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Short Communication

Perspectives on green hydrogen in Europe—during an energy crisis and towards future climate neutrality

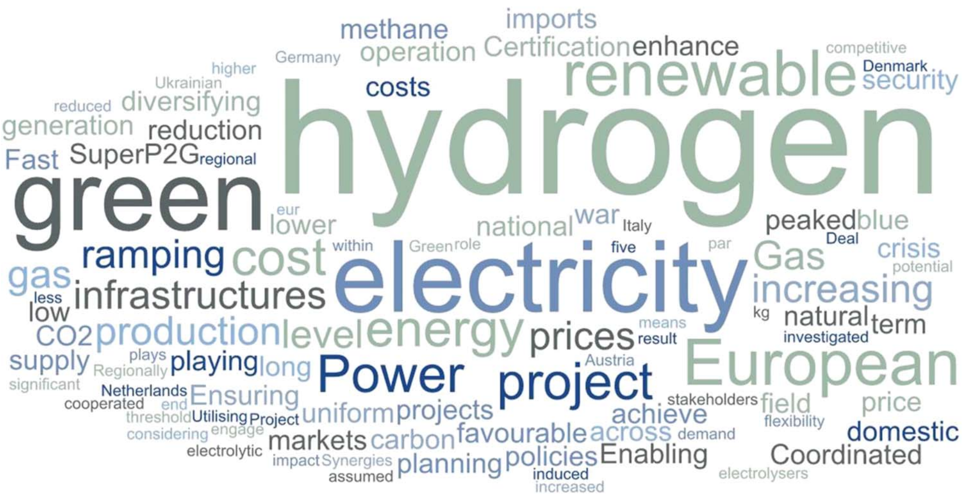
Marie Münster[1,*], Rasmus Bramstoft[1], Ioannis Kountouris[1], Lissy Langer[1], Dogan Keles[1], Ruth Schlautmann[2], Friedemann Mörs[2], Cesare Saccani[3], Alessandro Guzzini[3], Marco Pellegrini[3], Andreas Zauner[4], Hans Böhm[4], Darja Markova[4], Shi You[5], Martin Pumpa[6], Frank Fischer[6], Francesco Sergi[7], Giovanni Brunaccini[7], Davide Aloisio[7], Marco Ferraro[7], Machiel Mulder[8] and Hans Rasmusson[9]

[1]Department of Technology, Management and Economics, DTU Technical University of Denmark, 2800 Kgs Lyngby, Denmark
[2]Gas Technology, DVGW Research Center at Engler-Bunte-Institute of Karlsruhe Institute of Technology, 76131 Karlsruhe, Germany
[3]Department of Industrial Engineering, UNIBO, University of Bologna, 40126 Bologna, Italy
[4]Energy Technology, Energieinstitut an der Johannes Kepler Universität, Linz, AT 4040, Austria
[5]Department of Wind Energy Systems, DTU Technical University of Denmark, 2800 Kgs Lyngby, Denmark
[6]Gasnetze und Gasanlagen, DBI-Gastechnologisches Institut gGmbH, D-09599 Freiberg, Germany
[7]Institute of Advanced Energy Technologies CNR-ITAE, National Research Council of Italy, 98126 Messina, Italy
[8]Faculty of Economics and Business, University of Groningen, 9700 AB Groningen, Netherlands
[9]ERIG Office, ERIG European Research Institute for Gas and Energy Innovation, 1040 Brussels, Belgium
*Corresponding author. Produktionstorvet 424, 2800 Kgs Lyngby, Denmark. E-mail: maem@dtu.dk

Abstract

Hydrogen and regional energy infrastructure are significant for the European Green Deal and was the focus of the SuperP2G research Project (Synergies Utilising renewable Power Regionally by means of Power to Gas). Five national projects (Denmark, Netherlands, Germany, Austria, and Italy) cooperated to investigate power-to-gas feasibility. The energy crisis due to the war in Ukraine peaked during the project. The demand for green hydrogen increased as natural gas was reduced. In 2022, the cost of blue hydrogen was 9.5–12.6 €/kg. Higher electricity prices impacted the cost of green hydrogen less. Considering the 2021–22 level of electricity and gas prices, and the potential flexibility of electrolysers, electrolytic hydrogen was on a par with blue hydrogen. On the long term, green hydrogen is assumed to be competitive around 2030. A fast ramping up and favourable electricity cost development could halve the hydrogen production cost until 2040 with investment being the major contributor to a cost reduction. Meanwhile, the smart operation of a wind/electrolyser system might achieve 24% reduction of its operation cost. The following measures are recommended to introduce green hydrogen on a large scale: 1) certification of green and low carbon hydrogen and a uniform CO_2 price; 2) ensuring a level playing field across markets; 3) enabling policies to enhance European security of supply by increasing domestic production and diversifying imports; 4) fast ramping of renewable electricity generation; and 5) coordinated planning of hydrogen, methane, and electricity infrastructures.

Graphical Abstract



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Lay Summary: Power to gas is important to enable high renewable energy shares in the European Green Deal. This article provides perspectives from different analyses of feasibility of power to gas in Europe. Promising results were found about reduction of hydrogen costs through development of flexible and efficient operation, reduced investment costs driven by scaling and learning curves, optimized placement, and improved infrastructure with dedicated hydrogen grids. Furthermore, increasing prices for natural gas due to the Russian invasion to Ukraine led to favourable conditions for renewable hydrogen compared to blue hydrogen based on natural gas with carbon capture and storage (CCS).

Key words: renewable hydrogen; energy system analysis; hydrogen demand; energy crisis; electrolyser plant design; electrolyser operation optimization; power-to-gas plant location

Introduction

Large investments in variable renewable energy and electrification are required to meet the Paris Agreement's targets and avoid excessive climate change. Electrolysis can enable flexible electricity consumption [1] and provide hydrogen as a storable, green fuel, reducing greenhouse gas (GHG) emissions and dependency on natural gas imports. Green hydrogen can substitute the use of conventional grey hydrogen from natural gas in the short term and be used to provide power-to-X fuels for industry and heavy transport in the long term [2, 3]. Blue hydrogen produced from natural gas with carbon capture and storage may reduce GHG emissions compared to grey, but environmental benefits and security of supply are still debated [4]. However, the energy crisis triggered by the war in Ukraine led to dramatic increases in natural gas prices, affecting the electricity prices. Developing technologies for a renewable energy system is important, the urgency for reducing GHG emissions and meeting set climate targets requires sound technical and economic assessments to support purposeful decision-making. Therefore, to provide novel insights into the scale-up of green hydrogen technologies, while considering the competition between production technologies as well as synergies across the energy system, the European SuperP2G research project (Synergies Utilising renewable Power Regionally by means of Power to Gas) [5] aimed to minimize risks and estimate the feasibility of power to gas at different levels, focusing on the regional business case. The project was conducted before and during the energy crisis, and this article reflects on the project results and how the crisis impacted them. In this paper, we provide different perspectives on green hydrogen in Europe—during an energy crisis and towards future climate neutrality, based on research conducted during the SuperP2G research project. Compared to other studies in the literature, which often have a narrow and specific focus, e.g. on hydrogen production technologies, or using energy system models to address energy futures, this paper addresses the energy chain from supply through transmission and storage to demand, assessed both from technical, economical, and systems perspective. By doing so, we summarize findings from a large variety of studies to address key perspectives related to 1) how the energy crisis impacted gas and electricity costs; 2) future development of hydrogen production, transmission, storage, and use at European level towards 2050; 3) as well as five national case studies, which dive into technology development, industrial demands, and economical benefits.

The energy crisis and its impact on gas and electricity costs

As a direct effect of the war in Ukraine, Europe has turned away from obtaining Russian gas on short notice. The sudden displacement in the supply and demand balance has led to dramatic price increases while the member states are searching for new supply routes.

Historically, the Natural Gas EU Dutch Title Transfer Facility (TTF) [6] have reported natural gas prices ∼18 €/MWh (±10 €/MWh) before September 2021. Since then, until end of 2022, it has been >66 €/MWh, with spikes in December 2021 (180 €/MWh), March 2022 (225 €/MWh), and peaking in August 2022 with 340 €/MWh. The natural gas price has declined since, reaching a level ∼50 €/MWh in March 2023. However, still more than twice the former price level (Fig. 1).

In the second half of 2019 an average total purchase cost of 33.1 €/MWh and 37.0 €/MWh is reported, respectively, for Italian and EU-27 non-household customers including taxes and levies [6]. The database shows a price of 76.7 €/MWh for Italy (+130% with respect to the beginning of the project) for the first half of 2022 and 76.4 €/MWh for EU-27 (+106%).

Being the main feedstock in the steam methane reforming process, the natural gas purchase cost greatly affects the economic competitiveness of grey hydrogen. Based on Hydrogen Europe reference, [8] a total average cost of 2.67 €/kg for grey hydrogen is estimated in EU-27 in 2021, i.e. a value aligned with those reported by other authors in the literature like Stenberg *et al.* (2020) [9] and Pruvost *et al.* (2023) [10]. Almost 67% of this cost is referred to natural gas consumption. By conservatively assuming the same proportion, grey hydrogen production cost is estimated between 8.9 and 10.9 €/kg in the case that natural gas purchase cost ranges between 160 and 200 €/MWh, i.e. a set of values that occurred during the crisis in 2022. A higher cost has to be considered in case of blue hydrogen production, including the carbon capture and storage sections. Specifically, the additional cost depends on several techno-economic factors that rely on the specific project like, e.g. the adopted process, the plant capacity, and the adopted solution for CO_2 management. However, a first tentative value in the range of 0.6–1.70 €/kg can be assumed in accordance with Gislam (2021) [11], resulting in a production cost for blue hydrogen in the range of 9.5–12.6 €/kg.

Assuming that grid-connected power to gas (P2G) will be the dominating case in Europe, a major portion of electrolytic hydrogen production costs stems from the cost of renewable electricity. Correspondingly, the impact of electricity price levels is high if the electricity is acquired from the electricity market. The projection of the build-up of renewable electricity production is therefore a defining factor, but similarly is the fact that the gas prices also influence the electricity prices. According to the data presented by EURELECTRIC [12], there was aclose relation between changes in natural gas and electricity prices, where a change of the average gas price on a month-to-month basis in the period from January 2021 to April 2022 corresponded to a similar relative change in electricity price with only a ±20% difference.

In October 2022 the 'Regulation on an emergency intervention to address high energy prices (EU 2022/1854)' [13] was adopted for EU. These measures where limited in time to start before 1 December 2022 and run until 31 March 2023. A review is announced for October 2023. The regulation introduces a price limit for inframarginal electricity generation technologies at 180€ on realized

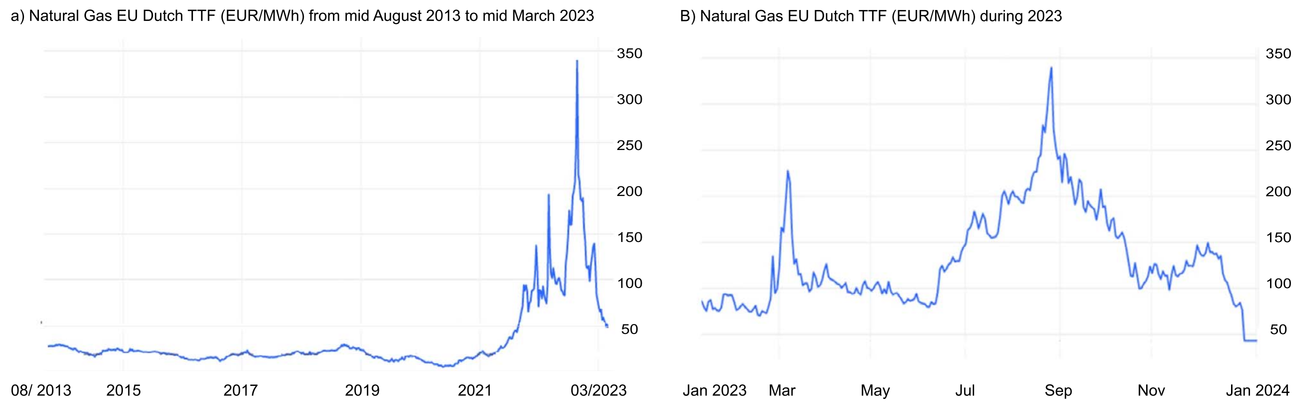

Figure 1. Illustrations how the war in Ukraine impacted the price of natural gas in Europe until end of 2022. A, Natural gas price the last 10 years and (B) natural gas price in 2022 [7].

market revenues per megawatt-hour. The limitation of the revenues for the relevant generators of inframarginal plants leads to extra financial benefits for member states, which can redistribute it to households, businesses, and the industry at large, exposed to high electricity prices. In addition, a so-called 'Solidarity contribution from fossil fuel companies' was introduced, which would cover profits that are above a 20% increase on the average profits of the previous 3 years. This could be redirected to households, business, and industry in a similar manner, and measures fostering the green transition are explicitly mentioned. The regulation introduces a price limit for inframarginal electricity generation technologies at 180€ on realized market revenues per megawatt-hour. The limitation of the revenues for the relevant generators of inframarginal plants leads to extra financial benefits for member states, which can redistribute it to households, businesses, and the industry at large, exposed to high electricity prices. In addition, a so called 'Solidarity contribution from fossil fuel companies' was introduced, which would cover profits that are above a 20% increase on the average profits of the previous 3 years. This could be redirected to households, business, and industry in a similar manner, and measures fostering the green transition are explicitly mentioned.

Looking at Denmark in 2019 [14], the average electricity price was 38 €/MWh. In 2022, the average price was 219 €/MWh (476% increase). However, if considering electrolyser operation of only 1224 hours, the average electricity price would have been only 31 €/MWh (8.8% decrease), which illustrates the benefit of highly flexible electrolysers. In Austria, the average price was 40.2 €/MWh in 2019 and 35 €/MWh in 2020. In 2021 it was 110 €/MWh (174% increase from 2019) and in 2022 it was 265 €/MWh (559% increase from 2019) [15]. In Italy, the average electricity price was 52.3, 38.9, and 125.5 €/MWh, respectively in 2019, 2020, and 2021 [16]. In 2022, the average price was 304 €/MWh (533% increase with respect to 2019). However, the Italian price cap mechanism [17, 18] would limit max electricity price to 210 €/MWh (338% increase).

Development of hydrogen demands and fluxes across Europe

Renewable hydrogen is expected to become increasingly important as a zero-emission option for all sectors that cannot be directly electrified or can only be electrified with great difficulty, such as some applications in industry (high-temperature processes, reduction processes) or in mobility, where battery electric drives are reaching their limits. In a European context, 'A Hydrogen Strategy for a Climate-Neutral Europe' [19] was published in 2020 to accelerate the deployment of hydrogen technologies. The strategy aims to achieve 6 GW (1 mt hydrogen (H_2) or 33 TWh) of hydrogen production by 2024, 40 GW (10 mt H_2 or 333 TWh) by 2030, and 13%–14% of the total energy mix by 2050. In 2022, the 'REPowerEU' strategy [20] updated these targets to 65 GW of electrolyser capacity by 2030, with 10 mt H_2 production in the EU and import possibilities of 10 mt H_2. The European Hydrogen Backbone [21] and Ready4H2 [22] initiatives by natural gas transmission and distribution system operators (TSOs and DSOs) aim to achieve a common European hydrogen grid. Hydrogen demand estimates vary widely depending on scenario conditions, but studies suggest that demand could be up to 3100 TWh by 2050.

In a European study, Kountouris *et al.* [23], investigate the future deployment of hydrogen production (green and blue), the benefits of a unified European hydrogen infrastructure, as well as considering the possibilities of importing hydrogen from outside Europe. The study applies the comprehensive, open source energy system model, Balmorel [24], which is well known and validated [25, 26], and it covers all main energy sectors and is suitable for performing long-term scenarios.

In the study by Kountouris *et al.* [23] hydrogen demand projections for industry (feedstock and energy) and transport were estimated at 326 and 1530 TWh by 2030 and 2050, respectively, based on the European Hydrogen Backbone. The results of the study [23] showed investments in electrolysers in the range of 24–68 GW by 2030, increasing to 310–507 GW by 2050. The results also suggested that hydrogen produced in the south of Europe could become prominent by exploiting cheap solar photovoltaic (PV) potential. A hydrogen transmission infrastructure is expected to be part of the least-cost solution for transporting hydrogen from the south, mainly from Spain and Italy, but also to a limited extent from the Nordics around the North Sea. The study also identified hydrogen corridors from the south, in line with the Iberian corridor [23], and suggested that potential hydrogen imports from North Africa could be possible (Fig. 2). The study estimated that ~100 TWh of hydrogen would be imported from outside Europe by 2050, while reaching higher import levels by 2045 of ~190 TWh, highlighting the competition in hydrogen production costs between the EU and its surroundings. Additionally, the study shed light on the potential lock-in effects of blue hydrogen, which can appear if investments are made in blue hydrogen production in the early years, before green hydrogen becomes more economically viable. The study, furthermore, suggests that high natural gas

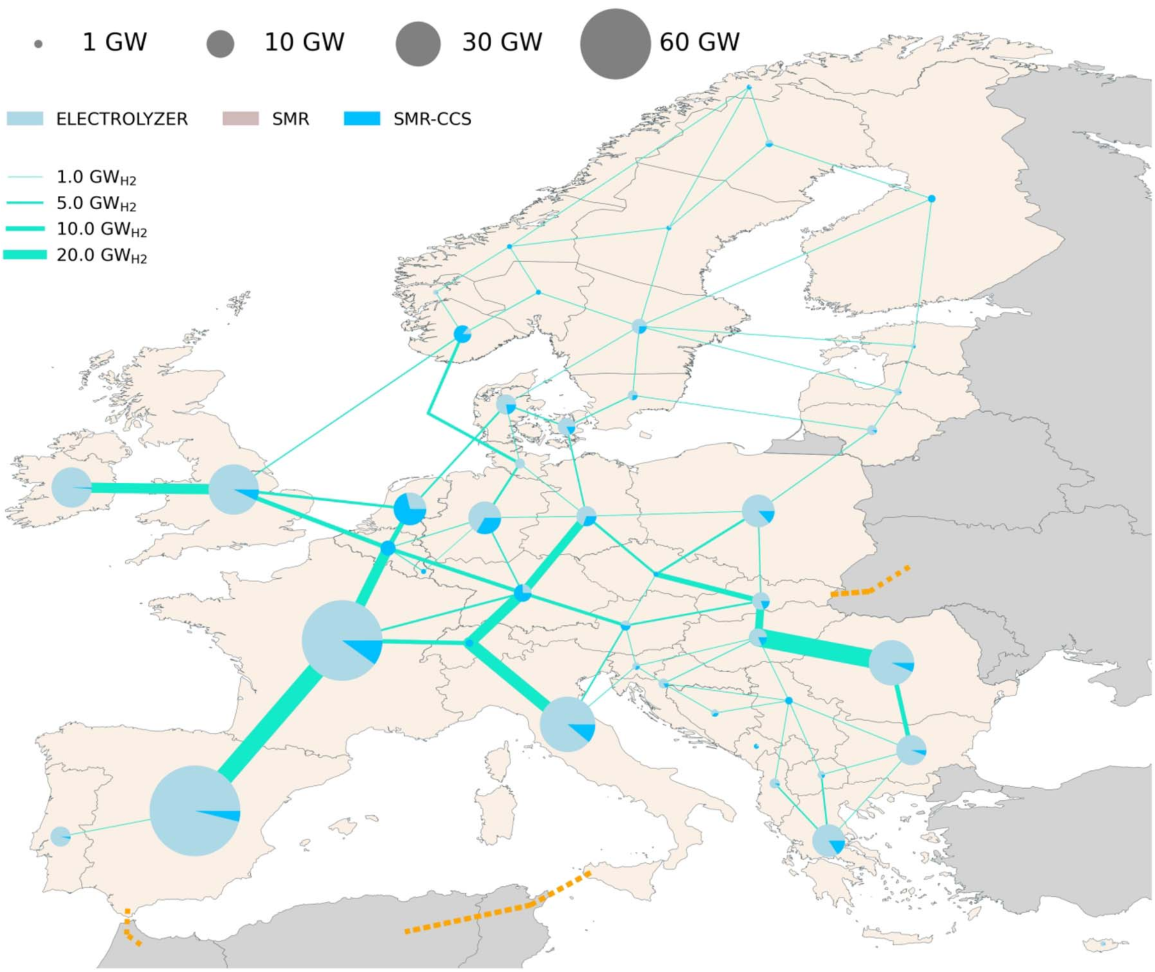

Figure 2. Estimated hydrogen production potentials and fluxes across Europe according to analysis conducted in SuperP2G on basis of the market conditions of 2021 [23].

or electricity prices could impact the competition between blue and green hydrogen.

P2G case in Austria

The Austrian case aimed to promote the integration of renewable energy in the industry sector by assessing the future demand and cost of renewable hydrogen and synthetic natural gas (SNG) using the SuperP2G project in the WIVA P&G model region[1]. The study conducted a literature review, held discussions with stakeholders, and used three tools developed by the Energieinstitut an der JKU Linz (CoLLeCT, PResTiGE, and MOVE2) to estimate future demand and costs for renewable gases.

Austrian chemical and steel industries will be the primary consumers of renewable gases, with a projected total demand of 60 TWh for hydrogen and 4.5 TWh for SNG by 2040 according to the Austrian Hydrogen Strategy [27]. Contrary to the historical trend of decreasing investment costs for hydrogen production units (electrolysers) due to learning curve and economies of scale effects, there has recently been an increase in investment costs due to global supply difficulties.

Recent studies [28–30] suggest that there is potential for an early and steep growth of global electrolysis capacities. However, investment costs have increased in recent years due to the aforementioned factors; further positive developments and the implementation of national or regional targets are expected to lead to significant cost reductions in the future (Fig. 3).

To enable stakeholders to consider the business case of a power-to-gas plant, a calculator based on the model PResTiGE[2] allows for a parameter variation for calculating the hydrogen production costs. According to a wide range of parameters used, the hydrogen production costs for a 100 MW electrolysis plant in Europe in 2030 could range from ∼4 to 23 €/kg, depending on the plant site and the development of future investment costs, electricity prices, technology performance, operation strategies, etc. However, analysing a range of hydrogen production costs and

[1] WIVA P&G (Wasserstoffinitiative Vorzeigeregion Austria Power & Gas) is one of three Austrian energy model regions aiming for the demonstration of the transition of the Austrian economy towards climate neutrality with the production of renewable gases, particularly hydrogen. See https://www.wiva.at/.

[2] PResTiGE, an in-house development of the Energieinstitut an der JKU Linz, is a toolbox for current and prospective techno-economic and environmental benchmarking of PtG systems. The tool comprises data from demo sites and benchmark systems as options for electricity storage or applications of the gaseous products H_2 or SNG at different scales, in forms that are regionally adaptable overall process steps of the PtG system and product application. The assessment results reveal the optimal P2G system configuration and implementation (i.e. with minimal cost and maximal system benefits). Sensitivities can be systematically analysed to explore the robustness of the results. The quantitative economic assessment via PResTiGE is based on the specific production costs of hydrogen or SNG, which are calculated from the total annual costs in relation to the amount of annually produced energy. The total annual costs are calculated using the so-called ‘annuity method’ following VDI 2067. Applied among others in [31, 32]

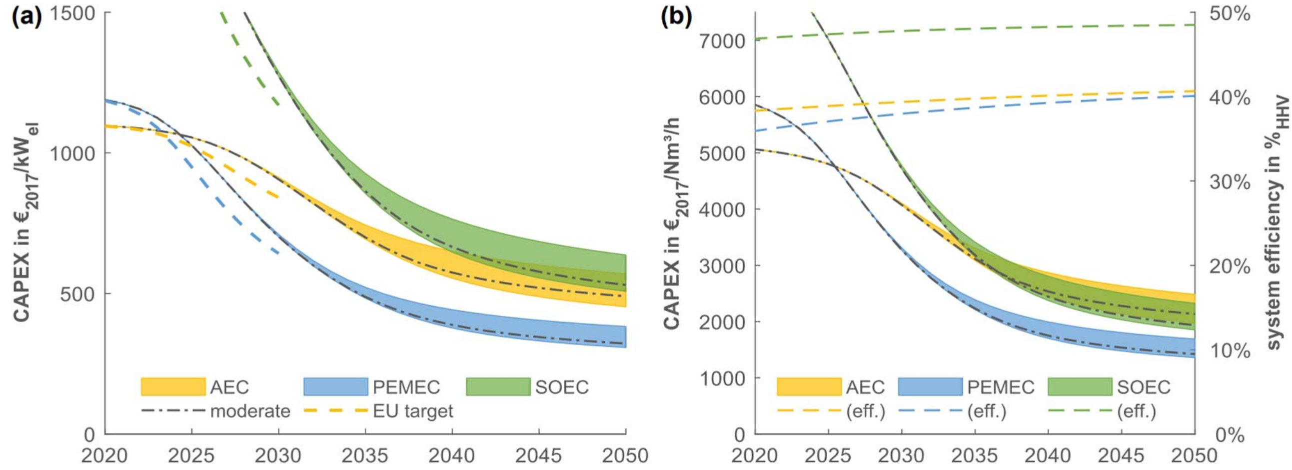

Figure 3. Estimated ranges for cost reduction based on technological learning of electrolysis for global industrial deployment scenarios related to electric input power (A) and to hydrogen output with developing efficiencies (B). Based on and updated from [28].

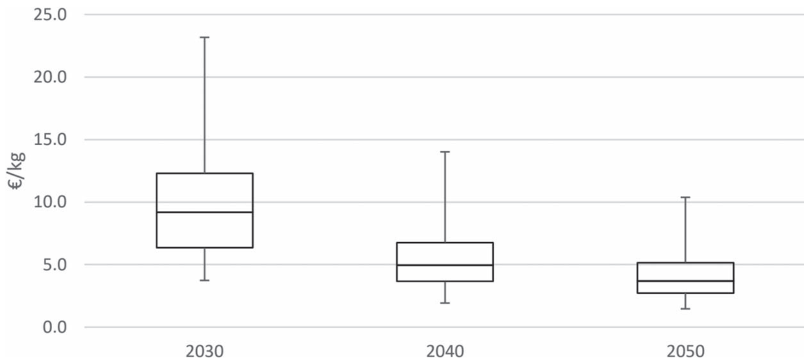

Figure 4. Range of hydrogen production costs due to parameter variation[3] (Source: Energieinstitut an der JKU Linz).

varying different parameters, production costs could be in the range of 9€/kg in 2030, 5€/kg in 2040, and 4€/kg in 2050 (Fig. 4).

According to the macroeconomic analysis, integrating renewable hydrogen into industrial processes, defined in the Austrian National Hydrogen Strategy, will have positive effects on the Austrian economy. The study shows an average annual GDP increase of 0.5 billion euros and employment increase by ~20 000 employees between 2025 and 2030. Additional investment impulses through the expansion of hydrogen production and value added through hydrogen production as the main drivers of these effects was identified. Additionally, as net exports increase, along with more or less constant yearly investments, private consumptions are expected to increase.

It is obvious that the higher the share of domestically produced hydrogen, the lower the value-added flows from hydrogen imports, and the higher the positive effects on GDP. The effects of hydrogen import quota intensity on GDP show a wide spread, with more intensive domestic hydrogen production leading to higher levels of investments and positive effects on the GDP of about +1.4% GDP increase until 2040 with 60% hydrogen import. The effects of hydrogen import price also show high impact on GDP, with a higher import price resulting in reduced positive effects on GDP and a lower import price resulting in a more positive effect on GDP. A hydrogen import price of 4 €/kg yielded a +1.4 bn€ GDP increase until 2040.

P2G case in the Netherlands

The University of Groningen's SuperP2G research projects have explored the economic value of P2G as a flexible source of energy that can aid in the transition to low-carbon energy systems. The projects examined the potential for P2G to provide flexibility services related to timing, location, and end-users, and analyzed the various economic benefits of these services.

Li *et al.* (2021) [29] developed a short-term partial equilibrium model of integrated electricity and hydrogen markets and analysed the economic potential of P2G as a source of flexibility in electricity markets with high shares of renewables and high external demand for hydrogen. They found that P2G reduces the price volatility of electricity prices, but a high external demand for hydrogen reduces this impact. P2G can deliver positive benefits for some groups, but the fixed costs of P2G assets and the costs of replacing natural gas with more expensive hydrogen outweigh these benefits. Investments in P2G become profitable

[3] The investigation of the potential range of hydrogen production costs was carried out by systematically changing six key parameters, resulting in a comprehensive dataset with 486 annual data points for the years 2030, 2040 and 2050. The range of these data points is summarized by utilizing a boxplot diagram. The parameters include: 1. Renewable energy source: the choice between photovoltaic and wind power take into account different energy sources; 2. Full-load hour of the electrolyser: investigating three sites with varying operational durations allows to discern the influence of electrolyser full-load hours on costs. 3. Electricity costs: varied within ±20%, this parameter explores the sensitivity of hydrogen production costs to electricity costs. 4. Electrolyser technology: the selection of alkaline electrolyzer (AEC), proton exchange membrane electrolyser (PEMEC), or solid oxide electrolyzer (SOEC) takes into account for each technology influencing factors like investment costs. 5. Investment costs: with a variability of ±20%, account for uncertainties, reflecting potential economic fluctuations in estimating capital outlays. 6. Efficiency of electrolyser: subject to a fluctuation of ±5%, this parameter considers practical operational aspects, such as how the electrolyser is operated.

from a social welfare perspective when the reduction in carbon emissions is valued at 150–750 €/ton.

Ghaemi *et al*. (2023) [33] examined the extent to which producing green hydrogen through electrolysers can contribute to congestion alleviation in medium-voltage distribution grids (MVDNs) in the presence of high amounts of renewable energy sources (RESs), flexible consumers of electricity, and a local heat system. They found that converting power to hydrogen can be an economically efficient way to reduce congestion in MVDNs when there is a high amount of RES, but the economic value of electrolysers as providers of flexibility to MVDNs decreases when other options for flexibility provision exist.

Perey *et al*. (2023) [34] analysed the most competitive sources of low-carbon hydrogen for the northwest European market, taking into account costs of local production, conversion, and transport. They found that local steam methane reforming with carbon capture and storage is the most competitive low-carbon hydrogen supply when international gas prices return to historical levels, while imports from Morocco with electrolysis directly connected to offshore wind generation is the most competitive source when gas prices remain high. For distances >10 000 km, imports in the form of ammonia become a competitive option, while otherwise, pipeline transport is preferable.

Overall, the research projects demonstrate the economic potential of P2G as a provider of flexibility to energy systems, although the economic value of P2G depends on various factors, such as carbon prices, installation costs, and the availability of other options for flexibility provision.

P2G case in Germany

The German case aimed to improve existing tools for H_2 analysis and optimal location of P2G value chains for regional development considering future H_2 demand and process engineering of P2G plants. EcoMeth [35], a tool developed by the DVGW Research Centre at Engler-Bunte-Institute, was enhanced to evaluate methanation and CO_2 capture technologies from a technical and economical point of view. For example, by optimizing the design of cooled fixed-bed and three-phase methanation plants [36], EcoMeth was expanded with additional technologies to support individual consulting and project implementation. The tool calculates capital expenditure (CAPEX) and levelized costs using factor and annuity methods, enabling fast computation and adaptation to different scales of the plant. It utilizes three major factors for efficient cost minimization in the design of the plant: adapting P2G plants to local site conditions, identifying cost drivers, and optimizing plant size in relation to storage capacities. The system analysis section focuses on utilizing heat sources and sinks with the pinch method, leading to high energy utilization through internal heat integration and integration into existing energy systems. During the analysis of the three-phase methanation plant, it was found that the main equipment cost plus the catalyst cost only have a 20% share on the total CAPEX. The specific CAPEX for the methanation plant can be reduced significantly from €450/kW to €160/kW when increasing the scale of the plant from 5 to 100 MW (regarding methane output) [37]. These results are not expected to be impacted directly by changing conditions in the energy market but indirectly through inflation affecting prices of equipment and services. The dynamic operation of the plant is also an important factor impacting the results, especially in a situation where there are price fluctuations for natural gas and electricity increase as seen during the energy crisis.

DBI developed the DBI-MAT tool [38] as part of the German Case project to determine optimized scenarios for integrating renewable energy sources, hydrogen applications, or other processes in an economically and ecologically feasible way.

Four different scenarios were analysed for a location in central Germany [39]. In scenario one, only wind power is used for the electrolysis plant, and grid electricity is used for the balance of plant (BoP). In scenario two, the electrolysis system is connected to the grid and operates at full load, with wind power taking priority over grid purchases. Scenario three includes a PV plant in addition to the wind farm and excludes grid electricity for electrolysis, while scenario four uses both wind and PV power, with the electrolysis system connected to the grid and electricity from renewable sources having priority.

The findings indicate that, in scenario one, the primary costs for producing hydrogen are most significantly influenced by the wind farm's CAPEX and the imputed interest rate. In scenario two, electricity procurement is the largest cost, with the cost ranging from €5.23/kg to €8.23/kg for the produced hydrogen. Scenario three reveals the interest rate, wind farm CAPEX, and PV plant CAPEX as major cost drivers, while scenario four finds that electricity prices from the grid are the most significant influence on hydrogen production costs. In summary, these findings collectively underscore that the cost of electricity emerges as the predominant driver impacting the overall production costs of hydrogen.

In the optimization investigation for scenario three, the size of the renewable energy sources is optimized with an electrolysis-to-wind ratio of 1.8:1 and an electrolysis-to-PV ratio of 3.5:1. These ratios come from a location with medium PV potential and onshore wind turbines and represent the situation in central Germany.

P2G case in Italy

The Italian case aimed to design a new tool to optimize P2G plants in size and location. For this purpose, a Geographic Information System (GIS)-based approach was adopted. Developed and validated through the collaboration of the Italian partners, i.e. CNR-ITAE and UNIBO, the alpha version of the tool allows the users to identify the optimal hydrogen supply chain (HSC) while minimizing the levelized cost of hydrogen (LCOH), i.e. production and transport cost. Specifically, to investigate the transport cost, GIS data about the existing energy and road infrastructure are implemented in a database developed for the purpose.

The tool is not specifically dedicated or linked to a single application, so that (ideally) the hydrogen demand modelling can approach different usage sectors (e.g. industrial applications). Therefore, the tool can be used by any interested stakeholder to investigate any scenario that is of interest. Furthermore, sensitivity analysis can also be performed by changing techno-economic input data. To date, state-of-the-art data have been used [40] . However, data obtained from experimental campaigns in testing facilities like, for example, the Green Hydrogen Lab at the University of Bologna [41] can be easily integrated.

Figure 5 schematically shows the concept map of the tool [42] and the development steps with the software used [43] . A detailed description of the methodology is reported in the project reports [40, 42] and in the paper by Guzzini *et al*. (2023) [43], where the SuperP2G-Italy tool was validated by investigating the penetration of hydrogen in the mobility sector. The SuperP2G-Italy tool was applied to study the hydrogen demand on Italian highways in 2030 and 2050. The baseline scenario predicts an annual

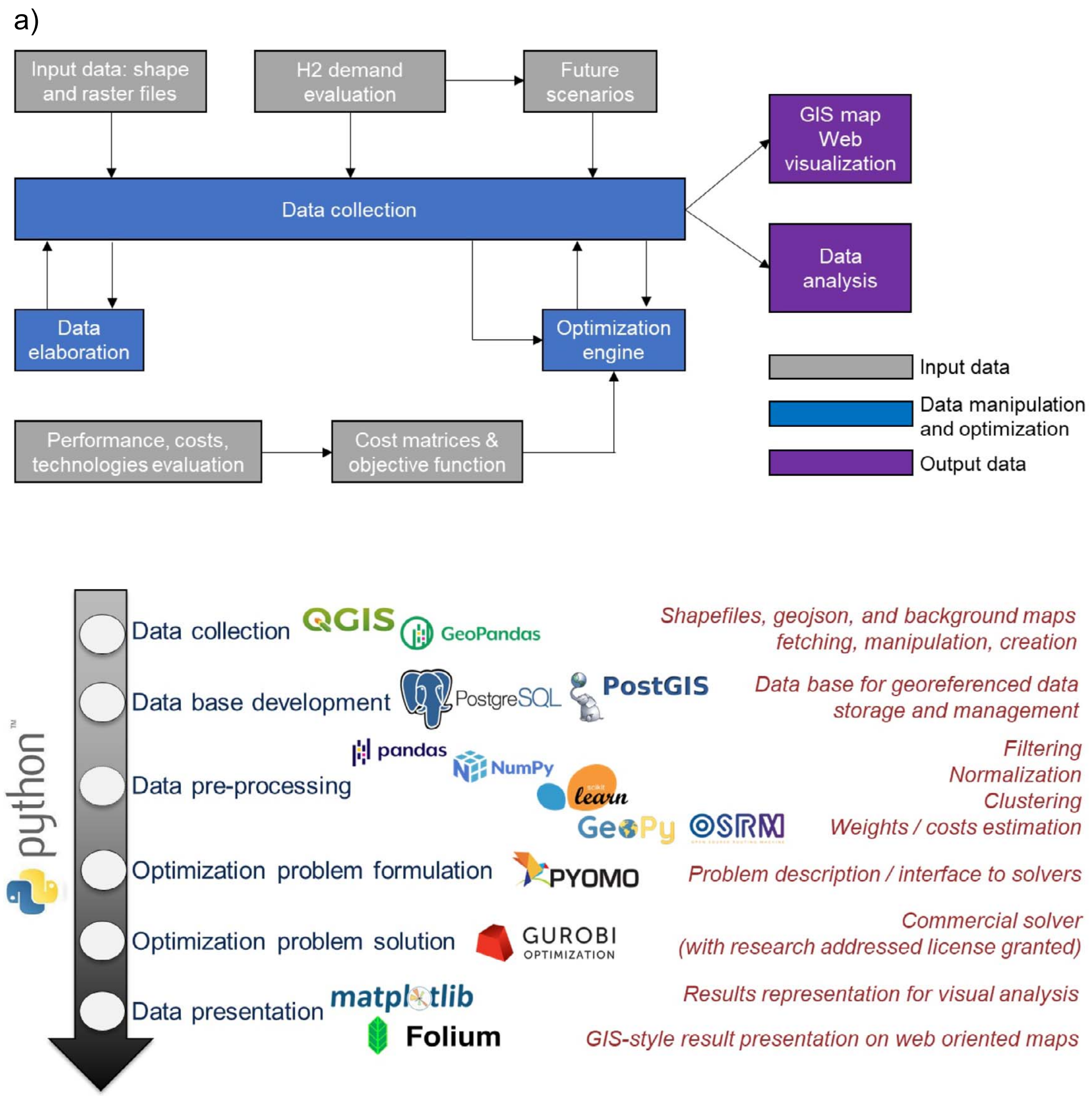

Figure 5. Illustration of SuperP2G-tool-Italy in regard to (a) its conceptual structure and (b) development process and supplementing plug-in applications. [42].

hydrogen demand of 10 000 and 72 500 tons/year for 2030 and 2050, respectively. However, the optimized case reduces demand to 7000 and 32 600 tons/year. The results show a 2030 scenario analysis in which the LCOH ranges from €6.93/kg to €7.46/kg, whereas the LCOH ranges from €5.62/kg to €6.12/kg in the 2050 projection, and the power-to-hydrogen (P2H) plants' cost is the primary contributor to the LCOH. These ranges have been calculated in a baseline case LCOH that is lower than the optimized case, primarily because of the scale effect on the investment cost of the P2H plants. In all the four scenarios, the LCOH is dominated by plants' investments and operations, which account for >90% of the costs. As a mitigation measure, the effort to increase the truck autonomy would reduce the number of plants required to meet hydrogen demand, and, consequently, this indirectly reduces the LCOH (while keeping constant the aggregated hydrogen demand) to meet challenging and competitive cost targets. Moreover, the performed analysis shows that, regarding the location of P2H-plants, high-capacity plants are uniformly located in the Italian territory in the baseline case, whereas, in the optimized case, the highest capacity plants are mainly located close to high-demand hydrogen refuelling stations.

The current range of potential applications and stakeholders interested in using it is wide. Furthermore, since the geographical correlation between hydrogen and renewable energy production is paramount for the definition of renewable hydrogen in the new RED II Directive, new releases of the tool are expected. The development process is still ongoing to add new features, for example, but not limited to the design of renewable hydrogen cost maps or the investigation of the effect on local electric grid stability.

P2G case in Denmark

GreenLabSkive, in western Denmark, served as a testing ground for innovative technologies and features a complete 12-MW electrolyser system to supply hydrogen to stakeholders and includes wind turbines and solar panels with a total capacity of 80 MW. The objective of the Danish case was to make it possible for the local multienergy carrier-based business park to manage multiple value streams in real time as well as optimize the infrastructure set-up by developing and testing advanced decision-support solutions.

From the operational perspective, GreenLabSkive is connected to the Nordic electricity market and faces multiple uncertainties from both the market and renewable power, leading to complex operational strategies. The Danish partners have developed a data-driven decision framework (DDF) using robust chance-constrained programming (DRCCP) to achieve an optimal operation of the wind/hydrogen system [44]. The proposed DRCCP framework considers multiple uncertainties of wind power production and electricity prices, embedded with short-term forecasts, data collection, and flexibility of the electrolyser and storage units. The proposed solution was validated based on on-site system parameters and market data. For a studied 30 days, the total operation cost was reduced by 24% using the proposed method in comparison with several other state-of-the art methods, demonstrating the effectiveness of the DRCCP and the feasibility of applying advanced optimization-based operation strategies to live operation and management of renewable-based hydrogen production facilities.

From the investment planning perspective, the team developed a two-layer multiobjective optimization framework to achieve optimal sizes of the electrolyser and storage units [45]. The framework is tested and validated based on today's platform data of GreenLabSkive. The results show that additional investment can improve the operational flexibility of the system, thereby increasing operating income but lowering project returns. For example, to gain an increase of 10% production in green hydrogen, the internal rate of return decreases by 1.2%, primarily owing to the current high capital cost of the electrolyser and hydrogen storage units. This concludes that lowering the technology cost and improving the valorization of flexibility are two key factors for achieving the maximum amount of green hydrogen at a competitive price in such an industrial park setup.

Summary and conclusions

The war between Russia and Ukraine has had a significant influence on several parameters, which may affect the competition between green and blue hydrogen in a European context.

First of all, the expected short-term demand for hydrogen has increased as the desire to reduce natural gas demand has surged. A high demand may impact the learning curve of green hydrogen, as well as the availability of European blue and green hydrogen and demand for hydrogen imports. This, in turn, has an impact on required hydrogen infrastructures. Results show potential for production of green hydrogen in Southern Europe with transmission through partly refurbished gas grids and new hydrogen grids to Central Europe, as well as a potential for imports either via hydrogen grids or as ammonia. The following parameters increase the feasibility of offshore wind investments for green hydrogen production: limited availability or high price of natural gas, high hydrogen demands, limited PV implementation in south Europe, limited onshore wind implementation, and limited possibilities for import.

Availability of large-scale hydrogen storage increases the competitiveness of green hydrogen over blue. Because blue hydrogen decouples hydrogen production from renewable availability, it requires less hydrogen infrastructure in the form of underground storage and extended grid expansion. Meanwhile, increased CO_2 grids and storage assets would be required.

Secondly, increased natural gas prices affected the cost of blue hydrogen, which would be ~9–11 €/kg with the average European natural gas price in 2022, while increased electricity prices affected the cost of green hydrogen. A higher local variation is seen across Europe on green hydrogen costs than blue, due to uniform natural gas prices versus differing local electricity prices. Ensuring availability of sufficient renewable electricity production and hydrogen storage will be key to facilitate cheap, green hydrogen production. On the other hand, green hydrogen production will have benefits in terms of increasing security of supply with local production. Furthermore, it will be cost competitive in a situation with high natural gas prices or high CO_2 taxes. Considering the 2021–22 level of electricity and gas prices, and the potential flexibility of electrolysers, electrolytic hydrogen was on a par with blue hydrogen. An electricity price cap, green fuel premiums, or power purchase agreements (PPAs) might further improve the competitiveness of green hydrogen.

A fast ramping up and favourable electricity cost developments could halve hydrogen production costs until 2040. Hereby, the technology improvements and reduction in needed investment (CAPEX) is the major contributor to such a cost reduction, as specific electrolysis costs are expected to decrease by >75% due to scaling in numbers and unit size. Meanwhile, the smart operation of a wind/electrolyser system might achieve 24% reduction of its operation cost. Further research is required to ensure upscaling of electrolysers in size and numbers in Europe, with smart designs and operation of the plants.

To ensure a level playing field, coordination is required at EU level in a number of areas between different types of hydrogen and other energy vectors:

1) Certification of green and low-carbon hydrogen and a uniform CO_2 price. EU regulation, including certification, is required to ensure that all embedded greenhouse gas emissions are accounted for across all sectors. This is required to ensure that emissions in one sector (e.g. heavy transport utilizing hydrogen) doesn't happen at the cost of emissions in another (e.g. electricity produced with fossil fuels).

2) Ensuring a level playing field across markets. There is a risk of suboptimization if silo thinking persists within sectors. It is hence necessary to establish efficient markets, which ensure that cost-optimal solutions are chosen, when taking decarbonization of the full society into account. Hydrogen may provide value in one sector, but an even higher in another, where electrification is not possible.

3) Enabling policies to enhance European security of supply by increasing domestic production of fuels and diversifying imports. To ensure a cost-efficient system, national suboptimization should be avoided, and energy carriers traded freely within Europe.

4) Fast ramping of renewable electricity generation, while respecting nature and local communities. The feasibility of green hydrogen will depend on the timely availability and price of renewable electricity.

5) Coordinated planning of hydrogen, methane, and electricity infrastructures. It will likely be feasible to move hydrogen across countries in Europe, from the outskirts of Europe to Central Europe (consumption centres). To facilitate this, joint plans and implementations are required, also considering other energy infrastructures.

To summarize, green hydrogen production has a promising potential in terms of contributing to decarbonization and self-sufficiency in a European context if the right regulatory frameworks are put in place; renewable electricity production is installed in time to meet hydrogen demand, thereby enabling fast ramp-up and technology learning of electrolysers; electrolyser plants are designed for flexible operation; and adequate infrastructure to transport, distribute, and store large volumes of hydrogen is established.

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Authors' contributions

Marie Münster (Conceptualization [Lead], Funding acquisition [Lead], Project administration [Lead], Supervision [Equal], Writing—original draft [Equal], Writing—review & editing [Equal]), Rasmus Bramstoft Pedersen (Data curation [Equal], Formal analysis [Equal], Software [Equal], Writing—original draft [Equal], Writing—review & editing [Equal]), Ionnis Kountouris (Data curation [Equal], Formal analysis [Equal], Software [Equal], Writing—original draft [Equal], Writing—review & editing [Equal]), Lissy Langer (Formal analysis [Equal], Investigation [Equal], Writing—original draft [Equal], Writing—review & editing [Equal]), Dogan Keles (Supervision [Equal], Writing—review & editing [Equal]), Ruth Schlautmann (Writing—original draft [Equal], Writing—review & editing [Equal]), Friedemann Mörs (Writing—original draft [Equal], Writing—review & editing [Equal]), Cesare Saccani (Supervision [Equal], Writing—review & editing [Equal]), Alessandro Guzzini (Data curation [Equal], Formal analysis [Equal], Investigation [Equal], Methodology [Equal], Software [Equal], Writing—original draft [Equal], Writing—review & editing [Equal]), Marco Pellegrini (Writing—review & editing [Equal]), Andreas Zauner (Writing—original draft [Equal], Writing—review & editing [Equal]), Darja Markova (Writing—original draft [Equal], Writing—review & editing [Equal]), Hans Böhm (Writing—original draft [Equal], Writing—review & editing [Equal]), Shi You (Formal analysis [Equal], Supervision [Equal], Writing—original draft [Equal], Writing—review & editing [Equal]), Martin Pumpa (Writing—original draft [Equal], Writing—review & editing [Equal]), Frank Fischer (Data curation [Equal]), Francesco Sergi (Writing—original draft [Equal], Writing—review & editing [Equal]), Giovanni Brunaccini (Writing—original draft [Equal], Writing—review & editing [Equal]), Davide Aloisio (Writing—original draft [Equal], Writing—review & editing [Equal]), Marco Ferraro (Writing—original draft [Equal], Writing—review & editing [Equal]), Machiel Mulder (Writing—original draft [Equal], Writing—review & editing [Equal]), and Hans Rasmusson (Project administration [Equal], Writing—original draft [Equal], Writing—review & editing [Equal]).

Conflict of interest

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Data availability

Data available on request.

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