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Timely delivery of electricity for industrial hydrogen demands: path dependencies in the transition of urban energy systems

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ABSTRACT

This study investigates how an increased demand of electricity to produce hydrogen through electrolysis affects three urban energy systems with hydrogen-based industries over a period of 50 years using an energy system optimisation model. Four scenarios are formulated based on access to electricity import capacity reinforcements and off-shore wind power in relation to increased industrial demands of hydrogen from electrolysis. Results show that electricity imports, off-shore wind power and solar PV parks are the main contributors of electricity in the studied urban energy systems in all the scenarios. Regardless of the scenario, investments are made in hydrogen pipelines that will connect the three urban energy systems investigated. The scenario with an increase in industrial load before access to electricity import capacity reinforcements and off-shore wind power, gives substantially more investments in combined cycle gas turbines fuelled by biogas to meet the demand, as compared to the other scenarios. Additionally, in that same scenario, the total system cost is 18% higher compared to the scenario when the grid is reinforced and off-shore wind power investments available already from Year 2030, before an increase in industrial loads. This can be compared to an increase in total system cost of 4% with access to either grid reinforcements or off-shore wind power respectively from Year 2030, suggesting that access to off-shore wind power and/or electricity import capacity reinforcements are important for a large-scale industry electrification in the studied system. Towards 2080, all scenarios show similar results with regards to electricity and hydrogen supply, which suggests that the pathway between Years 2030 to 2040 will not affect the long-term, most-cost-effective solution.

1. Introduction

Human activities have caused global warming, mainly through emissions of greenhouse gases, the levels of which continue to increase [1]. In limiting the effects of greenhouse gases on the climate, cities play an important role, as they account for around 75% of global energy consumption and 70% of global greenhouse gas emissions [2]. One measure to mitigate emissions in urban areas is through the electrification of end-use sectors, such as transportation, heating and industry. The increased demand for electricity in cities can be met through imported electricity and local electricity production, facilitated by flexibility measures that respond to variations in the electricity supply and demand [2,3].

Studies of the long-term planning of urban energy systems using energy system optimisation models include, for example, investigating policy-driven scenarios for city energy planning [4] and the integration of heating, electricity and gas networks [5]. The time resolution in long-term studies is typically a representative number of time-slices per season or month [4,6], rather than hourly. Horak et al. [6] investigated long-term energy supply strategies for Vienna, Austria using a techno-economic optimisation model with each day being divided into five time-slices of equal length. One conclusion from Horak et al. [6] is that with a high cost of imported electricity, the potential for solar photovoltaics (PV) becomes important for the energy supply in Vienna. In models used to study not only capacity expansion operation but also operation, chronological, hourly generation data is recommended to capture wind and solar PV variability [7].

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, according to a comprehensive review conducted by Gupta and Ahlgren [8]. Heinisch et al. [9] studied the integration of the electricity and

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heating sectors for Gothenburg, Sweden in Year 2050, using a techno-economic optimisation model with the assumption that no carbon dioxide emissions were allowed. In another study, Heinisch et al. [10] extended the techno-economic optimisation model to include the electrification of passenger electric vehicles and public transport. Menapace et al. [11] proposed a methodology to simulate a renewable urban energy system using as a case study the region of Bozen-Bolzano, Italy. The studies carried out by Heinisch et al. [9,10] included both investments and hourly dispatch of the energy system, whereas the study by Menapace et al. [11] simulated the hourly operation of an energy system with given capacities.

The present study adds to the current literature by investigating how the timing of events, such as investments in electricity supply and electrification of industry, impacts the cost-optimal system configuration over time, while maintaining an hourly time resolution. Although the time horizon spans decades, in contrast to the long-term planning studies described above, the time resolution is preserved as hourly to account for the variability of wind and solar PV and need for flexibility measures to meet the hourly electricity demand.

In contrast to most of the previous studies on future urban energy systems, we focus also on the use of hydrogen for the electrification of industry. In the industrial sector, hydrogen is expected to be an important energy carrier in terms of reducing emissions from hard-to-abate industries [12,13]. Today, around 85% of all hydrogen is produced using natural gas and coal and the remaining 15% is a by-product within, for instance, in oil refineries [14]. For hard-to-abate industries, such as oil refineries and chemical industries for which hydrogen is an important feedstock, carbon-neutral hydrogen production alternatives are needed. One method to produce hydrogen is electrolysis, whereby electricity is used to split water into oxygen and hydrogen. Using electrolysis to produce hydrogen increases the demand for electricity and, thus, affects the local energy system. On the other hand, producing hydrogen through electrolysis can add demand-side flexibility to the electricity demand and facilitate the handling of the variable output from renewables [12,15].

Although previous studies have investigated ways to meet the increasing demand for hydrogen by importing hydrogen into Europe [16], as well as producing it solely within European borders [17–20], less effort has been made to understand how an increased hydrogen demand could affect the local energy system. Wang et al. [21] studied how hydrogen production through electrolysis could help decarbonise ten cities in China, by calculating the potential of hydrogen as a substitute for fossil fuels in the industry and transportation sectors. They found that the substitution of fossil fuels in the transportation sector was the highest-paying sector and, thus, was prioritized. The study included ten individual cities without any possibility to collaborate in meeting the demand for hydrogen through pipelines and with an hourly time resolution for 1 year.

In recent years, the concept of "Hydrogen Valleys" has gained interest as hubs that are typically characterised by large industrial actors and the availability of renewable energy [22,23]. Pettinau et al. [24] modelled a hydrogen valley, focusing on providing hydrogen for the mobility sector, assuming an already existing solar PV park and pre-defined electrolyser size. They included revenues from selling the produced oxygen and excess electricity, yielding a cost for hydrogen of 3–4 €/kg_{H2}. The study carried out by Pettinau et al. [24] modelled only 1 year and did not consider the possibility to transfer hydrogen through pipelines between locations. Mendler et al. [25] suggested an iterative, non-linear, simulation-based optimisation approach to model a hydrogen valley for the Southern Upper Rhine Region in Germany, in order to capture the non-linear behaviour of gas flow. Mendler et al. [25] modelled only hydrogen actors and did not include fulfilling demands for electricity and heating from other sectors, thereby not modelling the whole urban energy systems. A levelized cost of hydrogen of 6.4–7.6 €/kg_{H2} was found when assuming demand projections for Year 2030, depending on the options to be self-sufficient or use grid electricity. Namazifard et al. [26] studied a hydrogen pipeline network in Belgium using a mixed-integer linear programming approach, where the investments in pipelines were Boolean variables. That study also included the possibilities to import ammonia and to produce hydrogen through steam methane reforming using natural gas with carbon capture and storage. The levelized cost of hydrogen was found to be in the range of 3.0–4.5 €/kg in Year 2040, with higher costs attributed to the case with ammonia imports. They found the investments in pipelines to be robust in the two studied years, although they did not include the dynamics of the gas in the pipelines.

Previous work by the authors of this paper [15] looked at how three municipalities in western Sweden could meet their industrial hydrogen demands by employing hydrogen pipelines to connect the municipalities. A pipeline made it possible to produce hydrogen in municipalities with good availability of variable renewable electricity and electricity import capacity and then transport hydrogen to more-congested municipalities. However, only one future year (Year 2050) was considered [15], under the assumptions that off-shore wind power was available for investments with only technical limitations, and that the transmission grid had been successfully reinforced relative to its current capacity.

Based on the afore-mentioned studies, there is a need for research into the optimal pathway for urban energy systems, including industrial electrification and associated hydrogen flexibility and infrastructure. The aim of this study is to understand how the timing of the availability of new electricity generation and electricity import capacity affects the cost-optimal energy system configuration over time, assuming large scale electrification through hydrogen production with electrolysis. This study uses a techno-economic energy system optimisation model with the objective to minimise the total system cost, which is run over a period of 50 years, using an hourly time resolution for the years modelled. The geographical scope of this study includes three municipalities on the west coast of Sweden (Gothenburg, Stenungsund and Lysekil). There are oil refineries located in Gothenburg and Lysekil, and in Stenungsund there are chemical industries. This means that all three municipalities modelled have industries that are dependent upon hydrogen as feedstock. Here, the following questions are addressed.

- How is the demand for electricity and hydrogen met and how does it depend on when in time off-shore wind power and electricity import capacity reinforcements become available?
- Where are the investments in electricity- and hydrogen-generating technologies located, and why?
- In what ways can a joint hydrogen pipeline infrastructure be used to supply hydrogen to each municipality?

2. Method

2.1. Model description

The techno-economic linear optimisation model used in this study was first introduced by Heinisch et al. [9] to study the inter-connections between the heating and electricity systems in urban settings. Subsequently, Heinisch et al. [10] added electric vehicles, and Rosén et al. [15] added a hydrogen infrastructure to the model. The main inputs to the model are: investment and running costs, hourly wind and solar profiles, hourly demand profiles for electricity, heat and hydrogen, and the hourly price for electricity imported to the modelled municipalities. The model gives the cost-optimal investments and dispatch for meeting the demands in each hour. In previous studies [10,15], only one future year was modelled. In this study, the model has been further developed to study a period of 50 years, with 5-year intervals for the period of 2030–2050, and 10-year intervals for the period of 2050–2080. The decision to model to Year 2080 was based on including two investment periods to understand how long the effects of the investments in Year 2035 might differ between the scenarios.

In Equation (1), the objective function of the model is presented. The aim is to minimise the total system cost, c^{tot}. c^{tot} is calculated by summarising the investment costs, $C^{inv}_{p,y}$, and the fixed operation and maintenance costs, $C^{OM_{fix}}_{p}$, for the installed capacity of a technology, $i_{n,p,y}$, where n is the set of municipalities, p is the set of technologies available, and y is the set of years modelled. The running cost, C^{run}_{p} , is multiplied by the generation of the invested-in technologies, $g_{n,p,y,t}$, as well as existing technologies, $y_{n,p,y,t}$, and subsequently added to the start-up and part-load costs, $c^{start}_{n,p,y,t}$ and $c^{partload}_{n,p,y,t}$, of the thermal units, where t is the set of time-steps per year. The electricity price, C^{el}_{t}, is included and multiplied by the imported or exported electricity, $w_{n,y,t}$. Lastly, the costs related to investments in pipelines to transfer hydrogen are presented, including the cost for the pipeline, C^{pipe}, and compressor, C^{comp}, that are multiplied with the capacity of the pipeline, $e^{max}_{l,y}$. The capacity of the pipeline is based on the maximum flow of hydrogen between the municipalities. All costs are annualized using a discount rate, r, of 5%.

$$MIN\, c^{tot}=\sum_{y\in Y}\left(\left(\sum_{p\in P}\sum_{n\in N}\left(\left(C^{inv}_{y,p}+C^{OM_{fix}}_{p}\right)*i_{n,p,y}+\sum_{t\in T}\left(C^{run}_{p}*\left(g_{n,p,y,t}+y_{n,p,t,y}\right)+c^{start}_{n,p,y,t}+c^{partload}_{n,p,y,t}\right)\right)+\sum_{n\in N}\sum_{t\in T}C^{el}_{t}w_{n,y,t}+\sum_{l\in L}\left(C^{pipe}_{l}+C^{comp}_{l}\right)*e^{max}_{l,y}\right)*\frac{1}{(1+r)^{y-Y_{start}}}\right) \quad (1)$$

Fig. 1 illustrates the modelled municipalities (Gothenburg, Stenungsund and Lysekil) and their three energy carriers: electricity, district heating, and hydrogen. The electricity demand can be met through investments in local electricity production and/or by importing electricity from the regional grid. Electricity can also be exported to the regional grid. Off-shore wind power is assumed to be directly connected to the municipal energy system. To shift electricity supply between hours, it can be stored in batteries or in the form of hydrogen. District heating can be supplied through local investments and the utilisation of waste heat from industries, together with waste incineration. Investments can be made in thermal tank storage units to store district heating. The hydrogen demand is met through investments in electrolysers, and hydrogen can be converted back to electricity through investments in fuel cells. Investments in lined rock caverns (LRC) and hydrogen tanks are possible means to store hydrogen. Furthermore, hydrogen can be transported between the municipalities if the model invests in pipelines. The hydrogen pipeline representation has been implemented to consider the gas dynamics, while being continuously linear, as suggested by Shchetinin et al. [27], instead of being a mixed integer, as was the case in previous work by the authors [15]. The model is described in its entirety in Appendix A together with economic and technical data.

2.2. Case study

As a case study, three municipalities located on the west coast of Sweden are included: Gothenburg, Stenungsund and Lysekil. Gothenburg is the second-largest city in Sweden with an electricity demand of 4.5 TWh/yr in Year 2020 [28]. Stenungsund and Lysekil are smaller communities with electricity demands in Year 2020 of 1.6 TWh/yr and 0.6 TWh/yr, respectively. Hourly based electricity and heating demand profiles are presented in Appendix B. These three municipalities are similar in having industries that use hydrogen in their processes. Oil refineries are located in Gothenburg and Lysekil, while Stenungsund hosts chemical industries. A report published by Edvall et al. [29] estimated that the total future hydrogen demand within the three municipalities would be 4.9–14.0 TWh_{H2}/yr per year, as compared with the current annual demand of 6.4 TWh_{H2}. Today, approximately half of the hydrogen demand is supplied as a by-product from industrial processes. In this study, an industrial hydrogen demand of 14 TWh_{H2} is assumed corresponding to the upper bound of the hydrogen demand assumed by Edvall et al. [29]. In this study, this amount needs to be produced through electrolysis to investigate how a significant increase in electricity demand from hydrogen production affects the urban energy system. The industrial demand for hydrogen is assumed to be constant for each hour of the year.

Five off-shore wind parks are under consideration (Year 2025) along the coast and are included in the model as the maximum potentials for off-shore wind power: to Gothenburg, 1 GW [30]; to Stenungsund, 1.12 GW [31]; and to Lysekil, 5 GW [32–34]. The possibility to import and export electricity also differs between the municipalities. In Lysekil and Stenungsund, the hourly limit of import based on the municipality's

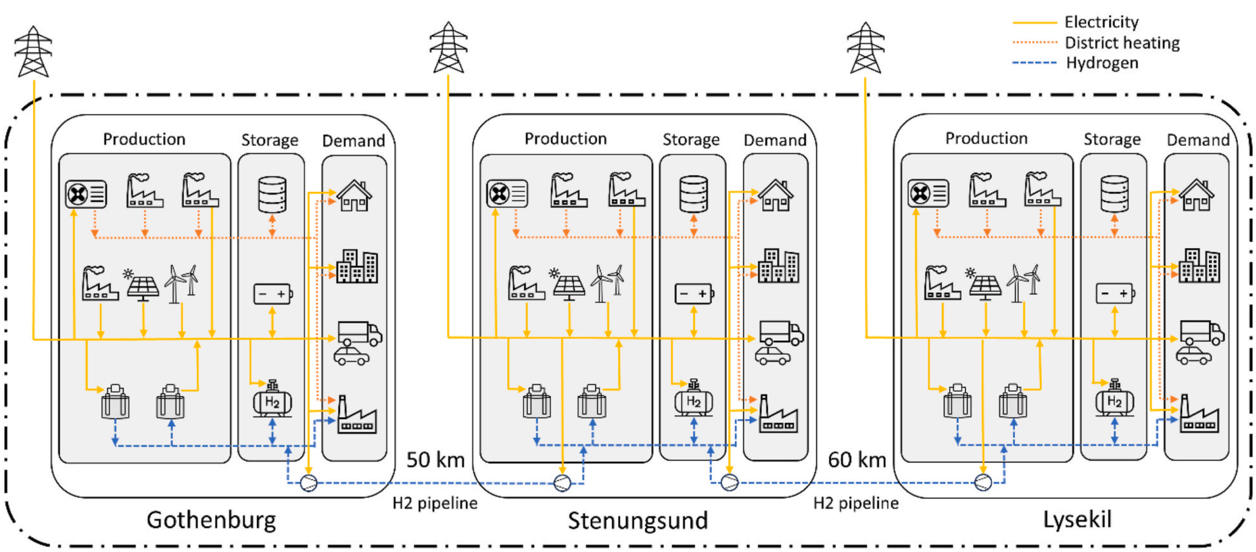

Fig. 1. Schematic overview of the scope of the study with the dash-dot line indicating the system boundary. The study includes three municipalities (Gothenburg, Stenungsund and Lysekil), production of electricity, district heating and hydrogen, storage (thermal tanks, batteries and lined-rock caverns (LRC)/H_2-tanks), and hydrogen pipelines, together with demand sectors (residential, commercial, transportation and industry). Each municipality can import and export electricity to the regional electricity grid (represented by the yellow line leaving the system boundary). Off-shore wind power is assumed to be directly connected to each municipality and is therefore treated as part of the municipality's energy system in the model. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

annual electricity demand [35] and adjusted to hourly values using the normalised demand profile for Gothenburg. To the demand, industrial loads are added, that are assumed to be constant for each hour. Stenungsund and Gothenburg are assumed to have initial import capacities of 0.4 GW/h [35] and 0.89 GWh/h [36], respectively, and in the national plans for the transmission grid there are long-term plans to expand these capacities. For this study, it is assumed that expansion leads to totals of 1 GWh/h for Stenungsund and 1.545 GWh/h for Gothenburg [37]. In Lysekil, the electricity import capacity is set to 50 MWh/h for all years as no concrete plans have been presented for grid reinforcements. Stenungsund and Lysekil have historically relied on imported electricity and industrial waste heat for district heating, while Gothenburg has local electricity and district heating production. Historically, around 90% of the electricity demand in Gothenburg has been met with imported electricity from the regional grid, and the remaining share provided by local production units [38].

The current and planned (up to Year 2030) technologies are presented in Table 1 and are included in the model as already existing technologies that are assumed to be present in the system until Year 2050. The investment costs for different technologies are taken from the Danish Energy Agency [39–41] except the hydrogen pipelines. The pipelines are based on costs from the European Hydrogen Backbone [42] and adjusted to the investments in smaller pipelines modelled in this study resulting in a cost of 3.7 M€/GW_{H2}/km (for more details, see Rosén et al. [15]). Since cost estimates are only presented up to Year 2050 by the Danish Energy Agency [39–41], the subsequent years (2060, 2070, 2080) are assumed to have the same technology costs as Year 2050. Year 2050 here represents a point in time from which carbon neutrality has been reached rather than a specific calendar year. The years reaching up to carbon neutrality likely includes scaling up intermittent energy sources as well as production of renewable fuels, such as hydrogen and biofuels, which in turn stimulate reductions in technology costs as indicated by the Danish Energy Agency [39–41]. When technology growth levels off after 2050, we assume that the technology costs stagnate. From Year 2030 to 2045, carbon dioxide emissions are taxed, and after Year 2045, no fossil carbon dioxide emissions are allowed, to comply with Sweden's climate targets [43,44].

As for the transport sector, the number of cars is assumed to increase with population and all vehicles assumed to be electric-powered from Year 2050 and onwards. Out of the total electric car fleet, 30% are assumed to be available for vehicle-to-grid services and flexible with respect to charging time when parked. Investments in LRC are not allowed in the Gothenburg municipality due to uncertainties related to suitable geographical locations. For Stenungsund and Lysekil, no upper limit is applied to LRC investments. In the model, Year 2019 is used for weather profiles and electricity and heating profiles. The demand for electricity is assumed to increase with population. The population increases are based on [45] and stated in Appendix B.

The hourly electricity prices used for buying electricity from and selling electricity to the regional grid for each respective municipality is retrieved from a European electricity system optimisation model called ELLI and described by Göransson et al. [46]. The ELLI model runs over a period from 2030 to 2065, with 5-year intervals and a geographical scope covering Northern Europe. From the model, the marginal cost of electricity for each year modelled can be retrieved for the electricity price area SE3, in which the three studied municipalities are located. The marginal cost of electricity retrieved from the ELLI model for Year 2065 is implemented as the electricity price for both Year 2070 and 2080 in this study. It is assumed, in both the model in this study and the ELLI model, that the investment costs for the years after Year 2050 are the same as in Year 2050. Similarly, Year 2019 is used for weather profiles also in ELLI. The ELLI model assumes large scale electrification in Europe, and a hydrogen demand from industries in SE3 of 6.8 TWh_{H2} in Year 2030 and 16.6 TWh_{H2}/year from Year 2035 and onwards, to be met with electrolysers this can be compared to the assumption in this study of 14 TWh_{H2}. Electricity price duration curves for each year are presented in Appendix C together with a more thorough explanation of how the electricity import prices are retrieved.

2.3. Scenario description

Four scenarios are formulated to study the impact on investment decisions based on the electricity import capacity from the regional grid to the municipalities and possibility to invest in off-shore wind farms, in relation to industrial loads. Table 2 shows how the scenarios differ in terms of industry load, electricity import capacity and maximum allowed investments in off-shore wind power at different years. In all the scenarios, by Year 2035, 10.5 TWh_{H2}/yr of the industrial hydrogen demand is assumed to be in place, reaching 14 TWh_{H2}/yr by Year 2040, and it remains constant between Years 2040 and 2080. Electrolysis is assumed to be the only available technology for producing hydrogen in all the scenarios to study how a significant increase in electricity demand affects the urban energy systems and how this increase in electricity affects the potential collaboration between municipalities under different circumstances.

The scenario names are based on the order in which the model can invest in off-shore wind power (WP) and when planned electricity import capacity (EC) reinforcements is taking place. In addition, the scenarios differ depending on whether WP and EC are available in the model before or after the increase in industrial loads (IL) due to additional hydrogen demand. The first scenario is WPEC-IL, in which the possibilities to invest in off-shore wind power and electricity import capacity reinforcements are in place at the same time from Year 2030, i.e., before the industrial load starts to increase in Year 2035. In the second scenario, WP-IL-EC, it is possible to invest in off-shore wind power from Year 2030, while the electricity import capacity reinforcements are in place in Year 2040, i.e., after both investments in off-shore wind power and the increase in industrial loads. In the third scenario (EC-IL-WP), electricity import capacity reinforcements are in place from Year 2030, and it is possible to invest in off-shore wind power from Year 2040. Lastly, in the fourth scenario (IL-WPEC), the industrial loads increase before electricity import capacity reinforcements are in place, and before it is possible to investment in off-shore wind power, as these options are made possible from Year 2040. From Year 2040 and onwards, the assumptions are the same for all the scenarios.

Table 1
Municipality-specific data given as input to the model including electricity demand, industrial loads, off-shore wind power availability, electricity import capacity availability and existing technologies. The electricity demand includes historical demand for Year 2020, as well as establishment of a battery factory in Gothenburg.

	Electricity demand [TWh/year]	Industrial load [TWh_{H2}/year]	Maximum off-shore wind power [GW]	Electricity import capacity (current/planned) [GW]	Existing technologies (capacity)
Gothenburg	6.7	5	1	0.9/1.5	Solar PV roof-top (300 MW), CHP wood chips (57 MW_e), CHP biogas (260 MW_e), HP (100 MW_{heat}), HOB pellets (170 MW_{heat})[a]
Stenungsund	1.6	5	1.12	0.4/1	Solar PV roof-top (40 MW)
Lysekil	0.6	4	5	0.05/0.05	Solar PV roof-top (20 MW)

[a] CHP, Combined heat and power; HOB, heat-only boiler; HP, heat pump.

Table 2
Descriptions of the four scenarios in terms of industrial loads, maximum allowed investments in off-shore wind power at different years and the electricity import capacity in place at different years. Note that the industrial loads are the same in all three scenarios.

Scenarios[a]	Industrial loads [TWh_{H2}/year]			Maximum allowed investments in off-shore wind power [GW]			Electricity import capacity [GW]		
Years	**2030**	**2035**	**2040**	**2030**	**2035**	**2040**	**2030**	**2035**	**2040**
WPEC-IL	0	10.5	14	7.5	7.5	7.5	2.6	2.6	2.6
WP-IL-EC				7.5	7.5	7.5	1.3	1.3	2.6
EC-IL-WP				0	0	7.5	2.6	2.6	2.6
IL-WPEC				0	0	7.5	1.3	1.3	2.6

[a] WP – off-shore wind power; EC – electricity import capacity; IL – industrial loads. The order of the abbreviations represents the order in which the different parameters are in place.

2.4. Sensitivity analyses

In addition to the four scenarios, a set of sensitivity analyses was carried out. As one part of the study is to investigate how a joint hydrogen infrastructure can be used to supply hydrogen to the municipalities, the four scenarios were run without the possibility to invest in hydrogen pipelines in the sensitivity analyses. An annual hydrogen demand of 14 TWh_{H2} for the three municipalities was chosen for the primary outcomes. As the future demand for hydrogen in the municipalities is uncertain and is dependent upon the pathways chosen by industry, a sensitivity analysis was carried out to investigate how the system is affected with hydrogen demands of 4.9 TWh_{H2} corresponding to the lower bound in the estimates by Edvall et al. [29] as well as 7 TWh_{H2} and 20 TWh $_{H2}$.

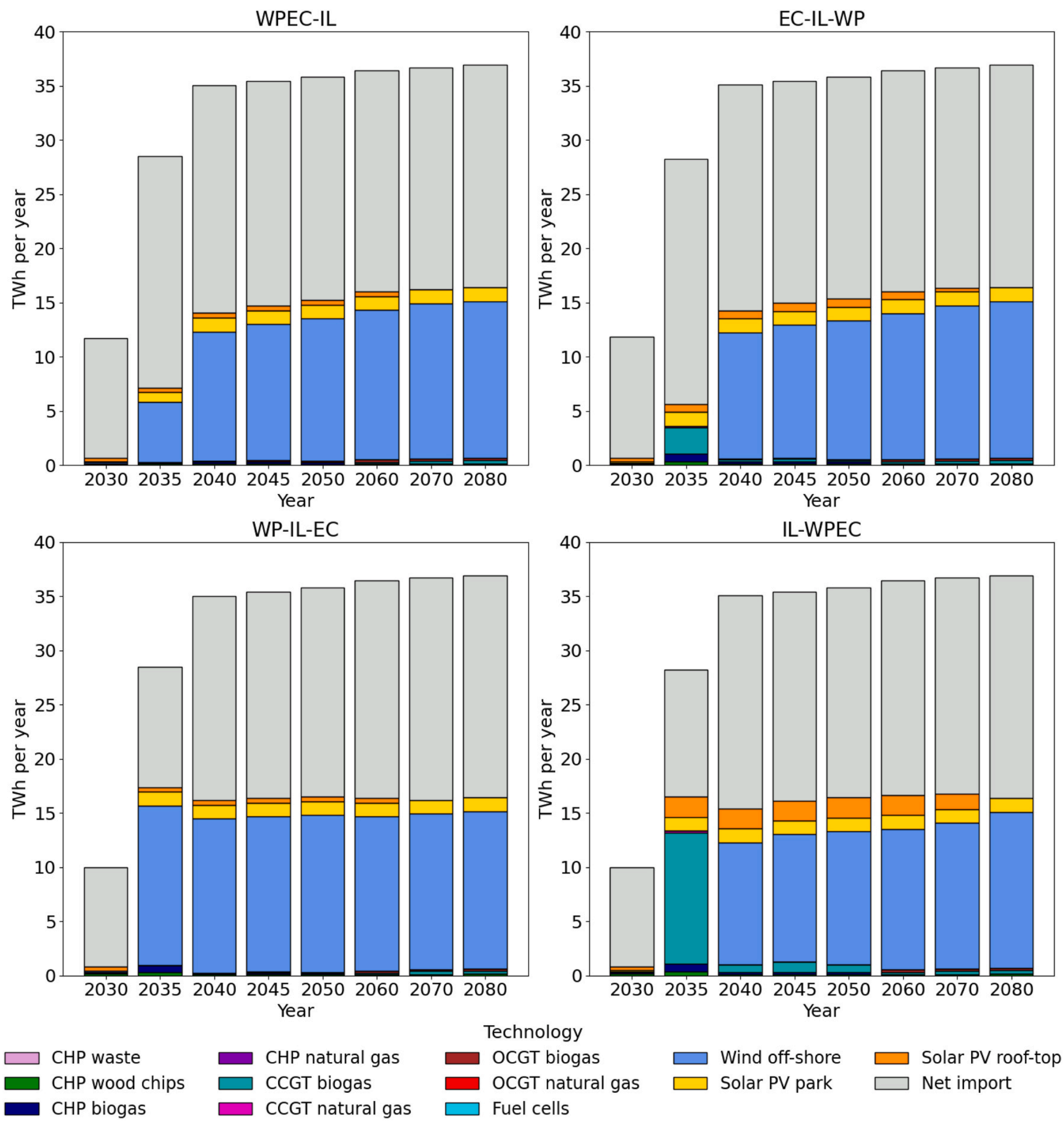

Fig. 2. Annual electricity supply for the three municipalities combined in the four scenarios. CCGT—combined cycle gas turbine; OCGT—open cycle gas turbine; CHP—combined heat and power.

The investment cost of LRC was varied in the range of 2–11 M€/GWh_{H2} due to uncertainties in costs and the investment cost for pipelines was varied in the range 1.8-3.7 €/kW/km to align the values presented by the European Hydrogen Backbone [42]. A restriction of 2.3 TWh of biogas annually was tested in the sensitivity analyses, which is similar to the biogas production in Sweden today [47]. The costs for electrolysers and off-shore wind power was decreased in the Years 2060-2080 to represent further learnings and to investigate how that affects the energy system configuration towards the end of the studied period. Lastly, the electricity import price was evaluated using two of the other cases presented by Göransson et al. [46] where investment in nuclear power are forced in SE3, resulting in higher average marginal cost of electricity in the Years 2030-2040.

3. Results

3.1. Supplying electricity and hydrogen to the region

This section presents the annual electricity supply, as well as the investments made in electrolysers and LRC for all three municipalities combined. Fig. 2 shows the annual electricity supply combined for all three municipalities over the modelling period (i.e., 50 years). In all scenarios for the whole modelling period, off-shore wind power, solar PV parks, and electricity imports from the regional grid are the three largest contributors to meeting the demand for electricity in the municipalities. Naturally, most of the differences between the scenarios appear in the first 10 years because the scenarios are based on the maximum allowed investments in off-shore wind power and the installed electricity import capacity between Year 2030 and Year 2040.

Focusing on Year 2035 for the scenario in which both off-shore wind power is available for investment and electricity import capacity reinforcements are in place (i.e., WPEC-IL), the demand for electricity is primarily met by imported electricity (75%), and secondarily by off-shore wind power (20%) and some solar PV parks (3%). With off-shore wind power available to invest in from Year 2030 and without electricity import capacity reinforcements (WP-IL-EC), larger investments are made in off-shore wind power compared to the WPEC-IL scenario. Off-shore wind power then accounts for 52% of the annual electricity supply in this scenario for Year 2035. Off-shore wind power investments remain in the system but as the electricity demands increase over time, off-shore wind power contributes with around 40% of the annual electricity supply in the following years. Until Year 2050, the scenario WP-IL-EC has then a higher level of off-shore wind power compared to the other three scenarios (where off-shore wind power covers 32% to 35% of the annual demand). After Year 2050 the scenarios reach similar levels of off-shore wind power deployment, as seen in Fig. 2.

In the scenarios where off-shore wind power can be invested in not until Year 2040, i.e., scenarios EC-IL-WP and IL-WPEC, investments in combined-cycle gas turbines (CCGT) using biogas are invested in to supply the electricity needed, together with solar PV and electricity imports. In the EC-IL-WP scenario, most of the electricity needed can be supplied with imported electricity from the regional grid as this scenario has a higher import capacity Year 2035 compared to the IL-WPEC scenario. In the IL-WPEC scenario, imported electricity supplies only 41% of the demand while CCGT biogas stands for 43% of the annual electricity demand in Year 2035. This results in a demand for 21 TWh of biogas in the IL-WPEC scenario in Year 2035. The 21 TWh of biogas can be compared to the amount of biogas that was produced in all of Sweden in Year 2022, which was 2.3 TWh [47], and the suggested national goal of producing 15 TWh of biogas in Year 2030 [48]. However, already in Year 2040, the electricity generation from CCGT biogas is reduced to 2% of the annual electricity supply. From Year 2040 and to the end of its life-time, the CCGT biogas is instead operated during peaks in net load with fewer full load hours as compared to Year 2035. These two scenarios where off-shore wind power is not possible to invest in before Year 2040, i.e., EC-IL-WP & IL-WPEC, also result in investments in CCGT natural gas in Lysekil. The operation of CCGT natural gas gives CO_2 emissions between Years 2030-2040. For the EC-IL-WP scenario this results in 42 kton of CO_2 emitted and for the IL-WPEC scenario 44 kton. These numbers can be compared to Sweden's territorial emissions in Year 2023 which was 44 Mton [49]. For Lysekil, a municipality with low electricity import capacity, CCGT natural gas is the most cost-optimal option for providing electricity in Years 2030-2040 as carbon taxes are still low in the years the plant is operated. From Year 2045, biogas outcompetes natural gas based on the EU-ETS price assumed in the calculations and thus no direct fossil CO_2 remain in the system.

From Year 2040 and onwards, the four scenarios show a similar energy mix in which electricity imports, off-shore wind power, solar PV parks and solar PV roof-top are the four main suppliers of electricity. The major differences between Years 2040 and 2070 is that the IL-WPEC scenario uses more solar PV roof-top compared to the other three scenarios. In Year 2080, solar PV roof-top production is not re-invested in for the IL-WPEC scenario. This is because solar PV roof-top production, as well as CCGT biogas, are invested in to cover the increased electricity demands in Year 2035 when both the electricity import capacity is limited and no investments are allowed in off-shore wind power. However, in Year 2080, it is most cost-effective to meet the electricity demand with primarily electricity imports, off-shore wind power and solar PV parks. Thereby, the most cost-optimal scenario is reached earlier in the two scenarios where investments in off-shore wind power is allowed already in Year 2030 as seen in Fig. 2.

Present in all scenarios in Year 2080, although not clearly visible in Fig. 2, is the electricity production from the open-cycle gas turbine (OCGT) biogas and CCGT biogas, which serve as peak technologies, being only operated during hours with high electricity import prices and low levels of production from primarily off-shore wind.

In Gothenburg, the maximum allowed off-shore wind power capacity (1 GW) receives investment in Year 2040 at the latest in all scenarios. This is because Gothenburg is the municipality with the highest electricity demand and, thus, runs the risk of congestion in the electricity grid in the absence of investments in electricity production. In Stenungsund, the maximum allowed capacity (1.12 GW) is always reached in the studied period but the year differs between scenarios. In Lysekil, the largest investments in off-shore wind are found among the three municipalities and towards 2080 a capacity of 1.6 GW is reached in Lysekil in all scenarios. For all the scenarios and municipalities, investments in solar PV parks reaches its maximum allowed capacity from Year 2035. Investments in generation technologies for all municipalities and scenarios are found in Appendix D.

The results converge towards Year 2080, which suggests that the long-term, most-cost-effective energy configuration is that presented for Year 2080. Comparing the results from the four scenarios, it seems necessary to make either investments in off-shore wind power or investments in more electricity import capacity before electrifying the industry in these municipalities. Although differing in system configuration, both scenarios are capable of meeting the increased electricity demand with relatively minor difficulty. However, if electrifying the industry first, large investments in biogas production until Year 2035 are needed, which after Year 2035 are not utilised to the same extent as fuel for electricity production. This build up biogas production capacity may on the other hand serve other actors, e.g., in the transport sector. The need for biogas in other sectors has not been investigated in this study.

In Fig. 3, the electrolyser capacities (PEM) and lined rock cavern (LRC) investments are presented for each scenario, summed for the three municipalities. The black crosses indicate the minimum capacities needed to meet the demand for hydrogen when running the electrolyser at constant load throughout the year. As the hydrogen demand is introduced in Year 2035, investments are made in LRC and more investments are made in electrolysers than are needed in all the scenarios. The over-investment in electrolyser capacity is cost-efficient in order to run the electrolyser with some flexibility. In Year 2035, there are

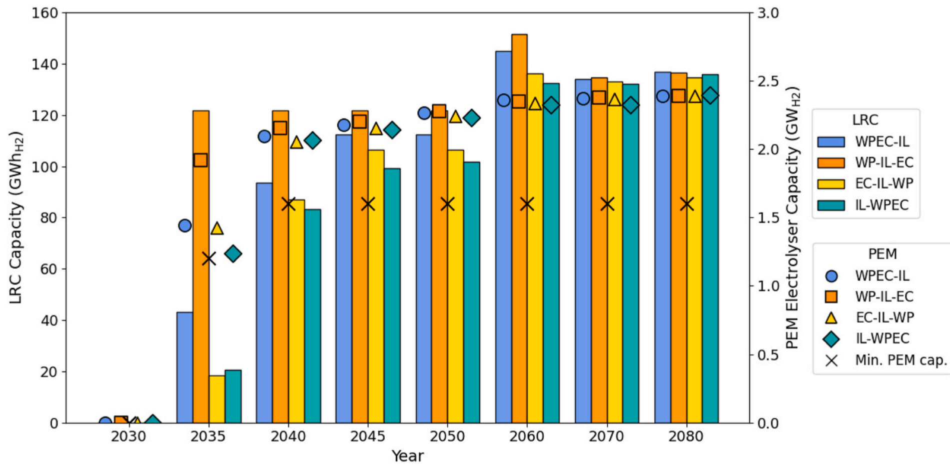

Fig. 3. Investments in proton exchange membrane (PEM) electrolyser capacity (GW$_{H2}$) on the right y-axel and line rock cavern (LRC) storage (GWh$_{H2}$) on the left y-axel for all three municipalities combined for the four scenarios (WPEC-IL, WP-IL-EC, EC-IL-WP, IL-WPEC).

investments in a larger over-capacity of electrolysers (60%) in the WP-IL-TC scenario where off-shore wind power can be invested in from Year 2030 and all planned electricity import capacity reinforcements are in place in Year 2040, than in the other scenarios (3%–20%). This is because the over-capacity makes it possible, together with storage units, to operate the electrolysers in a flexible manner which corresponds to the larger investments in off-shore wind power made earlier in the WP-IL-EC scenario compared to the other scenarios. In Year 2080, the over-capacity in electrolysers is similar for all the scenarios (~50%), the installed capacity is approximately 2.4 GW$_{H2}$.

Similarly, in Year 2035, the largest LRC in Year 2035 can be seen in the WP-IL-EC scenario. In this scenario, the LRC investment is 122 GWh$_{H2}$ in Year 2035 (corresponding to 76 h of hydrogen demand), as compared with the other three scenarios where LRC investments remain within the range of 18–43 GWh$_{H2}$ (corresponding to 11–27 h of hydrogen demand). The LRC size remains the largest in the WP-IL-EC scenario until Year 2070, when all the scenarios show similar investments. In Year 2060, the LRC capacity reaches its highest mark in the WPEC-IL and WP-IL-EC scenarios. This is because the CHP biogas reaches its end-of-life and new investments are made in CCGT biogas and OCGT biogas. CHP biogas has been operated for more hours while CCGT biogas and OCGT biogas are typically operated for fewer hours, meaning that it becomes cost-efficient to be able to store hydrogen for more hours and thus, investments are taken already in Year 2060 that remain in Year 2070 and onwards when the initial investment in LRC reaches its end-of-life. In Year 2070, the solar PV roof-top investments reach their end-of-life, and a new system configuration is established with more imported electricity annually compared to earlier years. In Year 2080, the LRC investments reach 135–137 GWh$_{H2}$, corresponding to approximately 85 h of hydrogen demand. The amount of LRC storage installed as seen in Fig. 3 can be compared to the LRC storage that is planned for in a large scale industrial fossil-free steelmaking project in Sweden called HYBRIT i.e., approximately 100,000–120,000 cubic metres, corresponding to 65 GWh$_{H2}$ [50,51]

In Table 3, the marginal costs of producing electricity and hydrogen are summarised, together with the annual and total system costs over the modelled period. For Year 2035, the lowest marginal costs for electricity and hydrogen are observed in the WPEC-IL scenario, and the highest is seen in the IL-WPEC scenario. However, from Year 2040, the lowest marginal cost for both electricity and hydrogen occurs in the WP-IL-EC scenario, where investments in off-shore wind power are the highest in the Year 2035 as seen in Table 3. Both annual and total system costs are presented in Table 3. For the total system cost, all investment costs are discounted to their net present value using a 5% discount rate. This means that in the objective function – which minimizes total system cost – investments made in the early years are valued as more expensive than in later years. In contrast, presented annual system costs in Table 3 are reported as undiscounted yearly values. The lowest system cost is found when both off-shore wind power and all planned electricity import capacity reinforcements are available from Year 2030 (WPEC-IL). The system costs in the EC-IL-WP and WP-IL-EC scenarios are ~4% higher, as compared to the WPEC-IL scenario, while the system cost for the IL-WPEC scenario is 18% higher than that for the WPEC-IL scenario. The annual system cost differs most in Year 2035 where, again the WPEC-IL

Table 3
Average marginal costs of producing electricity and hydrogen in different years and scenarios together with annual and total system costs.

	Scenario	2030	2035	2040	2045	2050	2060	2070	2080
Marginal electricity cost (€/MWh)	WPEC-IL	53	61	59	58	53	55	57	57
	WP-IL-EC	57	97	50	49	46	51	57	57
	EC-IL-WP	60	144	59	58	53	55	57	57
	IL-WPEC	68	149	59	57	53	54	56	58
Marginal hydrogen cost (€/MWh$_{H2}$)	WPEC-IL	-	114	109	105	94	95	97	97
	WP-IL-EC	-	173	93	90	82	89	97	97
	EC-IL-WP	-	255	109	106	94	95	97	97
	IL-WPEC	-	265	108	104	93	94	96	97
Annual system cost (M€/year)	WPEC-IL	380	1500	1840	1830	1780	1840	1830	1840
	WP-IL-EC	390	1680	1870	1860	1810	1860	1830	1840
	EC-IL-WP	390	1790	1850	1830	1780	1840	1840	1840
	IL-WPEC	400	2750	1890	1870	1830	1870	1860	1840
Total system cost (M€)	WPEC-IL	31,000							
	WP-IL-EC	32,100							
	EC-IL-WP	32,200							
	IL-WPEC	36,500							

scenario has the lowest cost and the IL-WPEC scenario the highest.

3.2. Hydrogen distribution and infrastructure localisation

In Fig. 4, the investments in electrolysers and LRC are presented for each municipality over the studied period. The black crosses indicate the minimum electrolyser capacity needed if run at constant load to meet the municipal hydrogen demand. From Year 2040, the largest electrolyser capacity (0.8-1 GW_{H2}) is found in the municipality with good access to off-shore wind power and electricity import capacity, as compared to its municipal electricity demands (Stenungsund). It is also here that the largest investments in LRC storage is found making it possible to operate the electrolyser in a flexible manner while meeting the hourly demand for hydrogen.

For the municipality with low electricity import capacity as compared to the municipal electricity demand (Lysekil), the EC-IL-WP and IL-WPEC scenarios result in a smaller electrolyser capacity than is needed to supply its own demand in Year 2035. This means that hydrogen needs to be imported to meet the local demand which is cheaper than investing in more dispatchable technologies locally.

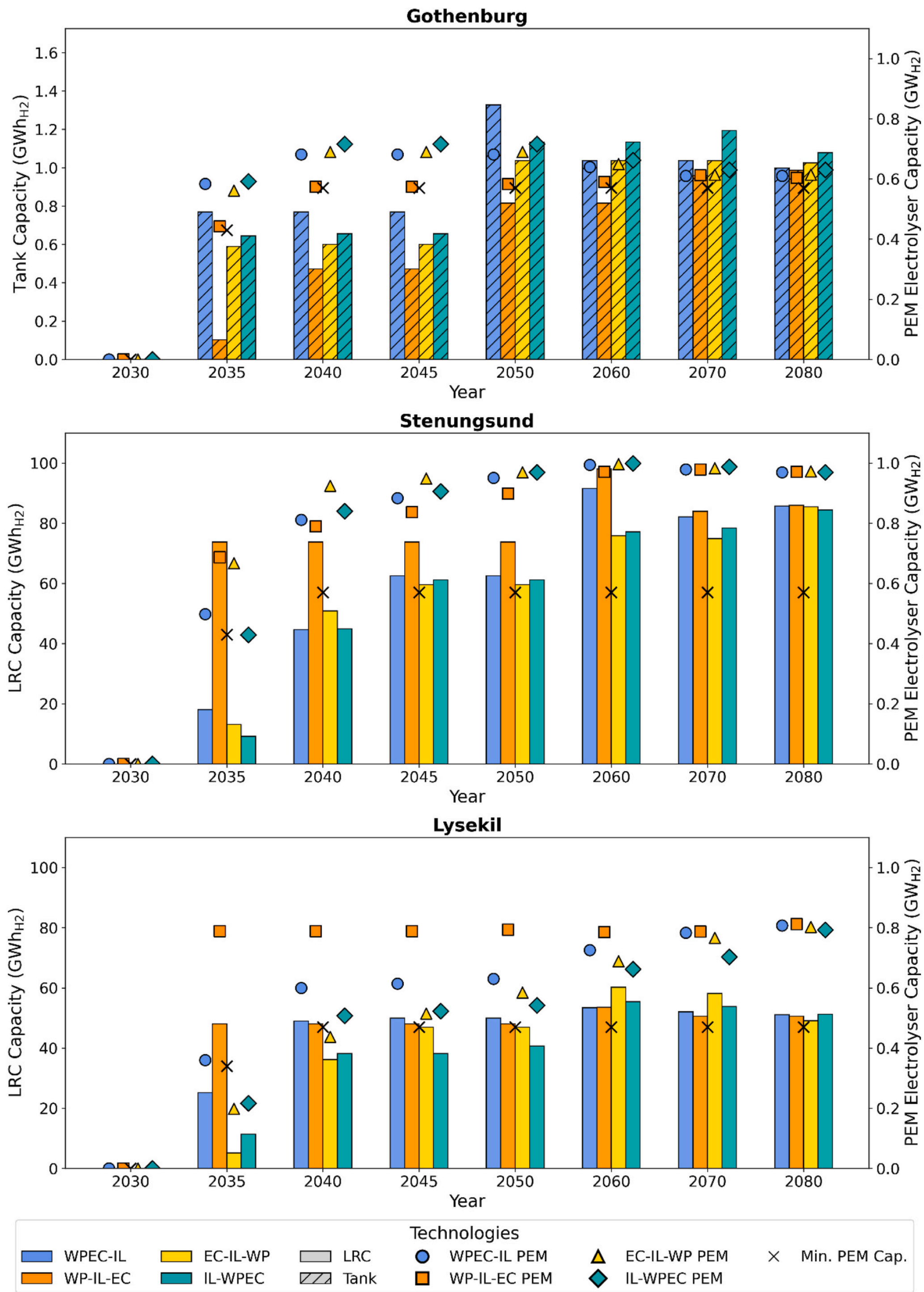

Fig. 4. Investments in proton exchange membrane (PEM) electrolyser capacity (GW_{H2}), H_2 tank storage and LRC storage (GWh_{H2}) per municipality and scenario. Note investments in tank storage is only made in Gothenburg. LRC storage is not allowed in Gothenburg.

Instead, for the WP-IL-EC scenario, an electrolyser capacity of 0.8 GW_{H2} (compared to the local demand of 0.47 GWh_{H2}/h) is invested in already in Year 2035. This is because the largest wind resources of the studied municipalities are found here, and in the absence of electricity import capacity reinforcements to the other municipalities, hydrogen production is to a larger extent placed in Lysekil. This means that Lysekil becomes more self-reliant as well as a net exporter of hydrogen.

In the largest municipality (Gothenburg) the WP-IL-EC differs in that a smaller electrolyser capacity is invested in compared to the other scenarios. This is because LRC storages cannot be invested in for Gothenburg which makes it more expensive to utilise off-shore wind power for hydrogen production as only tank storages are allowed. The tank storages invested in can cover only a few hours. Overall, hydrogen production moves from Gothenburg towards Stenungsund and Lysekil at the end of the studied period in all the scenarios with only a small overcapacity installed, following the trend of the electrolyser capacities presented in Fig. 4.

The WP-IL-EC and IL-WPEC scenarios result in a larger share of the total LRC capacity being located in Stenungsund, as compared with the WPEC-IL and EC-IL-WP scenarios where the differences between the storage sizes in Stenungsund and Lysekil are smaller. Stenungsund is located between the other two municipalities and has relatively good availability of off-shore wind and electricity import capacity, making it a beneficial location to balance hydrogen production and storage, so as to transport it to the other municipalities. In Year 2080, the LRC capacity settles at 84–86 GWh_{H2} in Stenungsund and 49–51 GWh_{H2} in Lysekil. In Gothenburg, tank storages with capacity of approximately 1 GWh_{H2} are invested in to balance short-term hydrogen supply.

In all the scenarios, investments are made in hydrogen pipelines from Year 2035, which make it possible to transfer hydrogen between the nodes (Fig. 5). Gothenburg and Stenungsund, each have an hourly demand for hydrogen of 570 MWh_{H2}/h from Year 2040 and onwards, as compared with the maximum investment in pipeline capacity, which is 500–530 MW_{H2} depending on the scenario. This means that the demand cannot fully be met in Gothenburg by importing hydrogen in any of the scenarios. Furthermore, investments are made in a H_2 tank storage system in Gothenburg that can charge, and discharge, faster than the pipeline can change flow. The largest difference in pipeline capacity between the scenarios is observed in Year 2035, when the WP-IL-EC scenario results in a larger capacity than the other scenarios, as off-shore wind power is used to produce hydrogen that is then transported between the nodes. Towards Year 2080, the pipeline capacity between Gothenburg and Stenungsund reaches 510 GWh_{H2} for all the scenarios.

The capacity difference between Stenungsund and Lysekil differs across scenarios and years, from 140 MW_{H2} (WP-IL-EC) to 230 MW_{H2} (EC-IL-WP) in Year 2035 and showing a maximum difference between the scenarios of 90 MW_{H2} from Year 2040 to 2070. The expanded pipeline capacity to Lysekil in the scenarios with all planned electricity import capacity in place already Year 2030 (i.e., WPEC-IL and EC-IL-WP), as compared to the other scenarios in Year 2035, is because only Stenungsund and Gothenburg get increased electricity import capacity compared to today, making it cost-effective to import more hydrogen to Lysekil rather than supplying its own demand. The pipeline connection between Stenungsund and Lysekil is overall smaller than that between Gothenburg and Stenungsund. This is partly because Lysekil can store hydrogen in LRC which means that hydrogen can be imported at a lower rate for more hours and stored for hours when the electrolyser is shut down. Meanwhile, Gothenburg can only use hydrogen tank storages for storing hydrogen that, cost-optimally, only covers few hours of hydrogen demand, instead, fluctuations in electrolyser load are primarily balanced with hydrogen import through the pipeline.

In Fig. 6, the net amounts of hydrogen transported between the municipalities are presented for the scenarios and for Years 2035, 2040, 2060 and 2080. The rationale for choosing these four years is that: Year 2035 is the year when the demand for hydrogen starts to increase; Year 2040 is the year in which both electricity import capacity reinforcements are in place and it is possible to invest in off-shore wind power capacity in all scenarios; Year 2060 is the year when the life-times of investments made in the period of 2030–2035 typically end (e.g., CCGT biogas); and Year 2080 is the year when all initial investments have reached their end of life and new investments have been made under circumstances other than those between Year 2030 and 2040. Fig. 6 shows a net transport of hydrogen, meaning that hydrogen is transported back and forth in the pipelines, i.e., they are not unidirectional. The blue dots in Fig. 6 represent investments in off-shore wind power, where a larger dot indicates a larger investment.

The general trend is that Lysekil is a net importer of hydrogen and Stenungsund is a net exporter of hydrogen throughout the studied period, and that Gothenburg starts as an exporter of hydrogen but

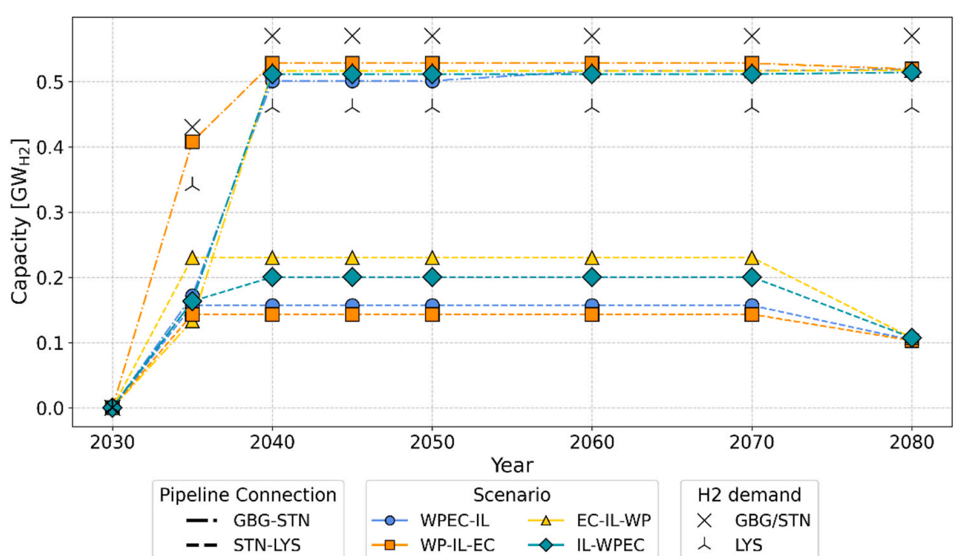

Fig. 5. Installed pipeline capacities (GBG-Gothenburg, STN-Stenungsund, LYS-Lysekil) over the studied period and for the four scenarios (WPEC-IL, WP-IL-EC, EC-IL-WP, IL-WPEC). The colour of the lines and shape of the markers indicate the scenario, while the pattern of the lines indicates the pipeline connection. The crosses and up-side-down Y symbols refer to the minimum capacity needed to cover the hourly demand of hydrogen in respective municipality. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

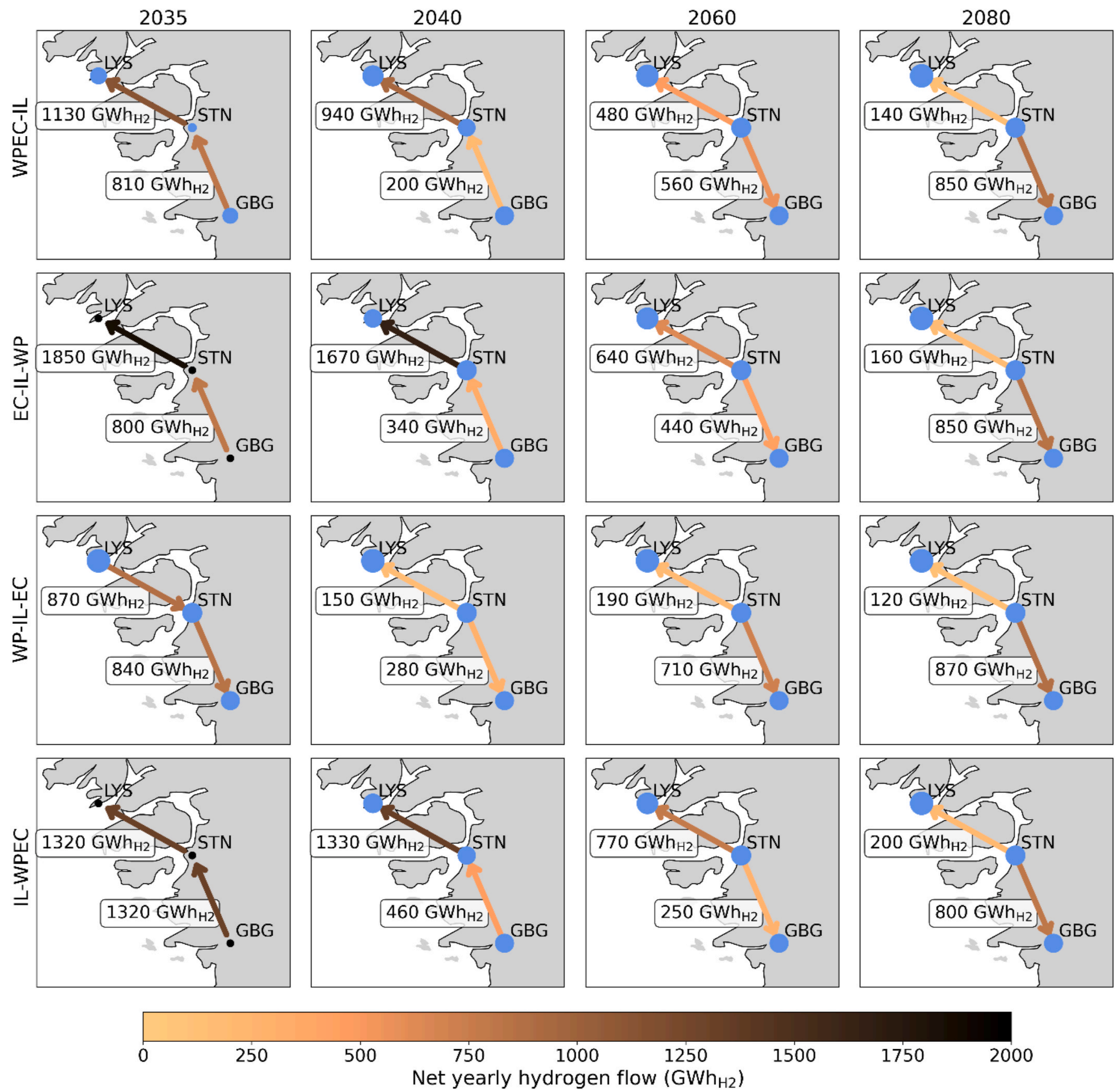

Fig. 6. Net annual flows of hydrogen between the municipalities. The sizes of the blue dots indicate how much off-shore wind power is installed in respective municipality, while a black dot indicates no investment in off-shore wind power. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

subsequently becomes an importer of hydrogen. Fig. 5 shows that Stenungsund makes the largest investments in LRC storage and electrolyser size among all the municipalities, and Fig. 6 shows that Stenungsund is the main net exporter of hydrogen. Again, this can be explained by the availability of off-shore wind power and electricity import capacity in relation to the electricity demand of the municipality, excluding the electricity needed to fulfil the industrial hydrogen demand. Even though Lysekil has the highest off-shore wind availability among the municipalities, importing hydrogen is more cost-effective than balancing local wind variability to meet the hydrogen demand, mainly due to the limited electricity import capacity. However, with wind power only accessible from Year 2030 (WP-IL-EC), Lysekil starts as a net exporter of hydrogen and Gothenburg remains a net importer throughout the studied period, which is mainly due to congestion in the electricity grid in Gothenburg. Larger investments in off-shore wind power in Lysekil in Year 2035 for the WP-IL-EC scenario, together with a larger electrolyser capacity, as presented in Fig. 4, explain why hydrogen is mainly exported from Lysekil, as compared to the other scenarios. As the full electricity import capacity becomes available in Year 2040, the direction of the trend changes.

To summarize, the timing with which access to investments in off-shore wind power and all planned electricity import capacity becomes reality affects both investments and operation of the hydrogen pipeline. The results also shows how the collaboration between the three municipalities to meet the demand for hydrogen differs between scenarios.

3.3. Supplying electricity and hydrogen hour-by-hour

In Figs. 7 and 8, the electricity supply for Gothenburg in the IL-WPEC scenario during six winter weeks and six summer weeks in Years 2030, 2035, 2040, 2060 and 2080 are compared. The positive values indicate electricity supply while the electricity demand is presented as negative values. The demand for electricity is divided into five categories: Fixed load, PEM electrolyser, Electric vehicle (EV) charging, Power-to-heat technologies and Compressors. The fixed load is based on historical values for Year 2019 and includes industries as well as residential and commercial demands. The fixed load is scaled based on population increase. The EV charging consists of direct charging and flexible charging, thus hours occur where EVs are both discharged and charged at the same time (e.g., Hours 600-624 in Fig. 7). The Power-to-heat category consists of heat pumps, heat pumps connected to the electrolyser to recycle waste heat and electric boilers. All investments made for supplying heat are presented in Appendix D together with the installed electricity production capacities. The Compressor category includes electricity for compressing hydrogen for storage as well as transport through pipelines. The load due to compressing hydrogen is small, compared to other loads in the system. Lastly, export of electricity from the municipality to the regional grid is added. When supply is larger than demand, it means that electricity is being curtailed. This occurs, for instance, between Hours 4320-4392 in Fig. 8 where electricity import prices are zero, meaning that the level of imported electricity, as long as meeting the demand, does not affect the system cost in the objective function.

In Year 2030, the electricity demand can be met with the existing CHP technologies in the municipality, in conjunction with imported electricity from the regional grid. In Year 2035, CCGT biogas acts as base load during winter-time, together with CHP biogas. During summer-time, CCGT biogas is operating to complement the electricity produced from solar PV on roof-tops. The electrolyser is operating with a high number of full-load hours, only reducing its load when electricity prices are high, e.g., between Hours 528 and 600 in Fig. 7. During summer-time, the electrolyser load increases slightly during hours with solar PV production. To balance supply and demand, EVs are charged during days with solar PV production and discharged in the evenings and nights.

In Year 2040, investments are made in off-shore wind power that results in a more varying load profile for the electrolyser than in Year 2035. The CCGT biogas produces electricity at full capacity but only during critical periods, such as winter days when electricity prices are high. For Year 2040 and between Hours 528 and 600 in Fig. 7, CCGT biogas can be seen to operate at its full capacity instead of reducing the load to meet the demand of electricity, rather electricity is sold to the regional grid through exports. However, this possibility to export electricity is not incentive enough to reinvest in the same capacity of CCGT biogas.

In Year 2060, a smaller CCGT biogas investment is in operation together with OCGT biogas. The OCGT biogas plant operates for even fewer hours than the CCGT biogas facility. While solar PV is present in the system, EV charging follow peaks in solar PV production. Similarly, power-to-heat technologies are operated during these hours. The heat is stored in tank thermal energy storages that are discharged during nighttime. A smaller electrolyser is being operated, as compared to previous years, which relates to Gothenburg being a net importer of hydrogen from 2060 instead of being a net exporter in previous years (Fig. 6).

Lastly, in Year 2080, no new investments are made in solar PV on roof-tops, and the system depends on a combination of off-shore wind power, solar PV parks, CHP wood chips, CCGT biogas, OCGT biogas and imported electricity. The charging of EVs and operation of power-to-heat technologies now instead follow off-shore wind production and hours with cheap electricity import prices. Similarly, in both Stenungsund and Lysekil, investments are made in CCGT biogas that is run for a high number of full-load hours in Year 2035 and subsequently acts more as a peak generation mode from Year 2040 and onwards. Figures showing the hourly electricity supply levels and electrolyser loads for Stenungsund and Lysekil in both winter-time and summer-time for the IL-WPEC scenario are provided in Appendix E.

Figs. 9 and 10 show the hydrogen supply, including the electrolyser load, together with the imports and exports of hydrogen for Gothenburg in the IL-WPEC scenario for Years 2035, 2040, 2060 and 2080, for six winter weeks (Fig. 9) and six summer weeks (Fig. 10). The hydrogen demands in Gothenburg are 430 MWh_{H2}/h in Year 2035 and 570 MWh_{H2}/h from Year 2040 and onwards. In Year 2035, the electrolyser over-capacity that was invested in is used to export hydrogen to Stenungsund most hours over the year, avoiding only the hours with high electricity prices (e.g., between Hours 528 and 600). During hours with high electricity prices, the hydrogen demand is instead covered partly by the import of hydrogen from Stenungsund. In Year 2040, the electrolyser size increases, as does the capacity of the pipeline connecting Gothenburg to Stenungsund. With investments in off-shore wind power, it becomes cost-effective to produce hydrogen during hours with good wind availability and then store it in LRC in Stenungsund. Hydrogen stored in Stenungsund is imported into Gothenburg during hours with high electricity prices when the load of the electrolyser is decreased. During, for example, Hours 576–578, the electrolyser is operated at the same time as hydrogen is imported from Stenungsund. This is because the flow in the pipeline cannot be changed too rapidly. Instead, the H_2 tank storage in Gothenburg is charged during these hours. Hydrogen balances for the WPEC-IL, WP-IL-EC and EC-IL-WP scenarios are found in Appendix F.

3.4. Sensitivity analysis

There are several assumptions made in this study for the future energy system that are still uncertain. This study assumes that investments in hydrogen pipelines are possible to connect the three municipalities, but it could also be that each municipality needs to supply their own hydrogen demand and that would affect the energy system configuration. The hydrogen demand assumed in this study is based on the maximum scenario presented by Edvall et al. [29] but the report suggests other scenarios as well with lower hydrogen demand and therefore additional model runs were made varying the demand for hydrogen. Important technologies in the cost-optimal energy system configuration are LRC storages, hydrogen pipelines, electrolysers and off-shore wind power and there are uncertainties in what their investment cost will be in the future, therefore the investment costs of these technologies were evaluated. Similarly, a large share of the annual electricity supply in this study comes from imported electricity and additional model runs were made with other price profiles. Lastly, the IL-WPEC resulted in biogas use much larger than what is produced in Sweden today, and the model was run with limited biogas availability. The following sensitivity analyses were done.

- *Hydrogen pipeline:* no pipeline was allowed to be invested in.
- *Hydrogen demand:* annual hydrogen demands of 4.9 TWh_{H2}, 7 TWh_{H2} and 20 TWh_{H2} were investigated as compared to the original demand of 14 TWh_{H2}.
- *Investment cost for LRC storage:* investment costs of 2 €/kWh_{H2} and 6 €/kWh_{H2} were evaluated in addition to the original cost of 11 €/kWh_{H2}.
- *Investment cost for hydrogen pipelines:* investment costs of 1.8 €/kW_{H2}/km and 2.75 €/kW_{H2}/km were evaluated in addition to the original cost of 3.7 €/kW_{H2}/km.
- *Investment cost for electrolyser and off-shore wind power:* the investment cost for off-shore wind power was assumed to continue to decrease with 5% per ten years after Year 2050 and electrolysers with 10% per ten years after Year 2050 as compared to remaining constant after Year 2050.

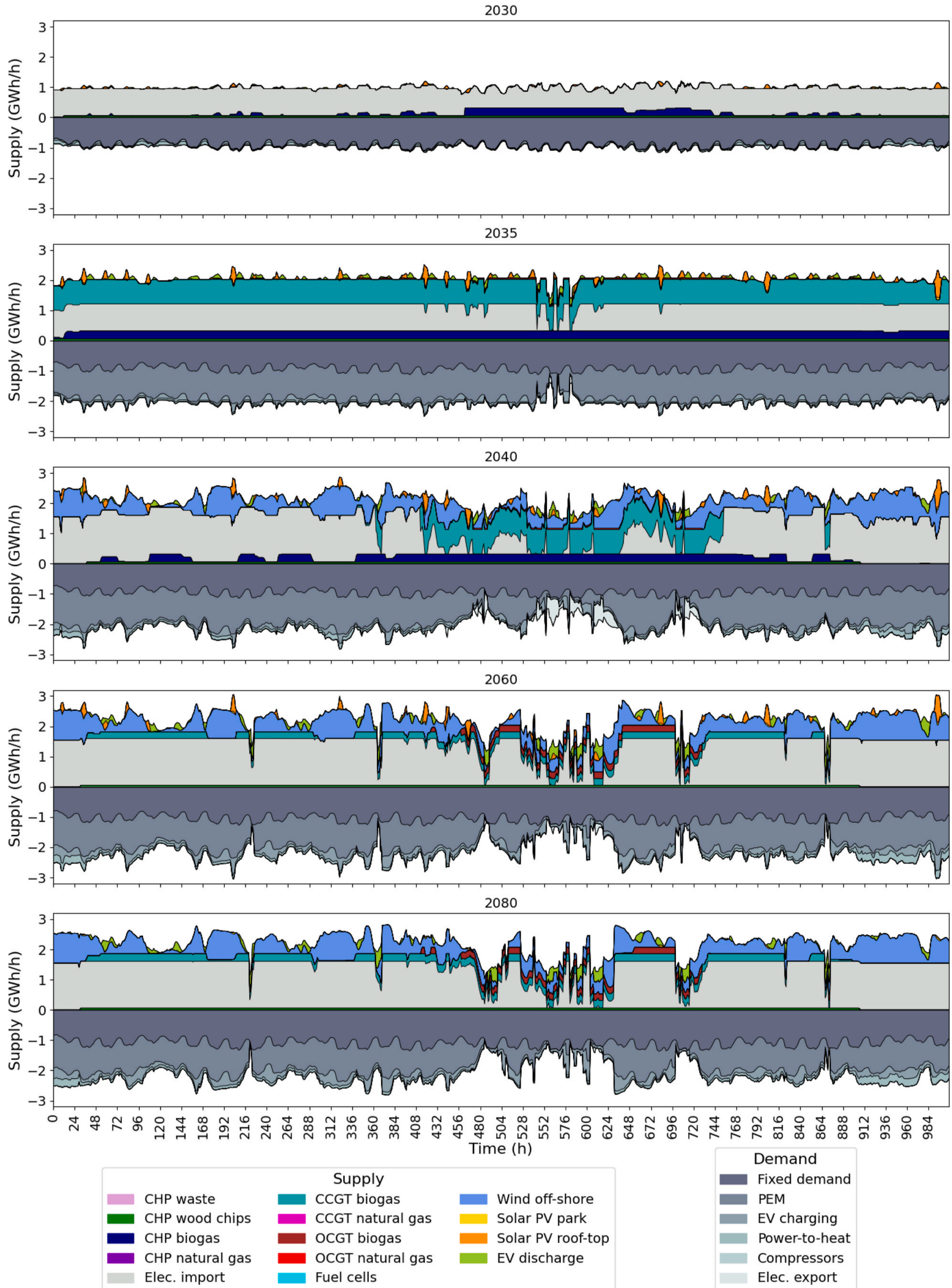

Fig. 7. Electricity supply in Gothenburg during six winter weeks in the IL-WPEC scenario. CCGT—combined cycle gas turbine; OCGT—open cycle gas turbine; CHP—combined heat and power; EV-electric vehicle; PEM - proton exchange membrane.

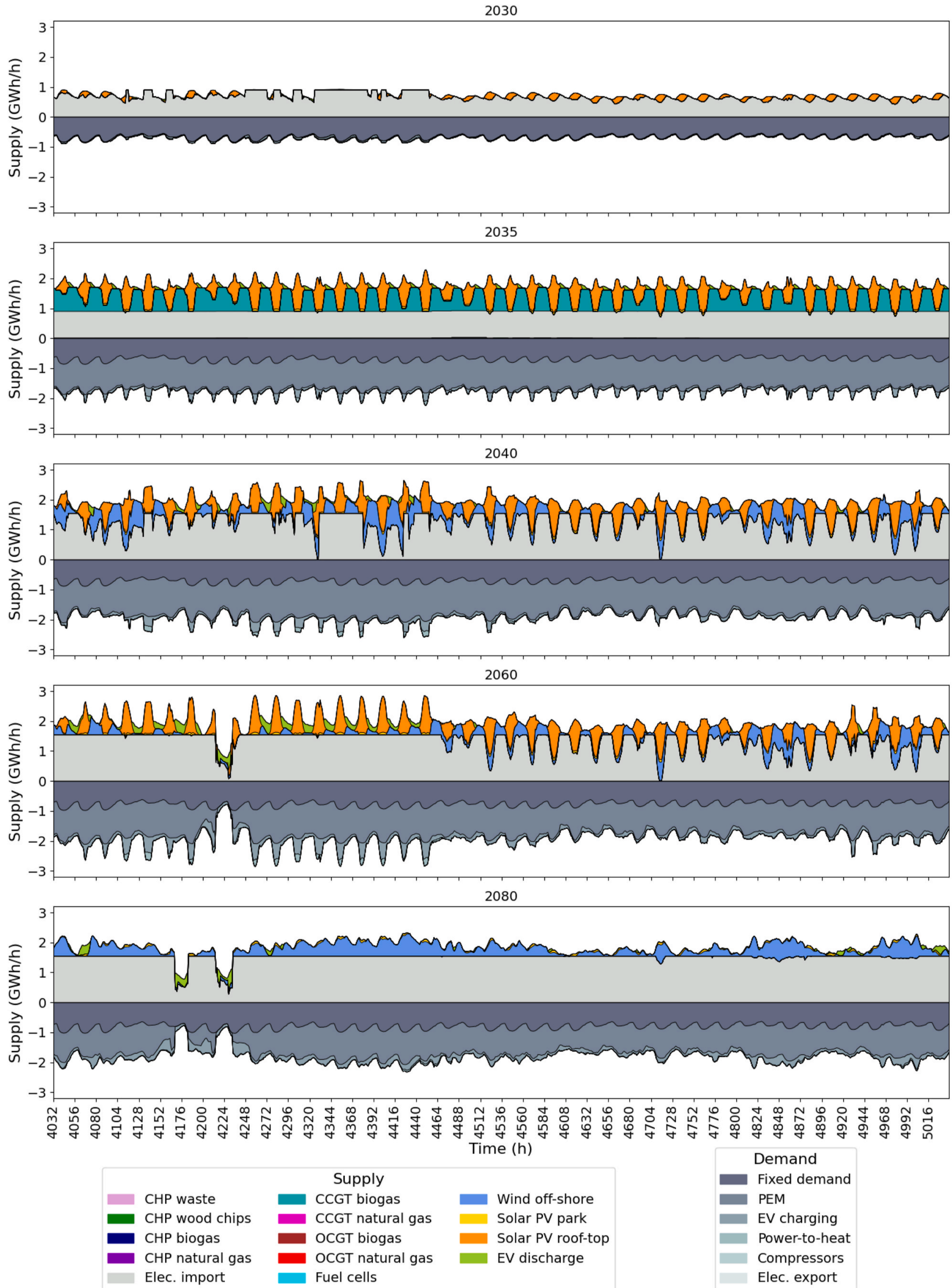

Fig. 8. Electricity supply in Gothenburg during six summer weeks in the IL-WPEC scenario. CCGT—combined cycle gas turbine; OCGT—open cycle gas turbine; CHP—combined heat and power; EV-electric vehicle; PEM - proton exchange membrane.

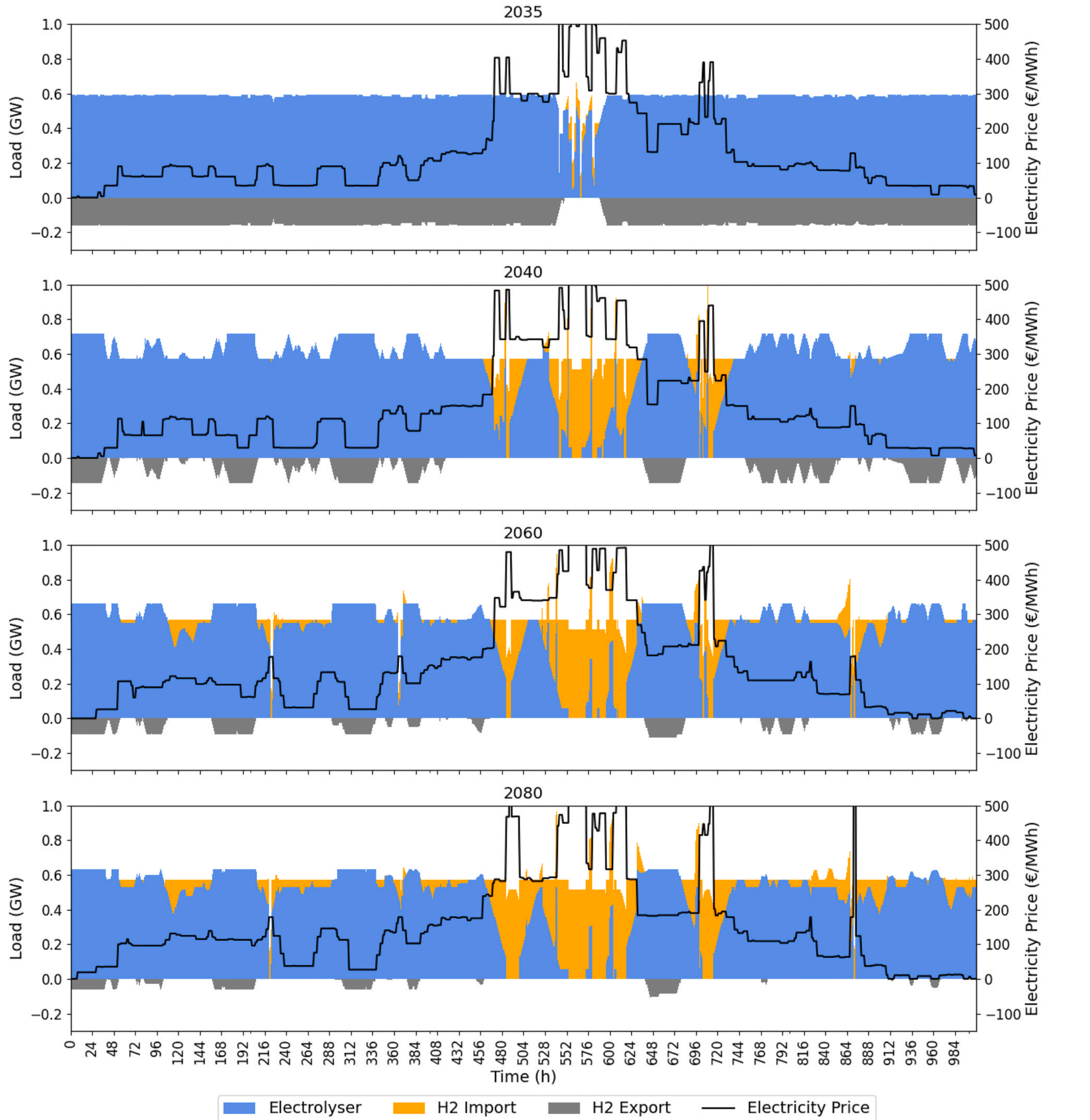

Fig. 9. Hourly hydrogen supply for Gothenburg, including the electrolyser load, imports and exports of hydrogen (H2), as well as the electricity prices during six winter weeks.

- *Electricity import price:* hourly electricity prices from two other scenarios were implemented and evaluated.
- *Biogas availability:* the annual biogas supply was limited to 2.3 TWh as compared to being unlimited in the original model runs.

In this section, results from the sensitivity analysis are presented that are complemented with additional figures found in Appendix G.

Without the possibility to invest in hydrogen pipelines, each municipality needs to provide for their own hydrogen demands. In Table 4, electrolyser capacities are presented for all municipalities and scenarios. For Stenungsund, this means smaller LRC storage and lower electrolyser capacity are invested in for all the scenarios, whereas in Lysekil, investments in LRC and electrolysers increase. This is because Lysekil becomes self-sufficient in meeting its hydrogen demand. The electrolysers in Stenungsund produce less hydrogen without a pipeline, as it only covers the demand for the municipality. As regards Gothenburg, investments in H_2 tank storages are made to a greater extent (up to 11 GWh_{H2} in all scenarios), as it is the only available option to balance the hydrogen supply in the municipality without a pipeline. However, for Gothenburg in Year 2035 for all scenarios apart from the one with wind power investments option available from the start, there is no investment in hydrogen storage, which relates to that the electrolyser is operated at constant load to meet the demand for hydrogen (0.43 GWh_{H2}/h). Another interesting observation is that the results overall

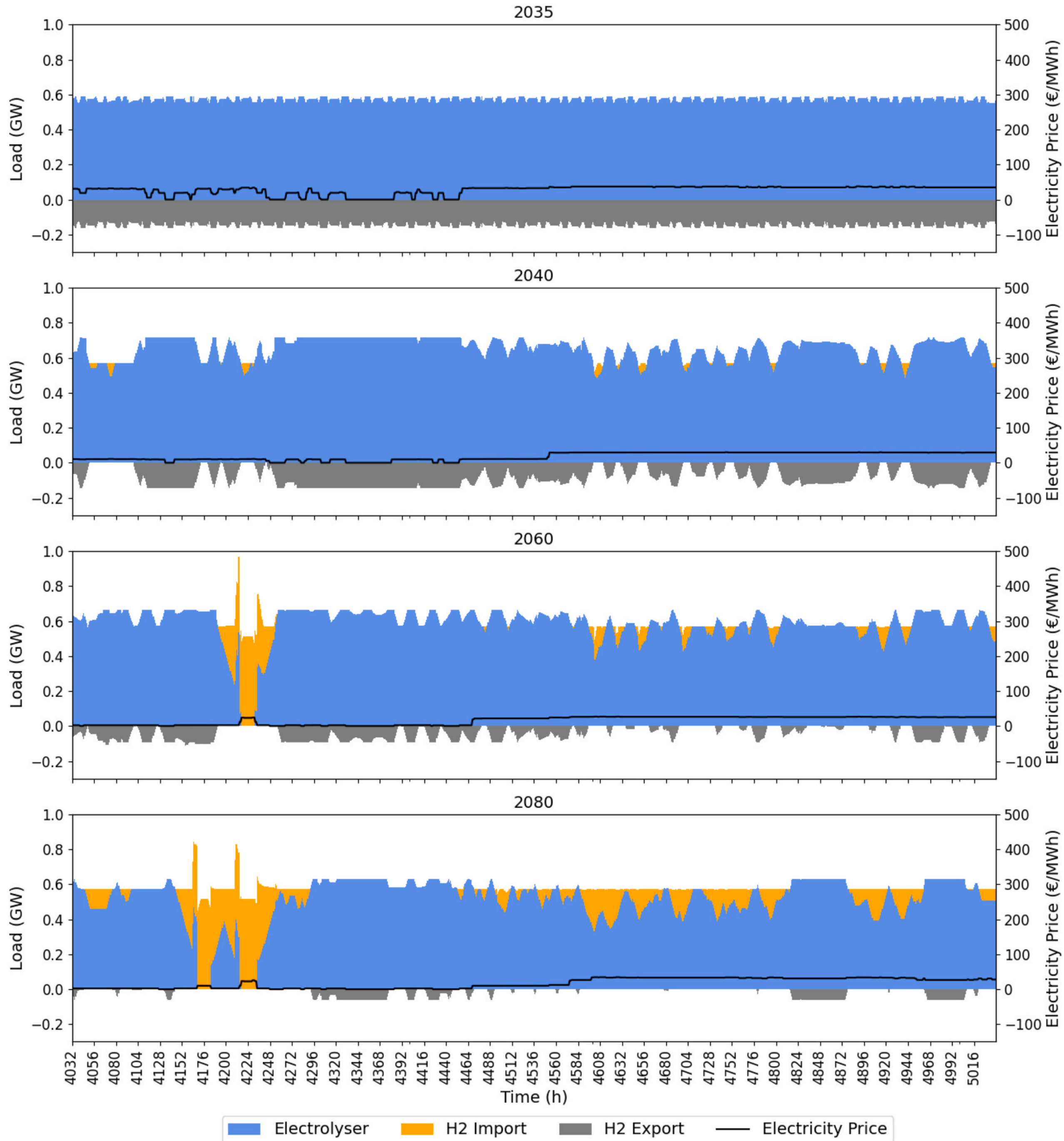

Fig. 10. Hourly hydrogen supply for Gothenburg, including the electrolyser load, imports and exports of hydrogen (H2), as well as the electricity prices during six summer weeks.

converge earlier without a pipeline than with a pipeline, such that between Year 2070 and 2080 there is hardly any differences in LRC and electrolyser capacity. This is because the technical life-time of the pipeline is longer (40 years) than those of most technologies (25 years), which means that the different investments made with access to a pipeline reach their end of life at different years, thereby prolonging the convergence.

With a lower demand for hydrogen (4.9 TWh_{H2}/year), imported electricity from the grid covers most of the electricity demands (92%) for all scenarios in Year 2080 (Table 5). For the WPEC-IL and EC-IL-WP scenarios this trend can be seen from Year 2030. As for the WP-IL-EC scenario, off-shore wind power accounts for 23% of the annual electricity production in the region in Year 2035, but only 5% in Year 2080, which means that it is more cost-efficient to import electricity when possible, rather than making new investments. In the IL-WPEC scenario, a mix of technologies is needed to cover the demand for electricity, and this includes solar PV parks, solar PV roof-top, CCGT biogas, and the running of the existing CHP biogas plant in Year 2035.

Fig. 11 shows over-capacity in electrolysers together with share of off-shore wind power in the annual electricity supply over different hydrogen demands in Year 2080 for the WPEC-IL scenario. With an increasing share of the annual electricity demand being supplied by off-shore wind power (6% - 53%), the over-capacity invested for electrolysers increase and range from 22% to 66%. Comparing the marginal

Table 4
Electrolyser investments for each municipality and scenario without possibility to invest in hydrogen pipelines.

Electrolyser capacity (GW_{H2})		2035	2040	2045	2050	2060	2070	2080
Gothenburg	WPEC-IL	0,43	0,63	0,65	0,67	0,67	0,68	0,68
	WP-IL-EC	0,49	0,62	0,65	0,66	0,67	0,68	0,68
	EC-IL-WP	0,43	0,62	0,64	0,67	0,67	0,68	0,68
	IL-WPEC	0,43	0,62	0,64	0,66	0,67	0,68	0,68
Stenungsund	WPEC-IL	0,46	0,66	0,67	0,69	0,73	0,75	0,76
	WP-IL-EC	0,65	0,68	0,73	0,73	0,82	0,75	0,76
	EC-IL-WP	0,46	0,66	0,67	0,69	0,73	0,75	0,76
	IL-WPEC	0,43	0,66	0,68	0,68	0,73	0,75	0,76
Lysekil	WPEC-IL	0,60	0,80	0,81	0,81	0,82	0,82	0,82
	WP-IL-EC	0,60	0,80	0,81	0,81	0,82	0,82	0,82
	EC-IL-WP	0,34	0,79	0,80	0,83	0,82	0,82	0,82
	IL-WPEC	0,34	0,79	0,80	0,83	0,82	0,82	0,82

Table 5
Percentage of annual electricity supply provided to the three municipalities combined by imported electricity from the regional grid in all four scenarios, assuming a hydrogen demand of 4.9 TWh_{H2}/year.

Imported electricity	2030	2035	2040	2045	2050	2060	2070	2080
WPEC-IL	95%	95%	95%	95%	95%	93%	93%	92%
WP-IL-EC	92%	67%	76%	76%	77%	80%	91%	92%
EC-IL-WP	94%	95%	95%	95%	95%	93%	93%	92%
IL-WPEC	92%	71%	89%	88%	89%	89%	89%	92%

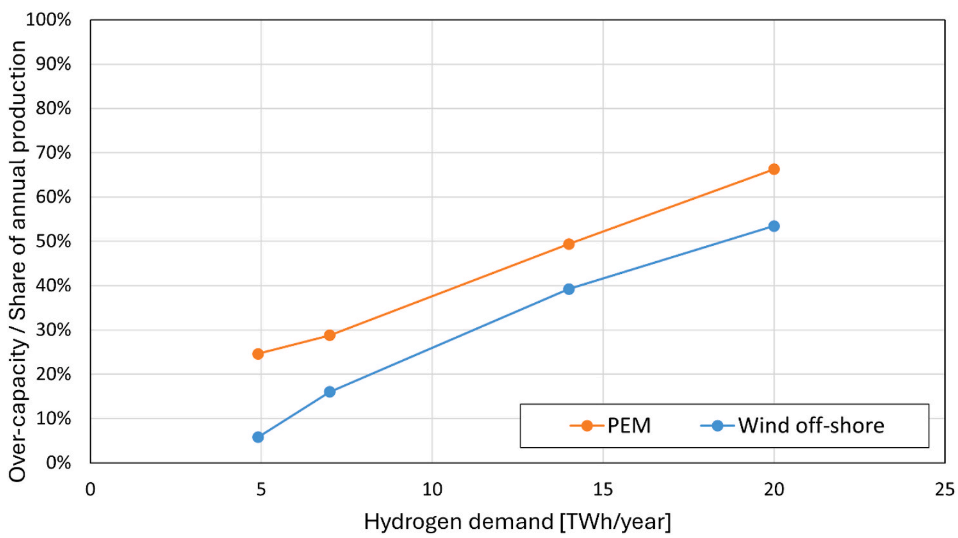

Fig. 11. Comparison of electrolyser (PEM) over-capacity and off-shore wind power share of annual electricity supply over different annual hydrogen demands. As off-shore wind power takes on a larger share of the annual electricity supply, the cost-optimal over-capacity in electrolysers increase. These results are for Year 2080 and considers the total PEM capacity in the studied region as well as off-shore wind power share in the total electricity supply for all three municipalities. The numbers are retrieved from the WPEC-IL scenario but all scenarios show similar results in Year 2080.

cost of hydrogen in Year 2080, it increases with hydrogen demand from 83 €/MWh_{H2} with a total hydrogen demand of 4.9 TWh per year to 107 €/MWh_{H2} with a hydrogen demand of 20 TWh_{H2} annually. Investments are still made in pipelines in all scenarios. Between Gothenburg and Stenungsund, the capacity invested in is 95%–97% of the hourly hydrogen demand (224 MWh_{H2}/h) in the respective municipalities from Year 2040 and onwards, independent of the scenario. The pipeline between Stenungsund and Lysekil becomes smaller in the WP-IL-EC scenario [76% of the hourly hydrogen demand (112 MWh_{H2}/h) in Lysekil] in Year 2040, as compared with the other scenarios (93%–105%).

With a lower cost for LRC (2 €/kWh_{H2}), hydrogen storage becomes even more concentrated to Stenungsund. In the original scenarios towards Year 2080, 63% of the total LRC capacity was located in Stenungsund and this number is now 83%. As the cost for LRC storages decrease, so does the investments in CCGT biogas and OCGT biogas (see Figure G1-G3 in Appendix G for electricity production capacities). From 2060 and onwards, only small capacities of CCGT and OCGT are invested in with a cost for LRC storages of 6 €/kWh_{H2} and no new investments are made in any of the scenarios with a cost of 2 €/kWh_{H2}. Furthermore, the pipeline capacities become slightly larger and more export of hydrogen from Stenungsund to the other two municipalities is observed. With a lower pipeline investment cost (1.8 €/kW_{H2}/km) slightly larger pipeline capacities are invested in, but the overall system configuration remains similar.

In this study, the technology investment costs stagnate after Year 2050, and no further cost reductions are assumed. Therefore, a sensitivity analysis was performed focusing on continued cost reductions for off-shore wind power and electrolysers as large deployment of these technologies could result in further learnings. With a reduction of 5% per ten years for off-shore wind power and 10% per ten years for PEM electrolysers, the off-shore wind capacity is increased with 10% and electrolysis capacity with 9% in Lysekil for Year 2080. As both electricity production (off-shore wind power) and variation management (electrolyser) become cheaper it becomes cost-efficient to produce more hydrogen in Lysekil as compared to the original model runs. In Gothenburg and Stenungsund, the maximum allowed off-shore wind capacity has already been reached and therefore the effect of the lowered costs is more prominent in Lysekil. Because of this, Lysekil becomes a net exporter of hydrogen in Year 2080 unlike the original scenarios where Lysekil is a net importer (ee Figure G4 in Appendix G for net annual hydrogen flows). As the off-shore wind power generation increases in Lysekil, the electricity production from CCGT biogas and CHP wood chips in Gothenburg decreases together with electricity production from OCGT biogas in Stenungsund. Still, investments in these technologies remain of 170 MW, 180 MW and 500 MW respectively in Year 2080, as compared to the original model runs with capacities of 180 MW, 230 MW and 550 MW respectively. The total electrolyser capacity remains approximately the same in the system which means that electrolyser capacities in Gothenburg and Stenungsund decrease. Following, Gothenburg imports more hydrogen, ~1000 GWh_{H2} per year compared to ~850 GWh_{H2} per year as in the original scenarios.

The electricity import and export price in this study is based on the reference case presented in a report by Göransson et al. [46]. To evaluate the electricity price, the model is run with marginal cost of electricity from two other cases in the report where investments in nuclear power are required, resulting in higher average and median marginal costs of electricity in Years 2030-2040, before they get lower in Years 2045-2070. For more details, see Appendix C and the report by Göransson et al. [46]. The overall results remain similar to the original model runs regarding annual electricity supply and overall investments. However, some differences were observed. With higher electricity import prices in Years 2030 and 2035, less electricity is imported in these years and instead, the maximum allowed investment in solar PV parks is reached already in Year 2035 for all scenarios as compared to the original model run where the maximum allowed investment was only reached for the EC-IL-WP and IL-WPEC scenarios in the same year. The pipeline capacity between Gothenburg and Stenungsund for Year 2035 in scenario WPEC-IL is 400 MW_{H2} as compared to 170 MW_{H2} in the original model runs. This increased capacity is used to import hydrogen to Gothenburg during the hours with the highest cost of electricity (e.g Hours 528-600). With lower electricity prices after Year 2040, more electricity is imported and OCGT biogas capacity investments in the WPEC-IL and WP-IL-EC scenarios are delayed (see Figure G5 in Appendix G).

With a limitation on annual biogas use, the scenarios most effected are the two without the possibility to invest in off-shore wind power before Year 2040 (EC-IL-WP & IL-WPEC). In Year 2035, electricity is supplied using CCGT natural gas and CHP wood chips in all three municipalities for these two scenarios. This is inconvenient, both because of the increased CO_2 emissions, but also because the heating demand in Stenungsund and Lysekil is already met with waste heat from the industries, resulting in even more heat production that needs cooling. Furthermore, the total system cost is approximately the same for the WPEC-IL, WP-IL-EC and EC-IL-WP scenarios as they were without a limitation on biogas use. Meanwhile, the system cost increases to +28% for the IL-WPEC scenario (compared to +18% previously) as compared to the WPEC-IL scenario. Although the energy system configuration differs in Years 2030 to 2050 with limitations on biogas use as compared to without restrictions, the energy system configuration from Year 2060 and onwards is remarkably similar. This means that the biogas annually supplied in Sweden (2.3 TWh/year) could be enough to support the system as presented in this study long-term (1.2 TWh/year) but that other measures are needed in the near-term.

To summarize the sensitivity analyses, without pipelines, the three municipalities cover their own demand of hydrogen which means that electrolysers and hydrogen storages become smaller in Stenungsund and larger in Gothenburg and Lysekil. In the studied region, a lower hydrogen demand results in a larger share of the annual electricity supply being met with imported electricity. As the demand for hydrogen increases, so does the annual share of electricity covered by off-shore wind power. With more off-shore wind power in the system, the cost-optimal over-capacity of electrolyser increase as well. An investment cost of 2 €/kWh_{H2} for LRC storages (compared to 11 €/kWh_{H2} in the original model runs) results in an energy system configuration where it is no longer cost-optimal to invest in CCGT biogas and OCGT biogas at the end of the studied period. Instead, investments are made in LRC storages that cover the hydrogen demand during hours where electricity import prices are high and production from variable renewable energy sources is low. Assuming continued learnings for PEM electrolysers and off-shore wind power resulting in lower investment costs after Year 2050, off-shore wind and electrolyser capacities are increased in Lysekil, resulting in Lysekil becoming a net exporter of hydrogen towards Year 2080, unlike the original model runs. With a lower average price of imported electricity, more electricity is imported as compared to with a higher average price. When biogas use is restricted, investments are made in CCGT natural gas and CHP wood chips to cover the electricity demand in Year 2035.

4. Discussion

In this study, one weather year (2019) is modelled to keep the supply and demand coherent as certain demand data is only available for Year 2019. In Year 2019 the wind power capacity factor in the studied region is 45% and the year is characterised by periods of low wind events at the beginning of the year, such that additional electricity production is invested in. Ullmark et al. [52] investigate the impact of different weather years on cost-efficient investments in generation and storage capacity and find that, in terms of normalised capacity, the choice of weather years has a large impact on investments in CCGT and peak generation while impact on wind power and hydrogen storage is lower. This can be explained by the role of biogas CCGT and peak generation to manage extreme net load events, which vary substantially between years, rather than providing bulk energy like wind power generation. Since hydrogen storage manage regular variations in wind power, and electrolyser over-capacity is proportional to the wind power capacity for the region investigated, these capacities can also be expected to be less sensitive to the weather year applied, except for the case with very low cost of hydrogen storage where this technology is shown to outcompete gas turbines and also manage extreme events. To conclude, the use of only one weather year in these calculations imply that the cost-optimal capacity levels is subject to some uncertainty and the levels given for gas turbines need further investigation.

The potentials for off-shore wind power are based on on-going projects. Although these projects give the most likely potentials for near-term off-shore wind power capacity, it is possible that the potentials may increase or decrease in the long-term. For future studies, it could be interesting to change the potentials to understand how the system configuration is affected, especially in the more congested municipalities (Gothenburg and Stenungsund) where the maximum capacity is invested in for all scenarios studied. It could also be of interest to investigate further how the system would be affected if not all off-shore wind farms are made available in the same year. Similarly, the connection to the regional grid could be reinforced to one municipality at a time. For this study, where off-shore wind is invested in as the primary electricity supply, together with imported electricity from the regional grid, it could mean that hydrogen production to a larger extent would be located where off-shore wind investments are made available first.

In the scenario in which access to full electricity import capacity and off-shore wind power comes after electrification of the industry, there is extensive use of biogas. It is expected that as fossil fuels are progressively phased out, the competition for biomass between sectors will increase.

Furthermore, the demand for biogas in this study is high (21 TWh) in the IL-WPEC scenario for Year 2035 but is reduced already in Year 2040, raising the questions as to: 1) how this biogas could be provided; and 2) who would make the investment knowing that the biogas plant would only be run for a few years (alternatively, there may be other sectors, such as transport, that could use the biogas later on). The amount of biogas needed is 9-times higher than the amount produced in all of Sweden today. In the model, the cost for biogas remains unaffected by the increase in demand, which is something to improve in future studies. Furthermore, hydrogen could be produced through steam-methane reforming (SMR) using biogas, thereby preserving the existing supply chain for hydrogen but replacing natural gas with biogas. To include and compare alternative supply-chains of hydrogen is planned future work. In addition, some studies have included the option to import ammonia [26], and carbon capture technologies together with SMR [26,53], which could also relieve the pressure on the electricity grid in the most-critical years. This could, however, keep natural gas in the system for longer, with risk of lock-in effects, but could also allow more time to expand the electricity import capacity and build off-shore wind power. The options mentioned above (imports of ammonia, using carbon capture together with SMR or biogas in the SMR process) are a basis for future work.

This study does not consider the amount of water needed to produce the hydrogen, as the studied region currently has good availability of water. Water availability could, however, be an important factor in the future and in other regions, affecting the optimal energy system configuration and supply of hydrogen, as presented by Löfving [54]. Similarly, this study does not consider the oxygen produced through electrolysis. If the oxygen can be sold, as was the case in the study of Pettinau et al. [24], this could result in an overall lower total cost for producing hydrogen. This becomes even more relevant when hydrogen from electrolysis needs to compete with hydrogen produced using fossil fuels, which typically has a lower cost currently.

5. Conclusion

The cost-optimal energy system configurations over a period of 50 years (2030 to 2080) for three municipalities in Sweden were investigated using four scenarios that differ in terms of the possibility to invest in off-shore wind power and the amount of electricity import capacity that is available in relation to an industrial load from hydrogen production through electrolysis (14 TWh_{H2} annually). Towards Year 2080, all scenarios show similar results for the region with regards to electricity and hydrogen supply, which suggests that the pathway in the early years will not affect the long-term, most-cost-effective solution. Electricity imports, off-shore wind power and solar PV parks are the main contributors of electricity in the municipalities in all the scenarios. These technologies are complemented by combined-cycle gas turbines (CCGT) and open-cycle gas turbine (OCGT) fuelled by biogas, which help to cover the electricity demand during hours with low production from off-shore wind power and high electricity prices. An electrolyser size of ~2.4 GW_{H2} (50% over-capacity) was invested in, as well as lined rock cavern (LRC) storages of ~135 GWh_{H2}, corresponding to the hydrogen demand for approximately 85 h in all scenarios. The electrolyser over-capacity was found to be highly dependent on the assumed hydrogen demand which resulted in different shares of the annual electricity supply provided by off-shore wind power. The over-capacity ranged from 22% with an off-shore wind power share of 6%, to 66% with an off-shore wind power share of 53% in Year 2080.

However, the pathway towards Year 2080 differs between the scenarios. If off-shore wind power can be invested in before the electrification of industry, then one obtains the most-cost-efficient, long-term system configuration directly. This generates larger investments in off-shore wind power, LRC and electrolysers in Year 2035 compared to the scenario in which investments in off-shore wind power come after the electrification of industry. If instead the electrification of industry comes before investments in off-shore wind power are possible, the system invests in CCGT biogas. The CCGT biogas plant is run with a high number of full-load hours in some few initial years until the model acquires the option to invest in off-shore wind power and gains access to additional electricity import capacity. Therefore, this study concludes that it will be difficult for the region if industry undergoes large-scale electrification before investments are made in off-shore wind power and/or more electricity import capacity is in place. This is because the demand for biogas reaches ~21 TWh, which can be compared to the annual level of biogas production in Sweden of 2.3 TWh in Year 2022, together with an increase in total system cost of 18% compared to early access to both off-shore wind and electricity import capacity reinforcements. For comparison, in the scenarios with access to either electricity import capacity reinforcements or off-shore wind power before the increase of the industrial loads, an increase in total system cost of 4% was observed.

Regardless of the scenario, investments are made in hydrogen pipelines that connect the municipalities. The municipality with relatively good availability of off-shore wind power and good electricity import capacity (Stenungsund) is shown to be a cost-efficient net exporter of hydrogen, while the municipality with high overall electricity demand (Gothenburg) and low electricity import capacity (Lysekil) become net importers of hydrogen. Electricity import is used to balance wind power variations and enable higher utilisation of the electrolyser. Thus, with low electricity import capacity, Lysekil imports hydrogen despite extensive off-shore wind power potential.

CRediT authorship contribution statement

Sofia Rosén: Writing – original draft, Visualization, Validation, Methodology, Investigation, Formal analysis, Conceptualization. **Lisa Göransson:** Writing – review & editing, Validation, Supervision, Project administration, Methodology, Funding acquisition, Conceptualization. **Maria Taljegard:** Writing – review & editing, Validation, Supervision, Conceptualization. **Mariliis Lehtveer:** Writing – review & editing, Validation, Supervision, Project administration, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Sofia Rosen reports financial support was provided by Göteborg Energi AB. Mariliis Lehtveer reports a relationship with Göteborg Energi AB that includes: employment. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

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