem
SMR	Steam methane reformer
TIMES	The Integrated Market allocation Energy flow optimisation model System
VGR	Västra Götalandsregionen
VRE	Variable renewable energy
V2G	Vehicle-to-grid

Declaration of generative AI-assisted technologies

In preparing this thesis, AI models (GitHub Copilot and ChatGPT) have been used for help with coding when plotting the results as well as for minor text editing and proof-reading. In **Papers II** and **III** these AI models have been used for help with coding for plotting results and in **Paper III** to translate code form GAMS to Julia. All code, text and figures have been reviewed and verified, and I take full responsibility for the content of this thesis.

1 Introduction

The industrial sector is a leading greenhouse gas (GHG) emitter accounting for 34% of global emissions in Year 2019, when including indirect emissions from power and heat generation [1]. Due to the extraction and production of mainly basic materials, the levels of emissions have been increasing faster since Year 2000 in the industry sector than in any other sector globally. Direct and indirect electrification are emerging as key mitigation options to reduce GHG emissions in industries. Indirect electrification through hydrogen from electrolysis is expected to be an important measure in terms of reducing emissions from hard-to-abate industries [2,3]. Currently, most hydrogen is produced using natural gas and coal, which results in significant emissions, with oil refineries and chemical industries being two of the main consumers of hydrogen [4].

Replacing hydrogen produced from fossil fuels and meeting new demands for hydrogen as a feedstock with electrolytically produced hydrogen would naturally increase the demand for electricity. Since most of the hydrogen demand is currently found at industrial sites [1], the possibility to change from fossil fuel use to electrolysis depends on the ability of the surrounding energy system to provide the required amounts of electricity. Another option could be to move hydrogen production elsewhere, with hydrogen being transported to the industrial sites instead. This means that industrial electrification could affect not only the urban energy system within which the industry is located, but also the surrounding region. Since electrolysers can be flexible in their operation, hydrogen production can be adapted to electricity generation from variable renewable energy (VRE) sources [5,6]. With a hydrogen pipeline grid, areas with good availability of VRE sources could be connected to regions with high demands for hydrogen [7]. Similarly, power line reinforcements could allow for electricity to be moved from production nodes to nodes with high demands for electricity.

1.1 Aim and research questions

This work investigates how the demands for electricity, district heating and hydrogen can be met in cost-efficient manners in urban and regional energy systems with large-scale industry

electrification. In particular, the work aims to understand the roles that electricity and hydrogen distribution grids will have in the regional energy system. The following research questions are addressed:

RQ1. How can the demands for electricity, district heating and hydrogen be supplied in a region that has a high demand for electrolytic hydrogen from industries?

RQ2. What are the roles of the electricity and hydrogen distribution grids in a regional energy system with a high demand for electrolytic hydrogen from industries?

RQ3. How does the level of detail used to model the hydrogen flow in pipelines affect the energy system configuration?

1.2 Scope and contribution

All of the papers appended to this thesis apply techno-economic, cost-optimising models that include demands for electricity, heat and hydrogen. The model results include investments in and dispatches of different generation, storage and distribution technologies, using an hourly time resolution. All of the papers assume large-scale electrification of the industry sector through replacing hydrogen production from natural gas with electrolysis, as well as covering new hydrogen demands. For **Papers I** and **II**, Gothenburg, Stenungsund and Lysekil in Sweden are used as a case study, as they all have hydrogen-based industries and can form a *hydrogen valley*. Oil refineries are located in Gothenburg and Lysekil, and a petrochemical cluster is located in Stenungsund. For **Paper III**, the geographical scope is expanded to include all of the Västra Götaland Region, Sweden. **Paper IV** compares the energy systems of Gothenburg and Gällivare, where the production of sponge iron for production of green steel is expanding.

Paper I introduces a model that represents a hydrogen valley and applies it to three municipalities with large industries that consume hydrogen and that can be connected through pipelines. Previous research mainly studied hydrogen pipelines on the national or continental geographical levels and rarely considered gas dynamics. In this paper, a future year is evaluated and analysed based on total system cost, placement of investments, and operation. Four cases are compared that differ with respect to the possibility to invest in pipelines to connect the three municipalities and the potential to invest in off-shore wind power capacity.

Paper II investigates the impacts of path dependency and timing of investments on the energy transition in three municipalities with hydrogen-based industries. Compared to previous research on this topic, this paper aims to provide an improved understanding on the pathways for urban areas that have high demands for hydrogen and that can be connected with pipelines. Four different pathways to reach carbon neutrality are compared based on the timing of industry electrification in relation to electricity import reinforcements and the possibility to invest in off-shore wind power. The modelled period is 2030–2080, with 5-year steps between Years 2030 and 2050 and 10-year steps between Years 2050 and 2080. Pipeline investments between the studied municipalities are possible.

Paper III investigates the role of distribution grids (power line reinforcements at 130 kV and hydrogen pipelines) in the regional energy transition. Previous studies at the sub-national level, including investments in power line reinforcements and hydrogen pipelines, as well as

production and storage units, have been found to be lacking. In this paper, four cases based on the availability of distribution grids to meet industrial electrification in a regional energy system are compared. One future year is modelled under the assumption that carbon neutrality is reached.

Paper IV investigates the role that waste heat from hydrogen production through electrolysis could play in the local district heating system. While previous studies focused on sector-specific or component-specific interactions, this study looks at the role of waste heat from hydrogen-based industries in two urban energy systems, including industry, residential, commercial and transportation sectors. The study compares the energy systems of Gällivare and Gothenburg.

In the papers included in this thesis, hydrogen pipelines are represented at different levels of detail: binary investments in specific pipeline diameter sizes when considering gas dynamics (MIP); and linear investments in pipeline capacity when considering gas dynamics (LP). Therefore, in this thesis, the impacts of different levels of detail in the representation of gas dynamics on the cost-efficiency of hydrogen infrastructures and regional energy system configurations are investigated and compared to having linear investments in pipeline capacity without considering the gas dynamics, giving an unrestricted energy flow (EF). Figure 1 gives an overview of the appended papers with regards to geographical scope and time horizon. The gas flow method used is indicated in the top-right corner of the boxes when implemented. The work presented in this thesis was conducted for the period of 2021–2026.

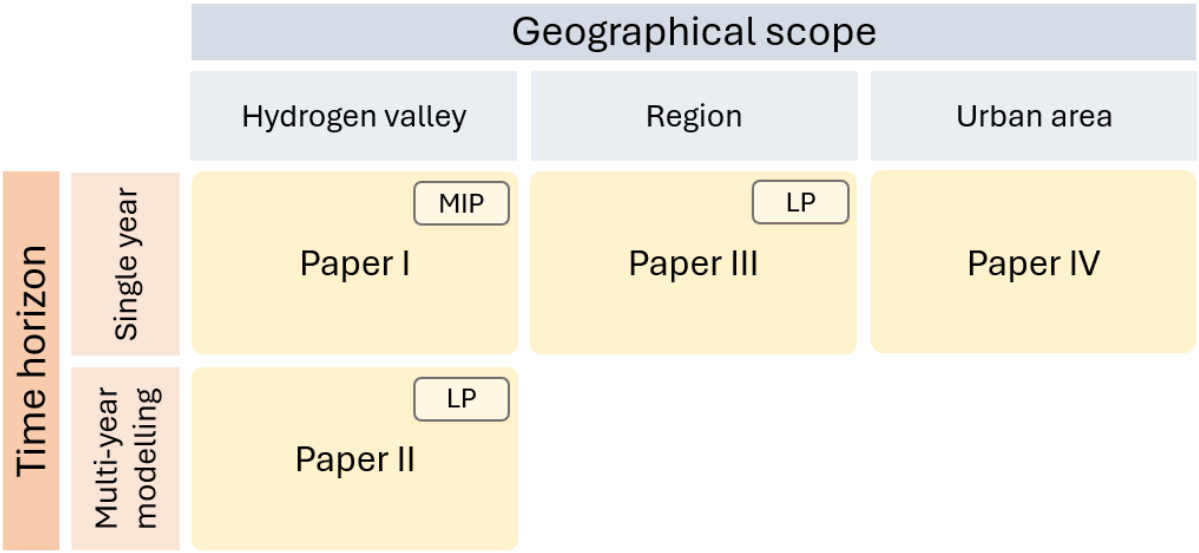


Figure 1. Overview of the four appended papers showing the geographical scope, time horizon, and the method used to represent the hydrogen flows in the pipelines. As two separate nodes, located far from each other, are investigated in **Paper IV**, no pipeline investments are included. LP, linear investments in pipeline capacity when considering gas dynamics; MIP, binary investments in specific pipeline diameter sizes when considering gas dynamics.

1.3 Structure of the thesis

This thesis consists of this introductory thesis and four appended papers. Chapter 1 provides the *Introduction* and *Aim* together with the research questions. Chapter 2 provides the *Background* information relevant to understanding how urban and regional energy systems can be affected by defossilisation of the industrial sector. Chapter 3 summarises previous *Related work* on the role of hydrogen in the energy system transition, how industries can form hydrogen valleys to meet the demand for hydrogen, and the roles of hydrogen and electricity distribution grids in the energy transition. Chapter 4 describes the *Methods* used in the appended papers and thesis, and introduces the models used to investigate the research questions. Chapter 5 presents the main *Results* from the appended papers, as well as additional results focusing on three different methods to model hydrogen flow through pipelines in energy system models. Chapter 6 contains a *Discussion* of the results based on the modelling assumptions, geographical scope, and an outlook on the role of hydrogen in future energy systems. Chapter 7 presents the main *Conclusions* from this work and lastly, Chapter 8 suggests topics for *Future work*.

2 Background

This section gives a brief overview of the challenges that urban and regional energy systems (Sub-section 2.1) face in the light of an expected increase in electricity demand, partly due to the defossilisation of industry (Sub-Section 2.2).

2.1 Urban and regional energy systems

Urban areas are responsible for 70% of global GHG emissions, and close to 10% of the increase in global emissions since Year 2015 can be attributed to urbanisation [8]. Historically, urban areas have imported power that was generated outside the city borders in order to meet the demand for electricity [9]. With electrification acknowledged as an important strategy to achieve carbon neutrality in cities [1,10] and slow power grid expansion to the cities to accommodate the new load, interest in local electricity production has grown [10]. Local electricity production depends on the resources that are available, such as space for solar PV parks and on-shore wind power, as well as the possibility to connect to off-shore wind power. By implementing local flexibility measures, the peak demand for electricity can be reduced. One way for urban areas to balance the demand and supply in relation to electricity is through flexibility markets in which actors can adjust their demands for electricity based on the market.

In this thesis, electrification of industry in urban areas is investigated with the industry-intense Swedish west coast as a case study. In Sweden, electricity is generated from primarily hydro, nuclear and wind power [11]. The country is divided into four electricity bidding zones (SE1–SE4) where hydro power is mostly located in the northern bidding zones (SE1–SE2) and nuclear power in the south (SE3) where most of the electricity demand is located currently. In recent years, the production levels of both solar and wind power have increased. However, wind power is often located at sites that are distant from the regions with the greatest demands for electricity [12]. In particular, with regards to the future demands for electricity from transport and industry, there could be a mismatch between where electricity is produced and where it is needed. Sweden is an example of a country that emphasises the role of sub-national regions (*län*) and municipalities (*kommun*) in achieving climate targets [13]. The Västra

Götaland Region (VGR), located in SE3, had the highest total energy demand and the highest industrial energy demand in Sweden in Year 2024 [11]. Industries located in the region include oil refineries and a petrochemical cluster, as well as ports, and companies involved in Life Sciences, the production of pharmaceuticals, and car manufacturing, among others. For the purpose of this work, oil refineries and the petrochemical cluster are in focus, as the electrification of these industries could result in a substantial increase in the electricity demand, partly for hydrogen production.

For those regions in which the demand for electricity has remained at similar levels for many years, as in the VGR, the electrification of industry and transport could become a major challenge. In Year 2023, only one-third of the electricity demand was met by production within the region, with the remainder imported from the national transmission grid [11,14]. Out of the locally produced electricity, most came from on-shore wind power and hydro power, complemented with CHPs and solar PV power. In the VGR, the future demand for electricity is uncertain, although an increase in the range of 150%–210% has been projected for Year 2045, as compared to the demand in Year 2024, with industry accounting for 60%–70% of the future electricity demand [14]. Since electrification is happening throughout Sweden, it seems unlikely that the future demand for electricity can be met through increased electricity imports to the region [15], and there is a risk for congestion both in the regional grid and for the lines carrying imported electricity on higher voltage level. Industries also provide job opportunities, so it is of interest to facilitate industrial defossilisation so that these industries can remain competitive while maintaining their presence in the region. In light of this, a regional energy agreement with the aim to increase access to electricity through grid reinforcements and local production has been signed [16].

District heating is present in 285 out of Sweden's 290 municipalities and covers about half of the annual heating demand from buildings in the country [17]. The integration of district heating in municipalities have reduced the emissions from the heating sector as biofuels and waste incineration are the main feedstocks. Also, industrial waste heat has a history of being recovered in district heating networks in Sweden and contributed with 5.6 TWh (9%) of the annual district heating supply in Year 2024 [18]. District heating networks are also linked to the electricity system through, for example, combined heat and power (CHP) plants that have contributed with electricity locally.

Some of the municipalities with the largest industries in the VGR are currently dependent upon electricity imported from the regional distribution grid and national transmission grid. For Gothenburg, the largest city in the region, around 90% of the annual electricity supply comes from imported electricity from the regional distribution and national transmission grids [19]. Locally produced electricity came from CHP units, solar PV parks and wind power, and district heating was largely supplied from industrial waste heat (70%) followed by CHP units in Year 2023 [19]. Apart from the expected increase in electricity demand from industries, municipalities such as Gothenburg have their own climate plans [20] in which the electrification of transport is emphasized as a way to reduce local emissions. While it might be overly ambitious for urban areas to meet their future electricity demands locally, it may be possible for the larger region, which benefits from the job opportunities that the urban areas

provide, to host the needed electricity generation plants. Comparing VGR and the three municipalities as a separate energy system in this work, a regional scope opens up for the operation of hydropower and investments in on-shore wind power. Furthermore, the potential for solar PV parks expands when considering a region rather than urban areas, as the region is less densely populated.

2.2 Industrial defossilisation

As mentioned above, the industrial sector accounts for a substantial part of global GHG emissions. In Sweden, the industrial sector stands for 30% of national emissions, out of which oil refineries accounted for 20% and the chemical industry 9% in Year 2024 [21]. Both oil refineries and a chemical cluster are located in the VGR. The oil refineries and chemical cluster are the main consumers of hydrogen in Sweden today and the most-common way to produce hydrogen is using natural gas in steam methane reforming (SMR) plants, which results in significant emissions [22]. The current annual hydrogen demand in the VGR is around 6.4 TWh_{H2} where approximately half is produced through natural gas and the other half is a by-product from industrial processes. Today, hydrogen production is typically located close to the where it is used as a feedstock or fuel [23]. To reduce the dependence on fossil fuels, the demand for low-carbon hydrogen is expected to increase. Alternatives to the current methods are to: use SMR with carbon capture; use biogas in the SMR process; gasification of biomass; or employ electrolysers that use electricity to separate water into oxygen and hydrogen.

In oil refining industries, hydrogen is used to remove impurities from the feedstock and to break hydrocarbon chains. Even though the demand for oil products may decline, this does not necessarily imply a reduction in the hydrogen demand of oil refineries. Firstly, due to regulations that require the use of low-sulphur fuels, hydrogen production per unit of output is instead expected to increase [4]. Secondly, to decarbonise further the value chain, refineries could switch to bio-fuels and/or electro-fuels production, which require hydrogen for their purification and production processes, respectively. With bio-based feedstocks, hydrogen is needed to remove impurities such as oxygen and using bio-based feedstocks in refineries would increase 3–4-fold the demand for hydrogen, as compared to using fossil feedstocks [23]. For electro-fuels, electrolytic hydrogen is combined with carbon that can come from biogenic origin, captured from a point source or from the air [24].

In the chemical cluster studied here, special and basic chemicals, plastics, and biodiesel are produced. Currently, hydrogen is used to produce chemicals and as a fuel together with methane in a steam cracker to process mixed hydrocarbon feedstocks [25,26]. In the future hydrogen could also be important for enabling the circularity of petrochemicals. Today, most plastic waste is either incinerated or undergoes mechanical-thermal recycling, which results in the products having unpredictable rheological properties that limit their applications in packaging and medical products [27]. Another option, which could improve the circularity of plastics, is thermochemical recycling of plastics, whereby both mixed and sorted plastic wastes can be recycled to produce light olefins that can be used for plastics production [28]. In the thermochemical recycling process, hydrogen together with carbon dioxide can be used for the synthesis of olefins [29].

Transitioning from SMR to electrolysis for hydrogen production will increase the demand for electricity locally. However, since electrolysers have the potential to operate in a flexible manner, they can adapt hydrogen production to VRE generation [3,30,31]. Even so, with rapid electrification, there could be a mismatch between the increased demand for electricity and its supply.

3 Related work

The description of related work is divided into the following categories: industrial sector coupling in urban areas (Sub-section 3.1); hydrogen valleys and industrial clusters (Sub-section 3.2); and hydrogen networks (Sub-section 3.3).

3.1 Industrial sector coupling in urban areas

Research on sector coupling in urban areas is a broad topic, and previous research has focused on integration of the electricity, heating and road transport sectors [32–34]. To name some, Heinisch et al. [32] studied the integration of the electricity and heating sectors as well as transport sector [34] in a future year using Gothenburg, Sweden, as a case study under the assumption of carbon neutrality. They used a techno-economic, optimisation model and concluded that a system with low-cost electricity in the form of solar PV resulted in power-to-heat technologies being used in the district heating system. Arabzadeh et al. [33] studied the energy system of Helsinki, Finland, in relation to different decarbonisation strategies. They found that energy storage and sector coupling of power-to-heat and power-to-vehicle enhanced the integration of renewables. Horak et al. [35] investigated long-term energy supply strategies for Vienna, Austria, and found that solar PV became important when there were high costs for imported electricity. In the studies presented so far [32–35], sector coupling with industries in urban areas have not been in focus.

Regarding connections between industries and the electricity, heating and transport systems, Wang et al. [36] studied the decarbonisation of ten cities in China through hydrogen production using electrolysis. The potentials of hydrogen to act as a substitute for fossil fuels in the industry and transportation sectors were calculated. They found that hydrogen was primarily used to decarbonise the transportation sector, as this was the highest-paying sector. Pelda et al. [37] have concluded that, in Germany, there is an un-used potential of industrial waste heat sources within urban borders, and that for some cities, industrial waste heat could supply the entire heating demand. Högnabba et al. [38] compared the district heating systems of Gothenburg, Sweden, and Turku, Finland, using a mixed-integer linear programming approach

with the objective to minimise the total system cost. They found that recovering waste heat from industries with heat pumps was preferred over air-sourced heat pumps, and that thermal tank storage capacity increased with investments in power-to-heat technologies in a majority of the scenarios. So far in refs. [36–38], the connection to the industry sector has been made with regards to hydrogen demand and waste heat from industrial processes. With electrolysis used for hydrogen production, it becomes important to study not only the connection to electricity supply but also the potential use of waste heat.

Some studies have investigated the integration of waste heat from electrolysers in urban energy systems [39–43]. Khaligh et al. [39] studied a system with existing technologies where waste heat from an alkaline electrolyser, as well as hydrogen boilers, could be used in the district heating system. In other studies, van der Roest et al. [40] and Burrin et al. [41] looked at the feasibility of recovering heat from a polymer electrolyte membrane (PEM) electrolyser. All three of these studies [39–41] found that the efficiency of the system increases with the use of recovered waste heat from the electrolysis process. Østergaard et al. [42] have concluded that with more power-to-heat technologies in the district heating system, as well as electrolysers using power, thermal energy storage units become increasingly important as a means to exploit lower-priced hours in the electricity spot market. Meriläinen et al. [43] studied waste heat recovery from an alkaline electrolyser in Finland, and they found that with storage units, waste heat could be recovered during the summer and used in winter-time. Furthermore, based on the hydrogen production capacity estimated by the Finnish transmission system operators (TSOs), all of the district heating demand in Finland could be met with the recovered heat from electrolysis. Common to the presented studies [39–43] is that they rarely included an urban energy system with electricity and heating demands from other sectors, such as transport and industry, but focused mainly on meeting the demand for heating.

3.2 Hydrogen valleys and industrial clusters

Hydrogen is increasingly viewed as a key factor in the decarbonisation of hard-to-abate industries. In recent years, the concept of *hydrogen valleys* has gained traction [44,45]. According to the European Commission, a hydrogen valley exhibits four characteristics: (i) providing supply to various end-sectors; (ii) broad value chain coverage; (iii) a clearly defined geographical scope; and (iv) being large in scale [46]. Supplying various end-sectors means that, ideally, a hydrogen valley should supply hydrogen to several sectors, such as transport and industry, and other energy end-users. Broad value chain coverage means that across their geographical scopes, hydrogen valleys should cover the production, storage, and distribution of hydrogen to off-takers. A clearly defined geographical scope entails covering a specific area, spanning from local to regional, as well as a specific national or international region. Lastly, the size of the hydrogen valley should be greater than one that involves only demonstration activities, and it should typically include several sub-projects as parts of the larger hydrogen valley.

Petrollese et al. [47] investigated a hydrogen valley located in Cagliari, Italy, that encompassed: a power generation unit; a re-fuelling station; injection into the natural gas pipeline; and the production of biomethane. Hydrogen was produced in an electrolysis plant supplied with electricity from a wind farm and/or a solar PV plant, and from the grid. The authors found that

producing hydrogen with electricity from solar PV gave a lower yield, as compared to producing hydrogen with electricity from the wind farm. The study employed a simulation framework in which the sizes of the PV unit, wind farm and electrolyser were inputs to the model. Similarly, Pettinau et al. [48] investigated renewable hydrogen production for the transport sector, assuming an already existing solar PV unit and electrolyser size. Due to flexible operation of the electrolysers, degradation was included, which led to a lower efficiency over time. They found that a levelised cost for hydrogen of between 2.97 €/kg and 4.09 €/kg could be achieved, depending on the revenues accrued from selling oxygen and the over-production of electricity.

Ahmed et al. [49] investigated the case of a hydrogen valley in Crete, Greece, using a mixed-integer linear programming framework. The objective function of the model was to maximise the profit for investors from selling electricity and hydrogen, and the results included the optimal installed capacities for wind and solar power, hydrogen tanks, and electrolyser units. As such, there was no demand for hydrogen, and the model could choose not to invest in an electrolyser if this was cost-efficient. With good access to renewable energy and the possibility to sell to the electricity grid a maximum of 20% of the generated electricity, it was found that investments were made in electrolyser capacity and hydrogen was sold at a profit (at a price of 3.5 €/kg).

Jodry et al. [30] studied how to meet the hydrogen demands from steel-making, refineries, and methanol and chlorine production plants in the port of Fos-sur-Mer in France. They used a bottom-up, techno-economic, optimisation model to identify investments in and the hourly operation of the hydrogen production and storage infrastructure. The study showed that electrolysers assumed an important role in producing low-carbon hydrogen, operating when electricity from solar PV and off-shore wind power was available or when electricity import from the grid was at a low price. Zhang et al. [31] studied how to meet the demands for electricity and hydrogen from the electricity, transport and heating/industry sectors in an isolated region of Australia. To meet the demand for hydrogen, the authors found that both electrolysers and the use of SMR with carbon capture were important technologies for cost-efficiently attaining >80% abatement of emissions, as compared to current emissions levels.

Based on the works found in the literature ([30,31,47–49]), most studies on hydrogen valleys have focused on the generation of electricity solely for hydrogen production. Fewer studies have been performed on how the local energy system, including commercial and residential loads, are affected by the demands for hydrogen. Furthermore, the studies of hydrogen valleys presented above have typically included only one site or region, and they have not included the possibility to transport hydrogen from one site to another using hydrogen pipeline networks. The present work takes into consideration local demands with regards to electricity and heating demands outside the industry sector, as well as hydrogen networks.

3.3 Hydrogen networks

In energy system optimisation models, hydrogen pipelines are used to connect regions with an abundance of VRE to regions that have strong demands for hydrogen [50,51]. Hydrogen systems benefit from being planned as corridor-and-hub networks, rather than as isolated

plants [52]. On a continental level Kountouris et al. [53] studied the development of a hydrogen network in Europe using a fully sector-coupled energy system optimisation model. They found that hydrogen was produced where access to solar PV and wind power was good (e.g., Ireland and Spain) and transported to the demand regions in central Europe. Furthermore, they highlighted the risk of lock-in effects of using SMR with carbon capture and storage (CCS), which would result in long-term dependence on methane. Frischmuth et al. [54] studied a pan-European energy system using two models for energy system planning, including investments in a pipeline network while studying the demand for seasonal hydrogen storage units under cost and market uptake uncertainties. Investments in pipelines in Europe remained, independent of the evaluated hydrogen storage costs. With a high cost of hydrogen storages, investments were made in pipelines to import hydrogen to Central Europe from the Middle East and North Africa region. With a low cost of hydrogen storage units the largest capacity consisted of repurposed pipeline capacity.

On national level, Namazifard et al. [55] studied a low-carbon hydrogen infrastructure for industrial decarbonisation, including a national hydrogen pipeline network, in Belgium for Years 2030 and 2040. They used a mixed-integer linear optimisation model, in which the investments in pipelines were Boolean variables. The study included investments in electrolysers, as well as SMR with carbon capture using natural gas, and the import of ammonia for the supply of hydrogen. In their study, they found that investments in pipelines were robust, and that the hydrogen network represented the smallest fraction of the levelised cost of hydrogen, as compared with investments in electricity generation and hydrogen conversion technologies with corresponding fuels. In later work, Namazifard et al. [56] studied multi-sectoral industrial decarbonisation by modelling competition among hydrogen-based, fossil together with CCS, biomass-based and electrification pathways. They found it cost-optimal to repurpose natural gas pipelines in the cases where green hydrogen routes were chosen but that green hydrogen routs were generally not cost-competitive with biofuel-based or carbon capture-integrated alternatives.

In references [50–55], the hydrogen pipeline network has been modelled without consideration of the gas dynamics when transporting hydrogen through the pipelines. This could lead to weaker investments in hydrogen storage and smaller pipeline diameters than those needed, as the pipelines risk being modelled as overly flexible [57]. Moreover, the line-pack (i.e., the gas stored in the pipeline) of pipelines is often neglected. Wang et al. [58] studied a hydrogen network in a mixed-integer, non-linear investment and dispatch model with the aim of supplying fuels to the transport sector. The model included hydrogen pipelines, hydrogen re-fuelling stations, hydrogen storage units, power-to-hydrogen units, and renewable energy generation. The pipeline implementation included consideration of pressure limits, as well as factors such as the lengths and diameters of the pipelines, although a steady-state flow was assumed. Similarly, Yuan et al. [59] considered the diameters of the pipelines and pressure differences but assumed a steady-state flow. Mendler et al. [60] presented an iterative, non-linear, simulation-based optimisation approach to capturing the non-linear behaviour of the gas dynamics. Shchetinin et al. [57] suggested and evaluated different methods to consider the gas dynamics in pipelines within energy systems models, while maintaining an LP approach.

The combination of electricity grid reinforcements and hydrogen pipelines has also been studied. Neumann et al. [50] compared power grid investments with hydrogen pipeline investments for the European energy system. The most-cost-efficient energy system configuration was found for investments in both power grids and pipelines. With investments in pipelines, wind power-based hydrogen hubs in the north-west of Europe and solar hydrogen hubs in the south were connected to demand nodes located in the centre of Europe. Investments in power grids and pipelines also led to larger investments in hydrogen storages, as compared with only having access to one or none of the distribution grids. Chyong et al. [61] studied a pan-European energy system, divided into 12 regions, using a techno-economic, linear optimisation model with the objective to minimise the total energy system costs, comprising investments and operational costs. They found that rather than trading hydrogen between the regions, the hydrogen balance was managed locally by adjusting production to the demand. Instead, the electricity grid between the regions was expanded. Koenen et al. [62] used an energy system optimisation model to represent the Oost-Groningen region in The Netherlands. They found that the most cost-effective system was a combination of distributed electrolysers, grid reinforcement and connection to the hydrogen transmission grid. Bødal [63] applied a least-cost capacity expansion model to study the relationship between electricity and hydrogen grids, using the State of Texas in the US as a case study. Flexibility obtained from hydrogen production from electrolysis was found to enable larger shares of VRE compared to not having a hydrogen demand. They also found that batteries were favoured over new transmission capacity because of the intermittent production and limited geographical smoothing in the region. Hydrogen pipelines were invested in to connect windy regions to hydrogen demand centres.

The studies carried out on hydrogen networks have a broad geographical scope, ranging from continents [50,51,53,54,61], to national [55] and regional [60,62,63] settings. Of the presented studies, only Shchetinin et al. [57], Mendler et al. [60] and Koenen et al. [62] have taken the gas dynamics and line-pack (the gas stored in pipelines) into consideration, while most studies have assumed that the pipelines operate as pure energy flows, meaning that no restrictions are imposed as to how rapidly the flow in the pipelines can be changed. Furthermore, the line-pack is not included, which disregards an important characteristic of pipelines. This thesis evaluates two different methods to consider the gas dynamics in pipelines in energy optimisation models, a mixed-integer programming (MIP) formulation with binary investments in pipelines, and a linear programming (LP) formulation with linear investments in pipelines, based on the work presented by Shchetinin et al. [57], and it compares the methods to pure energy flow (EF).

4 Method

In this introductory essay and the papers appended to this thesis, the method used is a techno-economic optimisation with the objective to minimise the total system cost. The energy system optimisation model applied in **Papers I**, **II** and **IV** was introduced by Heinisch et al. [32] who used it to study sector coupling in an urban energy system for a given future year. In **Paper I**, the model was developed further to include the energy systems of three municipalities with hydrogen-based industries. The municipalities can be connected with investments in hydrogen pipelines and, thereby, form a hydrogen valley. The pipeline investments and gas dynamics were implemented using a mixed-integer programming (MIP) approach. In **Paper II,** the model used in **Paper I** was refined to include more than one year, starting in Year 2030 and ending in Year 2080. Each modelled year used an hourly time resolution, and every fifth year between Year 2030 and Year 2050 and every tenth year between Year 2050 and Year 2080 were modelled. The time horizon was chosen to include more than one technology life-cycle. Due to the increasing complexity of having more years modelled, the pipeline representation was developed and expressed in completely linear (LP) equations.

In **Paper III** the Regional Electricity SYSTem (RESYST) model, which was first introduced by Prianto et al. [64] and designed to study primarily the power flow in a regional context (130 kV), was used. In the RESYST model, the modelled nodes represent sub-stations in the electricity grid resulting in 126 nodes, and each node has demands for electricity, heating and hydrogen. To calculate the demands for electricity, heating and hydrogen, and the potentials for wind and solar power, the region is split into Voronoi cells based on the sub-stations. The model was developed further to include both investments in power line reinforcements and new hydrogen pipelines, in order to study the relationship between the two distribution alternatives in a regional energy system. In **Paper IV**, two Swedish municipalities (Gällivare and Gothenburg) with hydrogen-based industries and with plans of use electrolysers are compared. Gällivare is modelled using the TIMES framework, adjusted to urban scopes [65] and developed to include a simplified representation of industrial facilities planned to produce sponge iron in Gällivare [66]. The model representing Gothenburg is the same as that used in

Paper I, but with only one municipality modelled. The model was developed further by allowing the option to use waste heat from electrolysis in the district heating network through investment in a dedicated heat pump. The possibility to recover heat from electrolysis was also used in **Paper II**. In this introductory essay, the MIP and LP methods used to model the hydrogen flows in pipelines are compared to using the more-common method of pure energy flow (EF), in which there is no consideration of the gas dynamics.

4.1 Model set-up

Figure 2 gives an overview of the models used in this thesis. Input data to the models include: the hourly demands for electricity, heating and hydrogen for each node modelled; techno-economic parameters, such as costs and efficiencies; and the hourly production profiles for wind and solar PV power. The variables that can be optimized include, among others, capacity investments and hourly operation, which are used to minimize the total system cost. Investments in the distribution of hydrogen are possible in **Papers I–III**, and investments in power line reinforcements are only allowed in **Paper III**. In **Paper I**, investments in hydrogen pipelines are binary and based upon a specified set of diameters, while investments in pipelines are linear in **Papers II** and **III**.

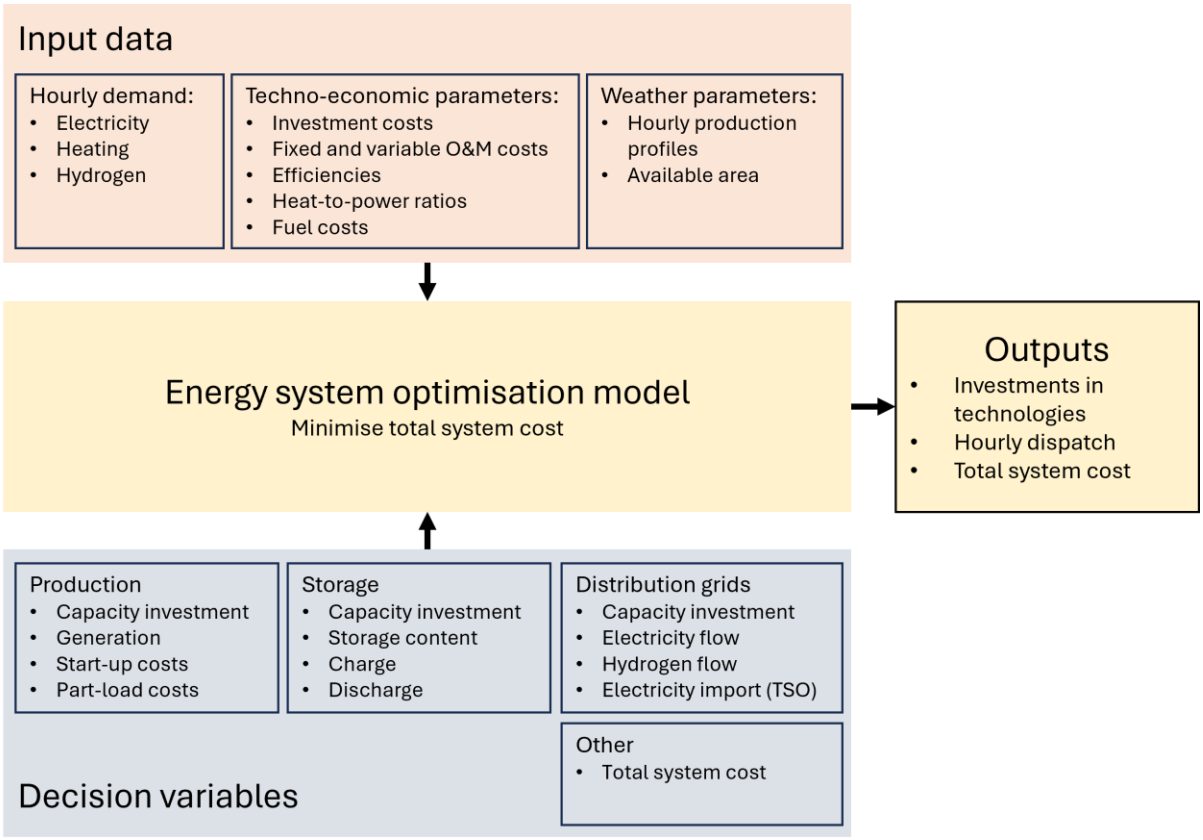


Figure 2. Schematic overview of the model frameworks employed in this thesis. O&M, Operations and Maintenance; TSO, Transmission System Operator.

The model is optimised to minimise the total system cost. For **Paper IV**, only one municipality was modelled to meet the hourly demands for electricity, heat and hydrogen, and the objective

function is shown in Equation (1). In **Paper I**, a set *N* representing the municipalities was added, as was the possibility to trade hydrogen between the municipalities by investing in a set of pipelines using integer investments based on the diameters of the pipelines, as presented in Equation (2). In **Paper II**, a set representing the years modelled was added, and the investment in pipelines was made linear with regards to the maximum capacity of hydrogen transported, as presented in Equation (3). In **Paper III**, the RESYST model is used, and investments can be made in both power line reinforcements and new hydrogen pipelines, as presented in Equation (4). The sets, parameters and variable nomenclature are summarised in Table 1 for the equations presented.

$$MIN\ c^{tot} = \sum_{p \in P} \left(\left(\mathrm{C}_p^{\mathrm{inv}} + \mathrm{C}_p^{\mathrm{OM_{fix}}} \right) * i_p + \sum_{t \in T} \left(\mathrm{C}_p^{\mathrm{run}} * g_{p,t} \right) \right) + \sum_{t \in T} \mathrm{C}_t^{\mathrm{el}} w_t \tag{1}$$

$$\begin{aligned} MIN\ c^{tot} = \sum_{p \in P} \sum_{n \in N} \Bigg(& \left(\mathrm{C}_p^{\mathrm{inv}} + \mathrm{C}_p^{\mathrm{OM_{fix}}} \right) * i_{n,p} + \sum_{t \in T} \left(\mathrm{C}_p^{\mathrm{run}} * g_{n,p,t} \right) \Bigg) \\ & + \sum_{t \in T} \sum_{n \in N} \mathrm{C}_t^{\mathrm{el}} w_{n,t} + \sum_{l \in L} \sum_{d \in D} \mathrm{C}_{l,d}^{\mathrm{pipe}} * r_{l,d} \end{aligned} \tag{2}$$

$$\begin{aligned} MIN\ c^{\mathrm{tot}} = \sum_{y \in Y} \Bigg(& \Bigg(\sum_{p \in P} \sum_{n \in N} \left(\left(\mathrm{C}_{y,p}^{\mathrm{inv}} + \mathrm{C}_p^{\mathrm{OM_{fix}}} \right) * i_{n,p,y} + \sum_{t \in T} \left(\mathrm{C}_p^{\mathrm{run}} * g_{n,p,y,t} \right) \right) \\ & + \sum_{n \in N} \sum_{t \in T} \mathrm{C}_t^{\mathrm{el}} w_{n,y,t} + \sum_{l \in L} \mathrm{C}_l^{\mathrm{pipe}} * e_{l,y}^{\max} \Bigg) * \frac{1}{(1+r)^{y - \mathrm{Y_{start}}}} \Bigg) \end{aligned} \tag{3}$$

$$\begin{aligned} MIN\ c^{tot} = \sum_{p \in P} \sum_{n \in N} \Bigg(& \left(\mathrm{C}_p^{\mathrm{inv}} + \mathrm{C}_p^{\mathrm{OM_{fix}}} \right) * i_{n,p} + \sum_{t \in T} \left(\mathrm{C}_p^{\mathrm{run}} * g_{n,p,t} \right) \Bigg) \\ & + \sum_{t \in T} \sum_{n \in N} \mathrm{C}_t^{\mathrm{el}} w_{n,t} + \sum_{l \in L} \mathrm{C}_l^{\mathrm{pipe}} * e_{l,y}^{\max} + \sum_{j \in J} \mathrm{C}_j^{\mathrm{reinforce}} * s_j \end{aligned} \tag{4}$$

The demands for electricity, heating and hydrogen need to be met for every hour of the modelled years. In Equation (5), the electricity balance is presented based on the sets used in **Paper II**. Apart from the fixed hourly demand for electricity ($\mathrm{D}_{n,y,t}^{\mathrm{el}}$), the demand side of the equation considers the charging of batteries and electric vehicles, electricity for heating purposes and hydrogen production, electricity for compressing hydrogen, and electricity for compressing the hydrogen that is transported in pipelines. The supply side has electricity generation from new investments, electricity generation from existing technologies, discharge of batteries and electric vehicles, and electricity imports from the national transmission grid.

$$\begin{aligned} & \mathrm{D}_{n,y,t}^{\mathrm{el}} + \sum_{p \in \mathrm{P_{ElSt}}} z_{n,p,y,t}^{\mathrm{ch}} + \sum_{e \in \mathrm{E}} EV_{n,e,y,t}^{\mathrm{ch}} + \sum_{p \in \mathrm{P_{PtH}}} \frac{g_{n,p,y,t}}{\eta_{\mathrm{p}}} + \sum_{p \in \mathrm{P_{H2}}} g_{n,p,y,t} + \sum_{p \in \mathrm{P_{H2St}}} \mathrm{K} \cdot z_{n,p,y,t}^{\mathrm{ch}} \\ & \quad + o_{n,y,t} \\ & \quad \leq \sum_{p \in \mathrm{P_{El}}} g_{n,p,y,t} + \sum_{p \in \mathrm{P_{ExE}}} y_{n,p,y,t} + \sum_{p \in \mathrm{P_{ElSt}}} z_{n,p,y,t}^{\mathrm{dch}} + \sum_{e \in \mathrm{E}} EV_{n,e,y,t}^{\mathrm{dch}} + w_{n,y,t} \end{aligned} \tag{5}$$

The hydrogen balance is presented in Equation (6), where the hourly fixed hydrogen demand and charging of storage units is on the demand side, while generation from electrolysers, discharge of hydrogen storage units, and imported hydrogen constitute the supply side.

$$\mathrm{D}^{\mathrm{H2}}_{n,y,t} + \sum_{p \in \mathrm{P_{H2St}}} z^{\mathrm{ch}}_{n,p,y,t} \leq \sum_{p \in \mathrm{P_{H2}}} g_{n,p,y,t} * \eta_{\mathrm{p}} + \sum_{p \in \mathrm{P_{H2St}}} z^{\mathrm{dch}}_{n,p,y,t} + \sum_{l \in \mathrm{L}} e_{l,k,y,t} \tag{6}$$

The heating balance is presented in Equation (7). The demand side contains a fixed hourly demand for heating and charging of heating storage units. The supply side contains the generation from new and existing heating technologies, discharge from heating storage units, and a waste heat profile based on industrial waste heat.

$$\mathrm{D}^{\mathrm{heat}}_{n,y,t} + \sum_{p \in \mathrm{P_{HSt}}} z^{\mathrm{ch}}_{n,p,y,t} \leq \sum_{p \in \mathrm{P_{H}}} g_{n,p,y,t} + \sum_{p \in \mathrm{P_{ExH}}} y_{n,p,y,t} + \sum_{p \in \mathrm{P_{CHP}}} \frac{g_{n,p,y,t}}{\alpha_{\mathrm{p}}} + \sum_{p \in \mathrm{P_{HSt}}} z^{\mathrm{dch}}_{n,p,y,t} + \mathrm{Q}_{n,y,t} \tag{7}$$

4.2 Modelling of hydrogen flow in pipelines

In this thesis, three different methods to describe the gas flows in pipelines are compared. The methods differ with regards to the gas dynamics, in that the first method, *Energy Flow (EF)*, does not consider the gas dynamics at all, the second method, *Linear investments with gas dynamics (LP)*, considers the gas dynamics while keeping the invested-in capacity of the pipelines linear, and the third method, *Binary investments with gas dynamics (MIP)*, considers the gas dynamics but with a fixed set of pipeline capacities and with individual constants to describe the gas flow. The latter two methods are based on the work of Shchetinin et al. [57], who have concluded that a simplification of the pipeline gas dynamics results in lower investments in pipeline capacity and hydrogen storage owing to over-estimation of the flow flexibility. To consider the gas dynamics of the pipelines, each pipeline is divided into three segments (I), as visualised in Figure 3.

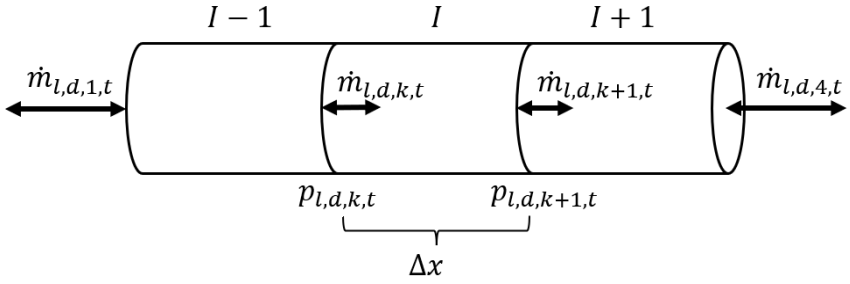


Figure 3. Pipeline divided into three segments.

Table 1. Nomenclature for Equations (1)-(29).

Sets	
P	Set of technologies
$\mathrm{P_{ElSt}}$	Subset to *P* including all electricity storage technologies
$\mathrm{P_{PtH}}$	Subset to *P* including all power-to-heat technologies
$\mathrm{P_{H2}}$	Subset to *P* including all hydrogen production technologies
$\mathrm{P_{H2St}}$	Subset to *P* including all hydrogen storage technologies
$\mathrm{P_{El}}$	Subset to *P* including all electricity generating technologies
$\mathrm{P_{ExE}}$	Subset to *P* including all pre-existing technologies
$\mathrm{P_{HSt}}$	Subset to *P* including all thermal energy storage technologies
$\mathrm{P_{CHP}}$	Subset to *P* including all CHP technologies
E	Set of vehicle types
T	Set of time-steps
N	Set of municipalities
L	Set of pipeline connections
D	Set of pipeline diameters sizes
Y	Set of years
K	Set of pipeline cross-sections
I	Set of pipeline segments
J	Set of power lines
Parameters	
$\mathrm{C^{tot}}$	Total system cost to be minimised [M€]
$\mathrm{C_p^{inv}}$	Investment cost for technology *p* [M€/GW]
$\mathrm{C_p^{OM_{fix}}}$	Fixed O&M costs for technology *p* [M€/GW]
$\mathrm{C_p^{run}}$	Running costs, including fuel costs, for technology *p* [M€/GWh]
$\mathrm{C_t^{el}}$	Cost to import and export electricity from the national grid in time-step *t* [M€/GW]
$\mathrm{C_{l,d}^{pipe}}$	Investment cost for hydrogen pipelines, including compressors for pipeline connection *l* with diameter size *d* [M€]
$\mathrm{C_j^{reinforce}}$	Cost of reinforcing the regional power line *j* [M€/GVA]
$\mathrm{D_{n,y,t}^{el}}$	Hourly electricity demand in node *n* for year *y* and time-step *t* [GWh/h]
$\mathrm{D_{n,y,t}^{H2}}$	Hourly hydrogen demand in node *n* for year *y* and time-step *t* [GWh/h]
$\mathrm{D_{n,y,t}^{heat}}$	Hourly heating demand in node *n* for year *y* and time-step *t* [GWh/h]
$\mathrm{\eta_p}$	Efficiency of technology *p* [-]
$\mathrm{\alpha_p}$	Power-to-heat ration [$\mathrm{GWh_{el}/GWh_{heat}}$]
$\mathrm{Q_{n,y,t}}$	Hourly waste heat profile in node *n* for year *y* and timestep *t* [GWh/h]
c	Speed of sound [m/s]
$\mathrm{\Delta t}$	Seconds in an hour [s/h]
A	Area [$\mathrm{m^2}$]
$\mathrm{f_d}$	Friction coefficients [-]
$\mathrm{\Delta x}$	Length of pipeline segment [m]
$\mathrm{a_{l,d}}$, $\mathrm{b_{l,d}}$, $\mathrm{c_{l,d}}$	Coefficients to describe plane fitting of the momentum equation [ms]
$\mathrm{\Delta P^{max}}$	Allowed pressure difference in a cross-section between two consecutive hours [Pa]
$\mathrm{V_{l,d}^{max}}$	Maximum line-pack for pipeline connection *l* with diameter *d* [GWh]
$\mathrm{p^{max/min}}$	Maximum and minimum pressures allowed in pipeline [Pa]
d	Diameter of pipeline [m]
L	Length of pipeline [m]

Table 1. (Continued) Nomenclature for Equations (1)-(29).

$\mathrm{LHV_{H2}}$	Lower heating value of hydrogen [kWh/kg]
Variables	
i_p	Capacity of technology *p* in which there is investment [GW]
$g_{p,t}$	Generation of technology *p* in time-step *t* [GWh/h]
w_t	Imported or exported electricity in time-step *t* [GWh/h]
$y_{p,t}$	Generation of pre-existing technology *p* in time-step *t* [GWh/h]
$r_{l,d}$	Binary investment in pipeline connection *l* with diameter *d* [-]
e_l^{max}	Maximum hydrogen flow in pipeline connection *l* [GWh/h]
s_j	Investment in power line reinforcements [GVA]
$z_{n,p,y,t}^{\mathrm{ch/dch}}$	Charging and discharging of storages in node *n* for storage technology *p*, in year *y* and time-step *t* [GWh/h] [GWh/h]
$EV_{n,e,y,t}^{\mathrm{ch/dch}}$	Charging and discharging of electric vehicles in node *n* for vehicle type *e*, in year *y* and time-step *t* [GWh/h]
$o_{n,y,t}$	Electricity for compression of hydrogen in node *n* for year *y* and time-step *t* [GWh/h]
$e_{l,d,k,t}$	Hydrogen flow in pipeline connection *l* with diameter *d* in segment *k* for time-step *t* [GWh/h]
$p_{l,d,k,t}$	Pressure in pipeline connection *l* with diameter *d* in segment *k* for time-step *t* [Pa]
$\dot{m}_{l,d,k,t}$	Mass flow in pipeline connection *l* with diameter *d* in segment *k* for time-step *t* [kg/s]
$v_{l,d,t}$	Line-pack in pipeline connection *l* with diameter *d* for time-step *t* [GWh]
v_l^{max}	Maximum line-pack in pipeline connection *l* [GWh]

The changes in pressure and mass flow between the cross-sections are modelled using the Euler equations, assuming isothermal gas flow through a horizontal pipeline. The Euler differential equations for the conservation of mass and momentum are shown in Equation (8) and Equation (9), respectively.

$$\frac{\partial \rho}{\partial t} = -\frac{\partial (\rho u)}{\partial x} \tag{8}$$

$$\frac{\partial (\rho u)}{\partial t} + \frac{\partial (\rho u^2 + c^2 \rho)}{\partial x} = -f_d \frac{\rho u |\rho u|}{2 d \rho} \tag{9}$$

By discretising the Euler equations in both space and time, Equation (8) can be expressed as Equation (10) and Equation (9) as Equation (11):

$$p_{l,d,k,t} + p_{l,d,k+1,t} - p_{l,d,k,t-1} - p_{l,d,k+1,t-1} = \frac{2\mathrm{c}^2 \Delta \mathrm{t}}{\mathrm{A} \Delta \mathrm{x}} \left(\dot{m}_{l,d,k,t} - \dot{m}_{l,d,k+1,t} \right) \tag{10}$$

$$\left(p_{l,d,k,t}\right)^2 - \left(p_{l,d,k+1,t}\right)^2 = \frac{\mathrm{f_d c}^2 \Delta \mathrm{x}}{4 \mathrm{d A}^2} \left(\dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t}\right) \left| \dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t} \right| \tag{11}$$

Equation (10) is now linear and can be implemented in the modelling framework, while Equation (11) remains non-linear and needs further adjustments. To linearise Equation (11), the mean mass flow's dependency on a pressure difference between two cross-sections was

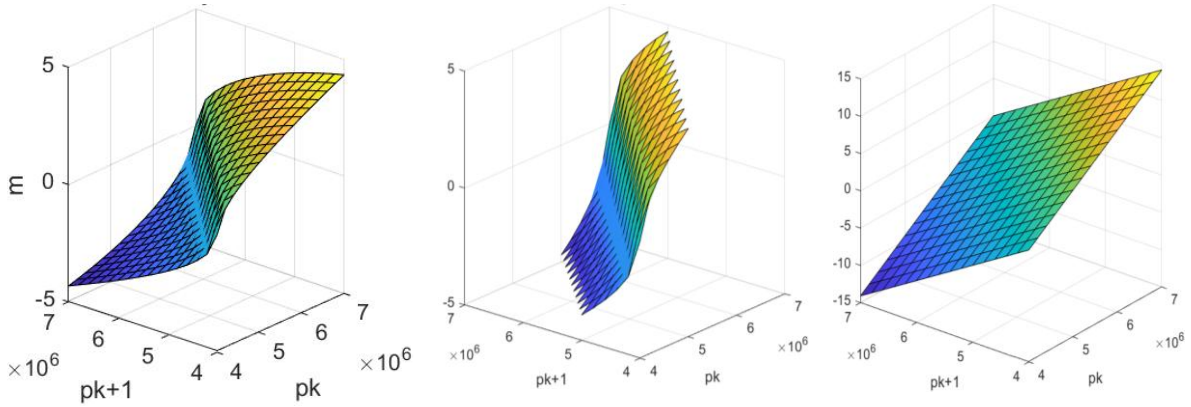
calculated in MATLAB. The mean mass flow is derived from Equation (11) and gives the expression presented in Equation (12):

$$\frac{\dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t}}{2} = \sqrt{\frac{\mathrm{dA}^2}{\mathrm{f_d c}^2 \Delta \mathrm{x}} \left(\left(p_{l,d,k,t}\right)^2 - \left(p_{l,d,k+1,t}\right)^2 \right)} \tag{12}$$

From Equation (8), and with the plane-fitting in MATLAB, the following three coefficients are retrieved that describe the plane: $a_{l,d}$, $b_{l,d}$ and $c_{l,d}$. As can be seen from Equation (12), the coefficients are dependent upon the allowed pressure difference in the pipeline (here, 40–70 bar), the number and lengths of the segments, and the diameter of the pipeline, indicating that these parameters are specific to each pipeline. While the diameter size of the pipeline is included as an investment option to yield different hydrogen flow capacities, it is assumed that the length of each pipeline connection is known. Using the coefficients retrieved from the plane fitting of Equation (12), it can now be expressed as in Equation (13):

$$\dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t} = \mathrm{a}_{l,d} * p_{l,d,k,t} + \mathrm{b}_{l,d} * p_{l,d,k+1,t} + \mathrm{c}_{l,d} \tag{13}$$

In Figure 4 the process going from Equation (11) to Equation (13) is visualized where: (a) is Equation (7) but for the whole pipeline length; (b) shows Equation (7) when the pipeline is divided into three segments; and (c) shows the plane as described through Equation (9). For Figure 4, a diameter of 0.2 m and a pipeline length of 50 km are assumed. Since no flow will occur when the pressure difference is zero and the relationship between the mass flow and pressure is symmetrical in the pipeline, the last coefficient ($c_{l,d}$) will always take the value of zero. Similarly, due to symmetry, $a_{l,d}$ and $b_{l,d}$ have the same value, although one is positive ($a_{l,d}$) and the other is negative ($a_{l,d} = -b_{l,d}$).



(a) (b) (c)

Figure 4. (a) Equation (7) but with the full length (L) of the pipeline, (b) Equation (7) as written, (c) shows the plane using Equation (9). A diameter (d) of 0.2 m is assumed as well as a length (L) of 50 km.

The mass flow (kg/s) is expressed as an energy flow ($\mathrm{GWh_{H2}/h}$), as shown in Equation (14), and is added to the hydrogen balance.

$$e_{l,d,k,t} = \mathrm{LHV_{H2}} * \dot{m}_{l,d,k,t} * \Delta \mathrm{t} \tag{14}$$

Another characteristic captured by the more-extensive representation of the gas dynamics is the possibility to analyse the *line-pack*. The line-pack represents the energy stored in the pipeline, as the hydrogen flow entering the pipeline does not necessarily correspond to the hydrogen exiting the pipeline during the same time-step. The difference between the in-flow and out-flow of hydrogen is described by Equation (15), and this gives the line-pack of the pipeline. Lastly, the pressure difference in a cross-section between two time-steps can be restricted, as expressed by Equation (16).

$$v_{l,d,t} = v_{l,d,t-1} + e_{l,d,1,t} - e_{l,d,4,t} \tag{15}$$

$$\left|p_{l,d,k,t} - p_{l,d,k,t-1}\right| \leq \Delta \mathrm{P}^{\max} \tag{16}$$

4.2.1 Binary investments with gas dynamics (MIP)

Equations (10) and (13)-(16) serve as the basis for the MIP formulation used in **Paper I**. The binary value, $i_{l,d}$, is included in the objective function, and is used to limit the flow of hydrogen by limiting the allowed pressure in each pipeline segment, as presented in Equation (16). Furthermore, the binary variable limits the line-pack, as described in Equation (18). The maximum line-pack for each pipeline diameter size and connection is calculated using Equation (19). In total, Equations (10), (13)-(19) are included in the MIP approach.

$$i_{l,d} * \mathrm{P}^{\min} \leq p_{l,d,k,t} \leq i_{l,d} * \mathrm{P}^{\max} \tag{17}$$

$$v_{l,d,t} \leq i_{l,d} * V_{l,d}^{\max} \tag{18}$$

$$V_{l,d}^{max} = \frac{2 * \mathrm{L} * \mathrm{A}}{3 * \mathrm{c}^2} * (\mathrm{P}^{\max} - \mathrm{P}^{\min}) * \mathrm{LHV}_{\mathrm{H2}} \tag{19}$$

4.2.2 Linear investments with gas dynamics (LP)

Until now, all the equations describing the gas flow in pipelines have been expressed with the sets used in the MIP formulation, where *l* represents the set of pipelines between two nodes, *d* is the set of diameters, *k* is the number of segments, and *t* is the time-step. As for the LP formulation of the gas flow, the set of diameters is no longer included, but instead the parameters specific to a pipeline (d, A, $a_{l,d}$, $b_{l,d}$ and $c_{l,d}$) are based on a "typical" pipeline, in accordance with the work of Shchetinin et al. [57]. Naturally, some of the equations are affected by this formulation. In the MIP gas dynamics formulation, $a_{l,d}$, $b_{l,d}$ and $c_{l,d}$, as well as the maximum line-pack can be calculated for each pipeline diameter size, whereas here, the implementation cannot rely on pre-determined parameters based on several specific diameters. This means that Equations (10) and (13) are updated to Equations (20) and (21). Furthermore, the maximum flow is calculated with Equation (22).

$$p_{l,k,t} + p_{l,k+1,t} - p_{l,k,t-1} - p_{l,k+1,t-1} = \frac{2c^2 \Delta t}{A \Delta x} \left(\dot{m}_{l,k,t} - \dot{m}_{l,k+1,t}\right) \tag{20}$$

$$\dot{m}_{l,k,t} + \dot{m}_{l,k+1,t} = 2a_l^1 * p_{l,k,t} + 2b_l^2 * p_{l,k+1,t} + c_l^3 \tag{21}$$

$$e_l^{max} \geq e_{l,k,t} \tag{22}$$

The hydrogen stored in the pipeline is expressed by Equation (23). Unlike the MIP formulation, where the maximum line-pack is calculated for each pipeline diameter size and length of connection, the LP formulation restricts the maximum line-pack through a number of linear constraints, as expressed by Equation (21). The *k* and *m* values are based on the relationship between the maximum energy flow, ${E_{l,d}}^{max}$ from Equation (25), and the maximum line-pack, $V_{l,d}^{max}$ from Equation (26). The ${E_{l,d}}^{max}$ and $V_{l,d}^{max}$ parameters are calculated using different pipeline diameters. Still, it is assumed that the lengths of the different pipeline connections are known. Overall, Equations (10), (14) and (20)–(24) are included in the LP approach.

$$v_{l,t} = v_{l,t-1} + e_{l,1,t} - e_{l,4,t} \tag{23}$$

$$v_l^{max} \leq \begin{matrix} k_1 \\ \dots \\ k_4 \end{matrix} * e_l^{max} + \begin{matrix} m_1 \\ \dots \\ m_4 \end{matrix} \tag{24}$$

$$E_{l,d}^{max} = \sqrt{\frac{d * A^2}{f_d * c^2 * L}} * \Delta T * \left(P^{max} - P^{min}\right) * LHV_{H2} \tag{25}$$

$$V_{l,d}^{max} = \frac{2 * L * A}{3 * c^2} * (P^{max} - P^{min}) * LHV_{H2} \tag{26}$$

4.2.3 Linear investments with pure energy flow (EF)

When gas dynamics are not considered, the hydrogen exported from one node corresponds to the hydrogen imported into another node, without any capture of the line-pack or gas dynamics. This means that the equations differ from those used in the previous two methods, and the new ones are listed as Equations (27)–(29). As can be seen in these equations, this method is based on having two similar sets corresponding to the import and export nodes (n and n_2), rather than having a set for the pipeline and subsequently connecting the flows in and out of the pipeline to each connected node. Similar to the previous methods, the electricity consumption per hour linked to transporting hydrogen is calculated using a positive variable that needs to be larger than or equal to the hydrogen exported multiplied by a factor that represents the electricity demand. Thus, Equations (23)–(25) are included in the EF model approach.

$$e_{n,n_2,t} = -e_{n_2,n,t} \tag{27}$$

$$e_{n,n_2}^{max} = e_{n_2,n}^{max} \tag{28}$$

$$e_{n,n_2,t} \leq e_{n,n_2}^{max} \tag{29}$$

4.2.4 Comparison of gas flow methods

The three methods described in the previous sections were compared using the following parameters:

- Maximum hydrogen flow
- Hourly flow patterns
- Investments in storage and generation technologies
- Computational time

Furthermore, the results were evaluated by changing critical parameters in the LP formulation, such as the allowed pressure difference between hours (ΔP) and diameters (d) used to calculate the coefficients ($a_{l,d}$, $b_{l,d}$ and $c_{l,d}$) that express non-linear Equation (7) as a plane. This becomes even more important for the LP formulation of the gas flow, since the coefficients ($a_{l,d}$, $b_{l,d}$ and $c_{l,d}$) are calculated for a "typical" pipeline, rather than being specific for each pipeline size, as is the case with the MIP formulation.

4.3 Scope and data

Figure 5 gives the geographical scope of the appended papers. **Papers I** and **II** cover Gothenburg, Stenungsund and Lysekil, three municipalities located on the west coast of Sweden that have hydrogen-based industries. Gothenburg and Lysekil have oil refineries and Stenungsund has a petrochemical industry cluster. In **Paper III**, the geographical scope is expanded to include all of the VGR as marked in Figure 5. In **Paper IV**, the municipalities of Gothenburg and Gällivare are compared using two different energy system models.

Gothenburg is the second-largest city in Sweden with an annual demand for electricity of 4.5 TWh in Year 2023, where the industry sector accounted for 35% of the electricity demand [11]. Stenungsund and Lysekil are smaller municipalities with annual electricity demands of 1.8 TWh and 0.7 TWh, respectively, and the industry sector accounts for 51% and 79%, respectively, of the electricity demand. The VGR has an annual electricity demand of around 18 TWh and is currently the region with the largest industrial sector in Sweden, both in terms of employment and energy demand.

The investment costs and technical characteristics of the generation technologies included in the model are retrieved from the Danish Energy Agency [67]. In the period between the publication of **Paper I** and **II**, updates were made with regards to investment costs, with the largest change being the investment cost of off-shore wind power. Similarly, the costs for hydrogen pipelines, derived from the European Hydrogen Backbone [68], were updated between **Papers I** and **II** (from 1.5 M€/km [69] to 1.8 M€/km [68] for a pipeline size of 1.2 GW). The cost for power line reinforcements in **Paper III** is taken from *Normvärdeslista*, a document produced by the Swedish Energy Market Inspectorate [70]. Nuclear power is not included in any of the studies because possible new units are planned to be located at existing sites, which there are none in the studied region. For all the papers, an interest rate of 5% is assumed.

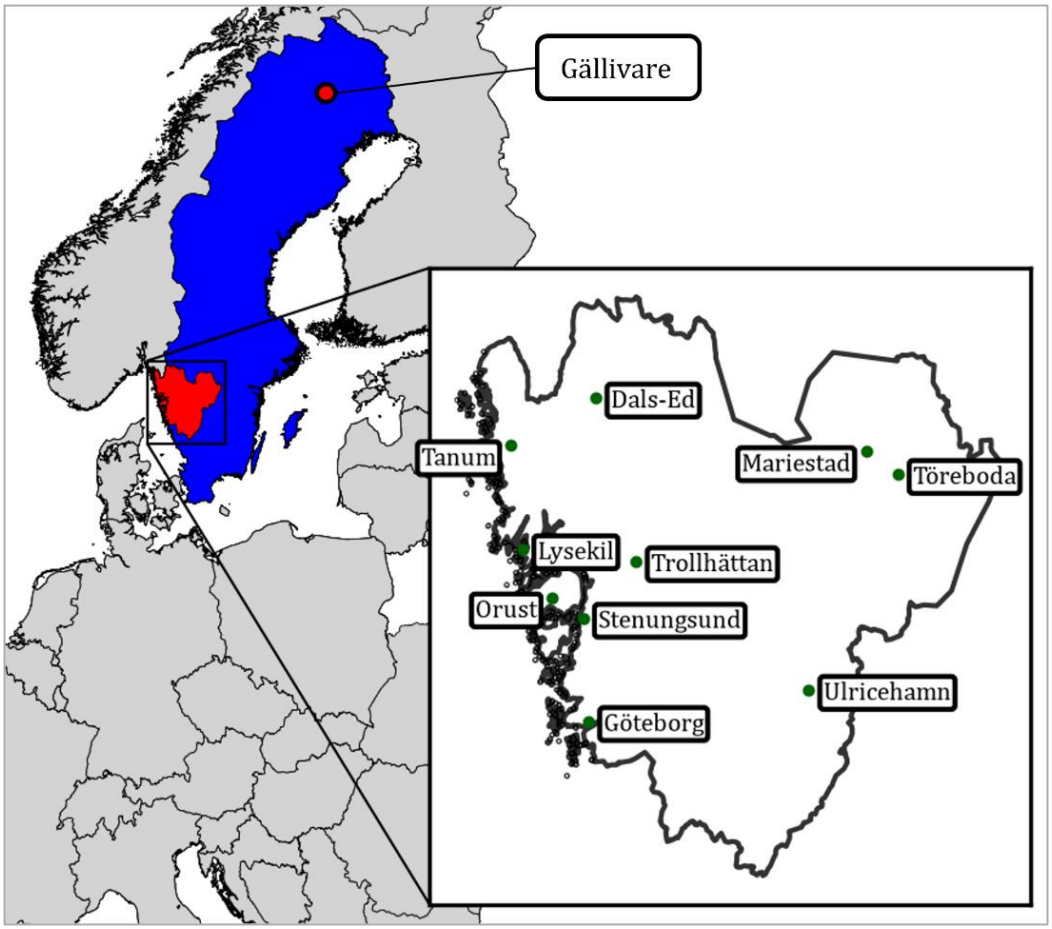


Figure 5. Geographical scope of the four papers with Sweden highlighted in blue and VGR highlighted in red as obtained from Eurostat [71]. **Papers I** and **II** considers Gothenburg, Stenungsund and Lysekil, **Paper III** considers all of Region Västra Götaland (displayed in the box where green dots indicate selected urban areas for navigation reference), and **Paper IV** considers Gothenburg and Gällivare (red dot).

The off-shore wind and solar PV profiles are in **Papers I**, **II** and **IV** retrieved from the renewables.ninja web tool [72–74]. The wind power capacity potential is based on five off-shore wind power projects along the coast [75–79] with the capacities distributed as presented in Table 2. For Gothenburg, there were two overlapping projects thereby resulting in two wind power capacities. The potential for solar PV on rooftops is based on population according to the method presented by [80] In **Paper III**, the potentials and hourly profiles for solar and wind power are based on the work of Mattsson et al. [81] in which Voronoi cells are used to calculate potentials. For all appended papers, Year 2019 is used as a reference year to calculate wind and solar potentials. **Paper III** also differs from the other papers in that off-shore wind power is divided into near and far off-shore wind power while there was only one category of off-shore wind power in **Papers I**, **II** and **IV**.

The prices of imported electricity for the years modelled is taken as the marginal cost of electricity in electricity price area SE3 as given by the European ELLI model originally presented by Walter et al, [82] and developed further to model a time period of Year 2030 to Year 2065 [83], starting from the existing energy system of Europe. The same reference year is used for weather profiles in the ELLI model as in the studies presented in this thesis (Year 2019). The import capacities in **Papers I**, **II** and **IV** are based and estimated from the

plans for the national transmission grid [84]. In **Paper III**, the electricity grid representation is obtained from OpenStreetMap [85] and considers the regional distribution grid as well as connection to the national transmission grid. Underground hydrogen storage in lined rock caverns (LRC) is not allowed in Gothenburg due to the population density.

Table 2. Summary of the characteristics for the three municipalities studied.

	Gothenburg	Stenungsund	Lysekil
Hydrogen demand (TWh_{H2})	5	5	4
Off-shore wind power availability [MW]	280/1,000	1,120	5,000
Rooftop solar PV availability [MW]	1,900	100	50
Solar PV parks [MW]	100	500	500
Electricity transmission capacity [MW]	1,545	1,000	50
Possibility to invest in LRC [yes/no]	No	Yes	Yes

LRC, Lined rock caverns; PV, photovoltaic.

The hourly electricity and heating demand profiles for Gothenburg are based on measured data for Year 2019. The historical annual electricity and heating demands for the other municipalities modelled are taken from [11] and distributed according to the number of nodes in the respective municipality. The annual demands together with the hourly profiles based on measured data for Gothenburg, gives the hourly demands in each node in **Papers III** and **IV**. In **Papers I** and **II**, this profile is modified based on how much of the electricity demand comes from industry, where industries are assumed to have a more-continuous load while the demands from the residential and commercial sectors are assumed to vary over the day and follow the before-mentioned profile. The electricity demand is assumed to increase with increases in population, as well as with electrification of the road transport sector and industrial demands. The private car fleet is assumed to include the same number of vehicles as today although 100% electric in Year 2050. Out of the vehicles, 30% is assumed to be available for vehicle-to-grid (V2G), i.e. also deliver electricity from the car battery to the grid, in **Papers I, II** and **IV** and 20% in **Paper III**. In **Papers I** and **II**, an hourly waste heat profile is implemented in Gothenburg representing waste heat from the industrial sector as well as waste incineration. For Lysekil and Stenungsund, industrial waste heat is assumed to cover the demand for heating.

The annual demand for hydrogen is today around 6.4 TWh_{H2} in the industries located in Gothenburg, Stenungsund and Lysekil. The future demand for hydrogen is uncertain and depends on which pathways will be chosen by the industry. A report by Edvall et al. [23] estimated the future annual demand for hydrogen to be in the range of 4.9–14.0 TWh_{H2} for the industries located on the west coast of Sweden. A more recent study has suggested future annual hydrogen demands in the range of 3–21 TWh_{H2} [86]. In **Papers I**–**III**, an annual hydrogen demand of 14 TWh_{H2} serves as the base case and different hydrogen demands are evaluated to understand how the results are affected. In **Paper IV**, an annual hydrogen demand of 5TWh_{H2} is assumed in Gothenburg for the base case and also here different hydrogen demands are evaluated.

4.4 Cases and scenarios

Paper I examines four cases that differ with respect to the availability of off-shore wind power outside Gothenburg and the possibility to invest in pipelines to transfer hydrogen between the nodes. This means that the model is run with access to a 280 MW and 1,000 MW wind farm

outside Gothenburg respectively, with and without the possibility to invest in pipelines. The off-shore wind power capacities for Stenungsund and Lysekil are as presented in Table 2.

In **Paper II**, the period of 2030–2080 is modelled for four scenarios based on the order in which the electricity import capacity is reinforced and off-shore wind power becomes available for investment, relative to the increase in hydrogen demand from the industry sector. The scenarios are presented in Table 3. *Early access* means that access to electricity import reinforcements and investments in off-shore wind power are in place before the industrial loads start to increase. *Late access* means that industrial loads start to increase before there is access to either electricity import capacity reinforcements or off-shore wind power investments. From Year 2040 and onwards, there are no pre-defined differences between the scenarios, and between Years 2060 and 2080, the investment costs are assumed to be the same as in Year 2050 due to a lack of cost estimates. For all the scenarios, it is possible to invest in hydrogen pipelines.

Table 3. Scenarios formulated in **Paper II** for the three studied municipalities.

Municipality	Parameter	Industrial loads [TWh_{H2}/year]			Max. off-shore wind power [GW]			Transmission capacity [GW]		
	Scenarios/Year	2030	2035	2040	2030	2035	2040	2030	2035	2040
Gothenburg	Early access	0	3.75	5	1	1	1	1.5	1.5	1.5
	Wind power first				1	1	1	0.89	0.89	1.5
	Grid reinf. first				0	0	1	1.5	1.5	1.5
	Late access				0	0	1	0.89	0.89	1.5
Stenungsund	Early access	0	3.75	5	1.12	1.12	1.12	1	1	1
	Wind power first				1.12	1.12	1.12	0.4	0.4	1
	Grid reinf. first				0	0	1.12	1	1	1
	Late access				0	0	1.12	0.4	0.4	1
Lysekil	Early access	0	3	4	5	5	5	0.05	0.05	0.05
	Wind power first				5	5	5	0.05	0.05	0.05
	Grid reinf. first				0	0	5	0.05	0.05	0.05
	Late access				0	0	5	0.05	0.05	0.05

Grid reinf., Grid reinforcement.

In **Paper III**, the geographical scope is expanded to include the entire VGR using the RESYST model. Each modelled node represents a substation in the electricity grid. Together with the nodes connecting the transmission grid to the regional grid, this results in 126 nodes in the model. Since the nodes are based on sub-stations, this means that cities, such as Gothenburg, consist of several nodes. Compared to the other papers appended to this thesis, the geographical scope of the VGR opens up for operation of existing hydro power and investments in on-shore wind power. Four cases are investigated based on the possibility to invest in hydrogen pipelines and power line reinforcements (130 kV): 1) no pipelines or power lines; 2) power lines only; 3) pipelines only; 4) pipelines and power lines. Pipelines refer to new investments in hydrogen

pipelines (green lines in Figure 6) and power lines refer to power line reinforcements of the existing grid (blue lines in Figure 6). The nodes that can be connected through pipelines are chosen because they have a demand for hydrogen (Gothenburg, Stenungsund and Lysekil), good availability of on-shore wind power (Ulricehamn and Dals-Ed), close connection to the national transmission grid (Töreboda) or is centrally located with close connection to the national transmission grid (Trollhättan).

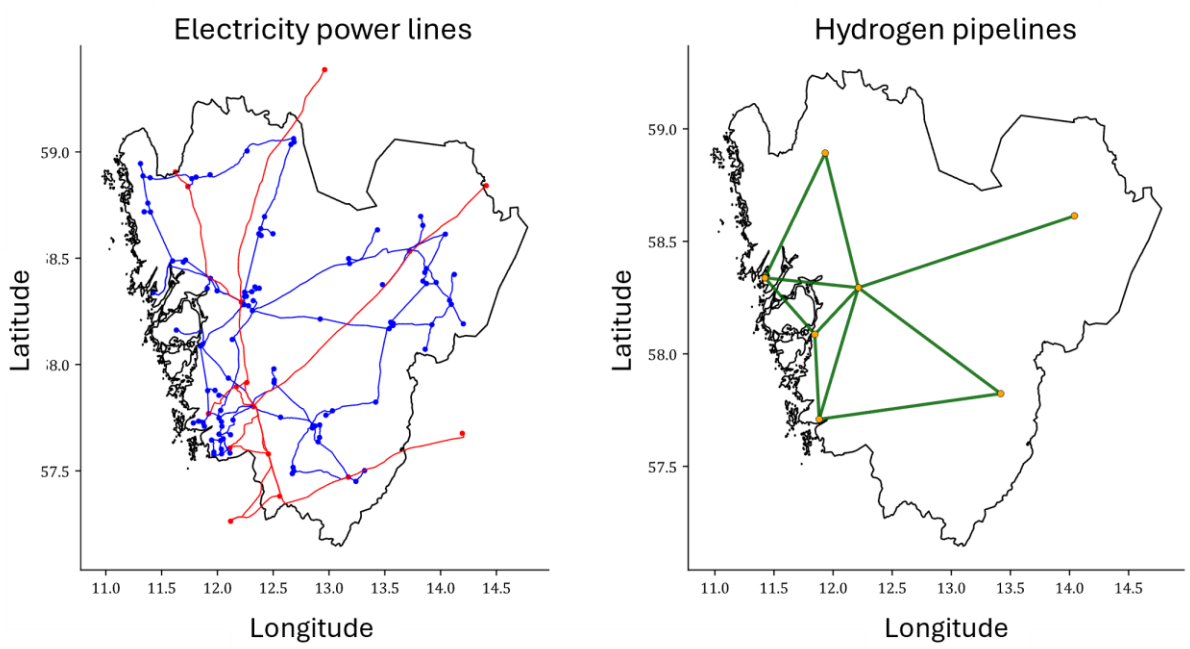


Figure 6. Grids depicted in RESYST: (left) electricity grids, with red and blue lines indicating national and regional grids respectively, and (right) potential hydrogen pipelines routes indicated by green lines.

In **Paper IV**, only Gothenburg and Gällivare are modelled for Year 2050, focusing on meeting the district heating demand. For the purpose of this part of the thesis, most of the focus will be on Gothenburg's energy system. Unlike the previous studies in **Papers I** and **II**, the levels of waste heat from the two refineries (St1 and Preem) as well as waste incineration (Renova) in Gothenburg are based on the distribution capacities presented by Romanchenko et al. [87] and limited by historical annual production [88–90]. Three scenarios are investigated based on the availability of waste heat from the refineries and the demand for hydrogen: 1) current waste heat potential and no demand for hydrogen; 2) no waste heat available from refineries due to being shut down; and 3) one-third of the waste heat remaining from the refineries, an annual electrolytic hydrogen demand of 5 TWh_{H2}, and recovery of waste heat from the electrolysis process. In order to use the waste heat from the electrolysis process, there needs to be investment in a heat pump, which can of course only be operated when the electrolyser is used. No investments in hydrogen pipelines are allowed in the study described in **Paper IV**, as Gothenburg and Gällivare are located far from each other and modelled separately.

5 Results

This chapter presents the results obtained from evaluating: the supply of electricity, heating and hydrogen (Sub-section 5.1), to answer RQ 1; how the hydrogen infrastructure and power line reinforcements affect the energy system configuration (Sub-section 5.2), to answer RQ 2; and the different methods used to model pipeline gas dynamics (Sub-section 5.3), to answer RQ 3.

5.1 Supplying electricity, hydrogen and district heating

In this section, results are presented and compared for **Papers I-IV**. For all scenarios and cases presented in this section, investments in hydrogen pipelines are allowed when possible. Instead, the differences between the cases are the availability of electricity production technologies to invest in and the geographical scope. All of the results represent a future year, around Year 2050, when carbon neutrality has been reached. For **Paper I**, this means the case with a wind power capacity of 1,000 MW outside of Gothenburg and possibilities for investment in pipelines. For **Paper II**, it is the scenario when off-shore wind power is available and the electricity import capacity is reinforced from the start. For **Paper III**, it is the scenario in which investments in hydrogen pipelines are allowed, but not in power line reinforcements. For **Paper IV**, it is the scenario with a hydrogen demand.

RQ1. How can the demands for electricity, district heating and hydrogen be supplied in a region that has a high demand for electrolytic hydrogen from industries?

5.1.1 Electricity

In Figure 7, the annual electricity production levels for the studied scopes in the appended papers are presented. For all the cases presented in Figure 7, electricity imports and wind power supply most of the annual electricity demand, followed by solar PV parks. Electricity imports account for the majority of the electricity supply in the results presented for **Papers I**, **II**

and **IV**. As the geographical scope is expanded to include all of the VGR in **Paper III**, investments can also be made in on-shore wind power, which together with off-shore wind power supplies most of the electricity demand in the region.

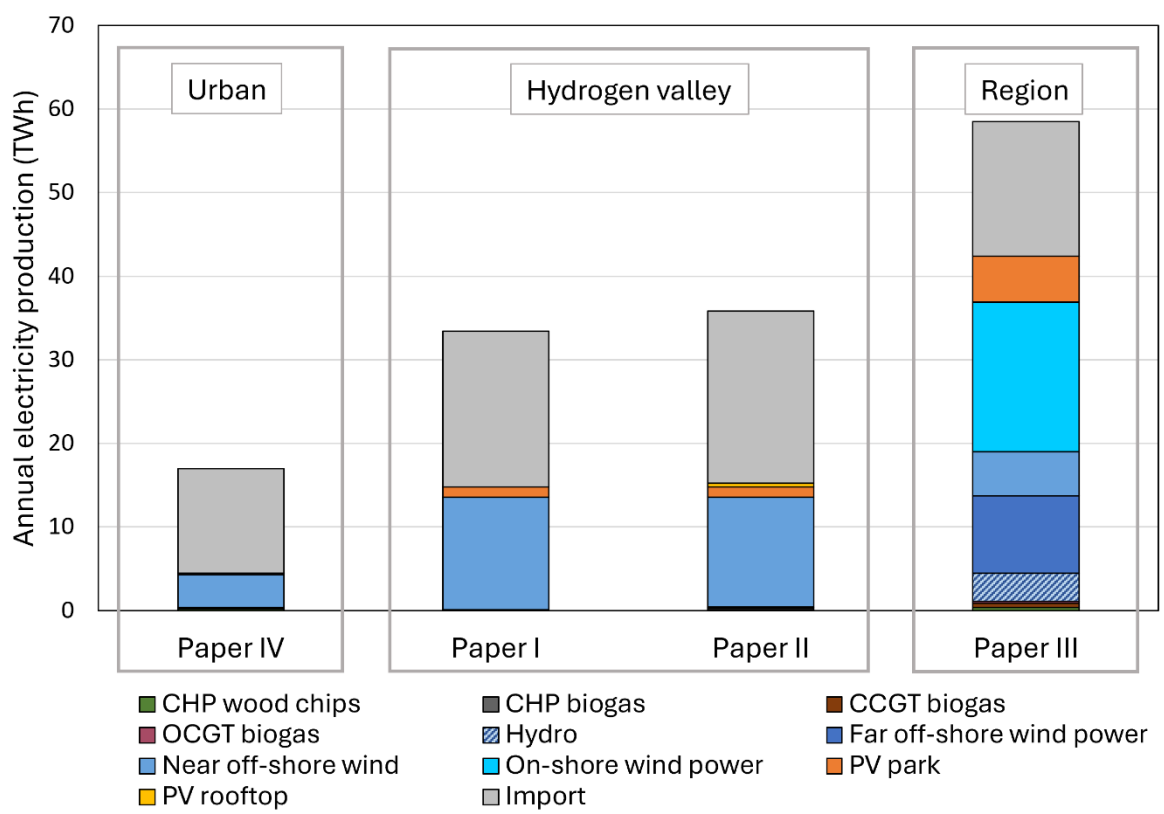


Figure 7. Annual electricity supplies for the studied systems: an urban area; a hydrogen valley that includes three municipalities; and a region contains several municipalities. Each case represents a future year, around Year 2050, where carbon neutrality has been reached and a demand of 14 TWh_{H2}/year of electrolytic hydrogen is assumed for **Papers I–III**, and a hydrogen demand of 5 TWh_{H2}/year is assumed for **Paper IV**. CHP, Combined heat and power plant; CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

In Figure 8, the annual electricity supply for Years 2030 to 2080 is presented, based on the scenarios described in **Paper II**. The largest differences in electricity supply are seen in Year 2035, while the results for the different scenarios converge towards Year 2080. With early access to off-shore wind power and electricity import capacity reinforcements, most of the new electricity demand that is due to electrolytically generated hydrogen is met primarily with imported electricity from the regional distribution grid, and secondarily by wind power in Year 2035. As the demand for electrolytic hydrogen increases in Year 2040, off-shore wind power takes on a larger share of the annual electricity supply. When off-shore wind power is available for investment from the start, but electricity import capacity reinforcements are not, large investments in off-shore wind power are made in Year 2035 and remain at high levels throughout the period. When electricity import capacity reinforcements are available from the start but off-shore wind power is not, additional investments in combined cycle gas turbines (CCGTs) fuelled with biogas are made in Year 2035. With late access to off-shore wind power and electricity import capacity reinforcements, investments are made in CCGTs in all three municipalities that are operated for a high number of full-load hours in Year 2035, but these CCGTs will already in Year 2040 operate for fewer hours per year, as seen in Figure 8. The

need for biogas in Year 2035 is 21 TWh which can be compared to the 2.3 TWh of biogas produced in Sweden in Year 2023, which renders this scenario highly unlikely.

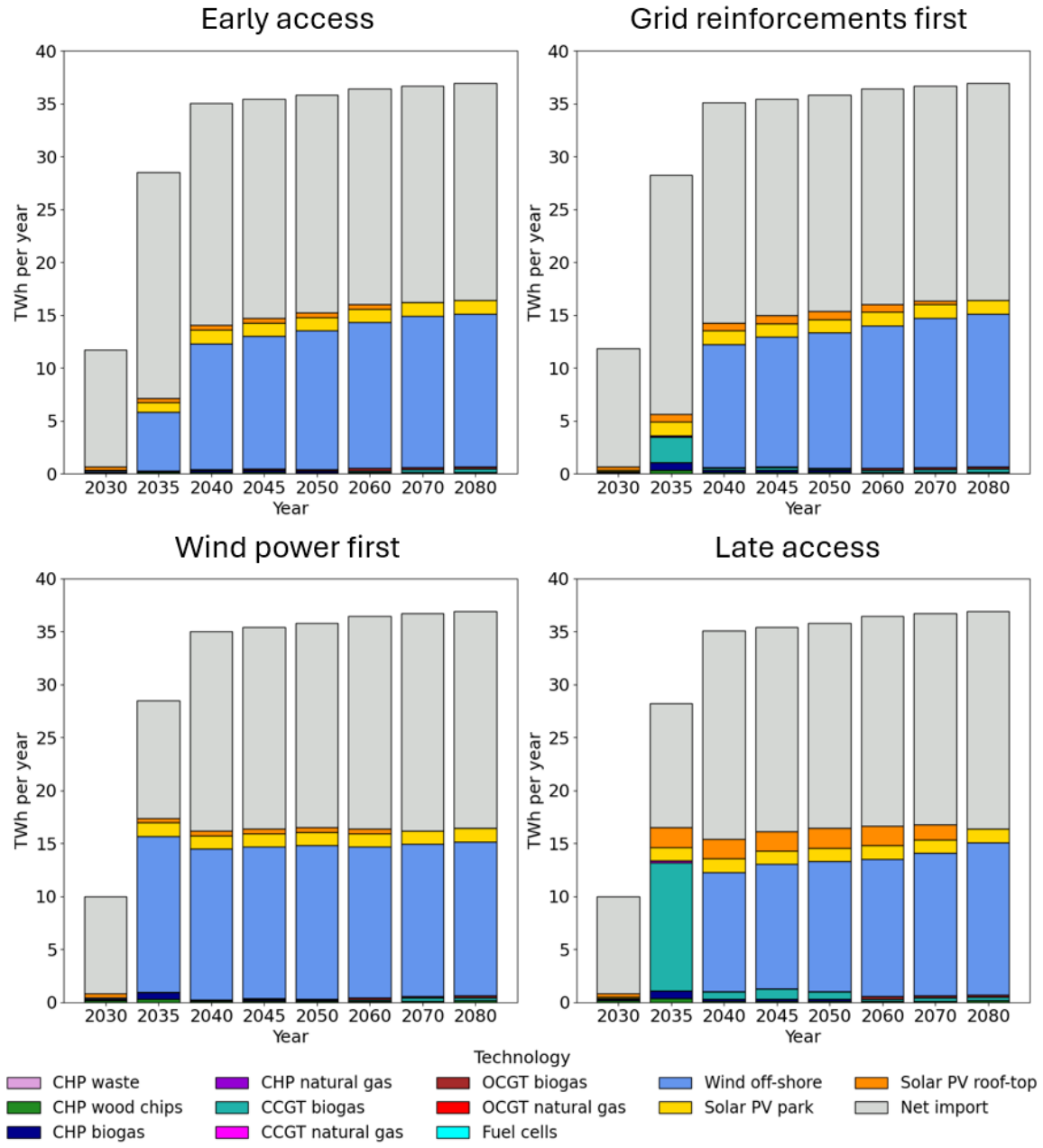


Figure 8. Total annual electricity supplies for the scope of a hydrogen valley, from Year 2030 to Year 2080, with the scenarios presented in **Paper II**. CHP, Combined heat and power plant; CCGT. combined cycle gas turbine; OCGT, open cycle gas turbine.

The total system cost is the lowest when investments in off-shore wind power and electricity import capacity reinforcements are available before the electricity load is increased by electrolytic production of hydrogen, and it is highest when the electrolytic hydrogen demand increases before off-shore wind power and increased electricity import become available (Table 4). Having access to either off-shore wind power or increased electricity imports to the studied nodes, results in a similar increase in the total system cost (+4%), which suggests that from the total system cost perspective both solutions can meet the increased demands at an equal cost. With late access to off-shore wind power and electricity import capacity

reinforcements, the total system cost becomes 18% higher than the scenario with early access. This suggests that the electricity demand due to electrolytic production of hydrogen is most cost-efficiently met by off-shore wind power and electricity imports, and that having access to either off-shore wind power or electricity import capacity is sufficient to meet the demand for electricity for hydrogen production at a low cost.

Table 4. Total system cost for the scenarios evaluated in **Paper II**.

	Total system cost (M€)
Early access	31,000
Wind power first	32,100
Electricity import first	32,200
Late access	36,500

5.1.2 Hydrogen

In Figure 9, the investments in electrolysers and LRC capacities are presented for the four appended papers. The cases that are compared from each paper are the same as those in Figure 7. In **Paper IV**, only one node (Gothenburg) is considered with a hydrogen demand of 5 TWh_{H2}/year, and in this node, investments in LRCs are not allowed. Instead, it becomes cost-efficient to invest in hydrogen tanks (11 GWh_{H2}) to handle short-term fluctuations in hydrogen production. In **Papers I–III**, an annual hydrogen demand of 14 TWh_{H2}/year is assumed. To meet this demand for hydrogen, it is cost-efficient to invest in over-capacity of electrolysers (e.g., invested in capacity compared to the hourly demand for hydrogen) and in LRC storage units. The combination of over-capacity and storage units makes it possible to operate the electrolyser when there is good availability of low-cost electricity and operation during periods of high net-load can be avoided. The increase in electrolyser capacity between **Paper I** and **Paper II** is explained by a lower electrolyser efficiency, which directly influences the capacity needed to produce the hydrogen; in both papers the electrolyser over-capacity is 40%. The increase in total electrolyser capacity in **Paper III** (over-capacity of 160%), as compared to the results from **Papers I** and **II**, is explained by the possibility to invest in on-shore wind power that results in a larger share of the annual electricity demand being supplied with wind power in **Paper III** than **Papers I-II** (Figure 7).

Common to **Papers I–III** is that Stenungsund remains the node with the largest electrolyser capacity and LRC storage capacity. Out of the three nodes modelled, Stenungsund is located in-between the other two nodes and has good availability of off-shore wind power and strong electricity import capacity. This means that it is cost-efficient to produce hydrogen in that node compared to the other two, given that one of them (Gothenburg) already has a high demand for electricity that results in a congested electricity grid and without possibility for investments in LRC storage units, and the other (Lysekil) has good potential for off-shore wind power but only a small electricity import capacity (50 MW) making it more expensive to balance hydrogen production and demand within the node. In **Paper III**, this means that Stenungsund remains an attractive location for hydrogen production while hydrogen production is partly moved away from the other two demand nodes (Lysekil and Gothenburg). For Gothenburg and Lysekil, hydrogen is instead imported, primarily from Dals-Ed (to Lysekil) and Ulricehamn (to Gothenburg) where on-shore wind power resources are good, following investments in hydrogen pipelines.

In **Paper I**, having access to an off-shore wind power capacity of 280 MW outside Gothenburg, results in a similar total electrolyser capacity as with 1,000 MW off-shore case presented here (3.5 GW and 3.4 GW respectively). The difference is that a larger share of the electrolyser capacity is located in Lysekil and a smaller share is located in Gothenburg with an off-shore wind capacity of 280 compared to 1,000 MW. Also for Year 2050 in **Paper II** the total electrolyser capacity is similar between scenarios (3.8-3.9 GW). The LRC storage capacity is in the range 100-120 GWh_{H2} where the smallest capacity is found with late access to off-shore wind power and increased electricity import while the largest capacity is found with wind power available before electricity import capacity reinforcements. The results from **Paper III** are presented further in Sub-section 5.2.2.

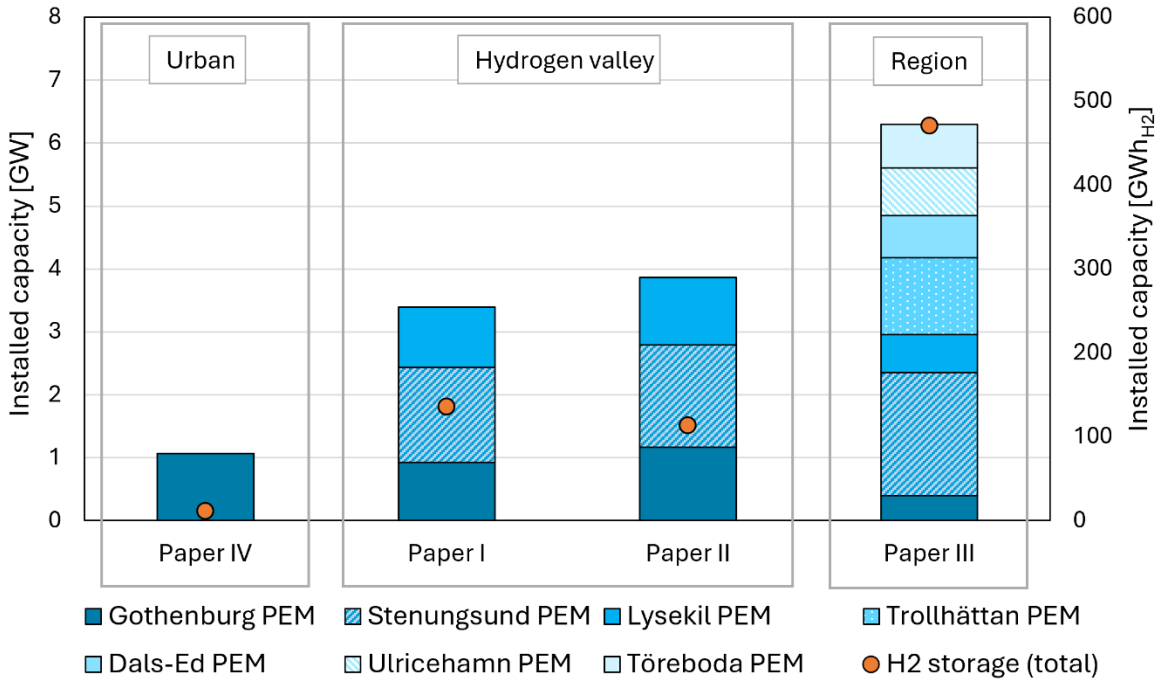


Figure 9. PEM electrolyser (GW) and lined rock cavern storage (GWh_{H2}) capacities for the studied systems: a single urban area; a hydrogen valley that includes three municipalities; and a region that includes several municipalities. Each case represents a future year, around Year 2050, in which carbon neutrality has been reached and a demand of 14 TWh_{H2}/year of electrolytic hydrogen is assumed for **Papers I–III**, and a hydrogen demand of 5 TWh_{H2}/year is assumed for **Paper IV**.

Table 5 presents the maximum flows of hydrogen in the different pipeline connections. The largest pipeline investments are found in the model runs from **Paper I**. This is because the MIP method was used with only a limited number of pipeline capacities. It was, therefore, cost-efficient to invest in a pipeline size that was larger than that required to meet the hourly demand for hydrogen for all the municipalities. As the pipeline investment becomes linear in **Paper II**, smaller pipeline sizes attract investments in between the studied municipalities, as compared to those described in **Paper I**. For the results from **Paper III**, only small pipelines are invested in between the three hydrogen demand nodes. Instead, in line with the results presented in Figure 9, hydrogen production is partly moved to other nodes in the region and transported to the demand nodes. This is explained by the characteristics of the three hydrogen demand nodes as mentioned earlier. Stenungsund has access to low-cost electricity from off-shore wind power and electricity imports and has flexibility from possible LRC storage units. In Gothenburg both

low-cost electricity and flexibility are lacking. Lysekil has only a small electricity import capacity to balance hydrogen production. For **Papers I** and **II**, allowing for pipeline investments benefits both Gothenburg and Lysekil, as hydrogen can be produced in Stenungsund and investments in the largest electrolyser capacity in the system are made here. However, from the regional perspective, hydrogen pipelines to Stenungsund are no longer cost-efficient, as seen in the results from **Paper III**. Instead, hydrogen production for Lysekil and Gothenburg is moved to other hydrogen production nodes in the region, while LRC storage capacity and electrolyser capacity remain high in Stenungsund, even as hydrogen is no longer exported to Lysekil and Gothenburg. A pipeline size of <50 MW_{H2} can be seen as unrealistic and is due to the linear modelling approach used.

Table 5. Pipeline capacities for the different pipeline connections and scopes presented in **Papers I–III**: a hydrogen valley that includes three municipalities and a region that includes several municipalities. Each case represents a future year, around Year 2050, in which carbon neutrality has been reached and a demand of 14 TWh_{H2}/year of electrolytic hydrogen is assumed.

	Maximum flow of hydrogen (MWh_{H2}/h)		
	Paper I	**Paper II**	**Paper III**
Stenungsund – Gothenburg	610	520	40
Lysekil – Stenungsund	490	210	10
Dals-Ed – Lysekil	-	-	180
Dals-Ed – Trollhättan	-	-	10
Töreboda – Trollhättan	-	-	160
Trollhättan – Ulricehamn	-	-	0
Ulricehamn – Gothenburg	-	-	230
Lysekil – Trollhättan	-	-	130
Trollhättan – Stenungsund	-	-	50
Trollhättan – Gothenburg	-	-	310

In Figure 10, the net annual flows of hydrogen are presented for all scenarios and with selected years from **Paper II**. As the three nodes included are located along the coast, the only investment options are to connect Gothenburg to Stenungsund and Stenungsund to Lysekil (i.e., it is not possible to connect Gothenburg to Lysekil directly). Again, most of the differences are observed in Year 2035, while the results converge towards Year 2080. In Year 2080, Stenungsund is a net exporter of hydrogen, while Gothenburg and Lysekil are net importers. In Year 2035, hydrogen flows in the northward direction in all the scenarios, except for the scenario in which only wind power investments are available from the start, where the flow instead goes in the other direction. This is because Lysekil is the node with the largest off-shore wind potential among the studied nodes, so when electricity import capacity reinforcements are not in place, it becomes cost-efficient to invest in off-shore wind power for hydrogen production in Lysekil that also has the largest electrolyser capacity among the nodes in Year 2035. Following, the LRC storage capacity is 5-25 GWh_{H2} in Year 2035 for the three scenarios apart from the scenario with only off-shore wind power available from the start where the LRC storage capacity is 121 GWh_{H2}. With access to off-shore wind power before the industrial loads start to increase, there is investment in a larger pipeline size between Gothenburg and Stenungsund, while a smaller pipeline size is invested in between Stenungsund and Lysekil, as compared with the other three scenarios in **Paper II**.

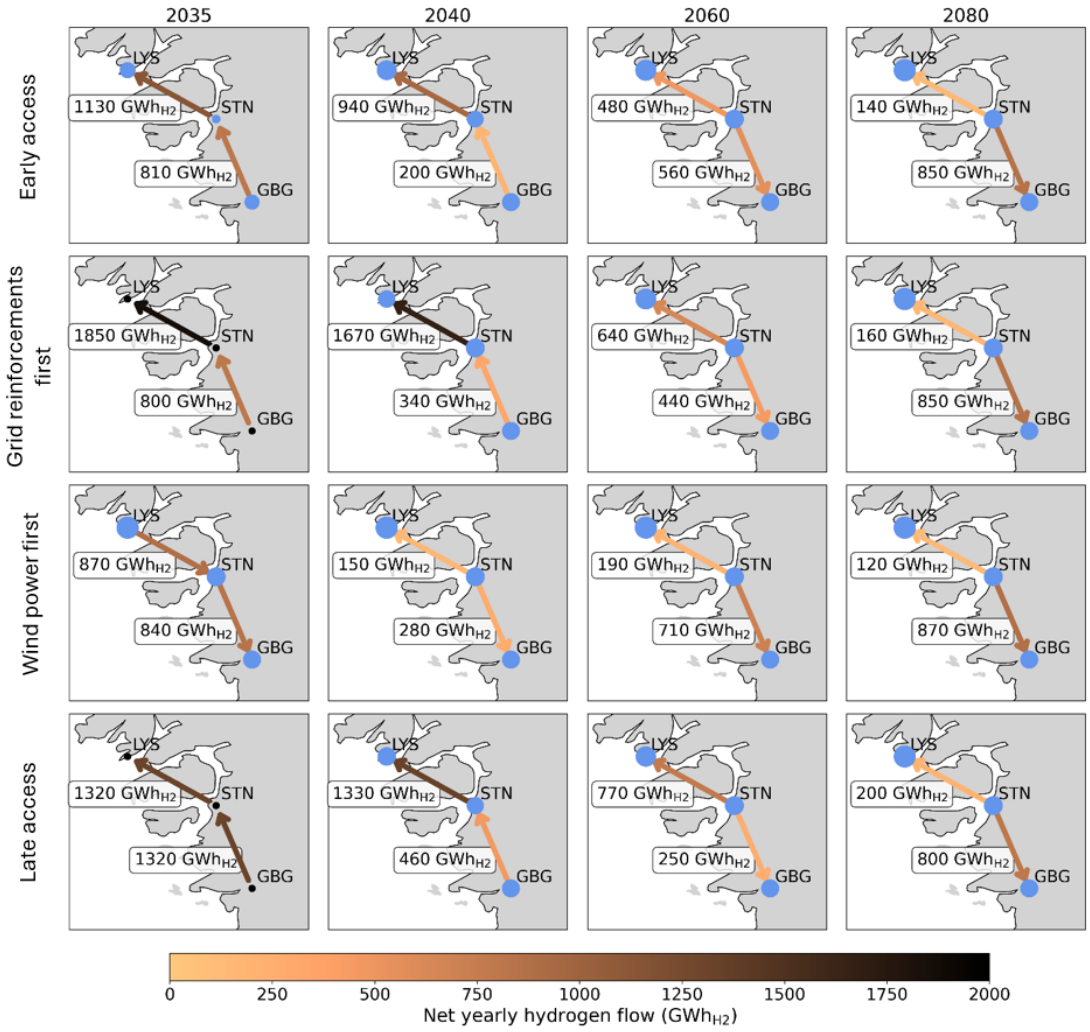


Figure 10. Annual net transfer of hydrogen between Gothenburg (GBG), Stenungsund (STN) and Lysekil (LYS), as presented in **Paper II**. The blue dots represent investments in off-shore wind power, whereby a larger dot represents a larger investment. For comparison, the blue dot for Gothenburg (GBG) in Year 2080 represents 1 GW.

The future demand for hydrogen is uncertain and because of this, different hydrogen demands have been evaluated in all papers. In **Paper II**, an annual demand for hydrogen of 4.9 TWh_{H2} resulted in a larger share of the annual electricity demand being supplied from imported electricity while an annual hydrogen demand of 20 TWh_{H2} resulted in a larger share of wind power. A clear trend between deployment of wind power and electrolyser over-capacity could also be observed. With a hydrogen demand of 4.9 TWh_{H2}/year, wind power supplies 6% of the annual electricity demand with an electrolyser over-capacity of 25%. With a hydrogen demand of 20 TWh_{H2}/year, wind power supplies 53% of the electricity demand with an electrolyser over-capacity of 65%.

Investments in hydrogen pipelines are made for all studied cases when allowed, although their role differs between cases. Lysekil and Gothenburg both lack some of the requirements for low-cost hydrogen: access to low-cost electricity supply (wind power or import) and flexibility (LRC storage units and electricity import) and benefit the most from a joint hydrogen infrastructure. Stenungsund fulfil both requirements and can to a larger extent meet the demand for hydrogen within the node as seen from the results in **Paper III** and Table 5.

5.1.3 District heating

In Figure 11, the annual heating supply for Gothenburg is presented. In **Paper IV**, three cases are evaluated that vary depending on their industrial waste heat and hydrogen demands. As the waste heat from refineries is removed, the heating is instead supplied from larger investments in heat pumps (HPs). However, when there is a demand for electrolytic hydrogen that results in a higher demand for electricity, investments are made in CHP plants which can provide both electricity and heating (as shown in Figure 11). A similar trend is observed in **Paper I**, where the cases are based on the potential for off-shore wind power (280 MW or 1,000 MW). With the possibility to invest in larger off-shore wind power capacity, HPs take on a larger share of the annual heating supply. In **Papers II** and **IV**, waste heat from hydrogen production can be recovered by investments in industrial HPs, which are restricted by the operation of the electrolyser. Since the coefficient of performance (COP) is higher for the HP connected to the electrolyser, it outcompetes ordinary HPs. In **Paper II**, techno-economic parameters for Year 2030 are used, while techno-economic parameters for Year 2050 are used in **Paper IV**. This means that the efficiency of the electrolyser is lower in **Paper II** but that more waste heat can be recovered. In **Paper III**, no industrial waste heat is implemented. With investments in pipelines, the electricity demand in Gothenburg becomes lower than without pipeline investments. Owing to this, electricity is used to a greater extent for heating in **Paper III**, as compared with, for instance, the results from **Paper IV** when only Gothenburg is modelled and it needs to cover its own demand for hydrogen. In all the papers, heat-only boilers (HOBs) are invested in to cover periods when both the heating demand and electricity prices are high. Thus, the HOB capacity is similar to that of HPs, although the HOB is only operated for few hours. In all the studied cases, investments are also made in tank thermal energy storage units that store heat between hours and balance heat production from power-to-heat technologies. The results presented in Figure 11 suggest that when there is availability of low-cost electricity, HPs are preferred, whereas when the electricity grid is more-congested, CHP plants are cost-efficient because they can provide both electricity and heating.

5.2 Roles of the electricity and hydrogen distribution grids

The results presented up to now have included the possibility to invest in hydrogen pipelines for the papers with more than one node (**Papers I–III**). In this section, the results presented in Section 5.1 are compared to cases in which pipeline investments are not available. This comparison is done firstly for the scope of a hydrogen valley (**Papers I** and **II**) in Section 5.2.1, and secondly for the regional scope (**Paper III**) in Section 5.2.2 where investments in power line reinforcements are also part of the evaluation.

RQ2. What are the roles of the electricity and hydrogen distribution grids in a regional energy system with a high demand for electrolytic hydrogen from industries?

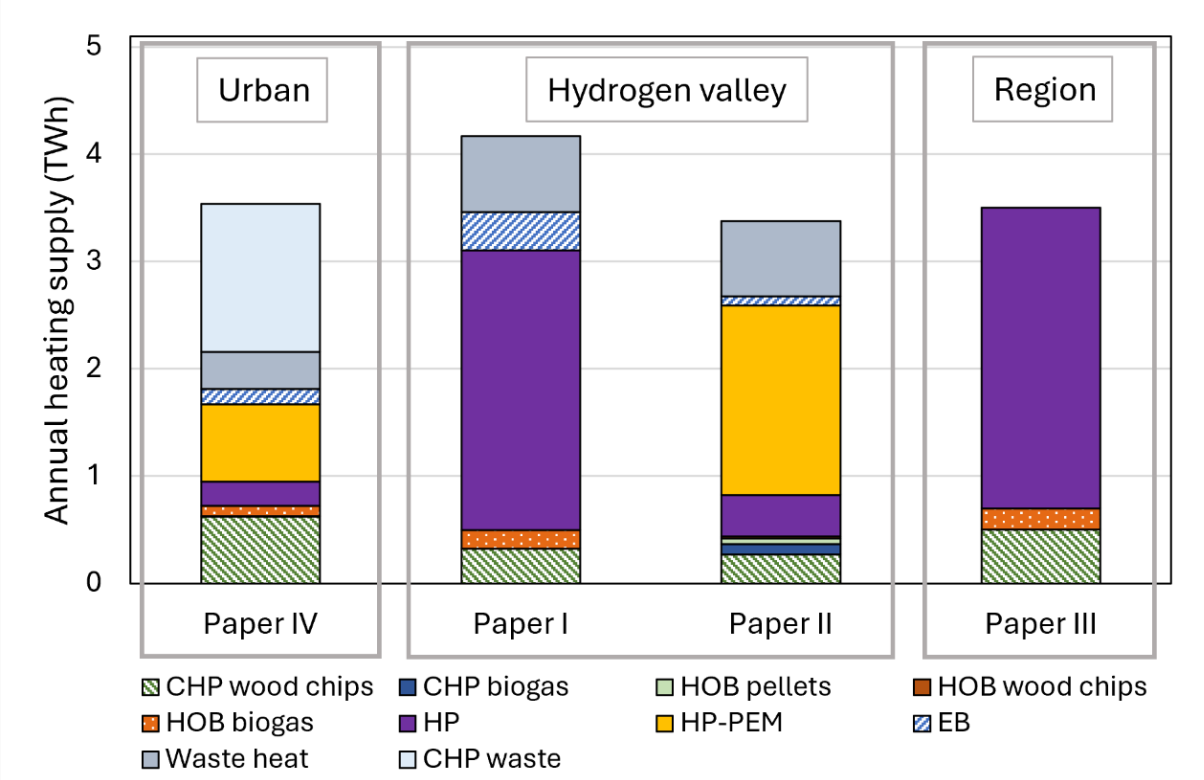


Figure 11. Annual heating supply for Gothenburg as a single municipality energy system (Urban), as part of a hydrogen valley energy system (Hydrogen valley) and as part of a regional energy system (Region). Each case represents a future year, around Year 2050, in which carbon neutrality has been reached and a total demand of 14 TWh_{H2}/year of electrolytic hydrogen is assumed for **Papers I–III**, and a hydrogen demand of 5 TWh_{H2}/year is assumed for **Paper IV**.

5.2.1 Hydrogen distribution grids in hydrogen valleys

In Figure 12, the differences in annual electricity and heating production for all municipalities combined are presented and compared for scenarios in which investments in hydrogen pipelines are not allowed and scenarios in which hydrogen pipelines are allowed. For **Paper I**, this means that the two cases that do not allow for investments in hydrogen pipelines and that have different potentials for off-shore wind power connected to Gothenburg (280 MW or 1,000 MW) are compared to the two cases in which pipelines are allowed. For **Paper II**, the comparison is made for the scenario with early access to electricity import capacity reinforcements but in two different years, Year 2050 and Year 2080. This is because the results converge towards Year 2080 and little difference is seen between the scenarios. In Figure 12, a positive value indicates that there is a higher production without pipeline investments than with pipeline investments, whereas a negative value suggests lower production without pipeline investments than with allowed pipeline investments. This means, as a difference between the cases is seen in Figure 12, that investments are made in pipelines when the option is available. This holds true for a range of assumptions regarding hydrogen demand, pipeline and LRC costs, and biogas availability.

As shown in Figure 12a, investments in and operation of off-shore wind power are lower when there is no possibility to invest in pipelines (-26% in the 280-MW case and -11% in the 1,000-MW case from **Paper I**; and -6% in Year 2050 and -11% in Year 2080 for **Paper II**). Instead, a larger share of the annual electricity supply originates from solar PV and imports together

with dispatchable technologies such as CHP plants and CCGTs. In the studied scope, this is because larger investments in off-shore wind power are made, primarily in Stenungsund, with investments in pipelines than without such investments, and hydrogen production is moved from Gothenburg to Stenungsund. For the heating supply (Figure 12b), smaller investments are made in HPs and electric boilers without the possibility to invest in hydrogen pipelines, while primarily CHP plants take on a larger share (4-times larger in the 280-MW case and 3.4-times larger in the 1,000-MW case in **Paper I**) of the annual heating supply. This is because there is a need for both electricity and heating in Gothenburg, so it is cost-efficient to have investments in CHP units.

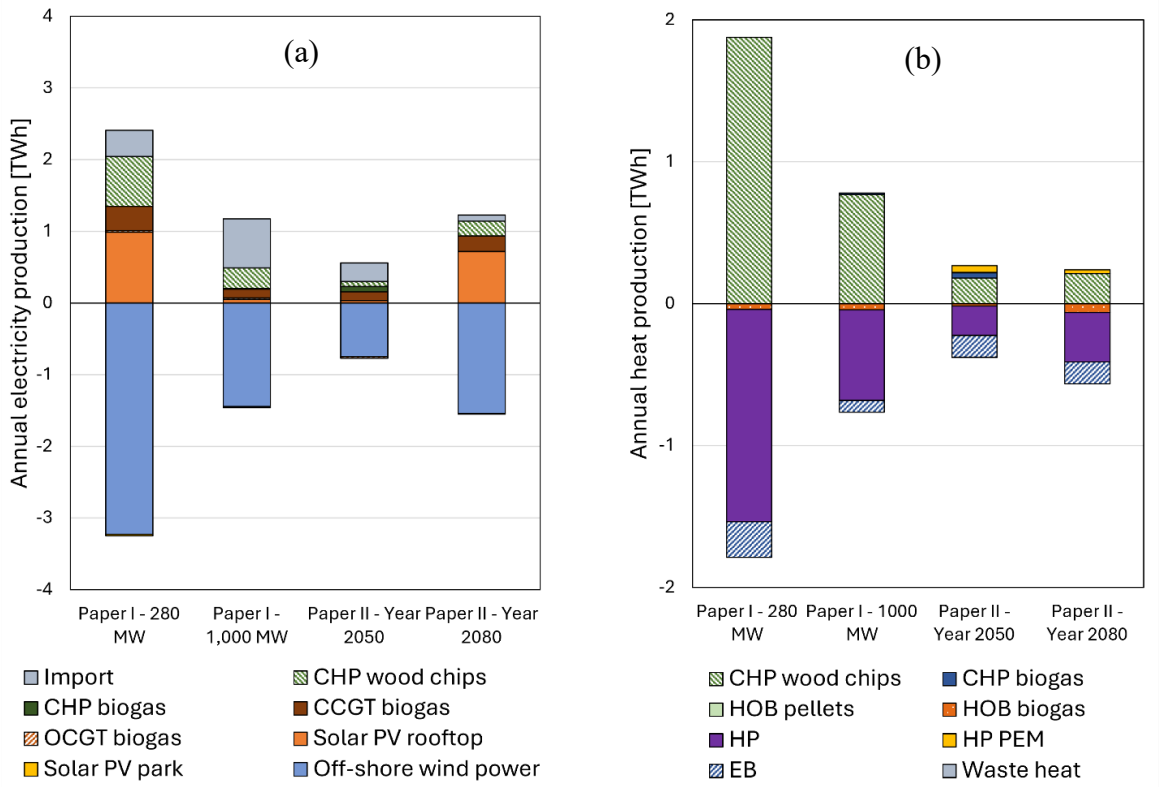


Figure 12. Difference in annual levels of electricity production (Gothenburg, Stenungsund and Lysekil combined; Panel a) and heating production (Gothenburg only; Panel b) in the absence of any possibility to invest in hydrogen pipelines, as compared with the possibility to invest in hydrogen pipeline for the cases presented in **Papers I** and **II**. CHP, Combined heat and power plant; CCGT, combined cycle gas turbines; OCGT, open cycle gas turbine; HOB, heat-only boiler; HP, heat pump; EB, electric boiler.

Without the possibility to invest in pipelines, the total system cost increases by 7% and 4%, respectively, for the two cases presented in **Paper I,** and increases by 3% for the case presented in **Paper II**. This is because the hydrogen pipeline allows for the part of the electricity demand that is linked to hydrogen production to be moved to where there is access to low-cost electricity and LRC storage units, thereby reducing the pressure on the electricity grid and making it possible to use electricity for other services, such as heating through HPs (Figure 12b).

In Figure 13, the differences in electrolyser (PEM) and hydrogen storage capacities associated with not allowing for investments in pipelines and allowing for investments in pipelines are compared. In the absence of any possibility to invest in pipelines, the total electrolyser capacity

is smaller than with investments in pipelines. Without any possibility to invest in pipelines, investments in electrolyser capacity and LRC storage units are for all cases reduced in Stenungsund while the electrolyser and hydrogen storage capacities are larger in Gothenburg and Lysekil. The exception to this is the case with only 280 MW of off-shore wind power potential connected to Gothenburg. In this case, the electrolyser capacity in Lysekil is also reduced without investments in hydrogen pipelines. This is because, similar to Year 2035 in the scenario with off-shore wind power available from the beginning of the studied period in Figure 10, hydrogen is produced in Lysekil and exported instead of being imported as in the other cases presented here. Thus, removing the possibility to invest in hydrogen pipelines, reduces the incentive for Lysekil to have a larger electrolyser capacity and to become a net exporter of hydrogen.

The increase in hydrogen production in Gothenburg is also the primary reason for investments in CHP plants and CCGTs as presented in Figure 12. Without allowing for pipeline investments, tank storage units are invested in for Gothenburg, although with pipelines, these investments are reduced to 0.1-1.0 GWh_{H2}. The line-pack in the pipeline between Gothenburg and Stenungsund is in the range 0.07-0.36 GWh_{H2} in the cases presented. This means that the line-pack is not large enough to replace the tank storages in Gothenburg, and that hydrogen is instead exported and stored in LRC storage units in Stenungsund, to be imported to Gothenburg at a later point. To summarise, in the studied system, hydrogen pipelines favour centralised hydrogen production as it gives access to sites with low-cost electricity and flexibility from storages that stimulate larger electrolyser capacities. Simultaneously, a joint hydrogen infrastructure can reduce the need for hydrogen tank storages.

5.2.2 Electricity and hydrogen distribution grids in a regional context

Compared to modelling only the three nodes as presented in the previous section, modelling a region opens up for investments in on-shore wind power and the operation of existing hydro power. Furthermore, the potential for solar PV parks is stronger outside urban areas. Figure 14 presents the placements of new hydrogen pipeline connections and power line reinforcements (130 kV), based on the cases in **Paper III**, where the VGR is modelled. In Figure 14, the grey lines represent possible investments while coloured lines show the investments made in each case.

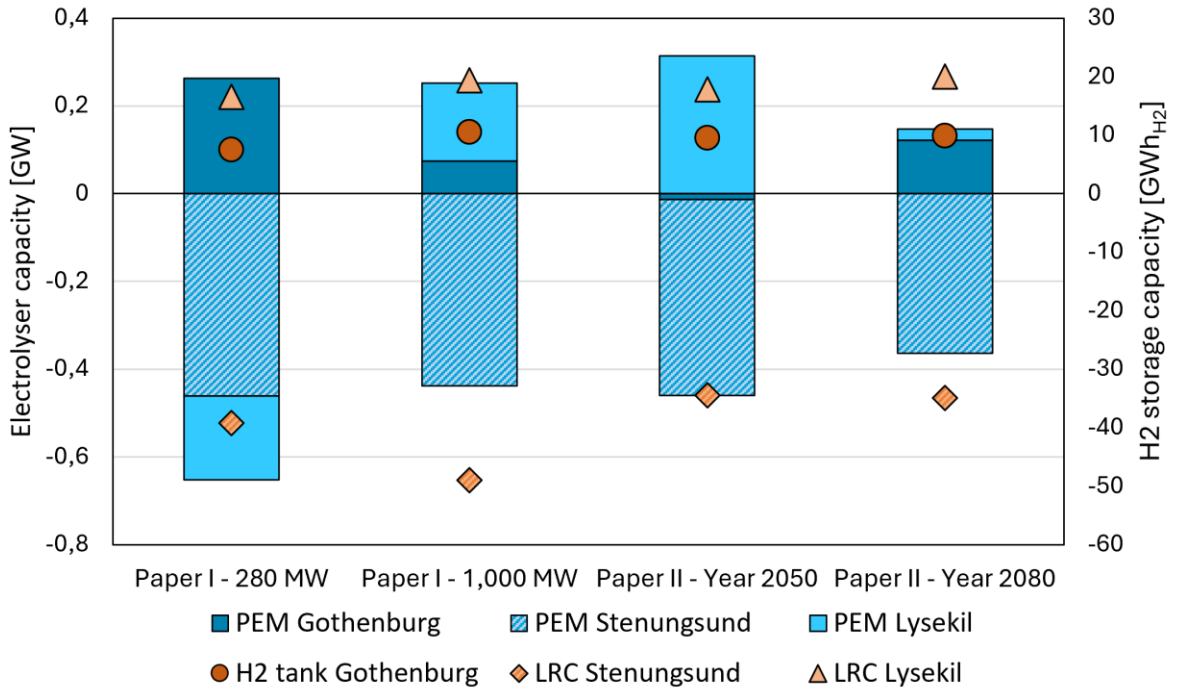
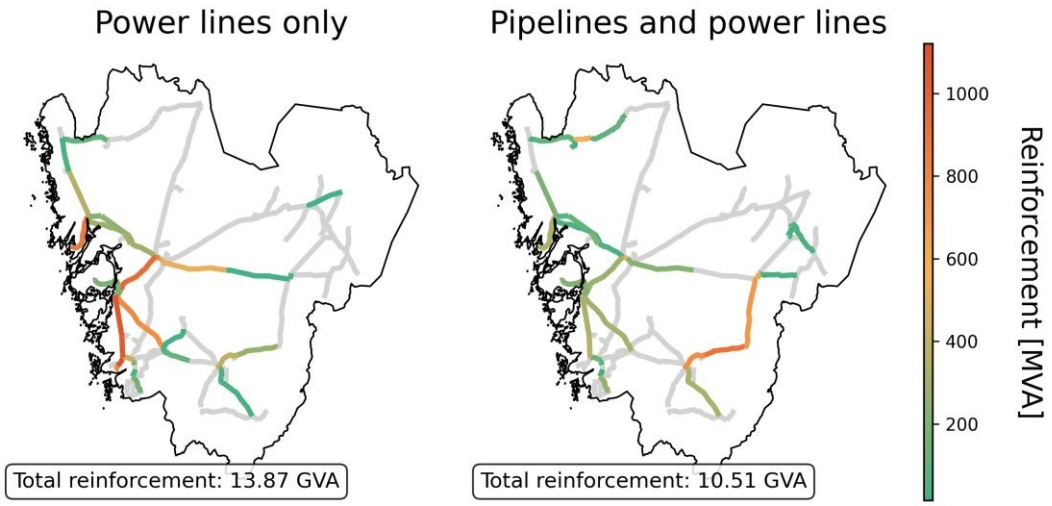
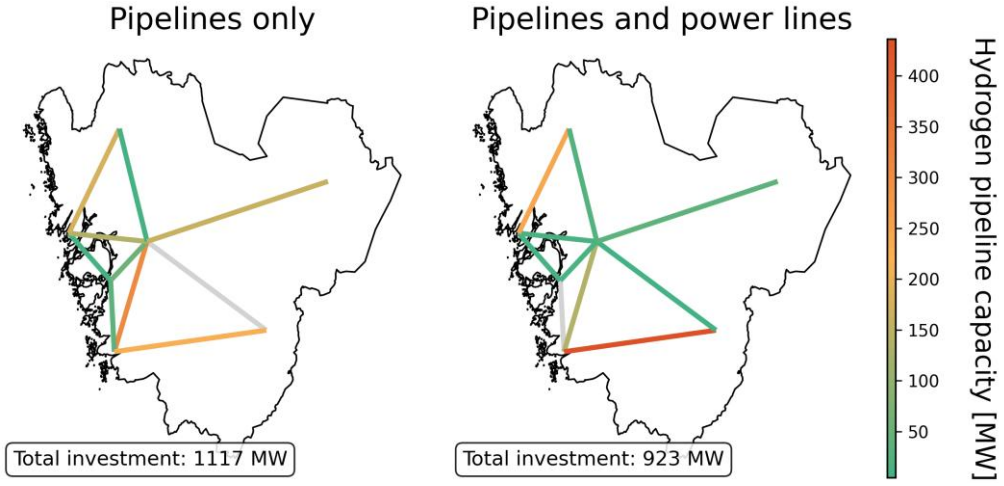


Figure 13. Differences in electrolyser and hydrogen storage capacities in the absence of any possibility to invest in hydrogen pipelines, as compared with allowing for investments in hydrogen pipelines, for the cases presented in **Papers I** and **II**.

Both pipelines and power line reinforcements are invested in when there is the opportunity, and they complement rather than out-compete each other. When only power line reinforcements are available the power lines closest to the hydrogen demand nodes show the largest reinforcements because the largest electricity loads are found in these nodes. This results in a larger total electrolyser capacity (+14%) in the three hydrogen demand nodes, as compared with not allowing investments in power line reinforcements or hydrogen pipelines. With new hydrogen pipeline investments only, there are investments in nine out of the ten possible pipeline connections. This means that hydrogen production is moved away from the demand nodes, primarily from Gothenburg and Lysekil which, as previously stated have higher costs for meeting the demand for hydrogen within the node. For the system, this results in a total electrolyser capacity that is 39% larger than that in the case without any distribution grid investments. With investments in both power line reinforcements and hydrogen pipelines, hydrogen production is concentrated to fewer locations. This is because power line reinforcements are made around the hydrogen production nodes, which make it cost-efficient to invest in larger electrolyser capacities and make use of the solar and wind potentials in the nodes surrounding the hydrogen production nodes. In none of the model runs are fuel cells invested in which means that it is not cost-efficient to use hydrogen for electricity generation and thus, hydrogen pipelines do not outcompete power lines as energy distribution technology.



(a)



(b)

Figure 14. (a) Reinforcements in power lines for the cases of *Power lines only* and *Pipelines and power lines*. (b) Investments in hydrogen pipelines for the *Pipelines only* and *Pipelines and power lines* cases.

Figure 15 presents the localisation of investments in on-shore wind power, solar PV parks, electrolysers, and LRC storage units, depending on the availability of distribution grids investments. With investments in one or both distribution grids, the on-shore wind power capacity increases by 5–11% compared to the case without investments in the distribution grids. The main difference in on-shore wind power capacity can be seen with investments in only pipelines or both pipelines and power line reinforcements, where on-shore wind power is invested in for Dals-Ed, as an electrolyser is located within the same municipality. As pipeline investments are allowed, electrolyser capacity is seen in all the hydrogen nodes, albeit with varying capacities. The total electrolyser capacity is 52% larger with investments in both power line reinforcements and hydrogen pipelines than without investment in any distribution grid. Similarly, LRC storage units are located where investments in electrolysers are made. This is explained by it being cheaper to invest in storage capacity than pipeline capacity, which means that a more-continuous flow of hydrogen can be achieved if there are storage units in both the export and import nodes. The exception to this is Gothenburg, where LRC storage units are not

allowed due to the population density. When both pipeline investments and power line reinforcements are allowed, both the electrolyser and LRC storage capacities are concentrated to fewer locations (e.g., Ulricehamn, Dals-Ed and Stenungsund). As previously mentioned, this is because electricity can, to a larger extent, be transported between the nodes surrounding the hydrogen production nodes, such that more low-cost electricity is available for hydrogen production. The longer the pipeline distance, the more costly the pipeline investment, so it is less cost-efficient to produce hydrogen far away (e.g., in Töreboda) from the demand centres when similar levels of low-cost electricity can be found closer to the hydrogen demand nodes.

Allowing for power line reinforcements results in an 11% reduction in total system cost. Allowing for pipeline investments results in a 21% reduction in total system cost, while allowing for both power line reinforcements and hydrogen pipeline investments gives a 23% reduction in total system cost, as compared to the case without pipelines and power line reinforcements. This means that, for the studied system, allowing investments in hydrogen pipelines could significantly reduce the annual system cost while meeting a future demand for electrolytic hydrogen, although the most cost-efficient solution is when both power line reinforcements and hydrogen pipelines are allowed. This is because pipeline investments open up for hydrogen production at sites with access to more low-cost electricity (primarily on-shore wind power and imports). With investments in both power line reinforcements and pipelines, power line reinforcements can collect electricity produced from VRE sources and transport the electricity to the hydrogen production nodes, thereby further reducing the total system cost.

5.3 Hydrogen pipelines modelling

In this section, the following three methods used to model hydrogen flows (as presented in Section 4.2) in pipelines are evaluated:

- EF: Continuously linearised investments in hydrogen pipelines only considering the energy flow;
- LP: Continuously linearised investments in hydrogen pipelines while considering the gas dynamics; and
- MIP: Binary investments in hydrogen while considering the gas dynamics

To study the impacts on the energy system revealed by the different methods, they are compared using the following variables: investments in pipeline capacities; hourly flow of hydrogen; and investments in storage units and electricity-producing units. Furthermore, important modelling parameters for the hydrogen flow methods, such as the pipeline diameter and the allowed pressure difference between two consecutive steps, are also evaluated.

RQ3. How does the level of detail used to model the hydrogen flow in pipelines affect the energy system configuration?

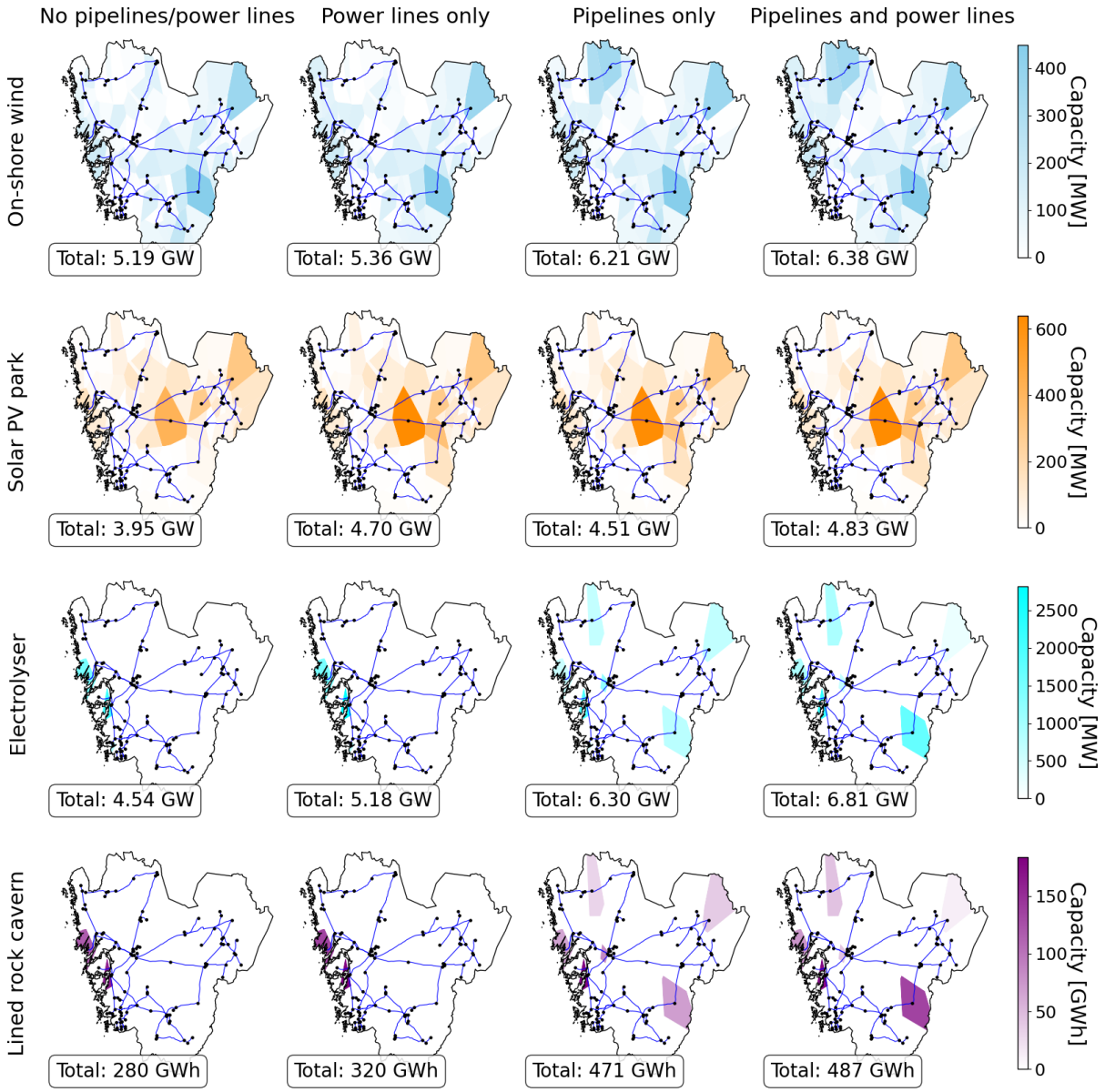


Figure 15. Localisation of investments in on-shore wind power, solar PV parks, electrolysers, and LRC storage units.

5.3.1 Linear system

In the linear system, the three methods to model hydrogen flow in pipelines are evaluated for the three demand nodes previously described as a hydrogen valley (from north to south: Lysekil, Stenungsund & Gothenburg). In this section, the EF, LP and MIP methods are first compared to each other in terms of investments in capacity, hourly hydrogen flows and annual flows. This comparison is followed by a sensitivity analysis of the allowed pressure difference in each pipeline cross-section for every consecutive hour and the different pipeline diameters used to calculate the pipeline coefficients.

Comparison of methods

Figure 16 shows the hydrogen flow profile for the first 2,000 consecutive hours of the year modelled in the two pipeline connections. The flow direction implemented in the model is from north to south, which means that a positive value indicates the flows from Stenungsund towards

Gothenburg and from Lysekil towards Stenungsund, while a negative value indicates the flows in the opposite directions. The simplest method, EF, results in the flow changing rapidly from high to low, for instance between Hours 500 and 750. With the LP method, the flow fluctuates less rapidly than it does in the EF method, although the most-restricted flow is found using the MIP method.

Compared to the LP version, the MIP method considers each diameter's effect on the pipeline flow coefficients ($a_{l,d}$, $b_{l,d}$ and $c_{l,d}$), whereas the LP method considers only one diameter size independently of the actual investments. Similarly, the MIP method includes investment costs that are specific for the pipeline diameter size invested in, while the LP method has the same investment cost regardless of the diameter for which investment is made. This means that the LP method is more-restricted than the simpler EF method but less-restricted than the MIP method. It also implies that the LP method will over-estimate how fast the flow can change in pipelines that have a diameter that is smaller than the chosen reference diameter used to calculate the pipeline flow coefficients, and will under-estimate how fast the flow can change in pipelines with larger diameters.

From Figure 16, it can be seen that the overall investment in pipeline capacity is lower when there are more restrictions on the flow (LP and MIP compared to EF). The pipeline connection between Gothenburg and Stenungsund is most-affected and is 570 MW_{H2} with the EF method (same as the hourly demand for hydrogen in Stenungsund and Gothenburg) and 230 MW_{H2} with the MIP method. Between Stenungsund and Lysekil, the pipeline capacity is smaller (0.18 GW_{H2}) than the hourly hydrogen demand in Lysekil of 0.46 GWh_{H2}/h. When the gas dynamics are included in the model, a lower hydrogen transfer capacity is invested in for this connection as well. This suggests that, for the system under study, the possibility to cause rapid changes in flow is an incentive for investment, and when the possibility to change rapidly the flow is restricted, it becomes cost-efficient with a smaller pipeline capacity.

Figure 17 presents the changes in technology investments for the LP and MIP methods, as compared with the EF method. Both storage units and generation technologies are affected by the method used. This is because it becomes more cost-efficient to produce hydrogen in a distributed manner and handle variations in electricity and hydrogen production locally, than it is to have more-centralised hydrogen production (as with the EF method). As the flow of hydrogen becomes more-restricted using the LP method, the storage investments in Stenungsund decrease (-18%), while the storage investments in Lysekil increase (+17%). In Lysekil, the increase in LRC storage units is even larger (+38%) when using the MIP method, as compared with using the EF method. Focusing on Stenungsund and Lysekil, off-shore wind power and electrolyser capacities are lower in Stenungsund when using the LP or MIP method, as compared with using the EF method, and they are instead higher in Lysekil, especially when using the most-restricted MIP method (+28% and +28%, respectively, compared to EF). Simultaneously, net imports of hydrogen to Lysekil are lower using the MIP method (270 GWh_{H2}/year), compared with using the EF method (990 GWh_{H2}/year).

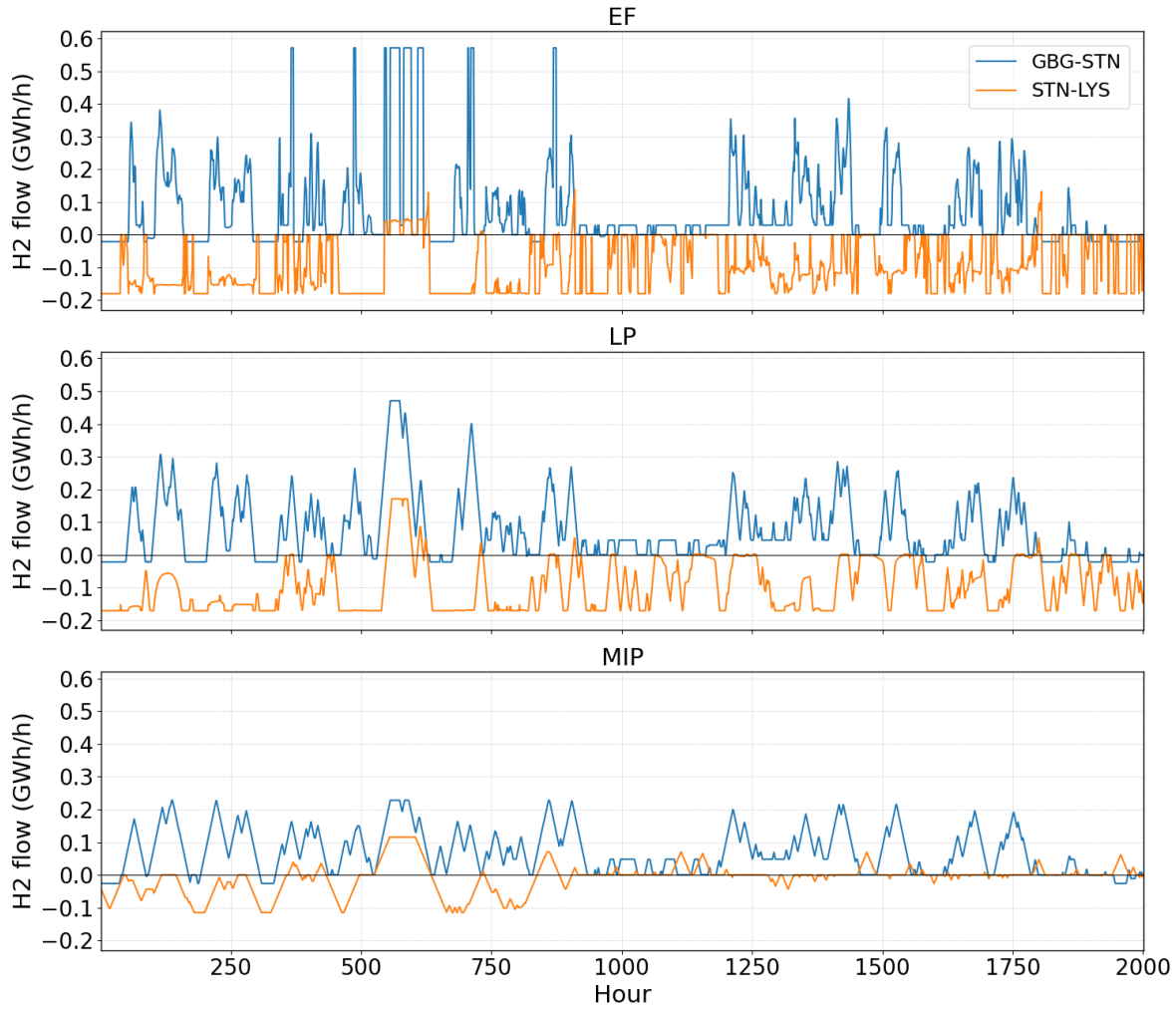


Figure 16. Hourly hydrogen flow for the three methods (EF, LP and MIP) used to describe the hydrogen flows in pipelines, over a period of 2,000 hours.

In Gothenburg, only small changes in capacity are apparent when comparing the LP and MIP methods to the EF method, namely in gas turbines that use biogas and electrolysers, but also with the introduction of hydrogen tank storage units that can cover a few hours of the hydrogen demand. This is because Gothenburg is a city with a high demand for electricity and in which the full potential of off-shore wind power has already been reached. Therefore, it is still cost-efficient to import hydrogen from Stenungsund. The net imports of hydrogen are 460 GWh_{H2}/year using the EF method and 430 GWh_{H2}/year with the MIP method. This suggests that even though the pipeline capacity decreases with a more-restricted pipeline implementation due to a diminished ability to handle rapid variations, the net amount of hydrogen transported remains similar.

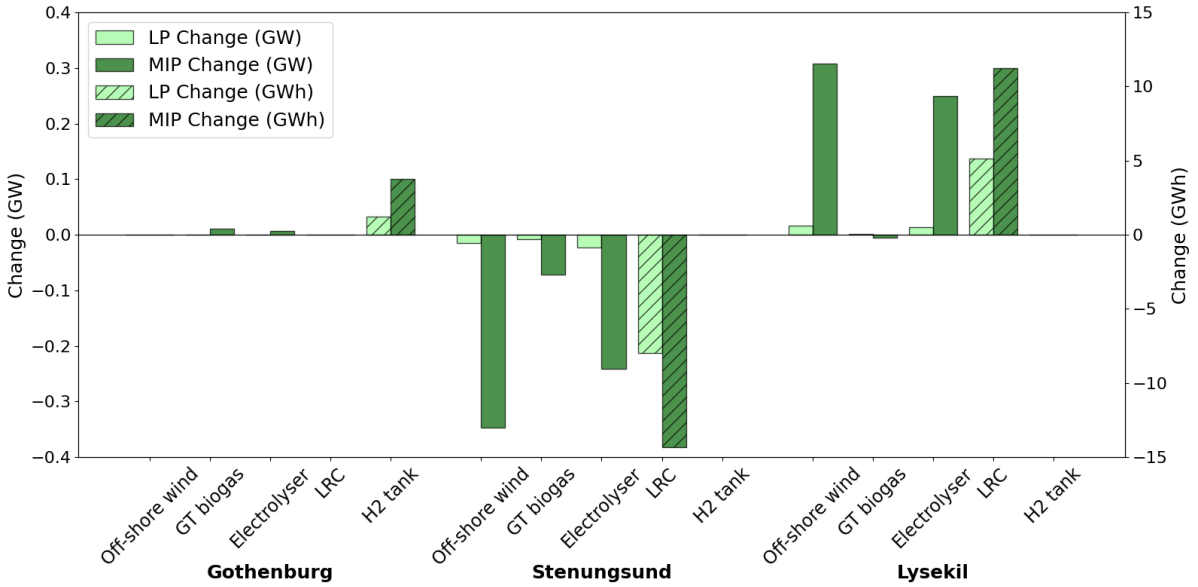


Figure 17. Changes in technology investments when comparing the EF method with the MIP and LP methods, for the three studied municipalities. GT biogas, gas turbine using biogas; LRC, lined rock cavern.

In Table 6, the computational times for the three methods are compared. As expected, the EF method is fastest, followed by the LP method and, lastly, the MIP method. The LP method, for the studied system, requires more than double the computational time than does the EF method, although it still reaches the solution within minutes. The MIP method takes significantly longer to solve, requiring several hours of computation.

Table 6. Computational time, including the pre-solve and after-solve processes, for the three methods used.

	EF	**LP**	**MIP**
Time (HH:MM)	00:05	00:12	15:05

To summarise, including equations to describe the gas dynamics in the energy system optimisation model affects investments in pipeline capacities, hydrogen storage units, and electricity-generating technologies, primarily off-shore wind. A more-constrained flow yields a more-distributed hydrogen generation profile, where both storage units and electrolyser capacities are moved, to a larger extent, to each modelled node. As less hydrogen is produced centrally with a more-restricted representation of gas dynamics, the localisation of off-shore wind power is affected, suggesting that creating overly flexible operation of pipelines impacts the cost-optimal energy system design.

Sensitivity analysis

The LP method is used to evaluate how the allowed pressure difference between two consecutive steps in each cross-section and the diameter size used to calculate the coefficients to describe Equations (10) and (13), affect investments in and operation of the pipelines.

In order to use the LP method, some simplifications need to be made, as compared to the MIP formulation. One of these simplifications involves assuming a specific diameter of the pipeline, in order to calculate the pipeline coefficients (a_l, b_l and c_l) that are needed to implement Equation (17). In Equation (7), the diameter, d, is multiplied by the area of the pipeline squared,

A^2 (which is also dependent upon the diameter), meaning that the diameter is an important parameter when calculating the coefficients. It should be emphasised that the model can still choose to invest in a larger capacity than that corresponding to the diameter of the pipeline used to calculate the coefficients, if there is no limit on the maximum and minimum pressures of the pipeline. Instead, it is the extent to which the flow can change between two consecutive hours that becomes restricted. For the LP results presented so far in this section, a diameter of 0.2 m is used. For comparison, the diameters invested in using the MIP method are 0.14 m between Stenungsund and Gothenburg, and 0.11 m between Lysekil and Stenungsund. The diameters investigated with the LP method are in the range of 0.1–0.5 m. A diameter of 0.5 m, which is the smallest diameter size presented in the European Hydrogen Backbone report, gives a flow of around 1.2 GW_{H2} with the assumed operational pressures listed in the report [69]. When a larger diameter is used to calculate the pipeline coefficients, larger capacities are invested in, and faster flow fluctuations occur in the pipeline (Figure 18). Similarly, a pipeline diameter of 0.1 m gives a result that is more similar to that obtained with the MIP method.

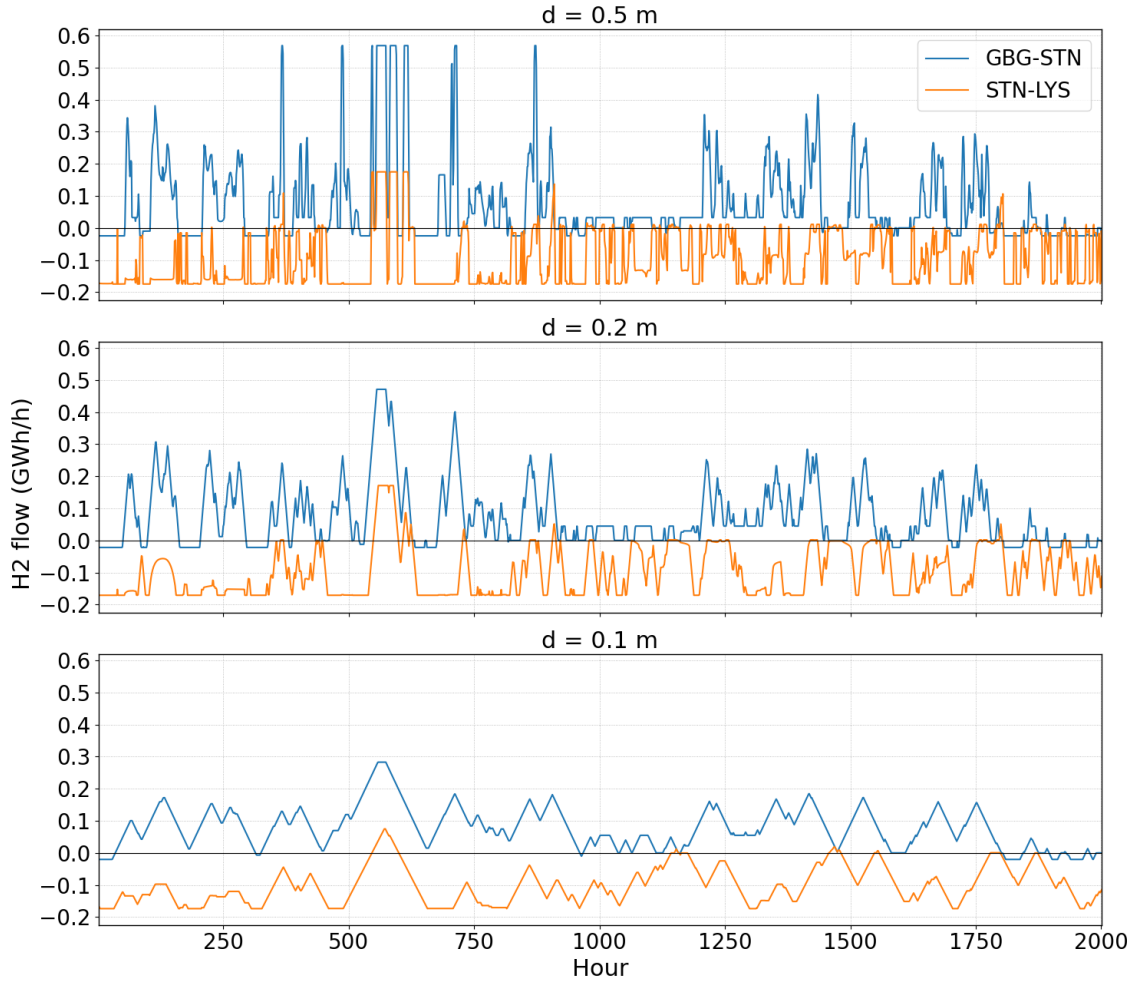


Figure 18. Hydrogen flow dependencies on the pipeline diameters (d) used to calculate the flow coefficients (a_l, b_l and c_l).[1]

[1] For a more-comprehensive figure that includes additional pipeline diameters, the reader is directed to the Licentiate thesis [91].

In the results presented for the LP and MIP methods in this section, an allowed pressure difference of 0.5 bar is assumed. Here, the allowed pressure difference in each segment between two consecutive hours is varied between 0.1 bar and 10 bar. In Figure 19, the hourly hydrogen flow is presented for three of the seven pressure differences investigated. As the allowable pressure difference is increased, the flow through the pipeline becomes increasingly similar to the hydrogen flow in the EF method, as presented in Figure 19, as a higher tolerance for changes in pressure between hours allows for larger fluctuations in flow. With an allowed pressure difference of dP = 0.1 bar, the pipeline capacity in which investment is made is the smallest for the compared pressure differences, following a similar pattern as that seen when using the MIP method. In the EF model runs, the pipeline capacities invested in are 0.570 GW_{H2} between Gothenburg and Stenungsund and 0.180 GW_{H2} between Stenungsund and Lysekil, which are close to the values presented in Figure 19 when the allowed pressure difference increases (dP ≥5 bar).

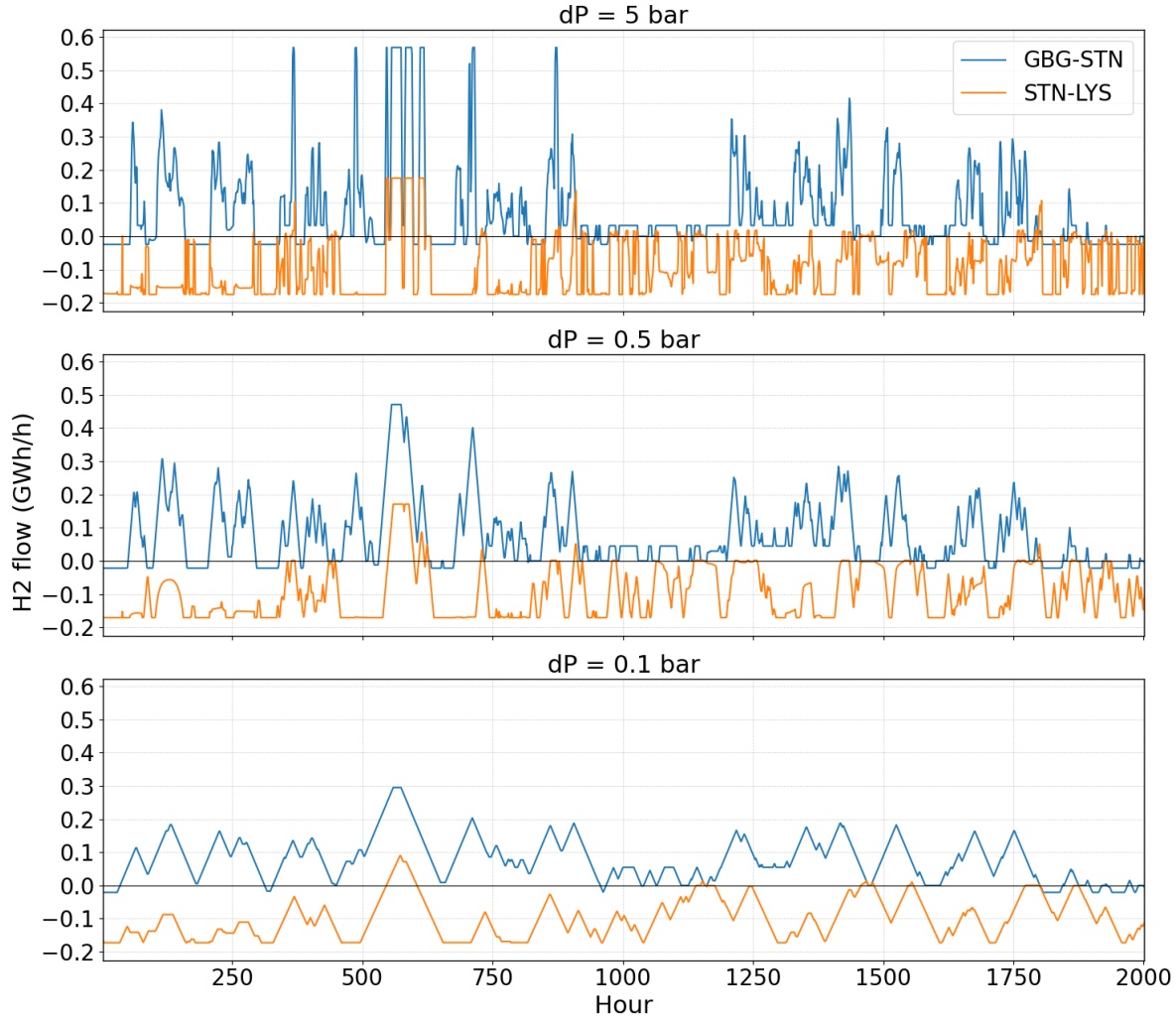


Figure 19. Hydrogen flow dependencies on allowed pressure differences (range, 0.1-5.0 bar) over 2,000 consecutive hours using the LP method.[2]

[2] For a more-comprehensive figure that includes additional pressure differences, the reader is directed to the Licentiate thesis [91].

5.3.2 Meshed system

In the meshed system, two methods to model the hydrogen flows in pipelines are evaluated for the regional scope with three demand nodes (Lysekil, Stenungsund and Gothenburg) and four production nodes in the region (Dals-Ed, Töreboda, Trollhättan and Ulricehamn). In total, there are ten different hydrogen pipeline connections in which investments can be made. In this section, the EF and LP methods are first compared to each other in terms of invested-in capacity, hourly hydrogen flow, and annual flow. This comparison is followed by a sensitivity analysis of the allowed pressure difference in each pipeline cross-section for every consecutive hour.

Comparison of methods

In Figure 20, the hourly hydrogen flows for the EF and LP methods are presented for the two cases where investments in pipelines are allowed, as described in **Paper III**. Compared to the results presented in Section 5.3.1, the hydrogen flows presented in Figure 20 only take positive values. This means that the flow in this system becomes uni-directional, from producer to consumer, as compared with the linear system where hydrogen was transported in both directions between the three nodes. Again, the hydrogen flow becomes less-flexible when the gas dynamics are considered in the modelling. However, unlike the results presented in Section 5.3.1, the pipeline capacities in which investments are made are not impacted. This is because the flexibility of the hydrogen flow is, instead, compensated by LRCs at both the export and import nodes (except in Gothenburg, where LRC units are not allowed but where imports of hydrogen are almost continuous anyway). In Gothenburg, most (95%) of the annual hydrogen is imported and the electrolyser is operated when the levels of imports decline (e.g., Hours 380–400). This suggests that for this case and in the studied system in which pipeline investments are made so as to make it possible to produce hydrogen at nodes other than the hydrogen demand nodes and when there are other options to provide flexibility, the inclusion of gas dynamics has only minor impacts on pipeline investments and the annual level of hydrogen transfer, although it does affect the hourly operation.

Figure 21 presents the investments in electrolysers and LRC storage units for the case that allows investments in both hydrogen pipelines and power line reinforcements, as described in **Paper III**, comparing the EF and LP methods. Only the seven nodes with hydrogen demand and production are compared. Small differences are observed with regards to electricity production investments and the annual electricity supply. When the gas dynamics is included (LP compared to EF), slightly smaller electrolyser capacities are found in Gothenburg, Trollhättan and Dals-Ed, while the electrolyser capacities increase in Stenungsund, Lysekil and Töreboda, in the case with both power line reinforcements and pipelines. For the LRC storage units, the largest impact is seen in the pipelines only case, where mainly Stenungsund (+4%) and Trollhättan (-10%) are affected. Using the EF method, an additional 25 GWh_{H2} (+8%) of hydrogen is transported from Trollhättan to Gothenburg, as compared to using the LP method. However, overall, the impact of including methods to model the gas flow can be regarded as limited in the regional energy system configuration.

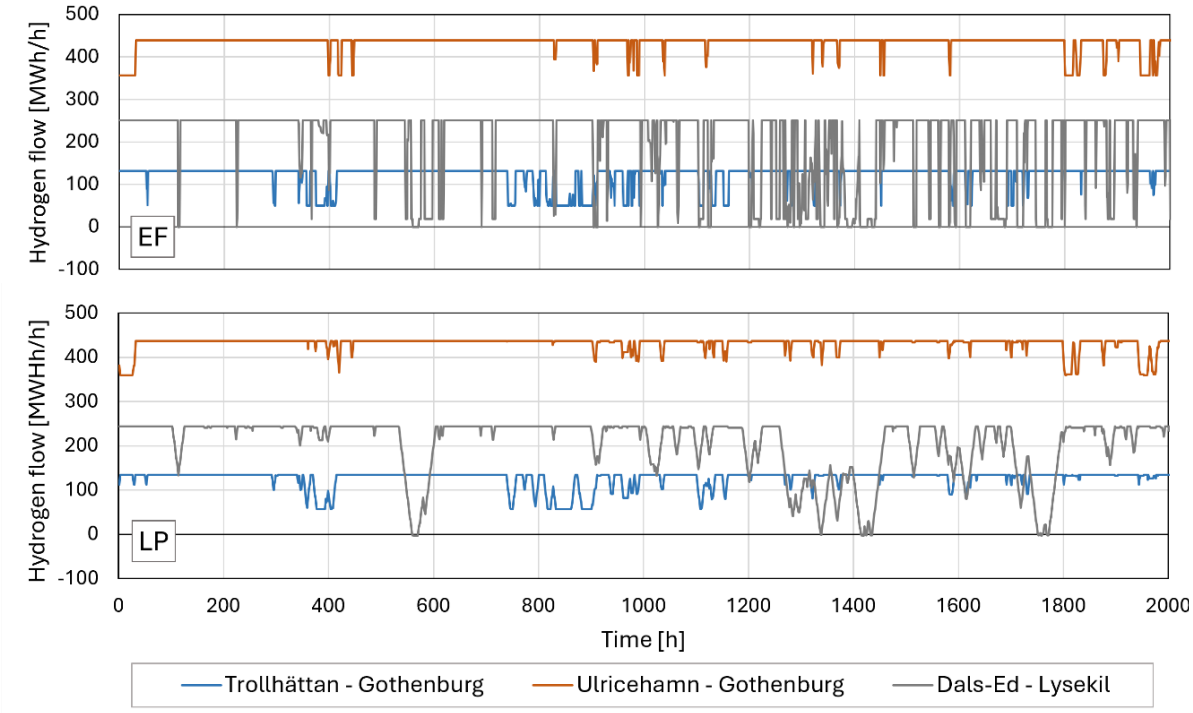


Figure 20. Hourly hydrogen flows comparing the EF (top) and LP (bottom) methods for the case that allows both power line reinforcements and pipeline investments, presenting three out of the ten pipeline connections.

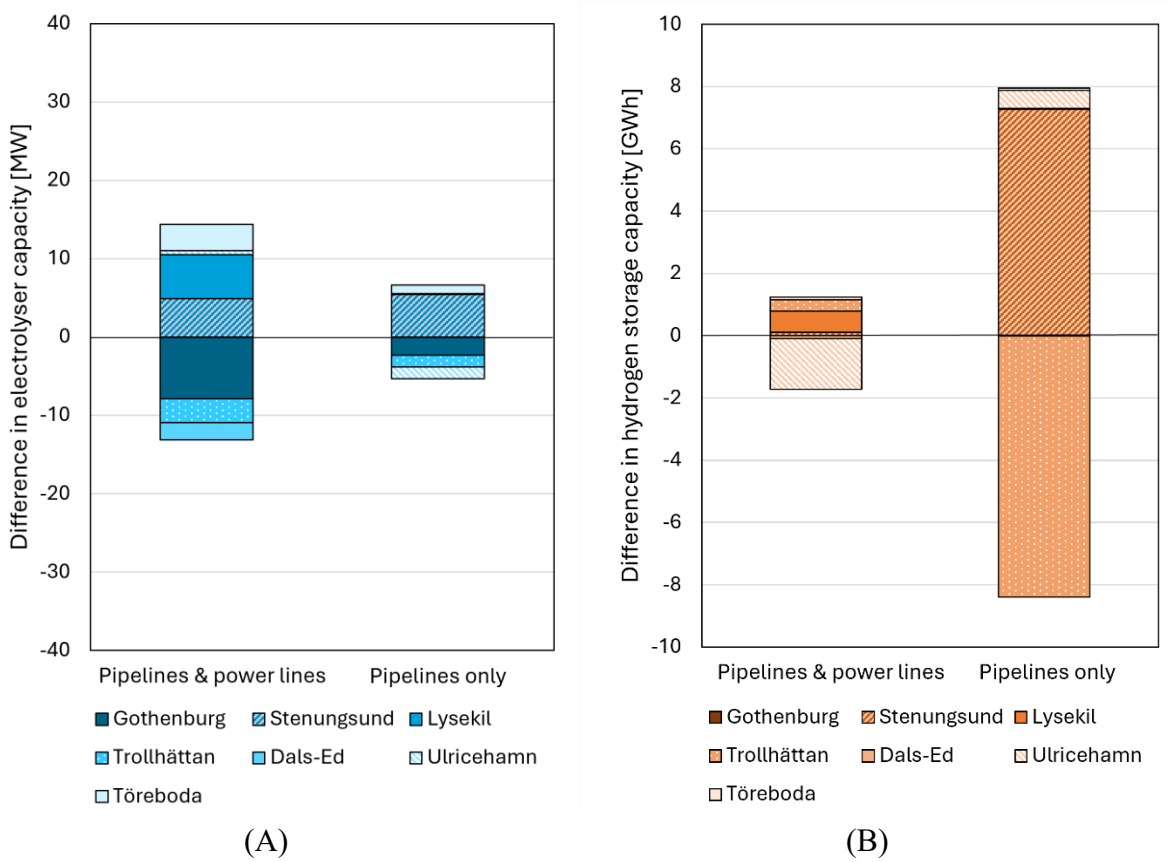


Figure 21. Capacity investments for the pipelines only and pipelines and power line reinforcement cases as described in **Paper III**, comparing the EF method to the LP method.

Sensitivity analysis

The LP method is used to evaluate how the allowed pressure difference between two consecutive steps in each cross-section affects investments in and operation of the pipelines. For the meshed case using the regional scope, the pressure difference was limited to 0.5 bar in the previous section and is here evaluated using allowed pressure differences of 0.1 bar and 5.0 bar using the case in which both power line reinforcements and pipeline investments are available. In Section 5.3.1, it was shown that restricting the pressure difference in the LP method resulted in a flow pattern similar to that obtained using the MIP method. Similar to the results presented in Section 5.3.1, the flow of hydrogen becomes less-fluctuating with a pressure difference of 0.1 bar, as compared to 0.5 and 5.0 bar, as seen in Figure 22. However, unlike the results presented in Section 5.3.1, there are no significant impacts on the energy system configuration when it comes to the location of electricity production technology investments and the annual electricity supply. Similarly, the total pipeline capacity and annual level of hydrogen transfer are barely affected. For example, the pipeline capacity between Dals-Ed and Lysekil goes from 240 MW_{H2} with pressure difference of 0.1 bar to 250 MW_{H2} with pressure difference of 5.0 bar, and this is the pipeline connection that is most strongly affected by pressure differences. The changes in LRC storage units are within 1%. The strongest impact is on the electrolyser capacity in Gothenburg, which goes from 120 MW to 90 MW with pressure differences of 0.5 bar and 0.1 bar. Instead, hydrogen imports to Gothenburg increase. Nevertheless, the imports are in the range of +/-1%, with a pressure difference of 5 bar or 0.1 bar as compared to a pressure difference of 0.5 bar.

5.3.3 Summary

Including methods to model the gas flows in pipelines has a potent effect when the pipelines themselves provide flexibility to the system. In the model runs, which include only Gothenburg, Stenungsund and Lysekil, investments in off-shore wind power, electrolysers, and LRC storage units are all affected by implementing a more-detailed representation of the gas flow (LP and MIP methods compared to EF method). These changes are driven by the fact that the pipeline offers flexibility, especially between the node with good availability of off-shore wind power (Lysekil) and the node with both good off-shore wind power and large electricity import capacity (Stenungsund). With restrictions imposed on the hydrogen flow (LP and MIP), the hydrogen supply is to a large extent balanced locally with larger investments in LRC storage units and electrolysers in Lysekil, while investments in Stenungsund decline, thereby affecting the most cost-efficient energy system configuration. However, when the geographical scope is expanded to cover a region, restricting the gas flow (LP compared to EF) has very little impact on the cost-optimal energy system configuration. This is because the flexibility in hydrogen flow can instead be provided by LRC storage units in the hydrogen production nodes. Another difference noted when comparing the hydrogen valley and the region is that the hydrogen flow is to a large extent uni-directional in the regional system, whereas in the hydrogen valley hydrogen is transported back and forth between the nodes. This suggests that implementing a more-detailed representation of the gas flow in energy system optimisation models has the strongest effect when the connected nodes have different potentials for flexibility, whereas there are only minor effects on systems in which flexibility can be met cost-efficiently by other means (e.g., LRC storage units in both nodes).

Based on the findings of this thesis, it is recommended to use the EF method for an initial understanding of the system. The MIP method can then be used for studies of smaller systems in which different nodes offer different dynamics regarding hydrogen supply flexibility, such as the possibility for handling electricity production locally. For larger systems, the EF method can provide the initial pipeline capacities that are used to calculate the pipeline coefficients needed for the LP method.

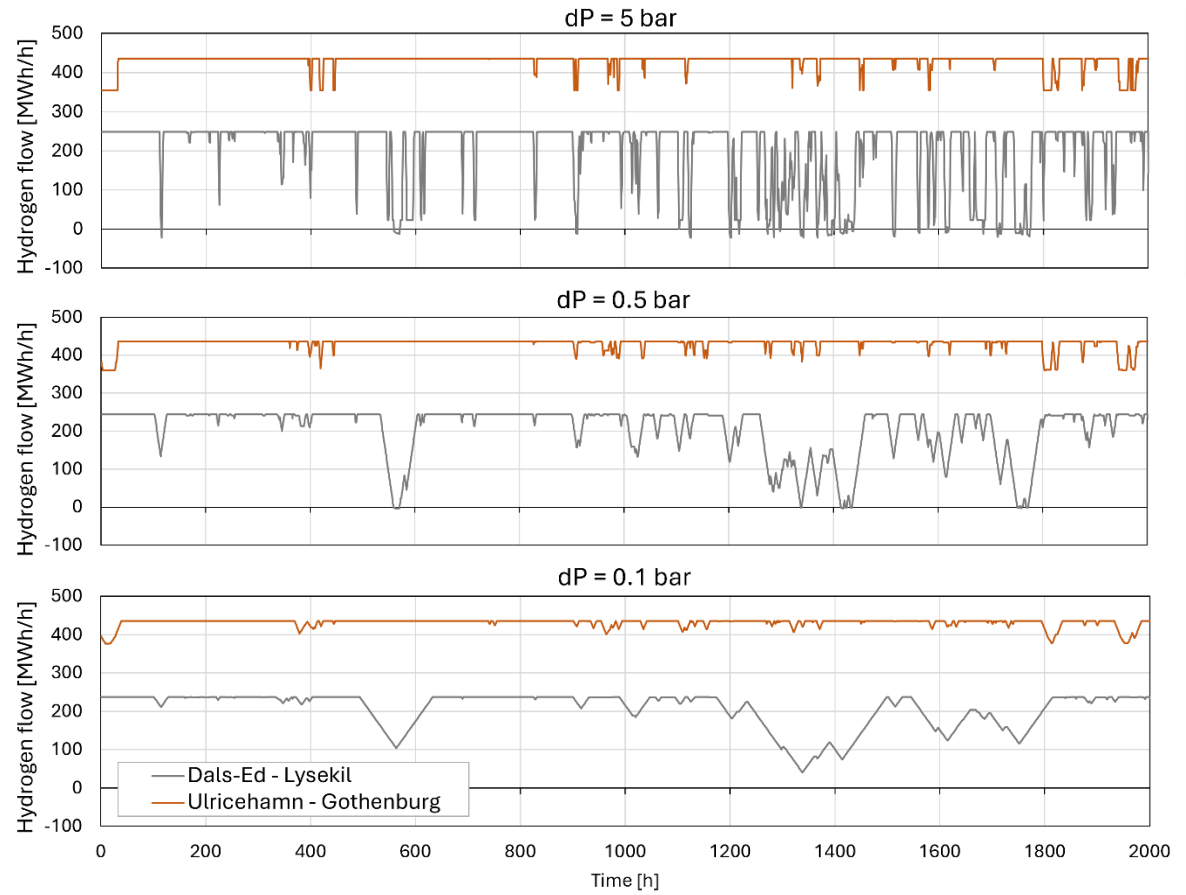


Figure 22. Hydrogen flows in the pipeline connections Dals-Ed to Lysekil and Ulricehamn to Gothenburg with three different pressure differences (0.1 bar, 0.5 bar and 5.0 bar).

6 Discussion

This section includes discussions on the modelling assumptions (Sub-section 6.1), impact of the studied geographical scope (Sub-section 6.2), modelling of pipelines in energy systems models (Sub-section 6.3), and outlook for hydrogen infrastructure (Sub-section 6.4).

6.1 Modelling assumptions

All of the work presented in this thesis is based upon the optimisation of total system cost given a set of techno-economic parameters and fuel costs. Other parameters, such as social and political factors, could also influence the results, for example social acceptance of wind power. Here, the available area for on-shore wind power in **Paper III** is based on a GIS analysis where land that is unsuitable for wind power is removed. These areas are for example areas with a high population density and areas of interest for the armed forces. The remaining area is limited based on a factor that represents the fact that not all possible land areas can be used for wind power investments. For off-shore wind power, the available capacities listed in **Papers I**, **II** and **IV** are based on currently ongoing projects along the coast. Already, in the course of this PhD project, two of the wind power projects have been denied while two projects have been accepted, one outside Stenungsund and the other outside Lysekil. Long-term, there could be new projects along the coast but near-term it could now prove difficult to build wind power outside Gothenburg. In **Paper I**, a hydrogen pipeline reduced the system cost more with a limited off-shore wind power capacity of 280 MW outside to Gothenburg than with a larger capacity of 1,000 MW. Under current conditions, this means that a hydrogen pipeline could have an even larger impact on the total system cost.

In all the studies presented in this thesis, Year 2019 is used for the weather profiles, to ensure that the supply and demand are coherent, given that certain demand data are actual measured data for Year 2019. Different weather years impact the capacity factors of wind and solar power, as well as the electricity and heating demands, which are temperature-dependent. Ullmark et al. [92] studied the impacts of different weather years and found that the most-affected technologies were CCGT and open cycle gas turbines (OCGT), while investments in

wind power and hydrogen storage capacity were less-affected. While wind power provides bulk energy, CCGT and OCGT typically manage extreme net-load events, which vary from year to year. Since hydrogen storage units manage regular variations in wind power, their capacities can be expected to be less-sensitive to the specific weather year applied.

Both models used in the work presented in this thesis employ perfect foresight meaning that the models have all the data for the full year and investments and operation can be perfectly planned. With perfect foresight, the model gives an optimal solution that might be hard to achieve in reality. This modelling approach with perfect foresight impacts investments and operation of both generation and storage technologies. For example, hydrogen storage units are dimensioned based on low-wind events and even though low-wind events can have a somewhat predictable duration, it is hard to know when a low-wind event occurs and, in that moment, have enough hydrogen in the storage to cover the period. This could lead to larger investments in storage capacity to factor in these uncertainties. Alternatives to perfect foresight could be limited foresight or stochastic modelling.

Unlike the use of bidding zones in the current electricity system, the method used in the work of this thesis assumes nodal pricing of electricity and hydrogen. This means that when electricity is transported in the region, such transport is based on the marginal cost of electricity in each node. In reality, these differences would not reach the actors, as all the nodes are located within the same bidding zone, SE3. For this reason, other incentives are needed to influence the relevant actors. Local flexibility markets could be one way to separate bidding zone prices and local investments, so as to optimise the production cost in each node. Still, studies like those presented here could help decision-makers to identify the need to find such incentives, and aid developers in finding suitable areas for electricity production.

In all the studies of this thesis, carbon neutrality is assumed in Year 2045, which limits the technology portfolio, and nuclear power is not allowed as an investment in the region in any of the appended papers. The latter reflects urban areas not being suitable sites for nuclear power (**Papers I**, **II** and **IV**) or that there are currently no nuclear power sites in the region (**Paper III**). For other regions, however, nuclear power could emerge as an alternative if, for example, the availability of wind and solar PV power is low. Even in the region studied in this thesis, applications have been made for small modular reactors that could be of interest to implement in future studies or in other regions. Pipelines are incentivized by connecting nodes with good availability of low-cost electricity and possibility for large-scale storages to nodes with hydrogen demands. With more centralized electricity production (e.g nuclear) it is likely that there would be less incentives for a meshed hydrogen grid connecting several sites but instead having a larger pipeline route, similar to the natural gas network in place today. The operation of the electrolysers in the studied area react to electricity cost and it is likely that the cost for electricity will continue to fluctuate even with investments in new nuclear power in Sweden [83]. Therefore, investments in over-capacity of electrolysers together with hydrogen storage units will likely remain, although the specific capacity might change.

Electrolysis is assumed to be the only available technology for hydrogen production, resulting in a significant increase in the annual electricity demand. Currently, the hydrogen demand in the studied region is met with SMR plants that use natural gas and hydrogen as a by-product

from industrial processes. In **Paper II**, the case with late access to off-shore wind power and electricity import capacity reinforcements faces extensive use of biogas, since only electrolytic hydrogen is allowed. This scenario seems unlikely, as biogas could instead be used directly in the already existing SMR units. Therefore, a natural continuation would be to implement more technologies for hydrogen production, as well as to exploit the possibility to import hydrogen from other regions. This becomes especially interesting when studying the transition and near-term hydrogen supply to industry. In the studies by Jodry et al. [30], Zhang et al. [31] and Roshan Kumar et al. [26] a combination of hydrogen production technologies gives more flexibility to the local energy system. Having several hydrogen production technologies like SMR of biogas, SMR with CCS or cracking of ammonia together with electrolysis also gives redundance to the system. As highlighted by Kountouris et al. [53], there is a risk associated with continued use of natural gas in SMR units with CCS in that it opens up for continued fossil fuel dependence.

The fuel costs are fixed and do not depend on how much fuel is used in this work. From the results presented in **Paper II**, where a large share of the annual electricity is supplied from biogas-fuelled technologies without early access to off-shore wind power, it seems likely that the price of biogas would increase. Similarly, due to carbon being an essential building block for many of the most-common products in society, the future need for green or recycled carbon atoms will likely be higher. This also raises the question as to how long the combustion of biofuels for electricity and heating, which emits green carbon back to the atmosphere, will be acceptable. Instead, new synergies could be found whereby the carbon is captured and can be used in industrial processes, such as plastics production. In future work, it would be of interest to implement a carbon balance, in addition to the electricity, heating and hydrogen demands present in the model used for the work of this thesis. A more-dynamic way of modelling fuel prices, based on how much fuel is needed, could also improve the modelling framework. The future demand for hydrogen used in this thesis is based on the continued existence of refineries and chemical clusters in the region. The models used do not capture the price sensitivity of the demand. If the cost of industrial electrification turns out to be too high, investments might not be made, and production might be moved elsewhere. Still, because of the uncertainty regarding future hydrogen demand, different hydrogen demands have been evaluated in this work and some trends remain, for instance regarding electrolyser over-capacity and pipeline investments that are still cost-efficient even with a lower (4.9 TWh_{H2}/year) hydrogen demand than today (6.4 TWh_{H2}/year).

Apart from costs and technical properties, other aspects, such as material scarcity, could impact the cost-optimal energy system configuration presented in this work. As more investments are made in carbon-neutral technologies, competition for materials arises. It is possible that minimising both material usage and total system costs impacts investments in, for example, the over-capacity of electrolysers. Still, investments in over-capacity and storages could improve resilience. The risk of depleting water supplies for electrolytically produced hydrogen is not considered in the present work, nor the possibility to use oxygen as a by-product from the electrolysis process. However, distributed hydrogen production could relieve the risk for depleting water resources compared to having hydrogen production focused to a few locations.

6.2 Geographical scope

The region and municipalities studied in this work have good local conditions for wind and solar PV power, as reflected in the most cost-efficient energy system configurations presented here. For other regions, these results could differ. For instance, in Gällivare, the availability levels of both hydro power and wind power are good, and this results in less over-capacity of the electrolysers. In regions with poor availabilities of wind, hydro power, and solar PV, other technologies, such as nuclear power, could become cost-efficient. Studies that cover Europe [50,51,53] typically find that hydrogen is most cost-efficiently produced in areas with good availability to either wind (e.g., Ireland) or solar PV (e.g., Spain) power and transported to central Europe where most of the hydrogen demand is located. The work performed here shows that even in smaller geographical scopes with less-significant differences in wind power and solar PV potentials, distribution grids can still offer a cost-effective way to balance the supply and demand based on regional differences in wind and solar power, as well as the possibility for storage. It could be easier for a hydrogen network to be formed as a hydrogen cluster as fewer actors are involved. With continental wide hydrogen transmission, permission times could delay the implementation of pipelines whereas smaller regional networks likely have a lower threshold for being built. The regional clusters could then be connected to national or continental hydrogen transmission grids.

In **Papers I**, **II** and **IV**, each municipality is modelled as a single node, which means that the transfer of electricity and district heating within these nodes is not considered. This could impact the possibility to utilise, for instance, the waste heat from the electrolysis process, as fluctuations in heat production could be difficult to implement in the current district heating grid layout [93]. Within the time-frames studied here, the district heating network could be adjusted to handle more-fluctuating flows, so as to make use of recovered waste heat, although the cost for such adjustments is not implemented in the modelling framework. The same goes for the low-voltage grid, which is not considered here. Congestion in the low-voltage grid and district heating network could affect the localisation of technologies, which is an aspect that is not studied here.

6.3 Hydrogen pipelines in energy system models

Similar to the findings presented by Shchetinin et al. [57], including the gas dynamics in the energy system optimisation model used in the present work affects the investments in both pipeline capacities and hydrogen storage, as well as the investments in off-shore wind power. Interestingly, while Shchetinin et al. [57] found that including the gas dynamics increased investments in pipelines, the present study finds that investments in pipelines are decreased. The reduction in pipeline investments could be explained by that the pipelines offered flexibility that, when restricted, could more cost-efficiently be provided by local investments in hydrogen storages.

The difference between the LP and MIP methods is significant, with the MIP method showing a stronger effect on the overall energy system configuration than the LP method, in terms of the location of technology investments. The MIP formulation is more computationally demanding, which could prove to be problematic in larger models than the one used in this thesis. The LP method is based on assumptions as to the diameter of the invested in pipeline,

and the same assumption (0.2 m) was used for both pipeline connections, although the results showed that the actual invested in pipeline capacity differed between the connections. As seen in the evaluation of the different pipeline methods, this means that for a pipeline with a smaller diameter than 0.2 m, the flow becomes overly flexible, and for a pipeline with a larger diameter than 0.2 m the flow becomes overly restricted. It is possible to instead of assuming the same diameter for both pipelines, include a specific diameter assumption for each pipeline connection. When possible, the MIP method should be chosen as it gives the most accurate description of the hydrogen flow between the methods presented here. In order to do this, the modeler need to already know approximately what size of pipeline that can be expected. Using the MIP method, the EF method can still give initial information of what range of pipeline diameters that should be included in the set of available pipeline diameter sizes. When the MIP method is too computationally demanding, the LP method can be used. The EF method can, again, give initial information of what diameters that is likely for each pipeline connection that can then be used to calculate the pipeline coefficients for each pipeline connection. However, some iterations might be needed using the LP method so that the pipeline flexibility does not get over-estimated while not limiting the maximum hydrogen flow too much. This is especially important when the pipeline provides flexibility with rapid changes in hydrogen flow and, in system like the one studied here, provide bi-directional flow.

The investments in pipelines in **Papers II** and **III** are implemented linearly assuming a pipeline diameter of 0.2 m (~300 MW_{H2} with the pressure limits assumed in this study) for most pipeline connections. Since the pipeline investments are implemented linearly, this also means that in some cases, the cost-optimal pipeline capacity is smaller than what is likely for an actor to build for the distances studied here. The smallest pipeline diameter listed in the data catalogues of the Danish Energy Agency are, for comparison, 8 inches (~0.2 m), while we see investments in even smaller capacities in our studies. For the system studied in **Paper III**, it is possible that the investments in smaller pipelines could more easily be substituted with increasing power line reinforcements for the existing power grid. Even so, some of the investments in pipelines can be seen as robust (e.g., Ulricehamn – Gothenburg, and Dals-Ed – Lysekil). An interesting difference between **Papers II** and **III** is that pipelines facilitate more-central hydrogen production in **Paper II**, while hydrogen production is more distributed in the region in **Paper III** when pipelines were allowed but not power line reinforcements. With both power line reinforcements and hydrogen pipelines, hydrogen production again became more centralised. This suggests that most cost-efficient distribution system changes depending on whether hydrogen is supplied within a hydrogen valley or by regional actors.

In this work, the cost of pipelines is extrapolated from reports by the European Hydrogen Backbone [69]. There is an uncertainty in the cost of hydrogen pipelines, in particular since pipeline investments in this work are typically smaller than those presented with costs in the reports. Furthermore, the MIP method is the only method studied here that can capture opportunities of scale, as smaller pipelines become more expensive per capacity than larger pipelines. The cost of hydrogen pipelines has therefore been varied in all studies and investments in pipelines still occur, although the invested capacity changes. Thus, results indicate that the service provided by pipelines stands quite robust, even when investments can be made in power line reinforcements.

To continue the evaluation of the methods used to describe the hydrogen flow, and understanding how simplifications of the gas dynamics in energy system optimisation models affect the cost-optimal energy system configuration, it would be interesting to compare the results using the non-linear gas equations, without the simplifications induced by plane fitting a non-linear equation. The representation of compressor stations is simplified and based on the flows of energy rather than pressure differences. This means that transporting hydrogen always comes at a cost for electricity, although that cost might be over-estimated. For the factor describing the electricity demand that is needed, it is assumed that the pressure increases from ambient to 70 bar, which is the highest allowed pressure for the pipelines in these studies. It is not certain that a pressure of 70 bar is needed. Looking at the results in, for example, Sub-section 5.2.2, the difference in electricity demand with and without pipelines is small in comparison to other loads. Therefore, it seems unlikely that the simplification will affect the total energy system configuration, although it could have importance for pipeline operators.

6.4 Outlook for hydrogen infrastructure

Common to the studies presented in this thesis are investments in the over-capacity of electrolysers, which are related to the deployment of wind power. For industries, this is different from how investments are usually made, where investments are made to optimise profit and have a shorter payback time using a higher discount rate than applied in this work. Investing in over-capacity of electrolysers leads to a high up-front cost and longer payback time. Furthermore, industrial sites do not see nodal prices but are instead exposed to the electricity price for the bidding zone in which they are located, unless they also invest in, for instance, a wind power farm that is dedicated to producing hydrogen. The scope of the hydrogen valley presented here represents industries that make use of the local differences in electricity production potentials to meet the hydrogen demand at the lowest societal cost. The flexible operation of an electrolyser thus is cost-efficient but since industries typically see different interest rates and pay back times than society, the investment decision differs from these presented in this work. The interest rate for industries could be reduced by, for example, loan guarantees that could reduce the differences seen in this work compared to how industrial investment decisions are typically made. Other measures could be local flexibility markets where industries are paid to reduce their load at certain hours. An alternative to industries investing in electrolysers is for another actor to produce, distribute and sell hydrogen to the industries. This alternative could be represented by the results from the regional model, where hydrogen production could become more distributed and make use of sites with good availability of low-cost electricity.

Hydrogen pipelines already exist for large-scale energy transfer. Nonetheless, hydrogen is different from natural gas or biomethane and there are still uncertainties regarding safety. As regulations for hydrogen pipelines in the studied scope are lacking, this could affect the time horizon in relation to how fast a hydrogen pipeline grid could be built. Power lines typically demand a larger area than pipelines per capacity of energy transferred, which could be a factor in favour of hydrogen pipelines from a social acceptance point of view, with regard to new capacities. On the one hand, power grids already exist and could have lower barriers to new

investments. Having both power lines and hydrogen pipelines could provide redundance in the region.

The results presented in this thesis also show a different way of operating gas networks. Currently, there are consumers that have a continuous need for natural gas, meaning that the flow direction has been typically uni-directional, from producer to consumer. This work shows that a future role of hydrogens pipelines could be to balance production and demand by transferring hydrogen in both directions.

7 Conclusions

This thesis investigates how urban and regional energy systems, in relation to electricity, district heating and hydrogen, are affected by large-scale industry electrification through electrolytically produced hydrogen. Different scenarios are evaluated using energy system optimisation models in which the total system cost is minimised. The roles of electricity and hydrogen distribution grids are evaluated, with a special focus on how to model hydrogen flows in pipelines.

It is found that the electricity demand to produce electrolytic hydrogen can be cost-efficiently supplied by variable renewable sources (on-shore and off-shore wind power for the region investigated on the west coast of Sweden) by over-sizing the electrolyser and combine it with underground storage units (i.e., lined rock caverns). The cost-optimal electrolyser over-capacity was found to depend on the deployment of mainly wind power. In the system studied, off-shore wind power is complemented with solar PV power, combined heat and power plants and gas turbines. The results show that in regions with good conditions for wind and solar power, local generation is cost-efficient and can, together with local flexibility, reduce dependence on expanded power grid capacity to achieve electrification.

For urban areas or regions with electrification of industry, the increase in electricity demand is typically substantial. The results show that either expansion of local variable renewables or reinforcement of the electricity import capacity to a city or region is needed to provide electrolytic hydrogen at a low cost. Allowing for either of these two options has a similar effect on the total system cost (+4%) compared to having early access to both off-shore wind power and electricity import reinforcements, although the energy system configuration differs. Delaying both options until hydrogen demand rises increases the total system cost by 18% mainly due to large investments in and operation of combined cycle gas turbines. For the three industry clusters on the west coast of Sweden, this suggests that access to either off-shore wind power or electricity grid reinforcements is crucial for meeting a high demand for hydrogen from industries through electrolysis in a cost-efficient manner.

The results show that, when access to electricity is proficient, power-to-heat technologies take on most of the new investments to meet the annual heating demand, with investments primarily in heat pumps and electric boilers. Heat-only boilers fuelled with biogas were operated during hours of high demand for district heating and high marginal cost for electricity. As the local electricity system became more congested, here due to hydrogen production, combined heat and power plants became competitive, as there were demands for both electricity and heat during many hours of the year. Waste heat from hydrogen production with investments in industrial heat pumps is found to be cost-efficient to recycle in the district heating system.

When allowing for investments in hydrogen pipelines, hydrogen production is moved to areas that have access to low-cost electricity and the possibility to build lined rock cavern storage facilities. The ability to import electricity from the surrounding grid is also found to be important when including hydrogen pipelines, as it increases the number of full-load hours for the electrolyser. When including only three demand nodes, representing a hydrogen valley, hydrogen production becomes more-centralised to the node that has a strong connection to the regional electricity grid as well as good availability of off-shore wind power. When the geographical scope is expanded to represent a region of Sweden with 126 nodes, hydrogen production is found to be moved to areas with access to low-cost electricity, mainly from on-shore wind and solar power. Furthermore, electrolyser over-capacity is found to increase with investments in power line reinforcements, hydrogen pipelines or both together.

Investments in hydrogen pipelines are found to be cost-efficient under a broad set of assumptions, not only when these pipelines are the only option to transport hydrogen between industrial sites, but also in the regional scope where investments in power line reinforcements can be made. Changing the cost of pipelines and the hydrogen demand affects the capacity of the pipelines, although the pipelines remain in the system to offer bulk energy transport between areas with good conditions for low-cost electricity generation and access to flexibility, such as the possibilities to build underground hydrogen storage units and to trade electricity. Investments in fuel cells are not made, meaning that the hydrogen pipelines do not out-compete power line reinforcements in the region as the primary infrastructure to distribute energy. Thereby, the most cost-efficient energy system configuration is that with investments in both power line reinforcements and hydrogen pipelines.

Restricting the flow of hydrogen by considering gas dynamics have different impact on the energy system configuration based on the role of the pipeline in the system. When hydrogen flow is uni-directional, from production node to demand node and providing bulk energy, restricting the hydrogen flow has minor impact on the energy system configuration and pipeline capacities. When hydrogen flow is bi-directional and offers flexibility between hydrogen demand nodes, restricting the flow impacts investments in pipeline capacity electrolyser capacity. The localisation of electrolysers, wind power and storage capacity is also affected and become more distributed with a restricted hydrogen flow than without. This suggests that there is a risk associated with having a too-simplified version of the pipeline flow, as the operation of the pipeline becomes overly flexible and, thus, takes on the handling of the fluctuations in electricity availability.

Although the MIP method gives the most-accurate representation of hydrogen flow in pipelines, it is computationally demanding, especially in larger systems with several possible pipeline connections. This means that the MIP approach is best-suited to smaller systems with few nodes, while the less-accurate but more computationally effective LP approach is better suited to larger models. Still, it is important that the coefficients used to limit the flow are on the same scale (pipeline diameter) as the modelled flow, as the flow will otherwise become overly flexible than what would be realistic according to the flow equations. Therefore, it becomes the modellers' duty to understand the system under study and to be aware of how these assumptions affect the results.

8 Future work

In this thesis, an attempt is made to understand the electrification of industry through electrolytic hydrogen and its effect on the regional energy system. To reach a better understanding of the complexity of the system, some suggestions for future studies can be made.

- Modelling the gas flows in pipelines

The methods evaluated in this work to represent hydrogen flows in pipelines for energy system optimisation models could be refined by improving the description of the compressors. Here, the compressors consume electricity based on the flow of hydrogen in energy terms rather than based on the desired pressure difference. Similarly, additional compressor stations are typically needed if the pipelines are to cover a long distance, and this could be improved in future work. The results of this thesis suggest that the MIP method provides the most-detailed representation of the gas dynamics in pipeline flows. However, owing to the heavy computational burden, it is difficult to use this method in large models. Still, the simplifications made for the LP method could result in some loss of information. Therefore, it needs to be evaluated further how this process could be improved. An iterative process could be made using only the LP method, where the pipeline coefficients are calculated based on the results from initial EF model runs. It could also be of interest to compare the results from the MIP and LP methods with a non-linear programming approach to understand if and in that case how the results differ.

- Investigate intra-municipality dynamics

In **Papers I**, **II** and **IV**, each municipality is modelled as a single node with demands for electricity, heating and hydrogen. This approach does not consider electricity transfers between the municipalities or district heating network capacities. Both the local electricity grid and district heating network can experience congestion and create bottlenecks where, for instance, waste heat from electrolysis cannot be utilised as effectively for district heating as is modelled here. The electrolyser load changes rapidly from high to low, and this could be a problem for the district heating operator. In a similar way, investments in production technologies do not

consider the energy infrastructures of the municipalities. Therefore, future work could focus on the intra-municipality dynamics.

- Include more alternatives for the production of hydrogen

In the work presented in this thesis, only hydrogen produced from electrolysis is considered. This differs from the usual ways in which hydrogen is obtained today: steam methane reforming, and as a by-product of different industrial processes. Especially when studying the transition over time, including other options to produce hydrogen could provide insights into how the current system could transition to carbon-neutral production.

- Carbon flows

Carbon is an important building block in many materials and fuels that we use on a daily basis. To achieve carbon neutrality, it is likely that the demand for carbon atoms that are recycled or that have plant-based origins will increase. With an increasing demand for non-fossil carbon atoms, using biomass for combustion to produce heating and electricity could be out-competed by other more high-value purposes. New synergies could be formed if the carbon from combustion of biofuels in CHP plants and gas turbines is captured and transported to industries that use carbon as a feedstock. Therefore, future studies could implement a carbon balance, in addition to the electricity, heating and hydrogen balances applied in this work.

- Material scarcity

Investments in electrolyser over-capacity are repeatedly observed on an energy system level. This is because it is cost-efficient to operate electrolysers in a flexible manner to follow the electricity production from, primarily, wind power. However, this means that the need for materials also becomes greater than if the electrolyser capacity is smaller. In this context, it might be of interest to explore rare/scarce materials, as their availability could limit investments.

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