THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

Generation and distribution of hydrogen for industry electrification in urban energy systems

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Abstract

This thesis investigates how hydrogen from electrolysis for industry electrification can be produced and distributed in future urban energy systems. Three municipalities on the Swedish west coast with hydrogen-intensive industries are used as a case study. The industries can be connected by investments in pipelines in order to transport hydrogen between them. Three different ways to include gas dynamics when transporting hydrogen through pipelines in energy system optimisation models are evaluated in this thesis.

Including a greater level of detail of gas dynamics into the energy system models results in a more constrained flow of hydrogen as compared to not including it. A more constrained flow of hydrogen makes the pipelines less flexible in terms of how fast the flow can be changed, affecting investments in pipelines but also hydrogen storage units and electricity production technologies. In the municipality with large availability of off-shore wind power but poor power transmission capacity (Lysekil), the hydrogen storage units and electrolyser capacity increase with a more detailed representation of gas dynamics, while they decrease in the municipality with larger power transmission capacity (Stenungsund). This means that the municipalities need to be more self-sufficient than relying on flexible import of hydrogen.

In the system studied, it is cost-efficient for the three municipalities to collaborate using hydrogen pipelines to supply hydrogen under a wide range of assumptions. Even with a relatively low demand for hydrogen (4.9 TWh compared to 14 TWh annually for the whole system) investments are made in pipeline infrastructure. For the whole system, it is cost-optimal with investments in approximately 40-50% over-capacity in electrolysers. With over-capacity of electrolysers and together with storage alternatives, the electrolyser can adjust its load depending on availability of electricity.

The demand for electricity includes, apart from the industry sector, the residential, commercial and road transportation sectors and it becomes cost-optimal to primarily meet this demand with off-shore wind power and imported electricity. With good connection to the transmission grid and available site for off-shore wind power, Stenungsund becomes a net exporter of hydrogen, while Lysekil and Gothenburg end up as net importers of hydrogen. If the industrial loads in terms of hydrogen increase before the power transmission grid has been reinforced, or off-shore wind power can be invested in, investments are made in combined cycle gas turbines using biogas. With a biogas consumption of 19 TWh (as compared to the total production of biogas in Sweden of 2.3 TWh) and an increase in total system cost of 17% compared to having access to both off-shore wind and power grid reinforcements, indicates that access to either off-shore wind or electricity grid reinforcement is crucial to meeting a high demand for hydrogen through electrolysis from industries in a cost-efficient manner.

Keywords: *industry electrification, hydrogen, hydrogen pipelines, urban energy systems*

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. Timely delivery of the electrification of industry: path dependencies in the transition of an urban energy system. In manuscript.

III. S. Rosén, P. Sobha, C. Wallmark. Waste Heat Availability from Hydrogen-based Industries in District Heating Systems – a Swedish Case Study. Submitted.

Sofia Rosén is the principal author of for all three papers. Associate Professor Lisa Göransson and Dr. Maria Taljegard contributed with method development, discussions and editing to **Papers I** and **II**. Dr. Mariliis Lehtveer contributed with discussions and editing to **Papers I** and **II**. Lic. Parvathy Sobha contributed with modelling and analysis, discussions and writing of the original draft of **Paper III.** Dr. Cecilia Wallmark contributed with discussions and editing to **Paper III.**

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Sofia Rosén

Göteborg, 19th of May, 2025

Table of Contents

1. Introduction

Urban areas account for around 70% of global greenhouse gas emissions and, thus, have a crucial role to play in mitigating climate change [1]. The electrification of end-use sectors, such as transportation, heating and industry, is considered to be an important measure to mitigate emissions in urban areas [2, 3]. As more sectors, such as industry and transportation, undergo electrification, the city energy system is expected to change. An important feedstock for chemical industries and refineries is hydrogen. Currently, hydrogen is mainly produced through steam methane reforming (SMR) of natural gas, in which generates significant levels of CO_2 emissions [4]. An alternative method is electrolysis, whereby electricity is used to split water into oxygen and hydrogen. Obviously, producing hydrogen through electrolysis would result in an increased demand for electricity. However, since electrolysers have the potential to operate in a flexible manner, they can adapt hydrogen production to variable renewable electricity (VRE) generation [5, 6, 7]. Even so, with rapid electrification, there could be a mismatch between the increased demand for electricity and its supply. Pipelines can serve to connect regions with an abundance of VRE generation to regions that have high demands for hydrogen [8]. Even on a local scale, different municipalities can have different characteristics in terms of the availability of VRE and electricity transmission capacity, where a hydrogen pipeline that connects municipalities could help to balance the supply and the industrial demand for hydrogen.

1.1 Aim and research topic

This thesis focuses on exploring how electricity, heat and hydrogen can be supplied in an urban energy system with large-scale industry electrification, and how collaboration around hydrogen infrastructure impacts the supply. The following research questions are addressed:

I. How can the demands for electricity, heating and hydrogen be supplied in a future carbon-neutral urban energy system? (**Papers I** and **II**)
II. How can hydrogen production through electrolysis be utilised in the district heating system? (**Paper III**)
III. Which path dependencies can be observed when studying the timing with which industrial electrification occurs in relation to electricity supply? (**Paper II**)
IV. What is the effect on the urban energy system of collaboration to meet the industrial demand for hydrogen through investments in hydrogen pipelines? (**Papers I** and **II**)
V. What effects do the level of detail describing the gas dynamics in pipelines have on the investments made in pipelines, other technologies, and levels of hydrogen transferred between municipalities? (In manuscript)

In **Papers I** and **II**, three municipalities (Gothenburg, Stenungsund and Lysekil) located on the west coast of Sweden are investigated due to their hydrogen-dependent industries. The aim is to study how the demands for electricity, heating and hydrogen can be supplied. In **Paper III**, only Gothenburg is modelled to study the synergies between hydrogen production and district heating, while considering the demands for electricity, heating and hydrogen. In **Papers I** and **III**, one future year with assumed zero CO_2 emissions is modelled with an hourly time resolution. **Paper II** includes Year 2030 to Year 2080, with an hourly time resolution in every fifth year (2030–2050) and tenth year (2060–2080), to elucidate the path dependencies as industries electrify their processes. In this thesis, three approaches to model the gas dynamics in pipelines are compared: mixed-integer programming (MIP), continuous linear programming (LP), and pure energy flow (EF). In **Paper I**, the pipeline gas dynamics are described using a MIP approach. In **Paper II**, an LP approach is used. In **Paper III**, only Gothenburg is modelled and, thus, no possibility to invest in pipelines is included.

1.2 Contribution of this thesis

The following points summarise the contributions of this thesis:

- Evaluation of methods to model gas flow in pipelines in energy system optimisation models.
- Operation of and investments in hydrogen infrastructure to meet the demands from industry in urban settings.
- Operation and investments to meet loads related to commercial and residential electricity and heating demands when electrification of industrial processes takes place in urban settings.
- Path dependencies in energy system configurations based on the availability of electricity in relation to increased industrial loads over time.

2 Background and related work

This chapter starts with a brief overview of energy system optimisation studies of urban energy systems (Section 2.1) and proceeds with the role of hydrogen in industries that can be located in urban areas (2.2), Further, the concept of clusters that collaborate in meeting the demand for hydrogen (*Hydrogen Valleys*) are explained (2.3) and in Section 2.4 studies on hydrogen pipeline networks are presented.

2.1 Energy systems modelling of urban areas

Urban areas are responsible for 70% of global green-house gas emissions and close to 10% of the increase in global emission since 2015 can be related to urbanisation [1]. Historically, urban areas have imported power that is generated outside the city borders to meet the demand for electricity primarily [2]. With electrification acknowledge as an important measure towards carbon neutrality of cities [3], the interest in local electricity production increases [2]. A review article by Gupta et al. concluded that modelling frameworks for urban energy systems have primarily focused on assessing the impacts of policies on urban energy systems and identifying pathways towards future, low-carbon energy systems [9].

Heinisch et al. [10] studied the integration of the electricity and heating sectors using Gothenburg, Sweden as a case study to evaluate two years representing a near-term future case and a more-distant future case. They used a techno-economic optimisation model with the assumption that no carbon dioxide emissions were allowed. The study concluded that a system with low-cost electricity in the form of solar PV did not only benefit the electricity system but also resulted in power-to-heat technologies in the district heating system. Arabzadeh et al. [11] studied Helsinki's, Finland, energy system for different decarbonisation strategies. They found that energy storage and sector coupling enhanced the integration of renewables. Less studies have focused on hydrogen production as a part of the urban energy system. Wang et al. [12] studied the decarbonisation of ten cities in China through hydrogen production using electrolysis. The potential of hydrogen 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 it was the highest-paying sector. As for long-term energy studies Horak et al. [13] investigated long-term energy supply strategies for Vienna, Austria, and found that solar PV became important with high costs of imported electricity.

This thesis investigates how the city energy system is affected by large-scale hydrogen production through electrolysis that increases the demand for electricity within the city. Furthermore, we evaluate how industries within a specific geographical context can collaborate in meeting the demand for hydrogen, unlike the studies presented above that include each city as a separate node.

2.2 Industrial electrification

In refining industries, hydrogen is used to remove impurities from the feedstock and to break down hydrocarbon chains. To decarbonise the value chain, refineries could switch to bio- and/or electro-fuels, which require hydrogen for purification and production processes, respectively [14, 15]. The current most-common way to produce hydrogen is using natural gas in an SMR, which results in significant emissions. Alternatives to the current methods are to use SMR with carbon capture, use biogas in the SMR, gasification of biomass, or use electrolysers that use electricity to separate water into oxygen and hydrogen. Transitioning from SMR to electrolysis for hydrogen production will increase the demand for electricity within the city.

2.3 Hydrogen Valleys

In recent years, the concept of *Hydrogen Valleys* has gained traction [16, 17]. 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 [18]. Supplying various end-sectors means that a Hydrogen Valley should ideally supply hydrogen to several sectors, such as mobility, industry and energy end-users. A 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, 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 has mere demonstration activities, and it should typically include several sub-projects as parts of the larger Hydrogen Valley.

Petrollese et al. [19] investigated a Hydrogen Valley located in Cagliari, Italy that encompassed: a power generation unit, a re-fuelling station, injection to 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 the grid. The authors found that producing hydrogen with electricity from solar PV leads to a lower yield, as compared to producing it 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. [20] investigated renewable hydrogen production for mobility, assuming an already existing solar PV unit and electrolyser size. Due to the flexible operation of the electrolysers, degradation was included which leads 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. [21] 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, solar, 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. [6] 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 will assume an important role in producing low-carbon hydrogen, operating when electricity from solar PV and off-shore wind power is available or when electricity import from the grid is at a low price. Zhang et al. [7] 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 reaching >80% abatement, as compared to current emissions levels.

Based on the works found in the literature ([6]- [7], [19]- [21]), most studies on Hydrogen Valleys have investigated a limited number of industries and the electricity generation is focused on hydrogen production. Less research has been performed on how the local energy system, including commercial and residential loads, may be 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. This study takes into consideration local demands with regard to electricity and heating demands outside the industry sector, as well as employing three different methods to model hydrogen flow in pipeline networks.

2.4 Hydrogen pipeline networks

In energy system optimisation models, pipelines are used to connect regions with an abundance of VRE to regions that have strong demands for hydrogen [8, 22]. Chyong et al. [23], 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. This model uses an hourly dispatch and allows the regions to connect through investments in hydrogen pipelines. However, they found that rather than trading hydrogen between the regions, the hydrogen balance was managed locally by adjusting production to demand. Instead, the electricity grid between the regions was expanded. Similarly, studies investigating national hydrogen networks can be found in the literature. Namazifard et al. [24] 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 hydrogen supply. It also included the hydrogen demands from sectors such as steel-making, ammonia (fertilizers), glass, cement and lime, and refineries. 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 references [8] and [22] - [24], the hydrogen pipeline network is modelled without consideration of the gas dynamics when transporting hydrogen through the pipelines. This could lead to lower investments in hydrogen storage and smaller pipeline diameter size than needed, as the pipelines risk being modelled as overly flexible [25]. Moreover, the line-pack (i.e., the gas stored in the pipeline) of pipelines is often neglected. Wang et al. [26] 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. Mendler et al. [27] presented an iterative, non-linear, simulation-based optimisation approach to capturing the non-linear behaviour of the gas dynamics. Shchetinin et al. [25] suggested and evaluated different methods to consider the gas dynamics in pipelines within energy systems models, while maintaining an LP approach.

The studies of hydrogen networks have a broad geographical scope, spanning continents [8, 22], to national [24] and regional [27] settings. Of the presented studies, only Shchetinin et al. [25] and Mendler et al. [27] took 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 there are no restrictions 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 gas dynamics in pipelines in energy optimisation models: an MIP formulation and an LP formulation, based on the work presented by Shchetinin et al., and it compares the methods to pure energy flow (EF).

3 Method

The method used in **Papers I–III** is a techno-economic optimisation model with the objective function to minimise the total system cost. The model was first introduced by Heinisch et al. [10] and described an urban energy system, focusing on the synergies between the heating and electricity sectors, and integration of personal electric vehicles and loads from public transport [28]. Outputs from the model included investments in generation and storage technologies to meet the demands for electricity and heat, as well as assessments of these technologies operated over a period of 1 year with an hourly time resolution. Inputs to the model are investment and operating costs for different technologies, together with the technical characteristics, weather data, prices for imported electricity, and demands for electricity and heat.

The main additions in this work, as compared to the model presented by Heinisch et al. [28], are related to the hydrogen loads. In **Paper III**, the excess heat from hydrogen production through electrolysis and its effect on district heating production were studied for Gothenburg. In **Paper I**, the geographical scope was expanded to include all three municipalities (Gothenburg, Stenungsund and Lysekil), which have in common that they possess hydrogen-intensive industries. Gothenburg and Lysekil have oil refineries, while Stenungsund has chemical industries. In the same study, the municipalities could be connected through hydrogen pipelines, so as to produce hydrogen in one municipality and then send it to another municipality.

In **Paper II**, the same three municipalities were studied over a period of 50 years, with every fifth year being modelled from 2030 to 2050 and, thereafter, every tenth year, using an hourly time resolution for the years modelled. Figure 1 visualises the energy systems of the three municipalities, including the production units and storage facilities, as well as the possibilities to import and export electricity and to transport hydrogen. Much effort has been expended in modelling the gas flows in the pipelines, whereby a mixed integer linear approach was used in **Paper I**. In **Paper II**, the method was developed further so that the gas flow could be modelled using a continuous linear programming approach, as suggested by Shchetinin et al. [25]. More information on the methods to describe the gas flows in the pipelines can be found in Section 3.1.1.

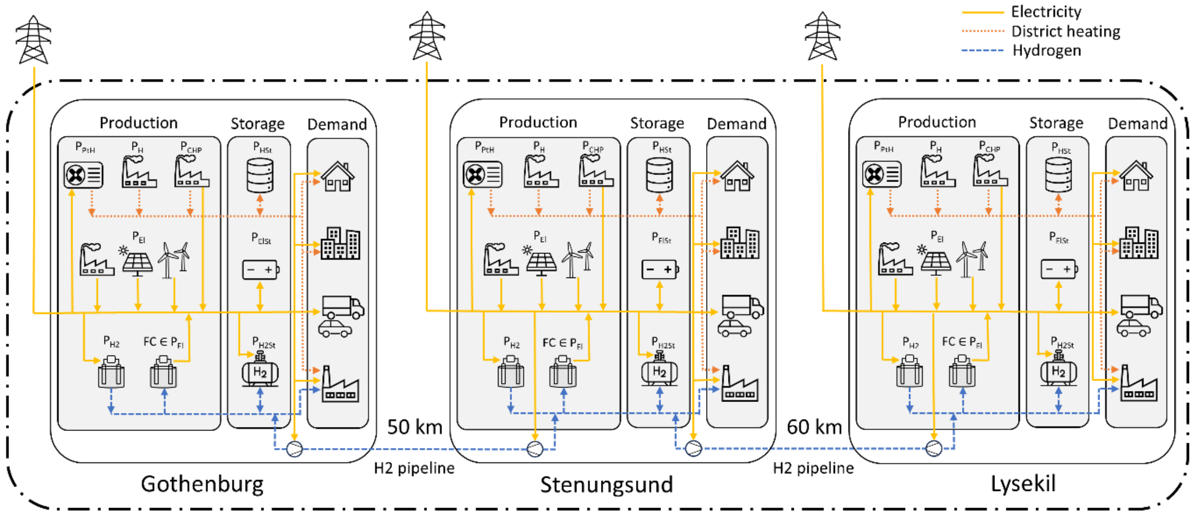


Figure 1. Schematic overview of the scope of the study, including the three municipalities included (Gothenburg, Stenungsund and Lysekil), the production, storage (thermal tanks, batteries, and lined rock caverns and tanks) and transmission technologies, together with the demand sectors (residential, commercial, transportation and industry).

3.1 Model set-up

The techno-economic optimisation model used in this thesis has as an objective function to minimise the total system cost. For **Paper III**, 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 well as the possibility to trade hydrogen between the municipalities by investing in a set of pipelines using integer investments based on the diameter size 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). The sets, parameters and variable nomenclature is summarised in Table 1 for the equations presented here, and the equations to come.

$$MIN\ C^{tot} = \sum_{p\in P}\left(\left(C_p^{inv} + C_p^{OMfix}\right) * s_p + \sum_{t\in T}\left(C_p^{run} * g_{p,t}\right)\right) + \sum_{t\in T} C_t^{el} w_t \tag{1}$$

$$\begin{aligned} MIN\ C^{tot} = &\sum_{p\in P}\sum_{n\in N}\left(\left(C_p^{inv} + C_p^{OMfix}\right) * s_{n,p} + \sum_{t\in T}\left(C_p^{run} * g_{n,p,t}\right)\right) \\ &+ \sum_{t\in T}\sum_{n\in N} C_t^{el} w_{n,t} + \sum_{l\in L}\sum_{d\in D} C_{l,d}^{pipe} * i_{l,d} \end{aligned} \tag{2}$$

$$\begin{aligned} MIN\ C^{tot} = &\sum_{p\in P}\sum_{n\in N}\sum_{y\in Y}\left(\left(C_{p,y}^{inv} + C_{p,y}^{OMfix}\right) * s_{n,p,y} + \sum_{t\in T}\left(C_{p,y}^{run} * g_{n,p,y,t}\right)\right) \\ &+ \sum_{t\in T}\sum_{n\in N}\sum_{y\in Y} C_{y,t}^{el} w_{n,y,t} + \sum_{l\in L}\sum_{y\in Y} C_{l,y}^{pipe} * e_{l,y}^{max} \end{aligned} \tag{3}$$

Table 1. Nomenclature for Equations (1) – (25).

Sets	
P	Set of technologies
T	Set of timesteps
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
Parameters	
C^{tot}	Total system cost to be minimised [M€]
C_p^{inv}	Investment cost for technology *p* [M€/GW]
$C_p^{OM_{fix}}$	Fixed O&M for technology *p* [M€/GW]
C_p^{run}	Running costs including fuel costs for technology *p* [M€/GWh]
C_t^{el}	Cost to import and export electricity from the national grid in timestep *t* [M€/GW]
$C_{l,d}^{pipe}$	Investment cost for hydrogen pipelines including compressors for pipeline connection *l* with diameter size *d* [M€]
c	Speed of sound [m/s]
Δt	Seconds in an hour [s/h]
A	Area [m^2]
f_d	Friction coefficients [-]
Δx	Length of pipeline segment [m]
$a_{l,d}$, $b_{l,d}$, $c_{l,d}$	Coefficients to describing plane fitting of the momentum equation [ms]
$\Delta \mathrm{P}^{\max}$	Allowed pressure difference in a cross-section between two consecutive hours [Pa]
$V_{l,d}^{max}$	Maximum linepack for pipeline connection *l* with diameter *d* [GWh]
$P^{max/min}$	Maximum and minimum pressure allowed in pipeline [Pa]
d	Diameter of pipeline [m]
L	Length of pipeline [m]
LHV_{H2}	Lower heating value of hydrogen [kWh/kg]
Variables	
s_p	Capacity of technology *p* invested in [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]
$i_{l,d}$	Binary investment in pipeline connection *l* with diameter *d* [-]
e_l^{max}	Maximum hydrogen flow in pipeline connection *l* [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 *l* with diameter *d* for time-step *t* [GWh]
v_l^{max}	Maximum line-pack in pipeline connection *l* [GWh]

3.1.1 Modelling of gas flow in pipelines

In this thesis, three different methods to describe the gas flow in pipelines are compared. The methods differ with regards to the gas dynamics, in that the first method, *Energy Flow*, does not consider the gas dynamics at all, the second method, *LP gas dynamics*, considers the gas dynamics while keeping the invested-in capacity of the pipeline linear, and the third method, *MIP gas dynamics*, considers the gas dynamics but with a fixed set of pipeline capacities with individual constants to describe the gas flow. The latter two methods are based on the work of Shchetinin et al. [25], who concluded that a simplification of the pipeline gas dynamics results in lower investments in pipeline capacity and hydrogen storage owing to an over-estimation of flow flexibility. To consider the gas dynamics of the pipelines, each pipeline is divided into three segments (I), as visualised in Figure 2.

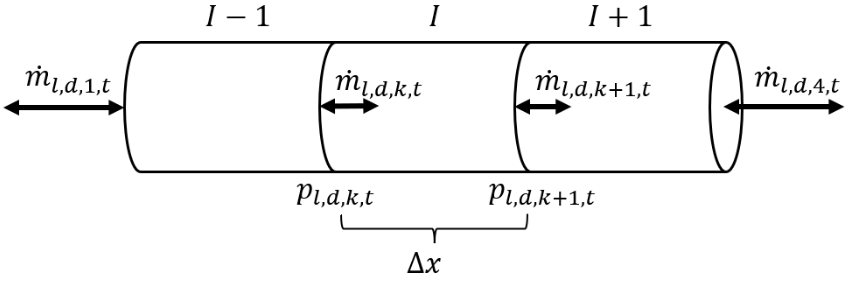


Figure 2. Pipeline divided into three segments.

In Figure 2, $\dot{m}_{l,d,k,t}$ is the mass flow, *p* is the pressure, *I* is the segment, *x* is the length of the segment, *k* is the cross-section, *d* is the diameter, and *t* is the time used in the equations. 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 (4) and Equation (5), respectively.

$$\frac{\partial \rho}{\partial t} = -\frac{\partial(\rho u)}{\partial x} \tag{4}$$

$$\frac{\partial(\rho u)}{\partial t} + \frac{\partial(\rho u^2 + c^2\rho)}{\partial x} = -f_d \frac{\rho u|\rho u|}{2d\rho} \tag{5}$$

By discretising the Euler equations in both space and time, Equation (4) can be expressed as Equation (6) and Equation (5) as Equation (7):

$$p_{l,d,k,t} + p_{l,d,k+1,t} - p_{l,d,k,t-1} - p_{l,d,k+1,t-1} = \frac{2c^2\Delta t}{A\Delta x}\left(\dot{m}_{l,d,k,t} - \dot{m}_{l,d,k+1,t}\right) \tag{6}$$

$$\left(p_{l,d,k,t}\right)^2 - \left(p_{l,d,k+1,t}\right)^2 = \frac{f_d c^2 \Delta x}{4dA^2}\left(\dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t}\right)\left|\dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t}\right| \tag{7}$$

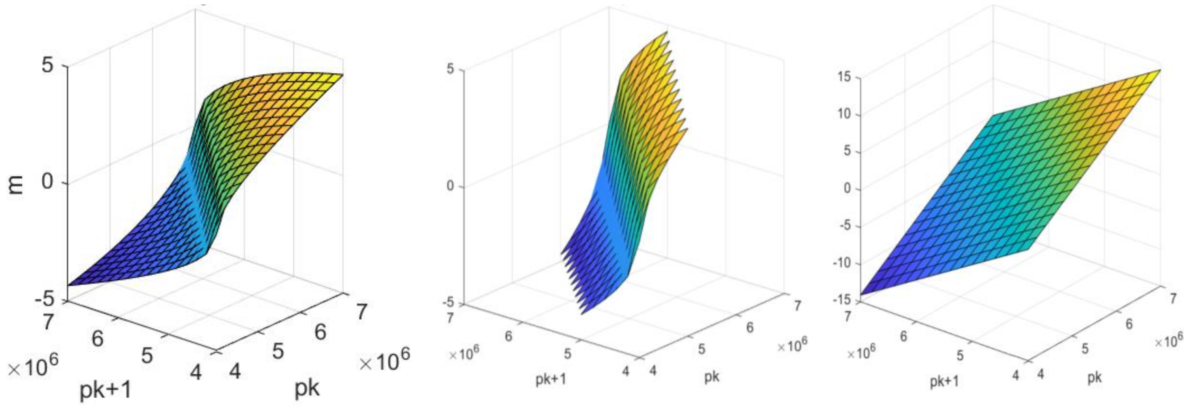
Equation (6) is now linear and can be implemented in the modelling framework, while Equation (7) remains non-linear and needs further adjustments. To linearise Equation (7), the mean mass flow's dependency on a pressure difference between two cross-sections was calculated in

MATLAB. The mean mass flow is derived from Equation (7) and results in the expression presented in Equation (8):

$$\frac{\dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t}}{2} = \sqrt{\frac{dA^2}{f_d c^2 \Delta x}\left(\left(p_{l,d,k,t}\right)^2 - \left(p_{l,d,k+1,t}\right)^2\right)} \tag{8}$$

From Equation (8), and with the plane-fitting in MATLAB three coefficients are retrieved that describe the plane: $a_{l,d}$, $b_{l,d}$ and $c_{l,d}$. As can be seen from Equation (8), 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 (8), it can now be expressed as in Equation (9):

$$\dot{m}_{l,d,k,t} + \dot{m}_{l,d,k+1,t} = 2a_{l,d} * p_{l,d,k,t} + 2b_{l,d} * p_{l,d,k+1,t} + c_{l,d} \tag{9}$$



(A) (B) (C)

Figure 3. (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.

In Figure 3, the process going from Equation (7) to Equation (9) 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) the plane as described through Equation (9). For Figure (3), a diameter of 0.2 m is assumed as well as a pipeline length of 50 km. 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 ($a_{l,d} = -b_{l,d}$). The mass flow (kg/s) is expressed as an energy flow (GWh/h), as shown in Equation (10), and is added to the hydrogen balance.

$$e_{l,d,k,t} = LHV_{H2} * \dot{m}_{l,d,k,t}\Delta t \tag{10}$$

Another characteristic captured by the more-extensive representation of the gas dynamics is the possibility to analyse the *line-pack*. The line-pack is 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 (11), 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 (12).

$$v_{l,d,t} = v_{l,d,t-1} + e_{l,d,1,t} - e_{l,d,4,t} \tag{11}$$

$$\left|p_{l,d,k,t} - p_{l,d,k,t-1}\right| \leq \Delta \mathrm{P}^{\max} \tag{12}$$

MIP gas dynamics (MIP)

Equations (6) and (9)-(12) serve as the basis for the MIP formulation used in **Paper I**. The binary value, $i_{l,d}$, is included in the objective function if a pipeline connection is invested in, and is used to limit the flow of hydrogen by limiting the allowed pressure in each pipeline segment, as presented in Equation (13). Furthermore, the binary variable limits the line-pack, as described in Equation (14). The maximum line-pack for each pipeline diameter size and connection is calculated using Equation (15). In total, Equations (6), (9)-(15) are included in the MIP approach.

$$i_{l,d} * P^{min} \leq p_{l,d,k,t} \leq i_{l,d} * P^{max} \tag{13}$$

$$v_{l,d,t} \leq i_{l,d} * V_{l,d}^{max} \tag{14}$$

$$V_{l,d}^{max} = \frac{2 * L * A}{3 * c^2} * (P^{max} - P^{min}) * LHV_{H2} \tag{15}$$

LP 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 Shchetinin et al. [25]. Naturally, some of the equations are affected by this. 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 depend on pre-determined parameters based on several specific diameters. This means that Equations (6) and (9) are updated to Equations (16) - (17). Furthermore the maximum flow is calculated with Equation (18).

$$p_{l,k,t} + p_{l,k+1,t} - p_{l,k,t-1} - p_{l,k+1,t-1} = \frac{2c^2 \Delta t}{A \Delta x} \left(\dot{m}_{l,k,t} - \dot{m}_{l,k+1,t}\right) \tag{16}$$

$$\dot{m}_{l,k,t} + \dot{m}_{l,k+1,t} = 2a_l^1 * p_{l,k,t} + 2b_l^2 * p_{l,k+1,t} + c_l^3 \tag{17}$$

$$e_l^{max} \geq e_{l,k,t} \tag{18}$$

The hydrogen stored in the pipeline is expressed by Equation (19). 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 (20). The k and m values are based on the relationship between the maximum energy flow, ${E_{l,d}}^{max}$ from Equation (21), and the maximum line-pack, $V_{l,d}^{max}$ from Equation (22). 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. In total, Equations (6), (10) and (16) - (20) are included in the LP approach.

$$v_{l,t} = v_{l,t-1} + e_{l,1,t} - e_{l,4,t} \tag{19}$$

$$v_l^{max} \leq \begin{matrix} k_1 \\ \dots \\ k_4 \end{matrix} * e_l^{max} + \begin{matrix} m_1 \\ \cdots \\ m_4 \end{matrix} \tag{20}$$

$$E_{l,d}^{max} = \sqrt{\frac{d * A^2}{f_d * c^2 * L}} * \Delta T * \left(P^{max} - P^{min}\right) * LHV_{H2} \tag{21}$$

$$V_{l,d}^{max} = \frac{2 * L * A}{3 * c^2} * (P^{max} - P^{min}) * LHV_{H2} \tag{22}$$

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 capturing the line-pack or limiting the material characteristics of the pipeline. The equations, therefore, differ from the previous two methods and are listed in Equations (23)-(25). 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 later 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. In total, Equations (23) - (25) are included in the EF model approach.

$$e_{n,n_2,t} = -e_{n_2,n,t} \tag{23}$$

$$e_{n,n_2}^{max} = e_{n_2,n}^{max} \tag{24}$$

$$e_{n,n_2,t} \leq e_{n,n_2}^{max} \tag{25}$$

Comparison of gas flow methods

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

- Maximum hydrogen flow
- Hourly flow patterns
- Investments in LRC, electrolysers and off-shore wind power
- Line-pack (LP and MIP)
- 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 the length of the pipeline (L) and diameter (d) that are used to calculate the coefficients ($a_{l,d}$, $b_{l,d}$ and $c_{l,d}$) that express the 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.

3.2 Assumptions and Data

The investment costs and technical characteristics of the generation technologies included in the model are retrieved from the Danish Energy Agency [29, 30, 31]. Between the publication of **Paper I** and creation of **Paper II**, updates were made with regards to investment costs, with the largest change being that for off-shore wind power. Similarly, the costs for the hydrogen pipelines, derived from the European Hydrogen Backbone [32], were updated between **Papers I** and **II** (from 1.5 M€/km [33] to 1.8 M€/km [32] for a pipeline size of 1.2 GW). The off-shore wind and solar PV profiles are retrieved from the renewables.ninja web tool [34, 35, 36]. The electricity prices for the years modelled represent SE3 and come from the model originally presented by Öberg et al. [37], with refinements to include long-term capacity expansion, starting from the existing energy system of Europe.

The geographical scope of the thesis covers Gothenburg, Stenungsund and Lysekil, three municipalities located on the west coast of Sweden that have hydrogen-based industries. Gothenburg is the second-largest city in Sweden with an annual demand for electricity of 4.5 TWh in Year 2023, and the industry sector accounts for 35% of the electricity demand [38]. Stenungsund and Lysekil are smaller municipalities with annual electricity demands of 1.8 TWh and 0.7 TWh, respectively, and the industry sector stands for 51% and 79%, respectively, of the electricity demand. Whereas the industrial demand for electricity is assumed to have a more-constant load, the residential demand fluctuates hourly. In this thesis, the demand for electricity is expected to increase in relation to population growth, which is assumed to be (comparing Year 2050 with Year 2019) 20% in Gothenburg, 14% in Stenungsund, and unchanged in Lysekil [39]. Furthermore, private vehicles are assumed to be electrified towards Year 2050 in all the municipalities, and for Gothenburg, the electricity load from a planned battery factory is included. The potential for investing in off-shore wind power differs between the nodes and is based on the current projects along the coast [40, 41, 42, 43, 44].

The demand for hydrogen is based on a report by Edvall et al. [45] in which interviews were conducted with industrial actors in the studied municipalities. The current demand for hydrogen on the west coast of Sweden is 6.4 TWh annually. Approximately half of this demand is met by a by-product of current processes, whereas the remainder is met by hydrogen produced from natural gas in SMR units. In the same report, the future demand for hydrogen was estimated to be 4.9–14 TWh annually. In this thesis, the demand is based on the maximum scenario (14 TWh) and is distributed in Year 2050, as presented in Table 2. In **Papers I–III**, hydrogen is assumed to be produced exclusively from electrolysis.

Paper I examines four cases that differ depending on 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 apart from the off-shore wind power availability presented for Gothenburg in Table 2, the model is also run with a stricter limit of 280 MW, as at the time of the study it comprised two overlapping off-shore wind farm projects.

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

	Gothenburg	Stenungsund	Lysekil
Hydrogen demand (TWh)	5	5	4
Off-shore wind power availability [MW]	1,000 [40]	1,120 [41]	5,000 [42] [43] [44]
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

In **Paper II**, the period of 2030–2080 is modelled for four scenarios based on the order in which the electricity transmission capacity is reinforced and off-shore wind power become available to invest in, relative to the increase in hydrogen demand from the industry sector. The scenarios are presented in Table 3. From Year 2040 and onwards, there are no pre-defined differences between the scenarios, and between 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 pipelines.

In **Paper III**, only Gothenburg is modelled for Year 2050, focusing on meeting the district heating demand. The levels of waste heat from the two refineries (ST1 and Preem) are based on the distribution capacities presented by Romanchenko et al. [46]. Three scenarios are investigated based on the availability of waste heat from the refineries and the demand for hydrogen; 1) the current waste heat potential and no demand for hydrogen produced through electrolysis (industries as we know them; IK scenario); 2) no waste heat available from refineries due to being shut down (net-zero; NZ scenario); and 3) one-third of the waste heat remaining from the refineries and with a hydrogen demand of 5 TWh and recovery of waste heat from the electrolysis process (sector coupling; SC scenario).

Table 3. Scenarios formulated in Paper II.

Scenarios[1]		Industrial loads [TWh$_{H2}$/year]			Max off-shore wind power [GW]			Transmission capacity [GW]		
Year		**2030**	**2035**	**2040**	**2030**	**2035**	**2040**	**2030**	**2035**	**2040**
Gothenburg	WPTC-IL	0	3.75	5	1	1	1	1.5	1.5	1.5
	WP-IL-TC				1	1	1	0.89	0.89	1.5
	TC-IL-WP				0	0	1	1.5	1.5	1.5
	IL-WPTC				0	0	1	0.89	0.89	1.5
Stenungsund	WPTC-IL	0	3.75	5	1.12	1.12	1.12	1	1	1
	WP-IL-TC				1.12	1.12	1.12	0.4	0.4	1
	TC-IL-WP				0	0	1.12	1	1	1
	IL-WPTC				0	0	1.12	0.4	0.4	1
Lysekil	WPTC-IL	0	3	4	5	5	5	0.05	0.05	0.05
	WP-IL-TC				5	5	5	0.05	0.05	0.05
	TC-IL-WP				0	0	5	0.05	0.05	0.05
	IL-WPTC				0	0	5	0.05	0.05	0.05

In a sensitivity analysis, the annual potential for waste heat is varied within the ranges of 0–900 GWh/year for ST1 and 0–780 GWh/year for Preem, together with changing the demand for hydrogen to 1–5 TWh. In order to use the waste heat from the electrolysis process, there needs to be investment in a heat pump, which can, naturally, only be operated when the electrolyser is used. No investments in hydrogen pipelines are allowed in the study described in **Paper III**.

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[1] WP - wind power becomes available; TC – transmission capacity is increased; IL – industrial loads increase. The order of the abbreviations represents the order in which the different parameters are in place.

4 Results

This chapter presents the results obtained from evaluating: the different methods to model pipeline gas dynamics (Section 4.1); how the hydrogen infrastructure can be used to meet the industrial demand for hydrogen (4.2); and how hydrogen production interacts with the electricity and heat supply (4.3).

4.1 Evaluation of methods to model pipeline gas dynamics

The three ways to represent gas dynamics in hydrogen pipeline networks, as presented in Section 3.1.1, are first compared to each other using parameters such as net annual flow, hourly flow, and computational time, in Section 4.1.1. In Section 4.1.2, important modelling parameters, such as pressure difference, length of pipeline and diameter size, are evaluated. Apart from the methods used to describe the hydrogen flow in the pipelines, all the parameters are the same in the evaluation of the methods.

4.1.1 Comparison of methods to describe gas dynamics

In Figure 4, the maximum and minimum flows in each pipeline connection and method [pure energy flow (EF), continuously linearised investments in hydrogen pipelines while considering gas dynamics (LP) and binary investments in hydrogen while considering gas dynamics (MIP)] are visualised. Using the EF method, the investment in hydrogen pipelines between Gothenburg and Stenungsund is the same as the hourly demand for hydrogen in the two municipalities (0.571 GWh/h). Between Stenungsund and Lysekil, the pipeline capacity is smaller, 0.18 GW compared to the hourly hydrogen demand in Lysekil of 0.46 GWh/h. When the gas dynamics are included in the model, a lower hydrogen transfer capacity is invested in, as shown in Figure 4. This indicates that it is not only the amount of hydrogen that can be transported that creates incentives for investments in hydrogen pipelines, but also the ability to balance fluctuations in the availability of electricity for hydrogen production. Figure 4 further shows that the pipeline connection between Stenungsund and Lysekil is used to its full capacity both flow directions (the minimum and maximum flows have the same magnitude), unlike the connection between Gothenburg and Stenungsund. The flow direction implemented in the model is from north to south, meaning that a positive value indicates the maximum flow from Stenungsund towards Gothenburg and from Lysekil towards Stenungsund, and a negative value the opposite direction. That the pipeline connection between Gothenburg and Stenungsund only has a small negative value means that the full capacity of the pipeline is never used to transport hydrogen from Gothenburg to Stenungsund but only from Stenungsund to Gothenburg. This can be related to the electrolyser capacity in Gothenburg where only a small overcapacity is invested in that can be used to produce more hydrogen than needed in the municipality whereas Stenungsund both has a larger electrolyser and possibility to invest in LRC storages.

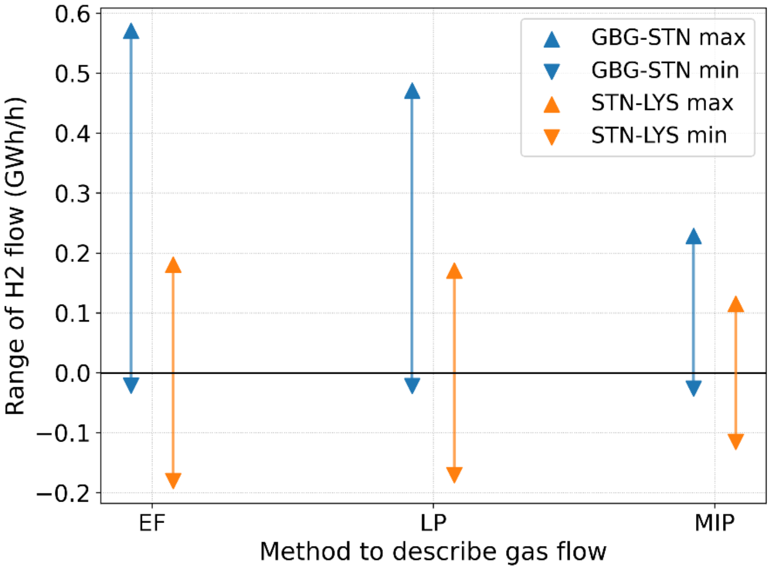


Figure 4. Maximum and minimum values of hydrogen flow depending on the method used to describe the gas flow (EF, LP and MIP).

In Figure 5, the EF, LP and MIP methods are compared in terms of net annual hydrogen transfer. The hydrogen demand is 5 TWh per year in Gothenburg and Stenungsund and 4 TWh per year in Lysekil. The EF method results in an overall higher net transfer of hydrogen, as compared to the LP and MIP methods. The MIP method results in the lowest net hydrogen transfer between Stenungsund (STN) and Lysekil (LYS). While the difference between the methods for the pipeline connection between Stenungsund and Gothenburg remains fairly similar (430-460 GWh) the annual net flow between Stenungsund and Lysekil goes from 960-990 GWh in the LP and EF methods, to 270 GWh using the MIP method, partly derived from the smaller pipeline capacity invested in.

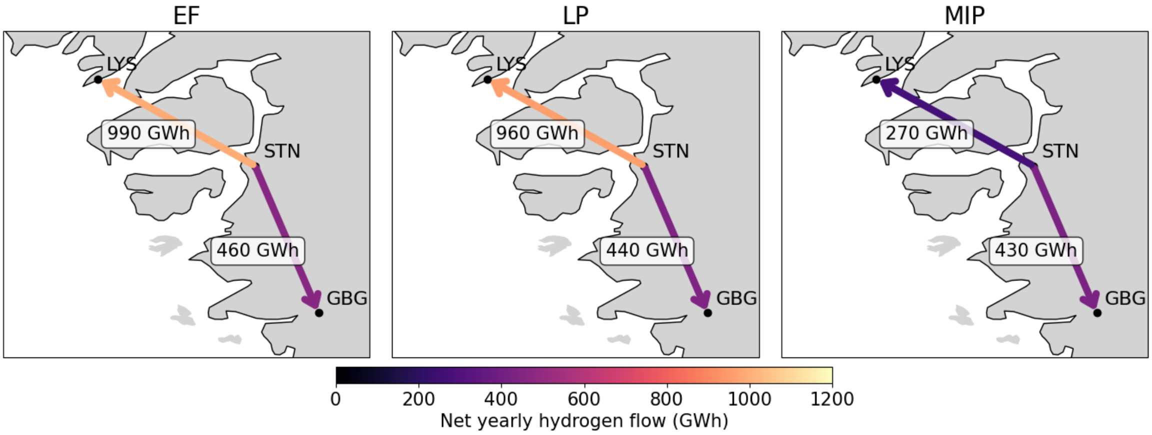


Figure 5. Comparison of the EF, LP and MIP methods to describe the hydrogen flows in pipelines in the case study.

In Figure 6, the hydrogen flows in the pipelines are presented for the first 2,000 consecutive hours of the year modelled. When using the simplest method, EF, the hydrogen flow changes rapidly from high to low, for instance between Hours 500 and 750. The MIP approach gives the most-restricted flow in terms of how fast the flow changes between time-steps in the model. Compared to the LP version, the MIP approach considers each diameter's effect on the $a_{l,d}$, $b_{l,d}$ and $c_{l,d}$ coefficients, whereas the LP approach considers only one diameter size, independent of the flow. This gives a method that is more-restricted than the simpler EF approach but less-restricted than the MIP approach. It also implies that the LP method will overestimate how fast the flow can change in a smaller pipeline than the size used to calculate the coefficients $a_{l,d}$, $b_{l,d}$ and $c_{l,d}$, and underestimate how fast the flow can change in a larger pipeline size.

In Figure 7, the line-pack for the LP and MIP methods are shown (line-pack is not present in the EF method). The line-pack is the difference between what is sent into the pipeline in one end and what is taken out in the other in each hour, similar to a storage unit. The LP method shows a larger line-pack which is reasonable since the LP method results in an overall larger pipeline capacity for both the connection between Gothenburg and Stenungsund, and between Stenungsund and Lysekil. If the line-pack would remain constant it would mean that the flow in and out of the pipeline is the same, but Figure 7 shows that it is cost-efficient to vary the flow and use the possibility for line-pack. For comparison, the H2 tank storage invested in in Gothenburg is in this model run (LP) 1.2 GWh and the LRC storage in Stenungsund is 41 GWh while the maximum line-pack is approximately 0.12 GWh.

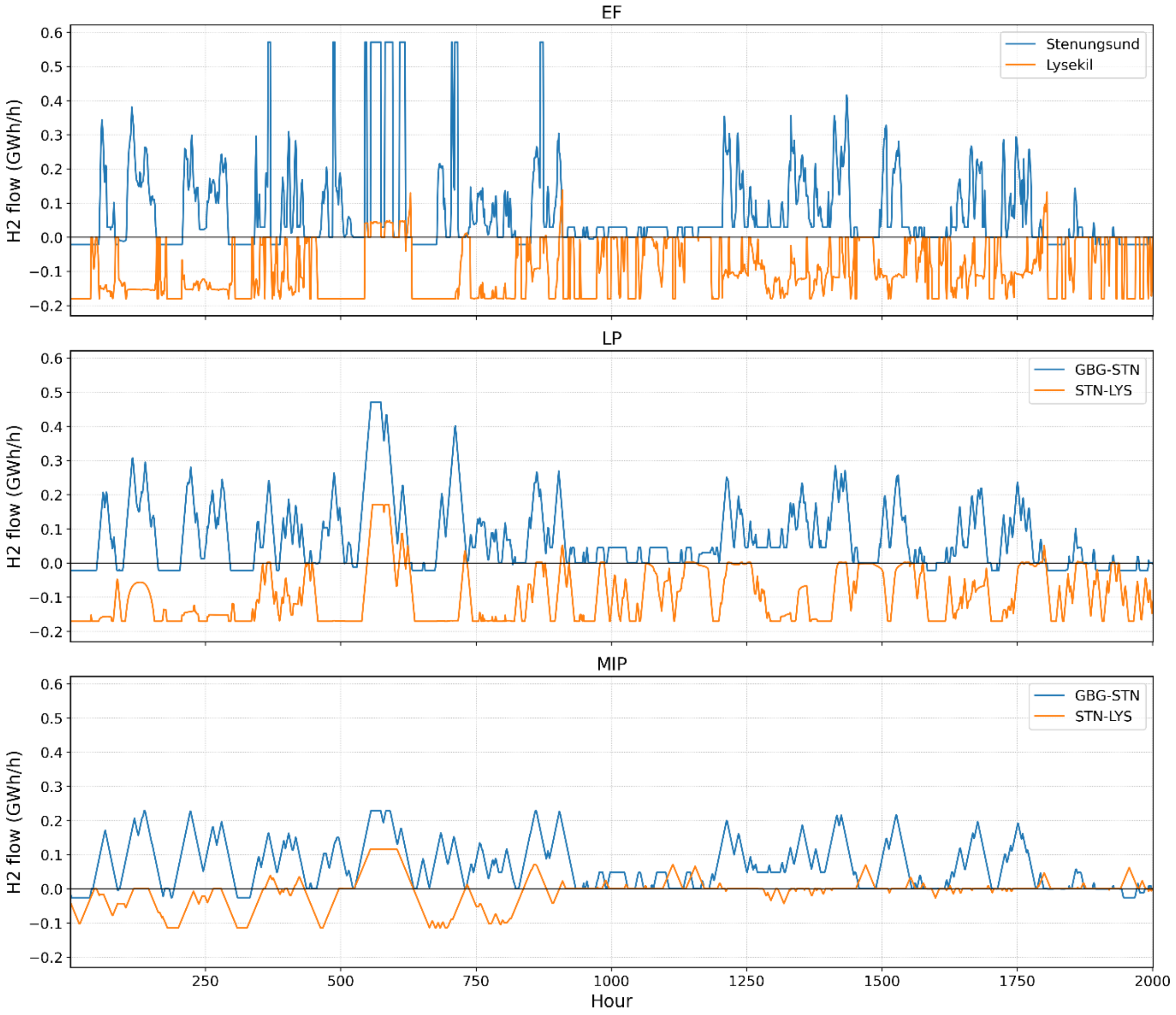


Figure 6. Hourly hydrogen flows depending on the method used to describe the gas flow (EF, LP and MIP) for first six weeks of the year modelled.

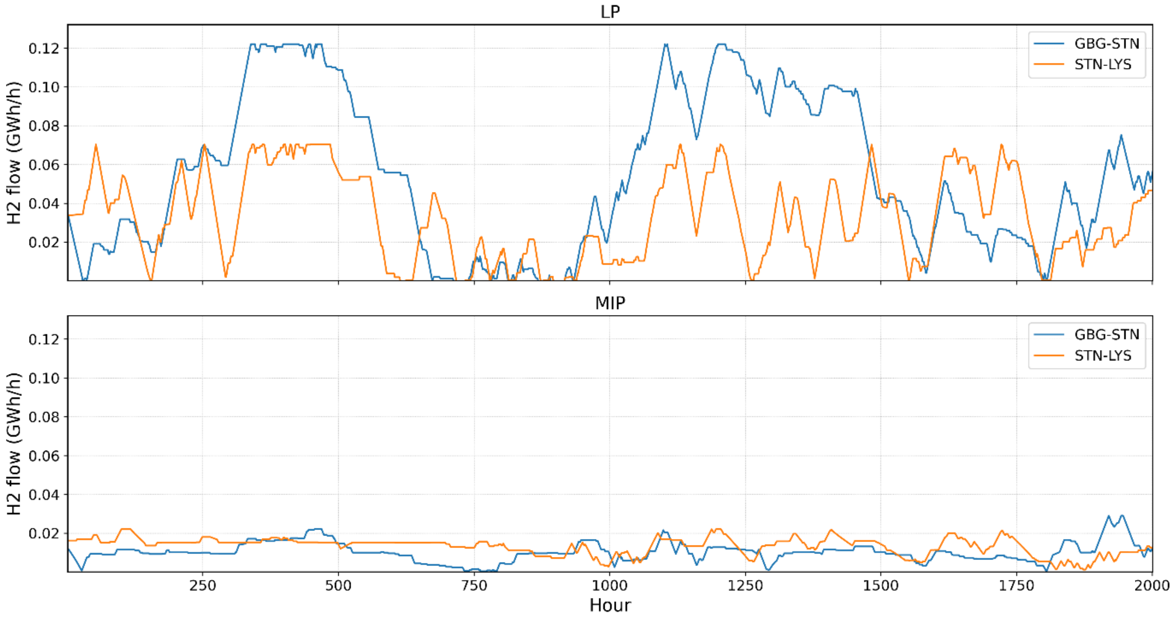


Figure 7. Hourly line-pack in the LP and MIP methods.

In Figure 8, the most-significant differences in technology investments are compared between the LP/MIP and EF method. In Gothenburg, investments in hydrogen tank storage units increase in LP and MIP compared to EF, i.e., if the flexibility of the pipeline is restricted with consideration of the gas dynamics. In Lysekil, investments in off-shore wind increase (+28% with MIP compared to EF), electrolysers (+28% with MIP compared to EF), and LRC storage units (+38% with MIP compared to EF), while investments in the same three technologies decrease in Stenungsund. This is because Lysekil needs to balance the variability in the electricity supply to a greater extent locally, instead of through the import and export of hydrogen. The most-significant change can be seen in LRC storage, which increases by 17% in Lysekil and decreases by 18% in Stenungsund, already with the LP method, while electrolyser size and off-shore wind power show only 1%–2% differences between the LP and EF methods in the two municipalities.

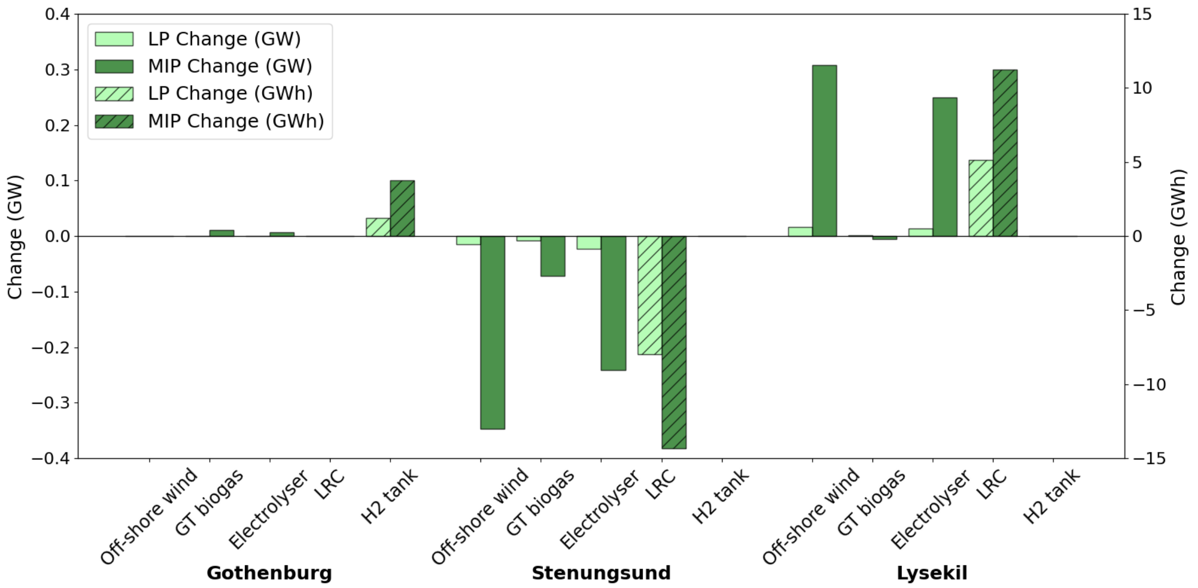


Figure 8. The changes in technology investments when comparing the EF method with the MIP and LP, for the three municipalities.

In Table 4, the computational time is summarised for the three methods, EF, LP and MIP. As expected, the EF is the fastest method for the system studied, followed by the LP approach, but the computational time for the MIP method is significantly longer than those for the other two methods.

Table 4. Computational time, including the pre-solve and after-solve processes.

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

Including equations to describe the gas dynamics in the energy system optimisation model affects the investments in both pipeline capacities, hydrogen storages and electricity generating technologies, primarily off-shore wind. A more-constrained flow yields larger storage units and electrolyser capacities in Lysekil and Gothenburg, and smaller units in Stenungsund. As less hydrogen is produced in Stenungsund with a more restricted representation of gas dynamics, the off-shore wind power investments are reduced, suggesting that creating overly flexible operation of pipelines affects the cost-optimal energy system design.

4.1.2 Evaluation of parameters in gas equations

In this section, the LP method is used to evaluate how the allowed pressure difference and diameter size (used to calculate the coefficients to describe Equations 7 and 8) and length (used to calculate the coefficients to describe Equations 7 and 8) of the pipelines affect investments and operation of the pipelines.

Pressure difference

In the results presented for the LP and MIP methods in section 4.1.1, 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, giving the results presented in Figure 9. With an allowed pressure difference of dP = 0.1 bar, the pipeline capacity invested in is the smallest for the compared pressure differences. Between Stenungsund and Lysekil, the pipeline size starts to converge already when dP = 0.5 bar. This is because a smaller hydrogen capacity is invested in overall between Stenungsund and Lysekil, as compared to between Gothenburg and Stenungsund. This becomes relevant as the diameter size chosen for the “typical” pipeline in order to retrieve the coefficients, a_l, b_l and c_l, needed to describe Equation (17), is closer to the corresponding pipeline capacity between Gothenburg and Stenungsund, than between Stenungsund and Lysekil. Because of this, the flow can change faster between Stenungsund and Lysekil than would be the case if the coefficients (a_l, b_l and c_l) were based on a smaller pipeline size, that more accurately describes the actual pipeline. Thus, the pressure difference has less impact on the invested in pipeline capacity between Stenungsund and Lysekil than between Gothenburg and Stenungsund. Furthermore, it becomes a trade-off between the energy carried and the flexibility the pipeline can offer. The pipeline capacity between Gothenburg and Stenungsund starts to converge when dP = 1 bar, and between dP = 5 bar and dP = 10 bar, no significant difference is observed with regards to pipeline investments. In the EF model runs, the pipeline capacity invested in is 0.571 GW between Gothenburg and Stenungsund and 0.180 GW between Stenungsund and Lysekil, which are close to the same values as presented in Figure 9 when the allowed pressure difference increase (dP ≥ 5 bar).

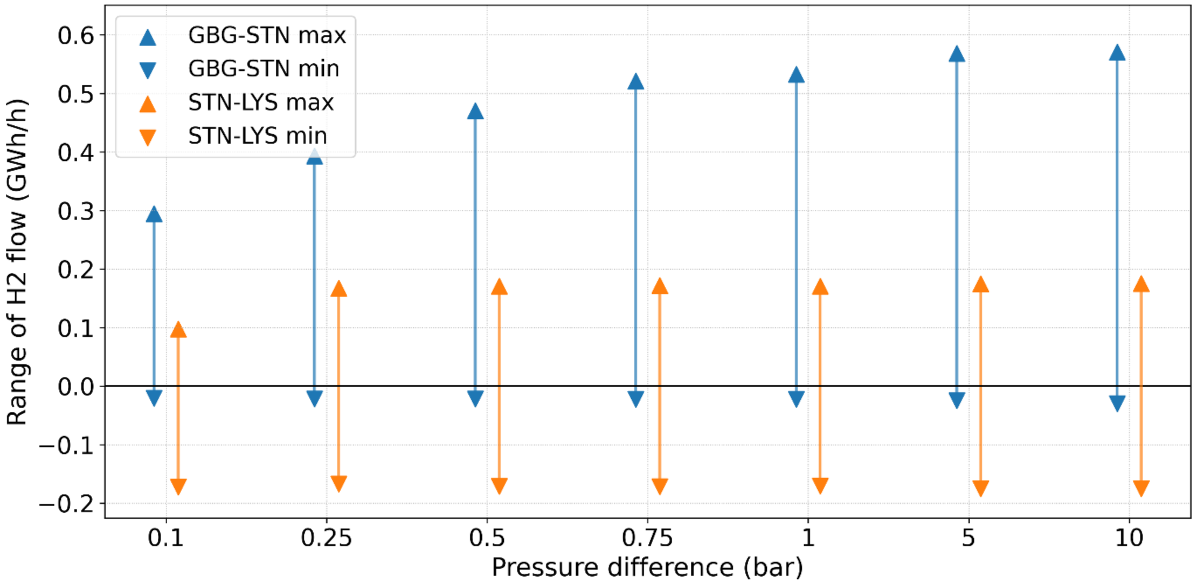


Figure 9. Maximum and minimum hydrogen flows for each pipeline connection using the LP formulation and changing the allowed pressure difference in a pipeline segment between two consecutive hours.

In Figure 10, the hourly flow is presented for the pressure differences investigated. As the allowed-for pressure difference is increased, the flow through the pipeline looks increasingly similar to the hydrogen flow in the EF method, presented in Figure 6, as a higher tolerance for changes in pressure between hours allow for larger fluctuations in flow. The trend where the pipeline between Stenungsund and Lysekil is used to its full capacity both flow directions while the pipeline between Gothenburg and Stenungsund uses its full capacity only in direction towards Gothenburg remains.

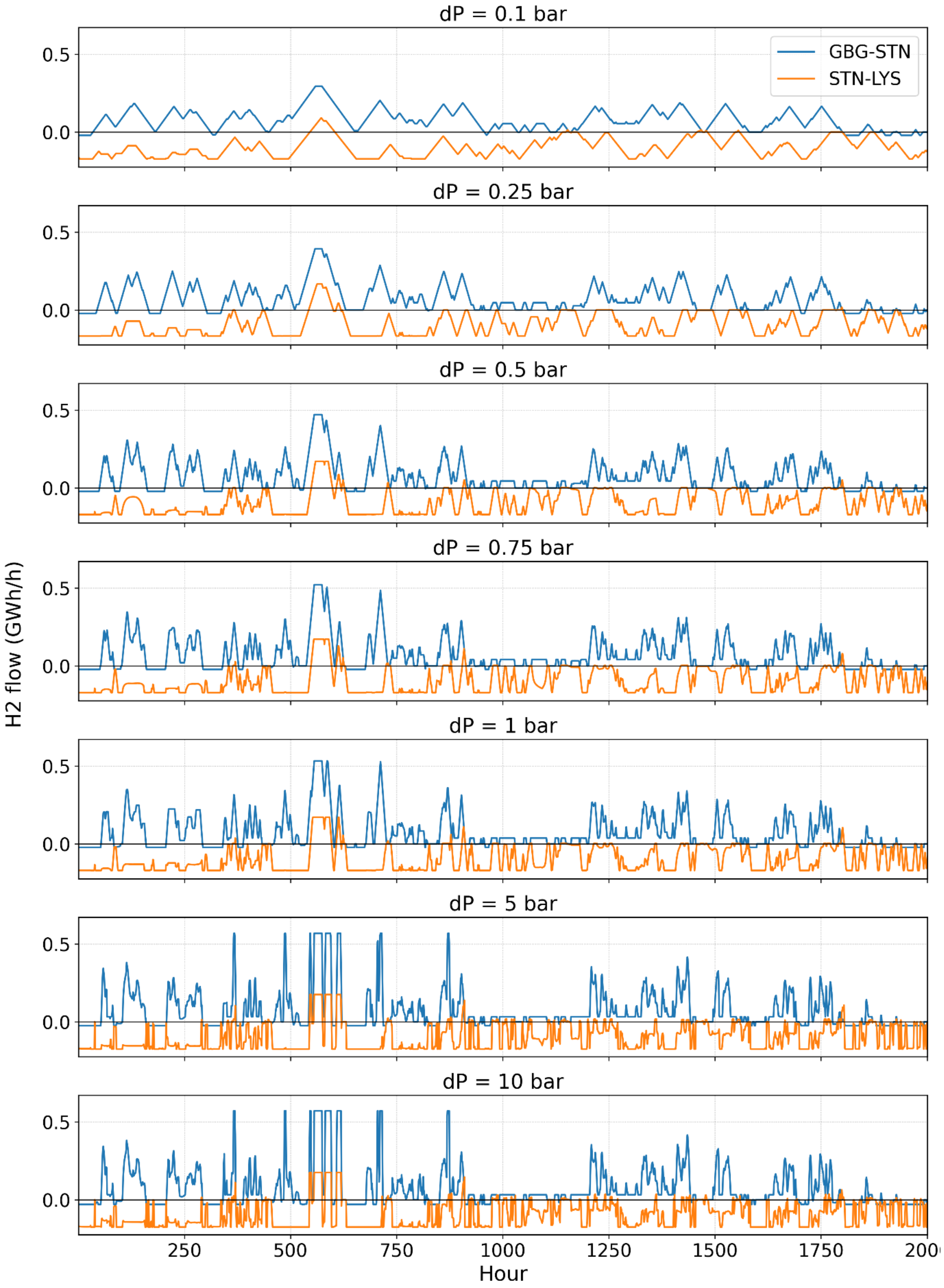


Figure 10. Hydrogen flow dependencies on allowed pressure differences (range, 0.1–10 bar) over 2,000 consecutive hours, using the LP method.

Diameter size in a "typical" pipeline

In order to use the LP method, some simplifications need to be implemented, as compared to the MIP formulation. One of these simplifications involves assuming a specific diameter of the pipeline in order to calculate the coefficients (a_l, b_l and c_l) needed to implement Equation (17). In Equation (7), the diameter, *d*, is multiplied with the area of the pipeline squared, A^2 (which is also dependent on 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. Instead, it is the speed with which the flow can change that becomes restricted. For the LP results presented in Section 4.1.1, a diameter of 0.2 m is used. The diameters investigated are in the range of 0.1 to 0.5 m. A diameter of 0.5 m is the smallest diameter size presented in the European Hydrogen Backbone report [32]. Similar to increasing the allowed pressure difference as presented earlier, assuming a larger diameter results in investments in larger capacities (Figure 11), as well as more fluctuations in the pipeline (Figure 12). In Figure 11, the range of H_2 flow between Gothenburg and Stenungsund for a diameter of 0.4 m differs in that a larger capacity is used to send hydrogen from Gothenburg to Stenungsund than in the other cases. This is because the storage in Gothenburg is discharged at the same time, giving a larger flow than that possible from the electrolyser over-capacity.

Length of pipeline

The length of the pipelines was varied between 25-100 km between Gothenburg and Stenungsund, and 35-110 km between Stenungsund and Lysekil. At approximately 100 km there is typically a need for additional compression. The length of the pipeline is used in Equation (7) to calculate the coefficients a_l, b_l and c_l. A shorter length results in faster change of flow in the pipeline and a longer pipeline in a more restricted flow. However, the difference between a shorter and longer pipeline with regards to how fast the flow changes are small in the studied range, as compared to the effect from changes in allowed pressure difference and diameter size.

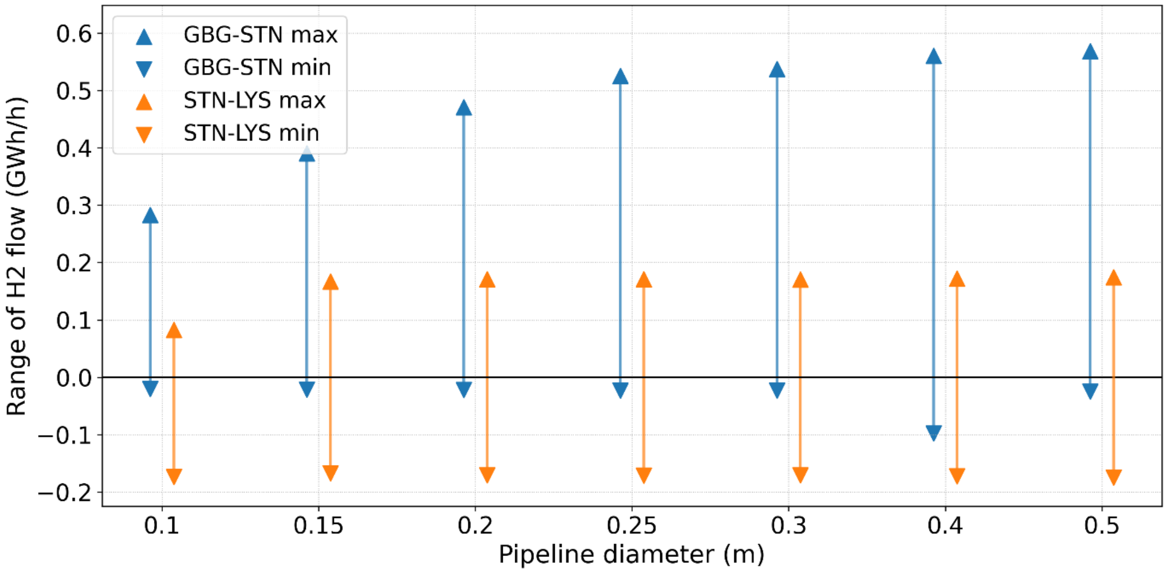


Figure 11. Maximum and minimum values of hydrogen flow depending on what diameter that defines a "typical" pipeline.

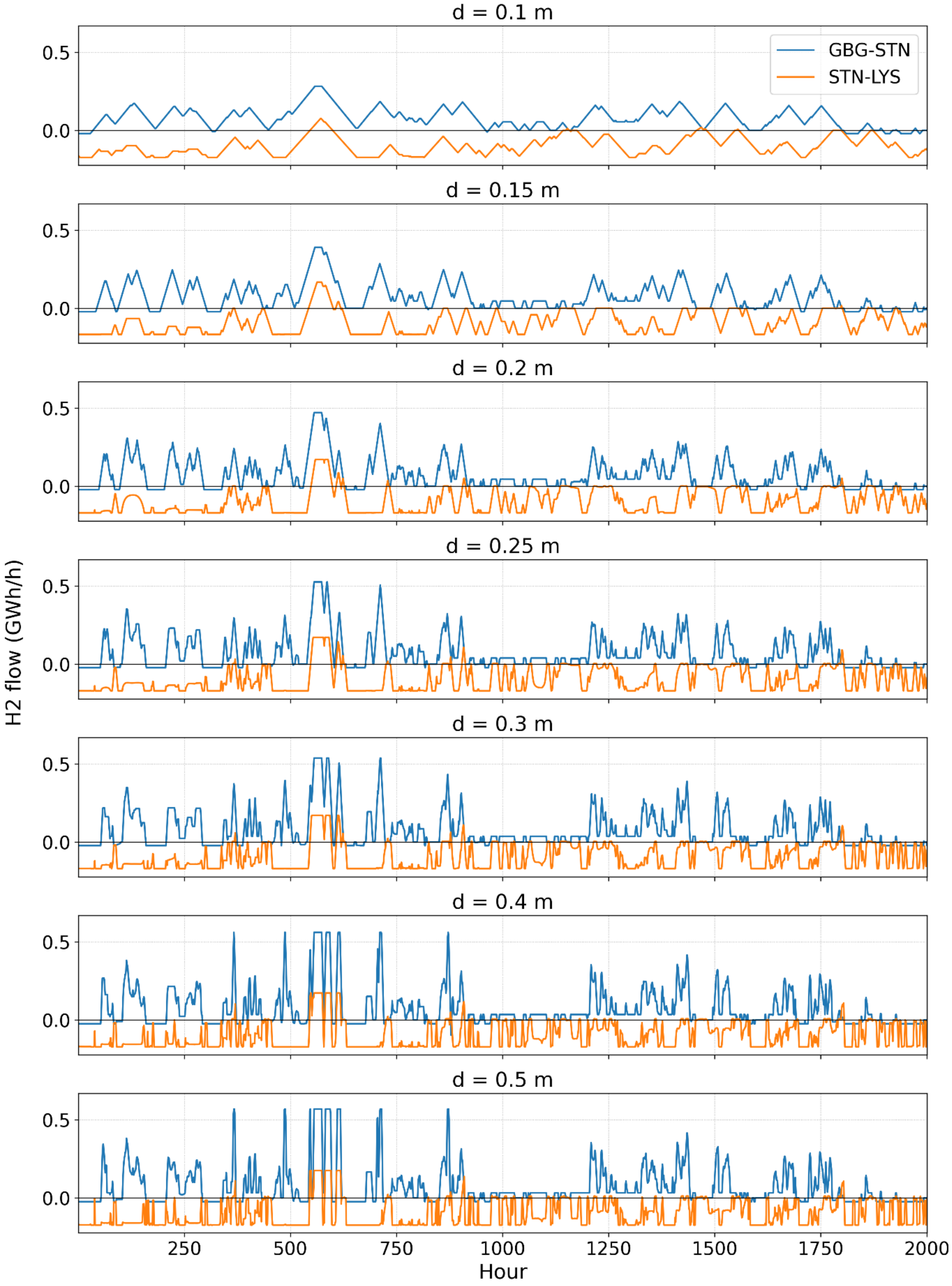


Figure 12. Hydrogen flow dependencies on the diameter sizes of a "typical" pipeline.

4.2 Meeting industrial hydrogen demands through a shared hydrogen infrastructure

4.2.1 Pipeline infrastructure

In **Paper I**, four cases were investigated for Year 2050, based on the possibility to invest in pipelines that connect the municipalities and access to off-shore wind power outside Gothenburg. In **Paper II**, the geographical scope is the same as in **Paper I** and the conditions assumed in the first scenario are similar to those in the fourth case in **Paper I**, i.e., with the possibility to invest in up to 1,000 MW of off-shore wind power outside Gothenburg and the possibility to invest in hydrogen pipelines. However, to increase the temporal scope in **Paper II (**i.e., 2030–2080 instead of only Year 2050), the equations describing the gas dynamics are changed from using a set of pre-defined pipeline sizes to making the investments in pipeline size continuously linear. The four scenarios in **Paper II** explore how an increased electricity demand from industry can be met with varying access to electricity import capacity and the possibility to invest in off-shore wind power. In both **Papers I** and **II**, the results show that investments are made in pipelines if allowed in the model, both between Gothenburg and Stenungsund and between Stenungsund and Lysekil.

Figure 13 shows a comparison of the investments in pipeline capacity in **Papers I** and **II**. The results from **Paper I** are presented as dots in Year 2050, as it is the only year modelled, while the results from **Paper II** are plotted for each year modelled. In addition, the hydrogen demands in the respective municipalities are plotted. For **Paper I**, the maximum flow is plotted rather than pipeline diameter size. There is only one dot per pipeline connection as the flows are similar between the cases. As seen in Figure 13, in both **Papers I** and **II**, a smaller pipeline capacity is invested in between Stenungsund and Lysekil, as compared to that between Gothenburg and Stenungsund. Even though less hydrogen is imported to Gothenburg in the case with availability of 1,000 MW of off-shore wind power in **Paper I**, the pipeline diameter increases (from 0.3 m to 0.4 m). This can be explained by the restrictions imposed on the change of flow by to the allowed pressure difference. With more wind being connected to Gothenburg, it becomes cost-effective to invest in a larger pipeline diameter, in order to allow more-rapid changes to the flow. In **Paper II**, overall smaller investments are made in pipeline capacity. This is because in **Paper I**, the pre-defined pipeline diameters allow for a certain flow while in **Paper II**, the model invests in pipeline capacity linearly, allowing for a smaller pipeline capacity.

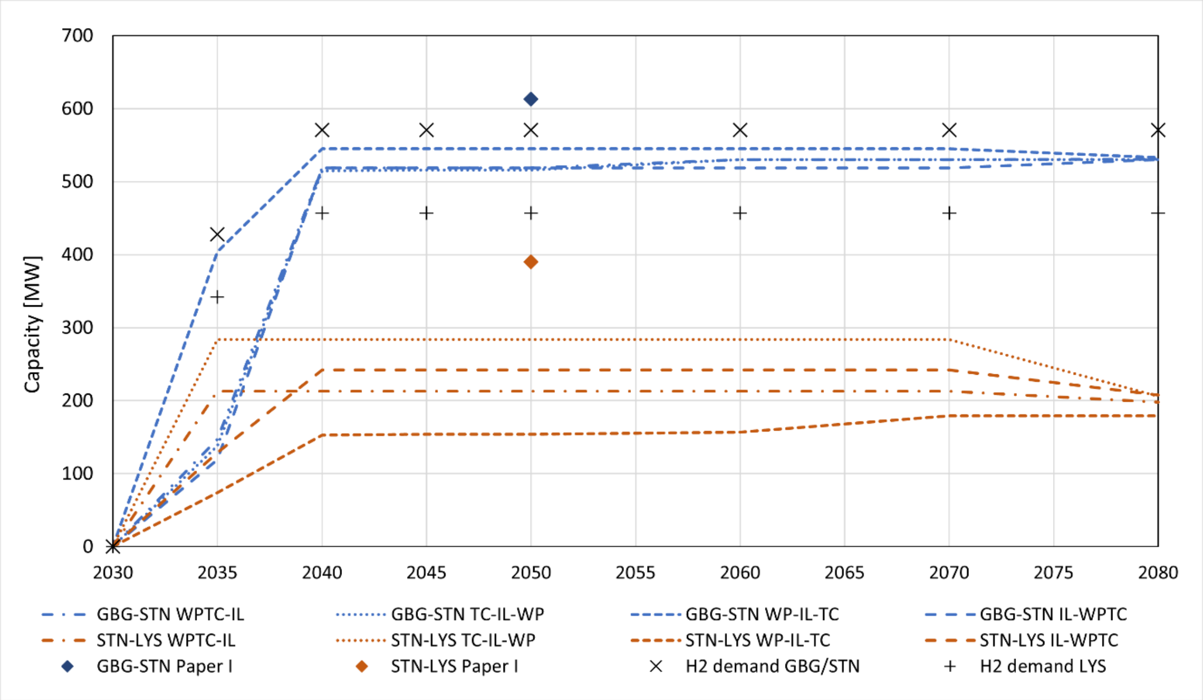


Figure 13.Comparisons of investments in pipeline infrastructure for the scenarios presented in Papers I and II.

In Figure 14, the hydrogen flows in the two cases from **Paper I** are presented. Gothenburg ends up as a net importer of hydrogen in both cases, although more hydrogen is imported with access to the smaller off-shore wind farm (280 MW) outside Gothenburg. The opposite is shown for Lysekil, which becomes a net exporter of hydrogen when there is little off-shore wind power generation outside Gothenburg, and a net importer of hydrogen when the availability of wind power is higher outside Gothenburg. This is because Lysekil has a limited transmission capacity to the regional grid, making it more difficult to balance low-wind events, as compared to Gothenburg and Stenungsund. The investments in pipelines persist even with a lower demand for hydrogen of 4.9 TWh compared to 14 TWh annually, although the diameter of the pipeline between Gothenburg and Stenungsund is reduced to one size smaller in both cases as compared to the sizes invested in with a hydrogen demand of 14 TWh.

In Figure 15, the net annual flows of hydrogen are presented for all scenarios and selected years from **Paper II**. With access to off-shore wind power before industrial loads start to increase (i.e., scenario WP-IL-TC described in **Paper II**), a larger pipeline size is invested in earlier 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**. This is because in most of the scenarios and years, Lysekil is a net importer of hydrogen, although in the WP-IL-TC scenario, Lysekil becomes more self-sufficient, as presented in Figure 15. Instead, Stenungsund exports even more hydrogen to Gothenburg, leading to the larger pipeline capacity presented in Figure 13.

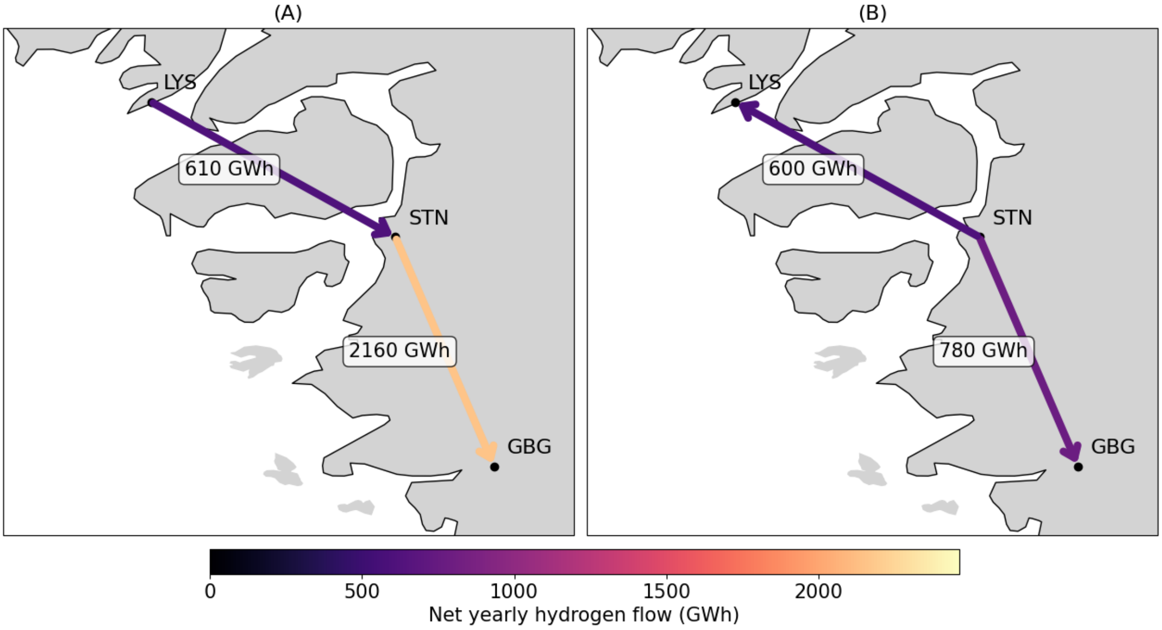


Figure 14. Direction and quantity of the net yearly hydrogen flows between the three municipalities, based on the results in Paper I, showing: (A) the case with 280 MW of off-shore wind outside Gothenburg; and (B) the case with 1,000 MW of off-shore wind power.

The overall maximum flows of hydrogen are smaller in **Paper II**, where the LP formulation is used, than in **Paper I** where the MIP formulation is used. This is mainly because the pre-defined pipeline diameters available in the MIP formulation were limited and spread over a broader range (0.2 m, 0.3 m, 0.4 m, 0.5 and 0.7 m). For instance, even though the pipeline size invested in between Lysekil and Stenungsund is the smallest available in **Paper I**, it still allows for a larger flow than any of those that received investments between Lysekil and Stenungsund in **Paper II** (see Figure 13). In contrast, in the evaluation of different methods to model gas flow in pipelines in Figure 4, the MIP formulation results in the smallest maximum hydrogen flow. However, including a greater variety of diameter sizes with corresponding properties, as is done in the evaluation of the MIP formulation presented in Section 4.1.1, would affect the computational time of the model runs, so there is a trade-off between the level of detail and time expended on model runs. Other differences that may affect the results between **Papers I** and **II** are the up-dated costs for pipelines and off-shore wind power in **Paper II**. In **Paper I**, with 1,000 MW of off-shore wind outside Gothenburg, a larger pipeline diameter was invested in between Gothenburg and Stenungsund to allow for faster changes in hydrogen flow. The same pattern could not be found in **Paper II** where the investments in hydrogen pipelines were always smaller than the hourly demand for hydrogen between Gothenburg and Stenungsund. One explanation could be the lower costs for hydrogen pipelines in **Paper I** as compared to **Paper II**.

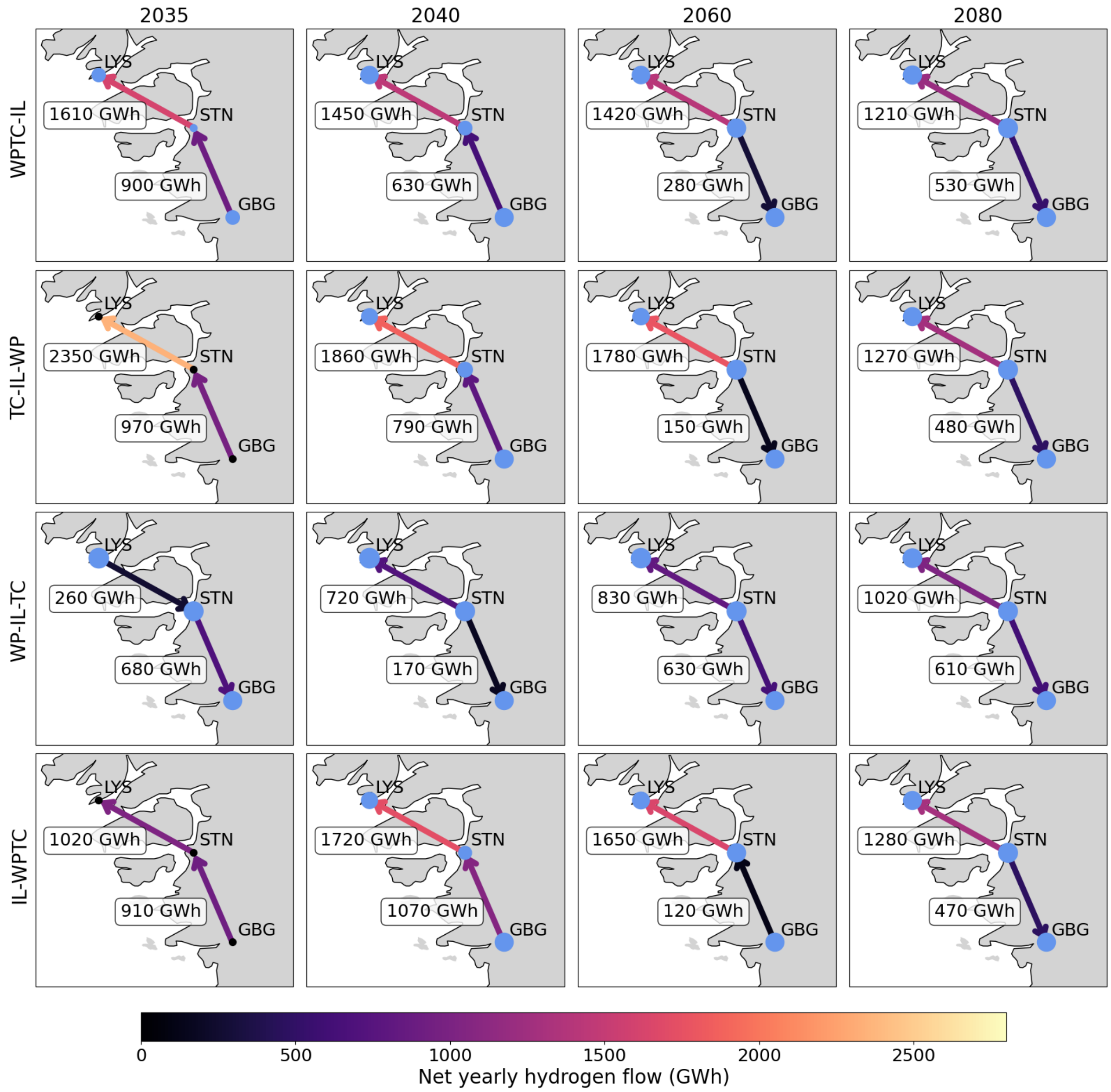


Figure 15. Annual net transfers of hydrogen in the modelled scenarios and for a selection of the years, from Paper II.

4.2.2 Electrolysers and H_2 storage units

Comparing the overall trends in electrolysers and H_2 storage units between **Papers I** and **II**, the over-investment in electrolyser is 49%–53% in the cases with pipelines in **Paper I** and converge at 43%–44% in all the scenarios in Year 2080 in **Paper II**. The over-capacity indicates that the electrolysers are run with varying load rather than constant load throughout the year. The investments in LRC storages are smaller in **Paper II** (71–106 GWh in Year 2080 depending on scenario) than in **Paper I** (129–136 GWh depending on the case).

In Figure 16, the electrolyser capacity and LRC storages are summarised for the case with possibility to invest in pipelines as well as the larger off-shore wind farm outside Gothenburg from **Paper I** together with Year 2080 results for the scenario with grid reinforcements and off-shore wind power from Year 2030, from **Paper II**. As the results start to converge towards Year 2080 in **Paper II**, only one scenario is visualised and compared. These two model runs are compared because they should resemble each other with regards to access to off-shore wind and electricity import limits, as well as possibility to invest in hydrogen pipelines. However, they do not resemble each other. While the electrolyser capacities are similar between **Papers I** and **II** in Gothenburg and Stenungsund, the electrolyser size in Lysekil is smaller in **Paper II** than in **Paper I**. Most significantly, the investments in LRC storage are lower in Stenungsund and higher in Lysekil. As explained in Section 4.1, a more-restricted hydrogen flow implementation results in increased LRC storage in Lysekil, as the node becomes more self-sufficient. This indicates that the pipeline diameter sizes chosen in **Paper I** were too general for the system studied, such that investment was made in a pipeline that had larger transfer capacity than was needed, albeit with the benefit of allowing for faster fluctuations than the much smaller cost-optimal pipeline in **Paper II**.

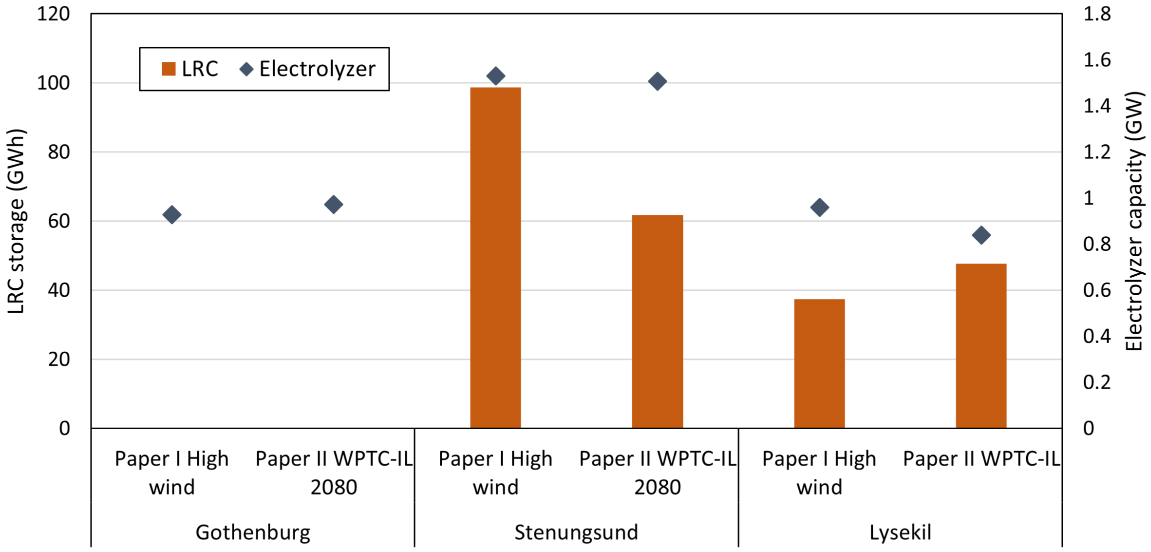
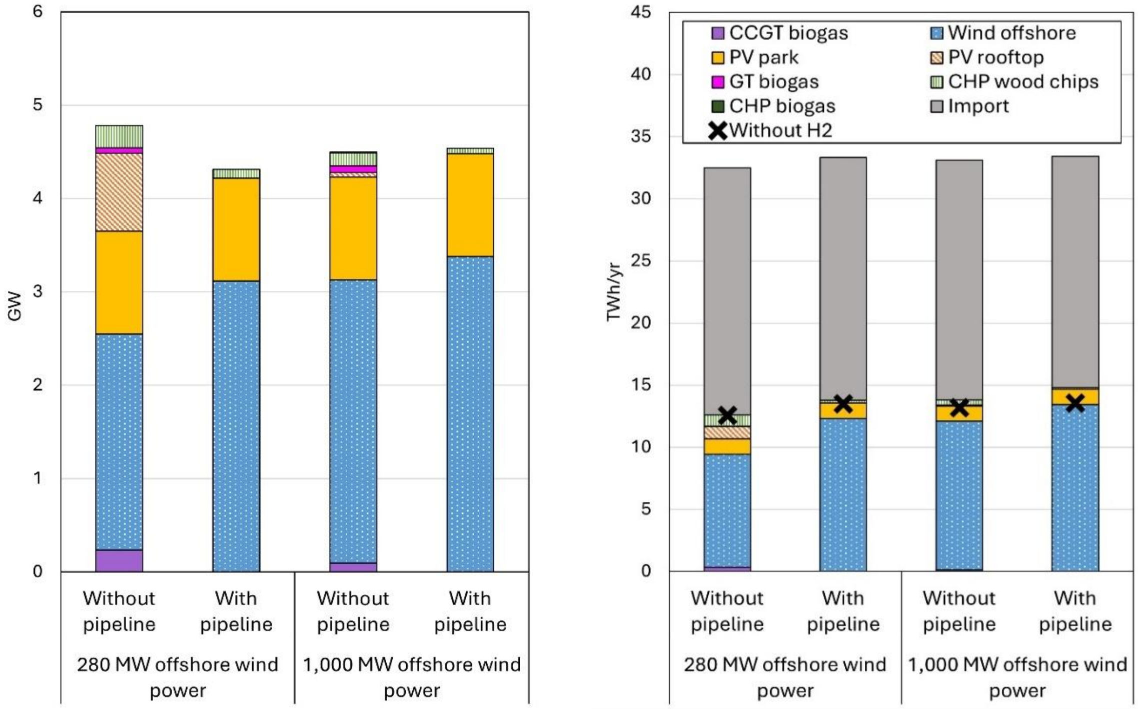


Figure 16.Electrolyser capacity (GW) and LRC storage size (GWh) for the case with a large off-shore wind farm and the possibility to invest in pipelines (from Paper I), and the Year 2080 values for the scenario with access to both off-shore wind and grid reinforcements from Year 2030 (from Paper II).

4.3 Supplying electricity and district heating

4.3.1 Electricity

In Figure 17, the electricity-generating technologies invested in and the annual levels of electricity production are presented for cases with smaller and larger availability of off-shore wind power outside Gothenburg and with and without the possibility to invest in hydrogen pipelines between the municipalities (**Paper I**). The installed capacity and electricity generation for all three municipalities investigated is combined. Without the possibility to invest in pipelines and with only a smaller off-shore wind farm outside Gothenburg, investments are made in combined cycle gas turbine (CCGT) fuelled with biogas, off-shore wind, solar PV parks, and solar PV roof-top, as well as combined heat and power (CHP) fuelled with wood chips and a small amount of gas turbines (GT) fuelled with biogas. With investments in pipelines, the share of off-shore wind and solar PV parks in the annual electricity supply increase, as compared to the cases without any possibility to invest in a pipeline. The impact of pipeline investments is more pronounced when Gothenburg can only be connected to a smaller off-shore wind farm, but a similar trend where investments in solar PV rooftop, GT biogas and CCGT biogas are no longer taken can be seen with the larger off-shore wind farm as well.



(a) (b)

Figure 17. Shares of invested-in technologies in relation to; (a) electricity generation; and (b) annual electricity generation, for all three municipalities combined (from Paper I).

In **Paper II**, it is assumed that an off-shore wind farm of 1 GW is available to invest in outside Gothenburg, and that it is allowed to make investments in hydrogen pipeline capacity, meaning that from Year 2040, the assumptions in **Paper II** are similar to those for the fourth case presented in **Paper I**. In scenarios where off-shore wind power or transmission grid reinforcements are available before the industrial electricity demand increase (WPTC-IL, TC-IL-WP and WP-IL-TC), the electricity mix is similar to that presented in **Paper I**, with off-shore wind power, solar PV parks and imported electricity being the main contributors to meeting the demand for electricity (Figure 18). However, if neither off-shore wind power nor transmission grid reinforcements are available (IL-WPTC), there is a more diverse mix in Year 2050 including off-shore wind power, solar PV parks, solar PV on roof-tops, CCGT biogas and CHP biogas. In Year 2035, CCGT biogas supplies 39% of the electricity supply demand, although it only supplies 2% in Year 2040. Furthermore, electricity production through CCGT biogas results in a biogas demand of 19 TWh per year, which can be compared to the total biogas production in Sweden of 2.3 TWh in Year 2022. This raises the questions as to which actors would make such an investment in biogas production and what other sectors would be interested in biogas if it were to be no longer needed in the electricity grid.

In Table 5, the total system cost for the four modelled scenarios in **Paper II** are presented. Although the specific number should be taken with a pinch of salt, the comparison shows that while the WP-IL-TC and TC-IL-WP scenarios only increase the total system cost by 4% and 2%, respectively, the total system cost is increased by 17% when neither off-shore wind power nor grid reinforcements are available until after the industrial demands for hydrogen from electrolysis have increased. This implies that access to either off-shore wind or electricity grid reinforcements is important to meet a high demand for electrolytic hydrogen from industries in a cost-efficient manner.

Table 5. Total system costs based on the scenarios from Paper II.

Total system cost (M€)	WPTC-IL	28,800
	WP-IL-TC	29,900
	TC-IL-WP	29,500
	IL-WPTC	33,700

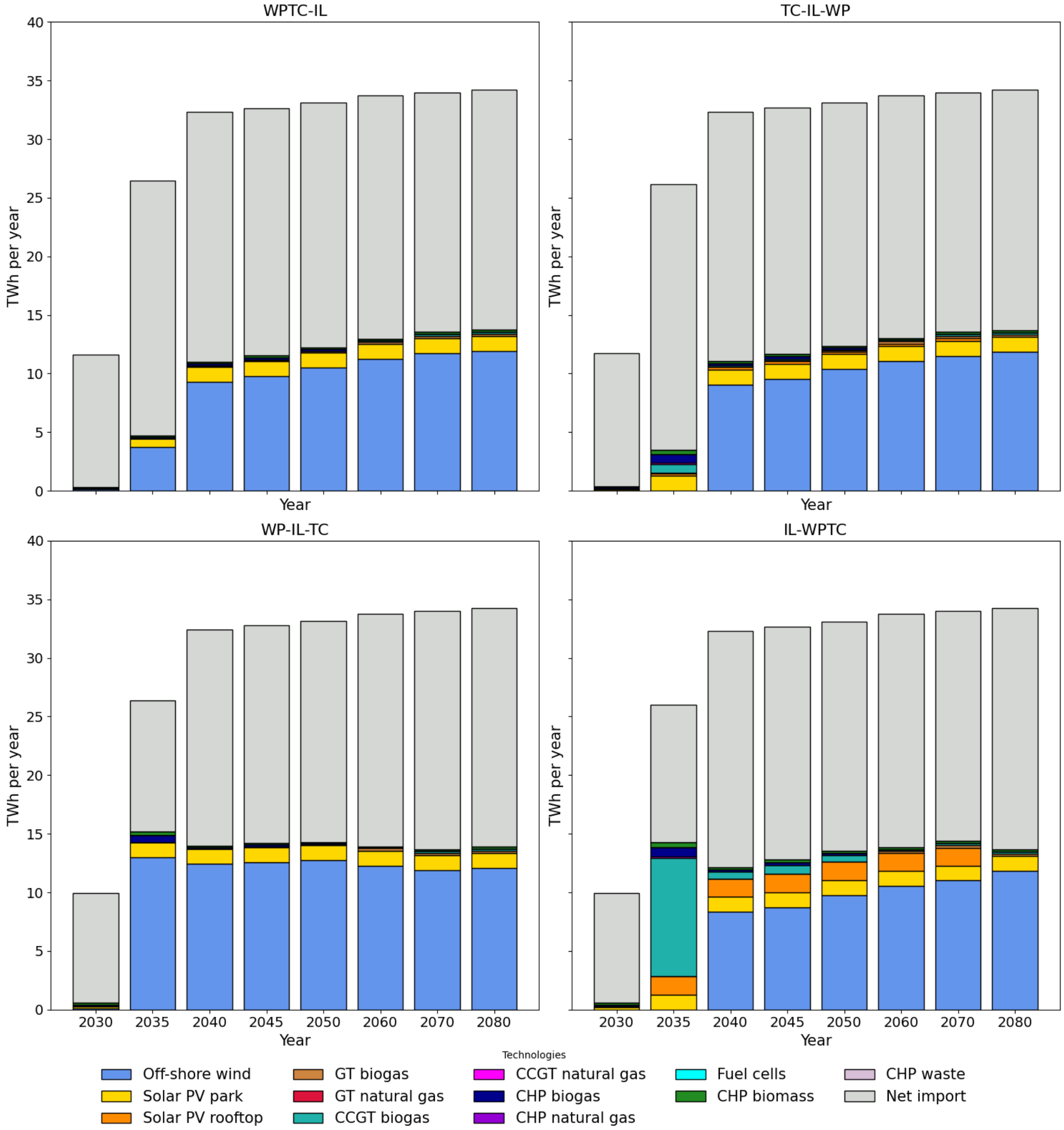


Figure 18. Annual levels of electricity generation for all three municipalities combined, from Year 2030 to Year 2080, based on the scenarios presented in Paper II.

4.3.2 District heating

The district heating system was primarily studied in **Papers I** and **III**, although the heating sector is included in all the papers. In **Papers I–II**, it is assumed that the waste heat (WH) from industry is sufficient to cover the heating demands in Lysekil and Stenungsund, both today and in the future. For Gothenburg, however, additional investments are needed to fulfil the demand for district heating. In **Paper I**, it is assumed that approximately one-third of the current WH would remain in the system in Year 2050. It was found that the annual demand for district heating was supplied mainly by WH (~40%) and heat pumps (33%–44% depending on the case), and also by CHP wood chips (5%–18% depending on the case), except for the case in which off-shore wind could not be invested in outside Gothenburg. In the case without off-shore wind outside Gothenburg, a larger share of the annual district heating demand was supplied by CHP wood chips (42%), which can produce both heat and electricity. Heat-only boilers (HOB) using biogas as a fuel are invested in to cover the hours during which electricity is expensive and power-to-heat technologies are shut down.

Since both the future hydrogen demand and the availability of WH from the refineries located in Gothenburg are uncertain, a sensitivity analysis varying these two parameters was carried out in **Paper III**. The results from the sensitivity analysis are presented in Figure 19. In **Paper III**, only one municipality (Gothenburg) was included in the model runs and up to 1 GW off-shore power capacity was allowed which makes the results most comparable to Case 3 in **Paper I**. Unlike **Paper I**, **Paper III** includes the possibility to re-use WH from electrolysis in the district heating system, albeit with investments in a heat pump (HP) to increase the temperature of the water. This option is also included in **Paper II**. Three scenarios (red boxes) were evaluated based on uncertainties related to the future WH potential and the hydrogen demand: ‘industries-as-we-know-them’ (IK), ‘industrial net-zero pledge’ (NZ), and ‘sector coupling’ (SC). In the SC scenario, the demand for electricity increases due to the demand for hydrogen, resulting in investments in CHP wood chips, similar to the results shown in **Paper I**. The WH from electrolysis covers 20% of the annual heating demand and mainly replaces other power-to-heat technologies in Figure 19.

Changing the potential of WH from the refineries and the demand for hydrogen, WH can be seen to replace primarily HPs in the energy mix. Furthermore, the off-shore wind farm is with explicitly what it implies instead invested in to 97% when the demand for hydrogen reaches 4 TWh, and investments reach 100% with WH potentials lower than 50%. This means that additional electricity generation is needed and the cost-optimal technology is CHP wood chips. The number of full-load hours of the Electrolyser HP increases when there is a weaker potential of WH from the refineries, although no significant additional investments are seen in electrolyser capacity, suggesting that the possibility to re-use the heat from the electrolyser does not incentivise a larger electrolyser. In **Paper II**, investments are also made in HPs connected to the electrolyser, thus utilizing the WH from hydrogen production through electrolysis.

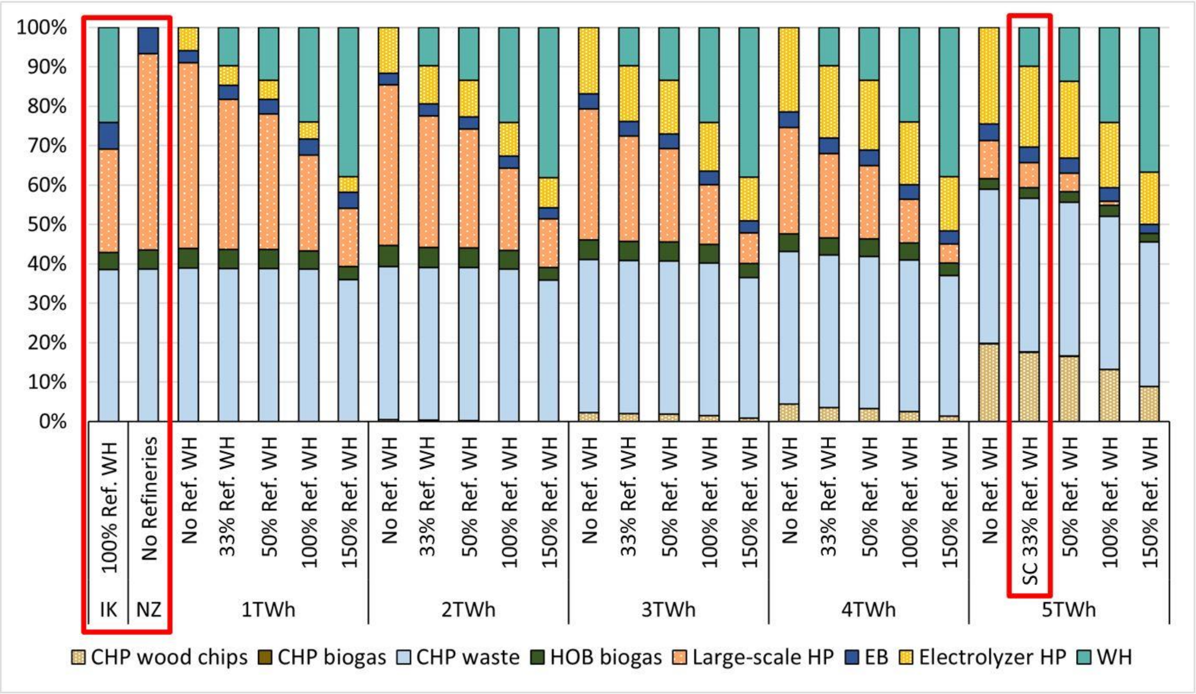


Figure 19. Annual district heating generation levels based on the availability of waste heat (WH) from the refineries and the hydrogen demand.

5 Discussion

Similar to the work presented by Shchetinin et al. [25], including the gas dynamics in the energy system optimisation model used here affects the investments in both pipeline capacities and hydrogen storage but also investments in off-shore wind power. Interestingly, while Shchetinin et al. [25] found that including gas dynamics increased investments in pipelines, this study found that investments in pipelines were decreased. Furthermore, the difference between the LP and MIP methods was significant where the MIP method shows a greater effect on the overall energy system configuration. The MIP formulation is more computationally heavy which could prove difficult in larger models than the one used in this thesis. The LP method is based on assumptions regarding the diameter of the invested in pipeline, and the same assumption (0.2 m) was used in both pipeline connections, although the results showed that the actual invested in pipeline capacity differed between the connections. It is possible to instead of assuming the same diameter for both pipelines, make an individual judgement. In order to do this, the modeler need to already know what size of pipeline that can be expected. Possibly, the MIP method can be used as an initial step to understand the system and what pipeline sizes that are invested in, to later calculate pipeline specific coefficients (a_l, b_l and c_l) depending on the optimal diameter found through the MIP formulation. How to include gas dynamics in energy system optimisation models in an efficient way thus needs further investigation. Furthermore, 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.

In the evaluation of the pipeline gas dynamics methods, investments in technologies, annual hydrogen transported, and hourly hydrogen flow were compared. For future evaluation it could be interesting to also compare full load hours of for instance electrolysers that could be affected by a more restricted possibility to transfer hydrogen. Similarly, curtailment of off-shore wind power and solar PV technologies could be interesting to evaluate. Another step to continue the evaluation could be to have a meshed system, unlike the system presented here where the nodes were located along the coast and only Stenungsund could be connected to the both nodes, a meshed system would include several connections. This is interesting to further investigate what role a pipeline infrastructure takes in the energy system.

Several aspects may influence the results and affect the comparisons between **Papers I**, **II** and **III**. The costs for hydrogen pipelines are lower in **Paper I** than in **Paper II**, as the costs were up-dated by the European Hydrogen Backbone [32]. This implies that in **Paper I** the extra cost for a larger pipeline had validity in order to have the possibility to change the flow more rapidly, thereby balancing the hydrogen supply by transferring hydrogen between the nodes, while this was not cost-optimal in **Paper II** due to the increased costs for the pipelines. This issue needs further investigation. Similarly, the costs for off-shore wind power were up-dated by the Danish Energy Agency [30] between the finalisation of **Paper I** and **Paper II**, as were the electricity prices used in **Paper II**, which were also influenced by the up-dated costs. An increase in price of imported electricity could explain why investments are made in CCGT and

GT in **Paper II**, while these technologies did not receive investments in **Paper I** when pipelines were available to invest in.

Another difference between **Papers I** and **II** is that the WH from the electrolysis process could be utilised in the district heating system, which could affect the operation of the electrolyser in Gothenburg. As of now, it has not been investigated how the results in **Paper II** are affected with and without the possibility to reuse the WH from the electrolysis process. In both **Papers I**, **II** and **III** there is a demand for biogas. For the district heating sector, heat-only-boilers are used during hours when the electricity prices are high and power-to-heat technologies are shut down. This results in a large demand for hydrogen under a short period of time. The biogas production process is continuous and cannot be increased only to cover a few hours of demand. Instead, a storage might be needed. This storage investment is currently not included in the model. In **Paper II** a great demand for biogas is found during few years in one of the scenarios, larger than the current production in all of Sweden. It is possible that biogas can be used in electricity sector in some years, but since hydrogen can be produced by steam methane reforming of biogas it seems like an inefficient production route. In future studies, alternative ways to produce hydrogen should be implemented to investigate if the most cost-optimal technology to produce hydrogen changes over years and scenario.

In **Paper II**, the energy system is studied over a period of 50 years, yet it is assumed that the potential off-shore wind power is limited by the current projects along the coast [40, 41, 42, 43, 44]. It is possible that the potential is larger than the one used in this thesis. This could be interesting especially for Gothenburg where the maximum off-shore wind power capacity is repeatedly invested in for the different scenarios. Another aspect that is not currently captured is the possibility to build power transmission grid between the municipalities, which was found by Chyong et al. [23] to out-compete hydrogen pipelines.

A fairly robust result is the over-investment in electrolyser capacity in the system, independent on cases and scenarios in **Papers I-III**, making it possible to operate the electrolyser in a flexible manner. A variable output affects the degradation of the electrolyser units. This is something that, for instance, Pettinau et al. [20] included in their modeling approach and that would be interesting to integrate into the model presented in this thesis.

6 Main findings

Three methods (EF, LP and MIP) to model gas dynamics in pipelines were evaluated in this work. The choice of method is shown to affect the amount of hydrogen transferred between the studied municipalities and the level of investment in pipeline capacity, as well as the levels of investments in hydrogen storage units, electrolysers and electricity-generating technologies (primarily off-shore wind). A higher level of detail in the modelling reduces the net amount of hydrogen transferred through the pipelines (i.e., LP/MIP compared to EF) over a year. As the pipeline is constrained regarding how fast the flow could be changed, the locations of the hydrogen storage units change, such that fluctuations in hydrogen production to a larger extent are balanced locally rather than through imports and exports *via* the pipeline. This suggests that there is a risk associated with having a too-simplified version of pipeline flow, as the operation of the pipeline becomes overly flexible and, thus, takes on the handling of fluctuations in electricity availability, which is in line with the conclusions of Shchetinin et al. [25].

The MIP method is more-restricted than the LP method with regards to describing the gas flows for different pipeline diameter sizes. However, the MIP method is computationally onerous already in this relatively small energy system model, making it an un-attractive option for larger models into which additional pipeline connections are incorporated, in its current state. However, it is possible that the MIP method can be improved from its current state which could make it more feasible to use. Instead, the LP version could be more suitable for larger models, with the disclaimer that it becomes the modelers' duty to define what a "typical" pipeline is and to be aware of how these assumptions affect the results.

The papers appended to this thesis investigate the role of hydrogen for industrial electrification in urban energy systems. The general trends in **Papers I** and **II** are that: (i) it is cost-efficient for the three municipalities investigated to collaborate around hydrogen supply using hydrogen pipelines under a wide range of assumptions; (ii) the most cost-optimal way to meet the hydrogen demand due to industry electrification is mainly through electricity imports and off-shore wind power and (iii) with good connection to the transmission grid and available site for off-shore, Stenungsund becomes a net exporter of hydrogen. This was further highlighted in **Paper II** when the timing with which electricity becomes available relative to industrial electrification is studied. Stenungsund remains a net exporter of hydrogen in all scenarios and over all the years. With access to off-shore wind, grid reinforcements or both, Lysekil is a net importer of hydrogen and only becomes a net exporter when off-shore wind power is allowed before grid reinforcements. This is because it is more cost-effective to balance fluctuations in electricity production in a municipality with relatively good electricity import capacity (Stenungsund), than locally in Lysekil. As a consequence, the largest LRC storage unit and electrolyser capacity is located in Stenungsund in both **Papers I** and **II**.

Regarding the electricity supply, the main contributors to meeting the demand for electricity are imported electricity and off-shore wind (when available). Furthermore, investments in solar PV parks are always close to maximal. When off-shore wind power is not available and there are delays in reinforcing the electricity grid to increase electricity imports, **Paper II** shows investments in CCGT biogas and a biogas demand that reaches 19 TWh per year, which seems unlikely to occur in reality. Moreover, there is a total system cost increase of 17% as compared to when grid reinforcements and off-shore wind power are in place from Year 2030. With access to off-shore wind power or reinforcements to the electricity grid, the total system cost increase is 4% or 2% higher, respectively, indicating that access to either off-shore wind or electricity grid reinforcement is crucial to meeting a high demand for hydrogen from industries with electrolysis in a cost-efficient manner.

In the district heating sector, power-to-heat technologies and WH are the main contributors to meeting the demand for heat. However, as the demand for electricity increases due to hydrogen production, investments are made in CHP plants that can produce both heat and electricity.

7 Future work

The methodology presented in this work for modelling the gas dynamics in pipelines in energy system optimisation models has been evaluated in a relatively small energy system comprising three municipalities. For the method to be applied to larger models, some improvements will be necessary. Since the pipeline is divided into three segments, the correct segment must be connected to the correct node. In the current model implementation, this has been done manually but in larger models, there would need to be a more standard way to connect each segment to the correct node so that the direction of the flow of hydrogen is consistent. The current implementation results in a separate hydrogen balance being needed for each node, which is inefficient in larger models with more nodes.

As can be seen in the evaluation of the methods to model gas dynamics, the effect of including or not including the gas dynamics affects not only the pipeline size and operation, but also investments in hydrogen storage and electricity production (mainly off-shore wind). The differences in the results obtained with the LP and MIP methods were also significant, which indicates that further analysis is required to establish a trade-off between accuracy and computational time. One way to proceed with this is to model the non-linear gas flow for comparison, as this was not performed as part of this work but was done by Shchetinin et al. [25]. Another characteristic that is not captured in the current model implementation is the need for additional compressors, which are typically needed for a pipeline length >100 km. In this work, the nodes are located within 100 km of each other, so it was deemed that no compressor was necessary, apart from within the nodes.

Leaving the model technicalities and moving onto future studies on the topic of hydrogen in urban energy systems, the results show that with a high demand for electricity and without early access to transmission grid reinforcement and off-shore wind power, dispatchable technologies are invested in and this results in a high demand for biogas. A large share of the electricity demand comes from hydrogen production through electrolysis. However, electrolysis is not the only way to produce hydrogen, and it would be interesting to investigate other technologies. These technologies include, among others, SMR using natural gas and CCS, SMR using biogas or biomass gasification. Furthermore, it might be interesting to include options for the importation of hydrogen.

This study has focused on three municipalities on the west coast of Sweden. In future work, an expansion of the geographical scope would be interesting, while maintaining a focus on urban areas. Given the context of this study, a relevant geographical expansion would be the Västra Götaland region. This could also lead to more technologies being available in the system, such as hydro power and on-shore wind farms, which might affect where it is most optimal to produce hydrogen and the best way to distribute it.

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