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Moving toward the low-carbon hydrogen economy: Experiences and key learnings from national case studies

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ABSTRACT

The urgency to achieve net-zero carbon dioxide (CO_2) emissions by 2050, as first presented by the IPCC special report on 1.5 °C Global Warming, has spurred renewed interest in hydrogen, to complement electrification, for widespread decarbonization of the economy. We present reflections on estimates of future hydrogen demand, optimization of infrastructure for hydrogen production, transport and storage, development of viable business cases, and environmental impact evaluations using life cycle assessments. We highlight challenges and opportunities that are common across studies of the business cases for hydrogen in Germany, the UK, the Netherlands, Switzerland and Norway. The use of hydrogen in the industrial sector is an important driver and could incentivise large-scale hydrogen value chains. In the long-term hydrogen becomes important also for the transport sector. Hydrogen production from natural gas with capture and permanent storage of the produced CO_2 (CCS) enables large-scale hydrogen production in the intermediate future and is complementary to hydrogen from renewable power. Furthermore, timely establishment of hydrogen and CO_2 infrastructures serves as an anchor to support the deployment of carbon dioxide removal technologies, such as direct air carbon capture and storage (DACCS) and biohydrogen production with CCS. Significant public support is needed to ensure coordinated planning, governance, and the establishment of supportive regulatory frameworks which foster the growth of hydrogen markets.

1. Introduction

1.1. Hydrogen complements electrification in the quest to reach net-zero emissions

Climate change has been on the agenda since the 1980s [1], and the Paris agreement [2] and its rapid ratification were important milestones of the Global commitment to reduce the emission of greenhouse gases (GHGs). The IPCC special report on the impacts of global warming of 1.5 °C above pre-industrial levels confirmed that: 1) 1.5 °C of warming will likely materialise between 2030 and 2052 ([3], Para. A1); 2) the terrestrial, freshwater and coastal ecosystems can retain more of their services to humans if the average temperature increase can be kept below 1.5 °C compared to a 2 °C scenario ([3], Para. B3); 3) climate-related risks are increased if the global average temperature increase exceeds and then reduced to 1.5 °C instead of a gradual increase to 1.5 °C above pre-industrial levels ([3], Para. A3.2). The sixth assessment report by IPCC [4] supports the benefits of limiting global warming to 1.5 °C.

A net-zero greenhouse gas emission target for 2050 is central in the European Green Deal [5], and requires the decarbonization of the energy system as a whole [6]. Hydrogen, as electricity, is a zero-carbon energy vector. When produced with low or net-zero emissions the two energy carriers offer significant decarbonization potential. Hydrogen and electricity can be used in the transport, residential and commercial, industry, and power sectors in a cost-effective manner. This has been widely recognized in the hydrogen strategies published lately in Europe [7–9].

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Hydrogen can be produced with low emissions via electrolysers powered by wind-, hydro- or solar-generated electricity. Hydrogen production from natural gas where approximately 95% of the produced CO_2 is captured and permanently stored (H_2 - CCS value chains) also has low associated GHG emissions given low upstream leakage rates for the natural gas supply chain [10].[1]

1.2. Appraisal of hydrogen as part of an integrated energy system

Comprehensive studies are needed to appraise the role of hydrogen within the energy system, particularly outside of the industrial sector where the hydrogen market is at present marginal. The first step is to assess the potential for hydrogen to displace existing fuels and reduce the overall GHG emissions of the system. Then elements, such as cost-efficient infrastructure for hydrogen and CO_2, business models with necessary risk mitigation measures, safety, legal, environmental, and societal aspects, must be addressed.

The potential for hydrogen has been assessed through mathematical models which consider integrated energy systems. For example, Chapman et al. [11] who analysed the energy system from a global perspective, "A Clean Planet for all" [6], Blanco et al. [12] considered the European energy system, and Ozawa et al. [13] assessed the energy system of Japan. Their models assess the sensitivity of hydrogen deployment outcomes to policies, technology developments, and limitations in the deployment of technologies, such as nuclear power generation and carbon capture and storage (CCS).

Studies have also focused on gas and power market dynamics and specific end-use sectors. Kolb et al. [14] applied a simulation-based optimization model with a strong focus on market dynamics to study the German gas mix for the period to 2050. Schulthoff et al. [15] and Matsuo et al. [16] studied the potential for hydrogen in low-carbon power systems. Lim et al. [17] applied a forecasting model for daily and monthly natural gas and electricity demand to optimize a renewable energy system. Blanco et al. [18] assessed the business case for hydrogen in the transport sector by soft-linking a transport behaviour model with an energy system model.

Efficient upscaling of hydrogen use in the energy system necessitates significant deployment of infrastructure to connect sites of production and demand and for intermediate storage. For hydrogen produced from natural gas, infrastructure for transport of the captured CO_2 to permanent storage sites must also be deployed. Johnson and Ogden [19] and Li et al. [20] showed how mixed-integer linear programming models can be used to assess optimal infrastructure deployment sequences for identified temporal and spatial hydrogen demand profiles. Johnson and Ogden [19] assessed networks of supply pipelines that link several production facilities and demand locations. Li et al. [20] considered options such as ship-transport alongside pipeline transport of hydrogen.

Life cycle assessment has been widely used to provide a more comprehensive assessment of environmental impact of different production pathways. Such analyses have, for example, been performed on the manufacturing and end of-life phases for electrolysers [21], for competing hydrogen production technologies [22,23] and for assessment of maritime propulsion fuels [24]. Similarly, discussion around the impact of methane emissions on the global warming potential of natural gas hydrogen with CCS has also been taking place [10,25].

Safe operations of hydrogen in gas grids can be addressed through experimental tests both in the laboratory and at scale as, for example, by the HyDeploy project [26]. In this project comprehensive laboratory test campaigns were undertaken to assess the compliance of domestic appliances and gas detection systems as well as the mechanical-property implications for materials. Thorough testing of all components of a university campus grid and a quantitative risk assessment was completed and regulatory approval gained for full-scale demonstration of 20 mol% blending operations in the campus grid [26].

To develop business cases for hydrogen and CCS value chains, both financial and legal barriers and risks must be understood and addressed. Stern [27] concludes that the business case for hydrogen in Europe depends on policy and regulatory actions. Adequate financial, legal and regulatory frameworks for the commercialization of technologies for hydrogen production must be implemented, together with certification of methane emissions.

Legal barriers for deployment of hydrogen in Europe were surveyed in the HyLaw project [28,29]. Significant legislative barriers were found that prevented injection of hydrogen in the gas grid, hampered the function of commercial power-to-gas facilities and prevented commercial scale hydrogen maritime and inland waterways vessels. Weber [30] summarises investigations of the European legal framework for CCS and observes that it does not secure sufficient certainty to operators of CCS value chains. The uncertainty particularly stems from the CCS directive regulations of CO_2 storage which lacks definitions of key terms and currently applies unclear criteria. Heffron et al. [31] addressed transboundary transportation of CO_2 which is not directly regulated by the EU CCS directive. Such infrastructure projects must therefore be regulated by bi-lateral or multi-lateral national agreements which may add to project complexity.

Societal acceptance of technologies and infrastructure for hydrogen and CCS is necessary to unblock barriers to their deployment. The German public interest in hydrogen-refuelling stations was investigated by Emmerich et al. [32]. They found that trust in industry impacted both general and local acceptance, whereas trust in the municipality influenced local acceptance. Environmental self-identity increased general acceptance and decreased local acceptance, although the perception of degree of future climate problems did not significantly impact local acceptance. Hienuki et al. [33] assessed the effect of initiatives aimed at improving the awareness and acceptability of hydrogen technologies and showed that this is fostered by increased trust in the technology. D'Amore et al. [34] developed a multi-objective mixed-integer linear programming model to optimize CCS supply chains to identify adequate trade-offs between economic objective and acceptance and presented an example where a significant increase in acceptance could be obtained at an increased cost of 8%.

However, there still exist several knowledge gaps for the roll-out of hydrogen-CCS value chains. Examples of knowledge gaps are: 1) the lack of practical and systematic overview and guidance on how to undertake the steps of defining the scope, analyse gaps, identify risks and mitigation options, and set up business models for hydrogen-CCS value chains; 2) in-depth cross-cutting analyses of domestic energy system characteristics and how these shape common opportunities and challenges across neighbouring countries.

1.3. Focus and structure of the current work

We present in-depth case study investigations of hydrogen and CCS value chains in Germany, the United Kingdom, the Netherlands, Switzerland and Norway. Each study investigates national challenges and provides examples of methodologies that can be applied in an investigation. The challenges are primarily related to the technical assessment of hydrogen potential, and cost- and energy-efficient infrastructure development. We identify risks and barriers to consider in business case development, assess environmental issues, and provide recommendations on the rollout of hydrogen and CCS value chains.

The methodologies and subsequent case-related results are presented in Section 2, starting with potential future development of regional hydrogen markets. Moreover, we demonstrate the importance of deployment constraints and robust strategies for development of infrastructures for both hydrogen and CO_2. We provide insights into identifying

[1] It should be noted that whenever the term CCS is used, we assume permanent storage of the captured CO_2. Furthermore, permanent storage has been assumed in all cases where hydrogen production from natural gas has been considered in the current work.

risks and barriers of a business case through an illustrative example considering the UK. The assessment is undertaken using a newly developed business suite that systematically guides the users through defining the scope, analysing gaps, identifying risks and mitigation options, and initiating business models. Further, we show that the life-cycle emissions of hydrogen vary significantly with its production route and subsequent impact on the climate effect of hydrogen-fuelled vehicles.

In Section 3 we discuss common opportunities and the challenges of implementing hydrogen and CCS value chains across the case study countries to provide insights on key system enablers.

2. Assessing hydrogen and CCS value chain development

2.1. Estimating the potential for hydrogen

2.1.1. Sector-based analysis of hydrogen potential

In the following we outline main considerations in the German and Dutch contexts for sectors such as industry, transport, and building.

Across Europe, the industry stock currently uses hydrogen supplied by unabated fossil fuel-based production [35]. The provision of low-carbon hydrogen for these applications is a necessary step toward greenhouse-gas emissions reduction. In the German context, the current total hydrogen production rate of approximately 15 billion Normal cubic metres per year (Nm^3/yr.) requires decarbonization. Hydrogen can also be used in other sectors resulting in an additional hydrogen demand. In this context, the steel industry may play an important role [36]. Hence, the estimated additional hydrogen demand is based on the assumption that hydrogen will be used as a reducing agent in the steel industry from the beginning of the 2020s with subsequent replacement of blast furnaces by electric arc furnaces from 2025, reaching 50% replacement by 2035. A constant production rate of steel is assumed.

Future use of hydrogen in the Rotterdam port area is primarily determined by the energy-intensive industries of oil refining, petrochemical, and power generation. These industrial stakeholders were approached within the H-vision Project [37,38] for provision of detailed input used in this analysis. The focus of the Rotterdam analysis is hydrogen demand for high-temperature processes, such as furnace applications and gas-fired turbines. The detailed analysis revealed that the hydrogen consumption profiles strongly depend on the timing of process modifications and upgrades to the furnace for high-temperature heating processes, as well as the need for initial hybrid solutions to gain technical experience. Further, the anticipated electrification of oil refining production processes revealed a significant amount of surplus off-gas. Ultimately, the available off-gases constituted almost 90% of the hydrogen production feedstock needed to cover the estimated hydrogen demands. The remaining volumes of hydrogen will be produced from natural gas. The produced CO_2 in both hydrogen production processes is captured and permanently stored. Hydrogen demand for power generation was split into baseload demand from combined heat and power plants and flexible load stemming from flexible despatch of balancing services for power-generation plants. The analysis showed that by integrating the flexible demand into the total demand of the Rotterdam area, the overall flexibility demand attained a relatively low share of the total demand. This reduces the demand for storage capacity for hydrogen and thus reduces the overall cost of the hydrogen infrastructure.

For the German transport sector, a distribution factor was determined for hydrogen-powered cars, buses, trains, and trucks, each based on specific localized data. These factors include the current fleet numbers, mileage or passenger volumes, fuel consumption, the share of diesel vehicles, population density, federal financial aids, gross domestic product (GDP), and the income of consumers in the respective region. Using forecast data from a meta-analysis and the respective distribution factors, an allocation on the NUTS-3[2] level was made. The analysis of the German heating sector has focused on the existing district heating networks that are currently consuming fossil fuels. The analysis thus partially covers heating of the German building stock, in addition to low-temperature industrial heat demands. The use of hydrogen in households was not considered as it was assumed this would cause more safety and acceptance concerns than using district heating networks with hydrogen-fuelled combined heat and power plant (CHP) units. The potential hydrogen demand was determined by the location and size of fossil fuel-fired CHPs that could be replaced by hydrogen CHPs.

In Germany, the highest hydrogen demand is predicted for the industrial sector at 89 TWh/yr. in 2035. The maximum potential demand in this sector is estimated at 120 TWh/yr., when all blast furnaces are converted to electric arc furnaces with direct reduction. The heat and transport sectors have similar demand levels of 24.4 TWh/yr. for transport and 26.6 TWh/yr. for heat. The distribution of total hydrogen demand is shown in Fig. 1. For the transport sector, a maximum total potential hydrogen demand of around 60 TWh/yr.is estimated for the period after 2035 related to heavy-goods and long-distance transport applications. See also [39] for a comprehensive overview.

2.1.2. Holistic energy system analysis of hydrogen potential and other decarbonization measures

The role hydrogen could play in the transformation to net-zero greenhouse gas (GHG) emission societies may be assessed by taking a holistic view of the complete energy system. The following analysis was carried out in the context of the announcement made in 2019 by the Swiss Federal Council for reaching this target by the middle of the century [40]. Moreover, since January 2021 the net-zero target is explicitly stated in the Swiss long-term climate strategy [41]. Given the objective of net-zero GHG emissions, the analysis focuses on both hydrogen and CCS value chains.

The Swiss TIMES[3] Energy Systems Model – STEM [42] is based on the TIMES modelling framework of the International Energy Agency's Technology Collaboration Programme – Energy Technology Systems Analysis Program (ETSAP) [43]. STEM is a bottom-up cost optimisation framework suitable to assess the long-term transformation of the entire Swiss energy system. The model combines a longtime-horizon (2010 – 2050) with 288 intra-annual operating hours, comprising four seasons and three typical days per season with 24 hour resolution, to better capture the variability in energy supply and demand.

STEM was used for a long-term scenario analysis focusing on the role of hydrogen to decarbonise the transport sector and the other sectors of the Swiss energy system. The analysis considers two core scenarios, a Baseline scenario reflecting current trends and a Net-Zero scenario aiming at achievement of net-zero CO_2 emissions in the Swiss energy system by 2050. Variants of the Net-Zero core scenario were also examined, exploring the drivers to accelerate the use of hydrogen as energy carrier. The variants looked at the role of technical improvements in hydrogen infrastructure and use technologies through cost reductions. Targeted policies that bring forward the introduction of hydrogen in the Swiss energy mix were investigated, focusing on subsidizing hydrogen production and infrastructure funded by an increased tax on fossil-fuelled transport.

Fig. 2 shows a possible pathway toward net-zero emissions split by demand sectors. The emissions remaining in the Swiss energy system in 2050 are predicted to be mainly from industry, and are offset by electricity and hydrogen production via CCS in waste incineration plants, CCS in wood gasification and DACCS.

Approximately 8.6 Mt CO_2/yr. would need to be captured and stored in 2050 to achieve net-zero CO_2 emissions in the energy system alone,

[2] Nomenclature of territorial units for statistics.

[3] https://iea-etsap.org/index.php/etsap-tools/model-generators/times. The code is open source available at https://github.com/etsap-TIMES/TIMES_model.

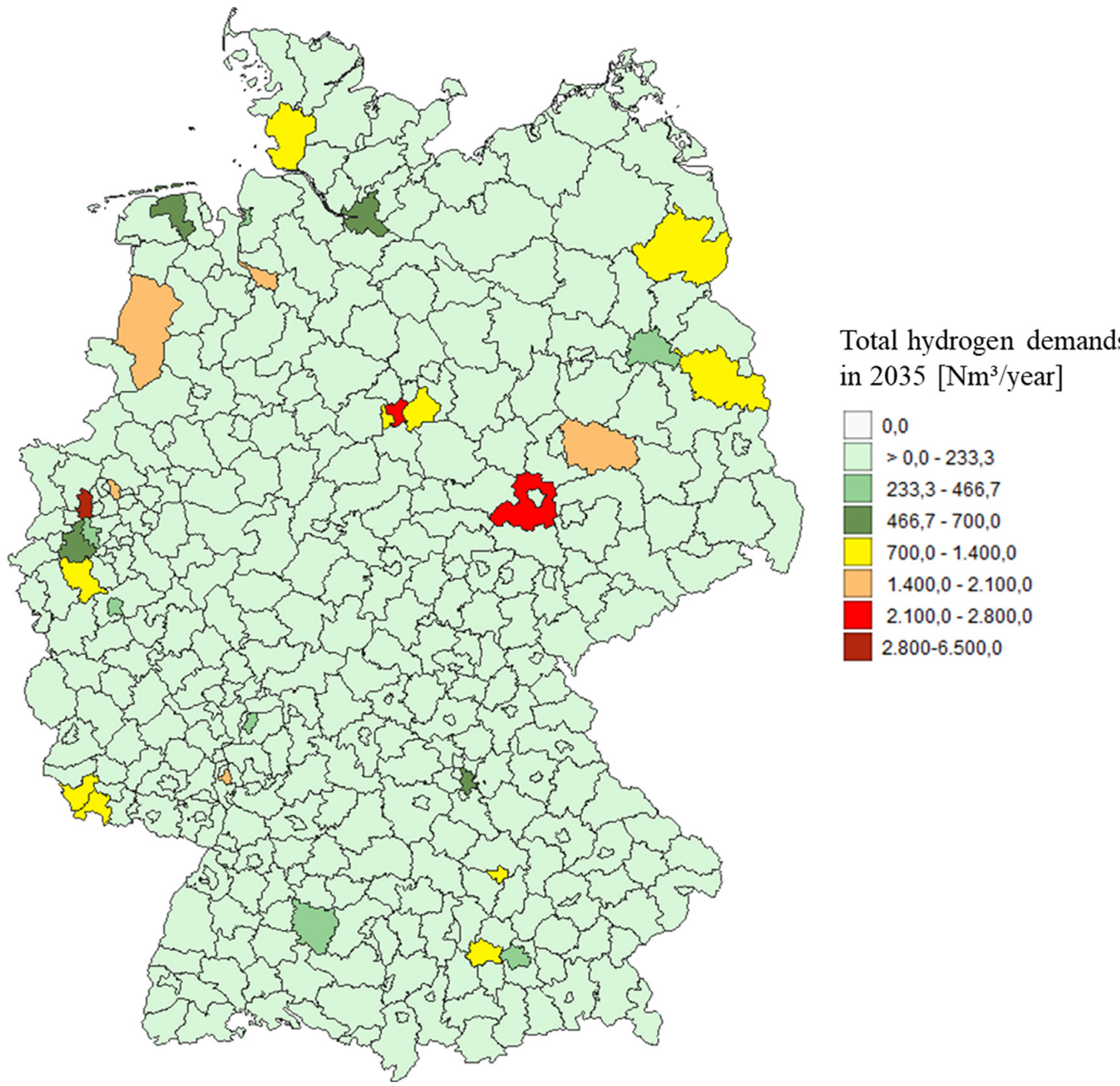

Fig. 1. Localized hydrogen demand for Germany in 2035.Based upon [39].

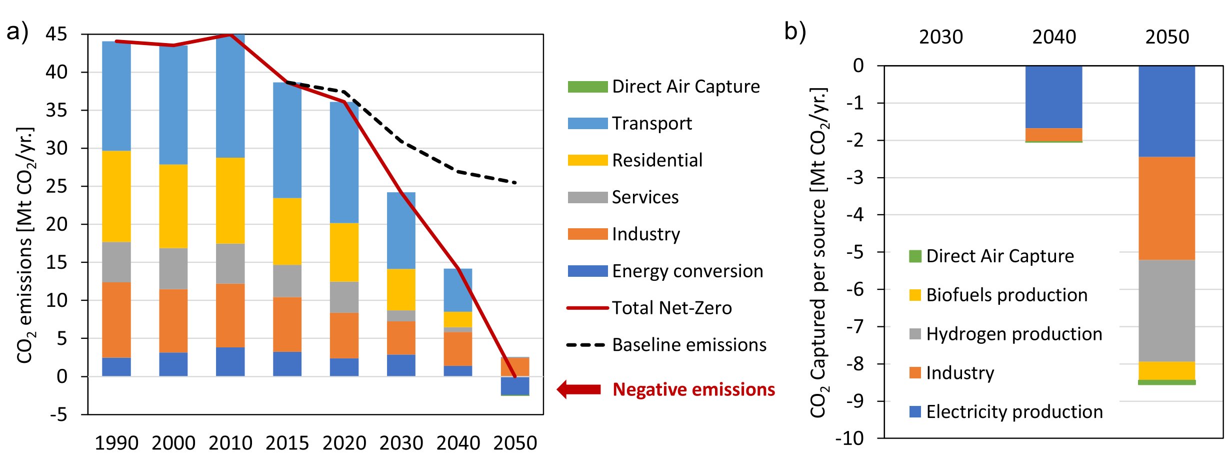

Fig. 2. Long-term analysis of emissions, Swiss case study: a) CO_2 emissions from fuel combustion (excluding international aviation) and industrial processes in the Net-Zero scenario; about 2.6 Mt CO_2/yr. are net negative emissions in 2050 offsetting emissions mainly from industry; the dashed line represents the emissions in the Baseline scenario. b) CO_2 captured from different sources to achieve net-zero in 2050.

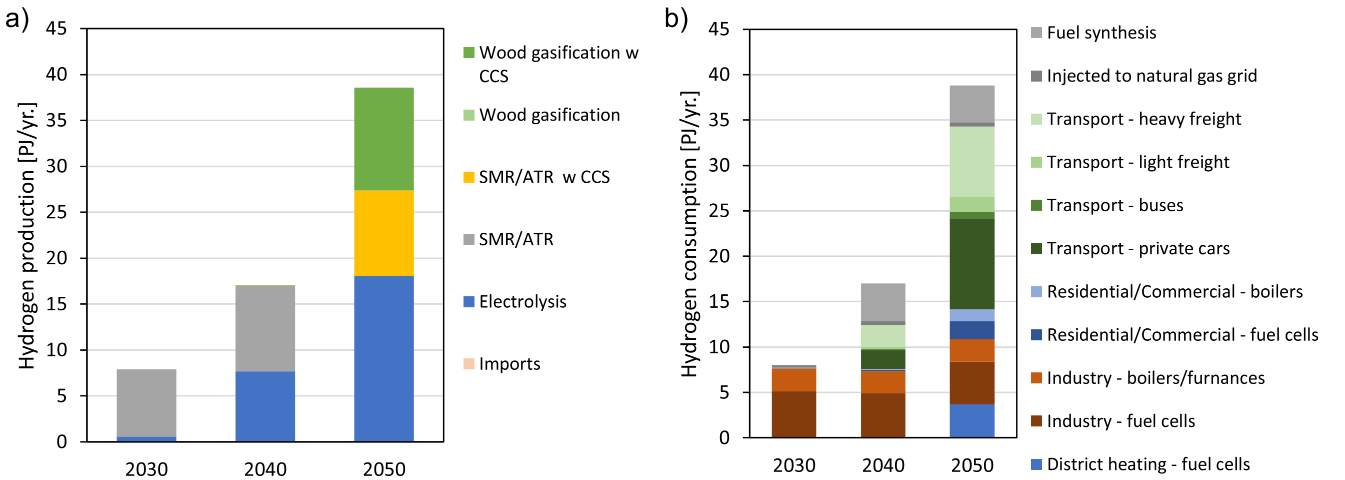

Fig. 3. Long-term analysis of hydrogen production and use, Swiss case study: a) hydrogen production in the Net-Zero scenario by technology. b) hydrogen consumption in the Net-Zero scenario by sector and application.

i.e., excluding agriculture, forestry, and international aviation. The sources of captured CO_2 are mainly municipal solid waste (MSW) incineration plants, industrial sources with CO_2 emissions captured from combustion and process-related emissions, and the production of hydrogen and bioliquids. Direct air capture is deployed as a backstop option at comparably low levels in 2050.

Taking a long-term perspective, hydrogen supply progressively shifts from first deployed natural gas-based methane reforming (steam-methane reforming (SMR)/autothermal reforming (ATR)) to hydrogen production by electrolysis using electricity generated by renewable sources, SMR/ATR using biogas from gasification as feedstock and wood gasification with CO_2 capture, see (Fig. 3a). SMR/ATR units will need to be equipped with CO_2 capture and storage by 2050 and natural gas as feedstock to be partly replaced by biomethane production, especially when deep negative emissions are needed. For scaling-up of hydrogen production from solid biomass, there are challenges related to biomass availability and the competition for this resource with other sectors in the energy system seeking carbon-neutral energy sources.

Electrolysis using renewable electricity generation and low carbon-based hydrogen as an energy carrier is of growing importance for a climate-neutral Swiss economy in 2050. A strong climate policy accelerates its deployment. However, the future success and timing of a hydrogen economy are highly dependent on technological developments and the achievable hydrogen technology performance. If long-term climate policy signals exist, some early investments in hydrogen technology in the industry sector around 2030 should replace decommissioning of current heating technologies, but as hydrogen use in transport scales up the hydrogen demand significantly increases during the post-2040 period (see Fig. 3b). The automotive applications constitute a key segment for the future of fuel cells, leading improvements that may spill over to other applications and carry forward infrastructure development. Heating of buildings using hydrogen-based technologies faces high upfront costs and strong competition with existing infrastructure. District heating micro-grids based on fuel cell CHP can be an option to provide hydrogen-based heat in building and industrial complexes. Hydrogen also plays an important role in the seasonal balancing of the Swiss energy system, via Power-to-X options. About one-fifth of the hydrogen produced by electricity by 2050, or 1.3 TWh, is modelled to be stored for interseasonal use. The required electrolysis capacity for interseasonal storage via Power-to-X options is about 320 GWh or 1.5 GW.

The development of hydrogen infrastructure is likely to be achieved in a stepwise manner, as in the gas and oil distribution analogue. Initially, local clusters could be formed around industrial sites and areas with relatively high hydrogen demand. In a second phase, local clusters are connected to form regional networks. In full-scale deployment of hydrogen, regional networks are connected, creating a nationwide infrastructure. However, as the variants showed, an early transformation of the Swiss energy system towards a hydrogen economy is unlikely in the absence of specific financial support. Even under extremely favourable technological developments in hydrogen-fuelled vehicles, hydrogen would only correspond to around 50% of Swiss transport sector with the remainder being electric private cars or electric and hybrid heavy vehicles. This outcome indicates the need for policies to help stimulate commercial demand for clean hydrogen and for proponents to demonstrate the feasibility of building on current developments.

If CO_2 storage in Switzerland cannot be realized at the required scale, a connection with European networks is a key requirement for the successful implementation of a net-zero scenario. Not having the option of capturing and storing CO_2 would have significant implications to achievement of the ambitious Swiss climate goals and associated costs. Access to transport and storage infrastructure across the EU and Norway would need international agreements and participation in projects of common interest enabling cross border CO_2 transport and storage infrastructure.

2.2. *Identifying constraints for development of hydrogen and CCS infrastructure*

2.2.1. *Investment in hydrogen production and storage*

Large-scale deployment of hydrogen and CCS necessitate significant infrastructure for production of hydrogen, capture of CO_2, and transport of gases, as well as temporary and permanent storage. In the context of decarbonization of heat and industrial decarbonisation by large-scale hydrogen production and CCS in the UK, a tool for optimisation of infrastructure has been applied to both local and national contexts to understand the inherent investment requirements [44][4]. In particular, the analysis has aimed to identify a cost-effective regional roadmap for decarbonising the use of domestic and commercial heat through the replacement of natural gas with hydrogen. At present, the UK uses approximately 460 TWh of heat from natural gas per year within the domestic and commercial consumer segments. The UK parliament passed a law in 2019 requiring net zero greenhouse gas emissions by 2050 and therefore this consumption of natural gas must be replaced with alternative energy carriers in a relatively rapid timeframe.

[4] The ELEGANCY chain tool, available at https://github.com/act-elegancy.

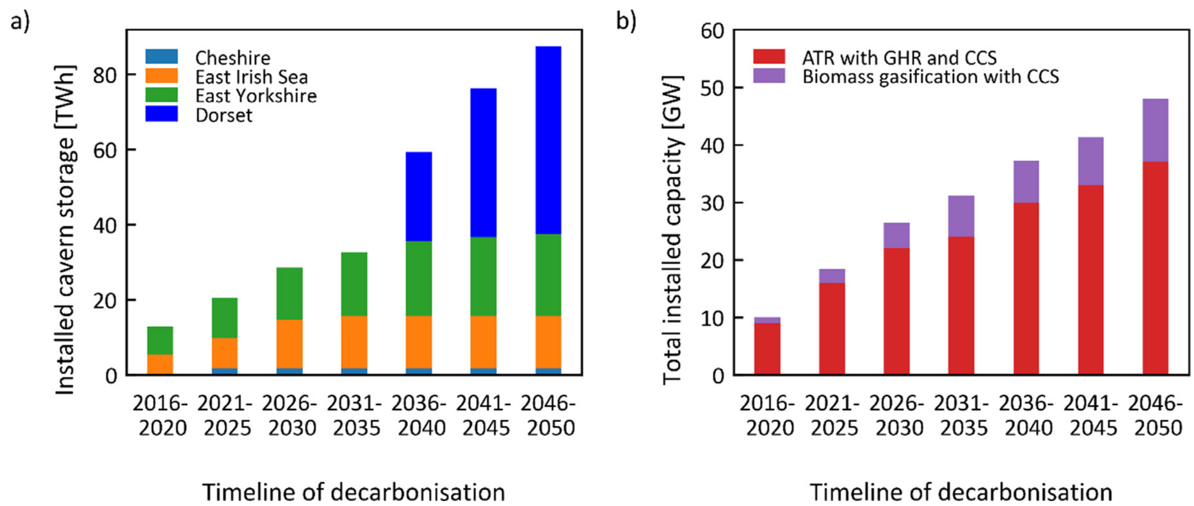

Fig. 4. The evolution of the installed capacity of a) hydrogen storage with time and b) production technologies.

The analysis on cost-effective decarbonisation of domestic and commercial heat has focused on the following questions:

1. What is the least cost, environmentally sustainable way to develop hydrogen and CCS infrastructure for the decarbonisation of domestic and industrial heat in the UK?
2. How do the regional factors influence the locations of production, transportation, and storage technologies? What are the most important factors on a regional basis?
3. What are the storage requirements for both hydrogen and CO_2 and does the UK have sufficient storage potential to support a methane-based reforming pathway?

The developed value chain tool comprises a mixed-integer linear program (MILP) based on the Resource Technology Network (RTN) framework. It has been developed in Pyomo with explicit definitions of key resources in addition to hydrogen production and CO_2 capture, along with transport and storage elements to provide a comprehensive description of the entire H_2 - CCS value chain. A detailed spatio-temporal analysis of the geographical region of UK is used to illustrate the key factors in the design of nation-wide H_2 - CO_2 infrastructure. Technological options such as SMR with CCS, ATR with CCS, water electrolysis and biomass gasification with CCS are compared to identify their potential and more importantly, to identify the conditions which influence the deployment of a particular technology over other options [44]. The overall system value of underground geological storage of hydrogen in salt caverns is also evaluated.

The value chain tool was used to analyse a variety of scenarios through the alteration of model parameters to:

- Quantify the optimal number of salt caverns needed for hydrogen storage, ensuring that the designs do not violate the maximum possible storage capacities within each region.
- Determine the cost-optimal technology mix when constrained by the lack of access to affordable hydrogen storage, reflecting the situation in regions which may not necessarily have suitable salt deposits for large-scale cavern storage.
- Develop a roadmap detailing the required technology and infrastructure investments to achieve net-zero CO_2 emissions.

The overall hydrogen storage requirements for cost-effective decarbonisation of domestic and non-domestic heat in the UK was approximated as 85 TWh, requiring over 800 caverns distributed across 4 key regions as shown in Fig. 4a). Current estimates of cavern storage capacity in the UK equate to approximately 6 TWh, under the assumption that natural gas caverns could be re-purposed to store hydrogen. Therefore, the estimated storage requirement by 2050 is an order of magnitude larger than present capabilities. Increases in the amount of available hydrogen storage capacity allows for a reduction in the total costs associated with the investment and operation of infrastructure.

The optimal production technology mix contains ATRs with gas heating reforming (GHR) and CCS in combination with biomass gasification with CCS to achieve a net-zero system as shown in Fig. 4b). Salt caverns are used to dispatch hydrogen at times of increased demand, allowing the reformers and gasifiers to operate at their design capacities with minimal operational variability.

Regions which do not have sufficient geological resources to facilitate cavern storage are reliant on the water electrolysis (WE) process to provide hydrogen at times of peak demand (shown in [44]). This is mainly due to the high operational flexibility offered by electrolysers in contrast to the limited operational envelope in conventional methane reformers. Importantly, WE has many parallels with the use of gas turbines in the power sector as it is only used at times of increased demand, with the methane reformers and gasifiers supplying baseload requirements. However, this may result in a largely idle WE assets depending on the demand for hydrogen. In this instance, approximately 100 gigawatts (GW) of WE capacity is needed to supply sufficient amounts of hydrogen at times of peak demand in the absence of cavern storage by 2050. The rate of deployment of WE units at these scales are yet to be realised. Furthermore, the supply of electricity for the WE process is likely to be sourced from the electricity grid, potentially necessitating expansions in the electricity grid and increasing the ancillary investments.

2.2.2. *Impact of transmission infrastructure on hydrogen costs*

Natural gas is a key export resource for Norway with the majority being exported to the EU and the UK [45]. With the climate neutrality ambition set by the EU, it is of foremost importance to identify robust strategies for Norway to provide clean energy, in the form of hydrogen, to support the decarbonisation of power, industry, and transportation in Europe. It is worth noting that the domestic hydrogen demand, in Norway, is however foreseen to be limited owing to the abundance of cheap, renewable electricity resulting in electrification of heating and, in recent years, the transport sector.

The identification of robust strategies to deliver clean hydrogen to Europe based on Norwegian natural gas was sought, taking account the following key questions:

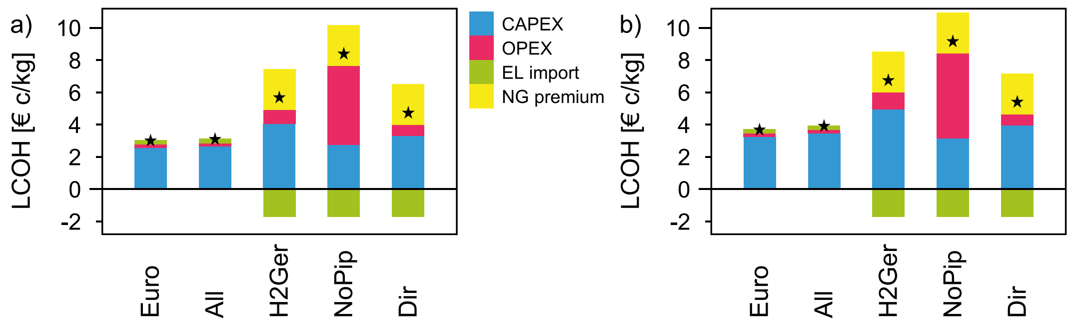

Fig. 5. Levelized costs of hydrogen (LCOH) for transport of CO_2 and hydrogen for a German hydrogen demand of a) 5 580 kt/yr. and b) 3 730 kt/yr. The star corresponds to the net costs.

- Is it beneficial to produce hydrogen in Norway and export the hydrogen or is it better to export natural gas, produce hydrogen in continental Europe, and import the captured CO_2 for storage on the Norwegian continental shelf?
- How does reusing the existing, extensive natural gas pipeline network affect the costs of hydrogen for the export market?
- How may limitations on offshore hydrogen and CO_2 transmission modes affect the locations of production facilities and investment in transmission technologies?

The chain tool, introduced in Section 2.2.1, was utilized for analysing the infrastructure development from the Norwegian continental shelf. Within the model, hydrogen could be produced by both electrolysers and ATR processes with carbon capture.

Simulations with different constraints regarding transmission options were carried out and analysed in the context of exporting hydrogen to Germany. Five scenarios where considered: 1) The Europipe natural gas pipeline could be converted for hydrogen export from Norway (Euro), 2) The Europipe pipeline is not available for hydrogen export (All), 3) it is not possible to export hydrogen from Norway to Germany (H2Ger), hence hydrogen production must take place in Germany, 4) it is not allowed to build any pipelines between Norway and Germany or convert any natural gas pipeline for hydrogen export, and hence, requiring ship transport (NoPip), and 5) like H2Ger, but direct storage from Germany to the continental shelf is allowed (Dir).

These evaluations were performed for both a German hydrogen demand of a) 5 580 kt/yr. and b) 3 730 kt/yr. The reported costs are for 2015 in Euro (€). The levelized cost of hydrogen is given for the Euro case as a) 1.54 €/kg and b) 1.55 €/kg, respectively. The key factors in the levelized costs are related to the natural gas costs (93.1 € c/kg hydrogen in Norway) and capital (26.3 € c/kg hydrogen) and operational costs (24.5 € c/kg hydrogen) for the reforming process. As the demand is fixed, the same production facilities consisting exclusively of autothermal reforming processes with carbon capture are observed in all cases. Similarly, the number of CO_2 injection wells are the same for a given demand as the amount of captured CO_2 is constant for a constant hydrogen production. Hence, it is more interesting to focus on differences in capital costs for the transmission infrastructure (blue), operational costs for the transmission infrastructure (red), costs for electricity import or export (green) and the natural gas premium to be paid in Germany (yellow).

Fig. 5 illustrates the results for the investigated cases for each hydrogen demand. In general, the production of hydrogen is cheaper in Norway. The reason for this is the reduced distance for CO_2 transport and avoiding the natural gas premium in Germany[5] despite receiving a profit for electricity export. As we can see, reutilizing Europipe does not reduce the costs significantly as its capacity is limited. Hence, it is necessary to construct a new pipeline in addition to converting Europipe (Euro vs. All). However, it was not investigated whether the conversion of Europipe might allow a cheaper development of the hydrogen export infrastructure. If it is not feasible to export hydrogen from Norway (H2Ger, NoPip, and Dir), it is in general preferential to transport the CO_2 in pipelines (H2Ger) than ships (NoPip). This is caused by the relatively short distance from Germany to Norway and the high transport volume of 50 Mt CO_2 (a) or 35 Mt CO_2 (b). Costs for production in Germany could be decreased further if it is feasible to directly transport the CO_2 from Germany to the injection wells without transporting it first to Norway (Dir vs. H2Ger). This reduces the required pipeline length by 15% and avoids the construction of landfalls on the Southern Norwegian coast, although it is still more expensive than producing directly in Norway.

Recent price changes in both energy, natural gas as well as electricity, and raw material will affect the presented values. However, we expect that the ranking of the investigated 5 scenarios will remain the same, as: 1. the used energy prices are based on production prices; and 2. the material requirement is, when excluding ship transport, similar as all scenarios use natural gas reforming with CCS for hydrogen production.

2.3. Addressing financial risks and investment barriers through business models

To ensure implementation and economic viability of H_2 - CCS chains, it is essential to develop suitable business models that address risks and barriers to investment. Indeed, unlike renewable energy entering mature electricity networks, H_2 - CCS infrastructure and its applications have not in general been supported by fit-for-purpose holistic ‘programmatic’ government interventions. In large part, this has been because of an inertia to commit to CCS as a climate mitigation technology. This in turn has created barriers to investment which extend beyond the business risks that an individual project may experience, even with government financial or fiscal incentives.

Building on the many years of experience in attempting to deploy large scale CCS infrastructure in European countries, a business model and business case development and assessment methodology, presented in the flowchart in Fig. 6, was created for selecting business models tailored to H_2 - CCS opportunities. A business case can be defined and assessed once a business model is selected. As business model preferences can change with changing business contexts, as well as with the maturity of a project, the combined selection and assessment process is iterative, but follows the same steps and analysis at fit-for-purpose levels of detail. This methodology is supported by an Excel toolkit [46].

The Business Model Development process is divided into four distinct steps:

Step 1: Definition of the scope of the particular H_2 - CCS chain for the relevant case study.

[5] Increased price in Germany due to costs associated with transport of natural gas from Norway to Germany.

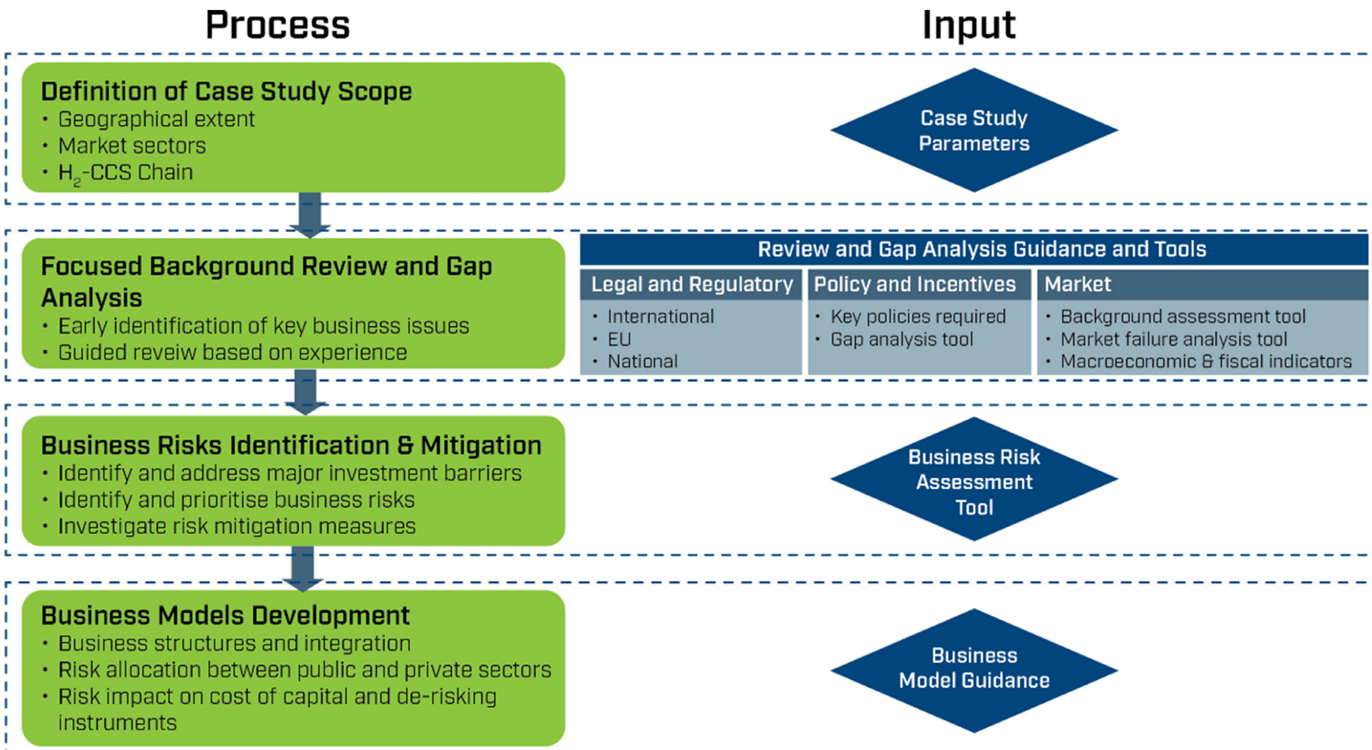

Fig. 6. Business Model Development Methodology adopted.

Step 2: Focused market and policy background review and gap analysis.

Step 3: Business and investment risk identification and mitigation.

Step 4: Business model development.

To create further clarity about business models the methodology differentiates between system or macroeconomic business models and business segment or micro-economic business models. System business models are the principal means for the mitigation of exogenous risks (including political, policy, social and outcome risks) that cannot in general be managed by the private sector alone and provide a macroeconomic solution that can overcome barriers to investment by both the public and private sectors into the various operational segments of a full chain H_2 - CCS infrastructure. Operational business models focus on the risks and delivery of the outputs and services for a particular business segment within the H_2 - CCS chain.

A business case assessment at the "concept definition" level was undertaken for the UK case study based on the H21 North of England Roadmap [47], which focuses primarily on residential and commercial heating with some possible industrial fuel switching. This assessment included a very detailed analysis of the strategic rationale, investment barriers and collaborative public-private system business model required for delivering the first phase of the H21 North of England Roadmap through to 2034. The recommendations from this case study provide guidance for an enduring government policy and support framework that can facilitate the further infrastructure build-out and investment optionality in subsequent phases of the H21 Roadmap. This system framework is also consistent with the techno-economic network modelling of heat decarbonisation of the entire UK presented in the Section 2.2.

The analysis of the public-private risk sharing for the H21 Roadmap [48] using the methodology and tools discussed above results in the recommended H21 system business model shown in Table 1 (Appendix A).

From this research the principal recommendations to create business conditions required to achieve the early stages of market creation and H_2 - CCS infrastructure roll out for cost-effectively decarbonising residential and commercial heating in the north of England, and to support further decarbonisation of the UK energy system, are:

1. A successful business case for H21 North of England requires a narrative supported by the public.
2. The UK 2050 Net Zero policy must be the overarching system strategic direction to evaluate all projects and technologies. The business case for H21 North of England should be defined and evaluated in the context of Net Zero policy and not in the context of separate strategies for decarbonisation of power, industry, heat, or transport.
3. A delivery body/organisation is required with a clear mandate to coordinate a collaborative UK system-wide business case and deployment across all regions and sectors. The UK has governance expertise for governing and delivering the H_2 - CCS system spread throughout several organisations including the Infrastructure Commission, the Infrastructure and Projects Authority, HM Treasury, Office of gas and electricity markets (Ofgem), the Low Carbon Contracts Company (LCCC), the Oil and Gas Authority (OGA), and the Health and Safety Executive (HSE).
4. Government will need to be responsible, with public sector intervention and participation, for creating and developing new low carbon markets and sustained demand for hydrogen and for CCS. Decision making will need to be based on the principles of low regrets and creation of real options at key points in time, not just at the initial first-of-a-kind infrastructure investments.
5. Any Net Zero pathway/business case needs to plan for the development and deployment of innovative carbon dioxide removal technologies (such as DACCS and BECCS) and markets because many emissions sources cannot be reduced to zero, leaving residual emissions in 2050.

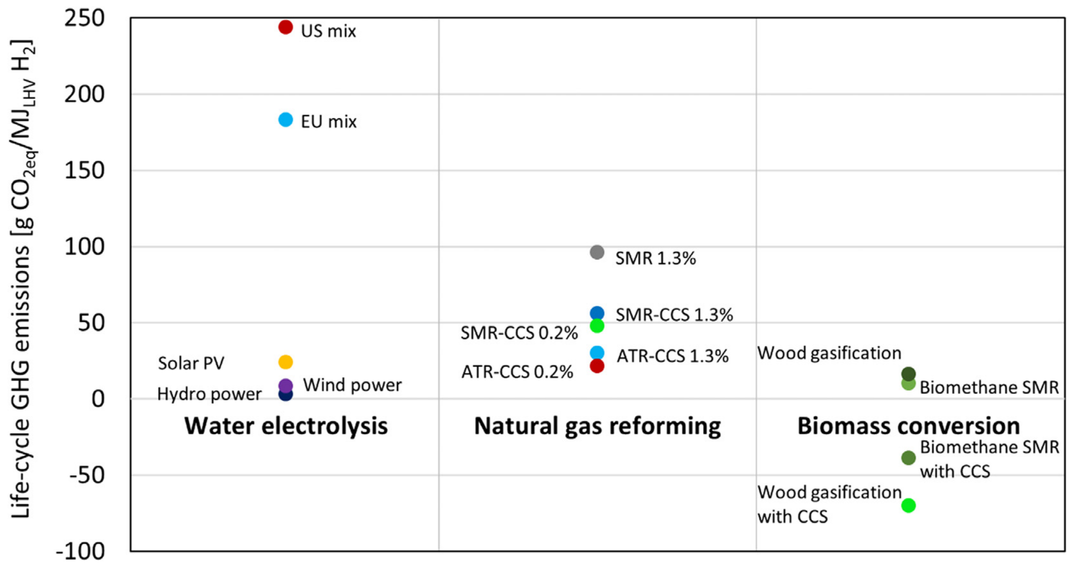

Fig. 7. Impacts on climate change in terms of life-cycle GHG emissions of hydrogen production, applying global warming potentials for a time horizon of 100 years. Adapted from [10,54,55,57]). SMR: Steam Methane Reforming[1]; ATR: Auto Thermal Reforming[2]. 0.2% and 1.3% indicate methane emission rates of natural gas supply chains with 1.3% being the current rate of average gas supply to Europe and 0.2% the goal of the international Oil and Gas Climate Initiative [10]. Markers for hydro, wind and PV power are calculated using typical GHG intensities of these power sources at central European locations. Figure Notes: 1 SMR-CCS with a CO_2 removal rate of 55%. 2 ATR-CCS with a CO_2 removal rate of 93%. SMR-CCS with the same removal rate will have similar life-cycle GHG emissions.

2.4. Using life cycle analysis to reveal the overall impacts on climate change of technology options

The use of hydrogen – for example in fuel cells – does not generate direct environmental burdens. However, since hydrogen is not a primary energy resource, but an energy carrier, which must be generated from primary energy resources, its production can be associated with (substantial) environmental burdens. Therefore, an evaluation of the environmental performance of hydrogen must consider the so-called "life-cycle perspective", i.e., any quantification of environmental benefits and potential trade-offs compared to alternative options must include hydrogen production as well as its use with all the required infrastructure and associated energy and material supply and disposal chains. Life Cycle Assessment (LCA) can be used to quantify a broad range of burdens and associated impacts on the environment, human health, and resource demand [49–51]. In this article, we only address impacts on climate change due to GHG emissions.

GHG emissions of low-carbon hydrogen production are determined by only a few key parameters. Notably the GHG intensity of electricity, particularly if water electrolysis is used [52,53], CO_2 removal rates at the hydrogen production facility as well as methane emissions from natural gas supply chains, if produced from natural gas in combination with CCS [10]; and biomass type, origin, and conversion route, if biomass is used as feedstock [54,55]. Fig. 7 provides an overview of GHG emissions associated with these hydrogen production pathways. In this context, the "low-carbon" threshold for GHG emissions of hydrogen production, as specified by the European CertifHy initiative, of 36.4 g CO_{2eq}/MJ_{H2} or 4.4 kg CO_{2eq}/kg_{H2} can be considered as an important benchmark [56].

Water electrolysis can only be considered as a low-carbon hydrogen production pathway, if major shares of electricity required for operating the electrolyser are provided by renewable sources, i.e. hydro, wind or photovoltaic power plants with associated GHG emissions of not more than around 60 g CO_2eq/kWh [10,52,53]. Hydrogen from reforming of natural gas with CCS only exhibits low carbon emissions if the vast majority of CO_2 generated at the production plant (in the order of 90% or more) can be captured and geologically stored and if natural gas supply chains exhibit methane emission rates of around 1% or less [10]. Such low methane emission rates, however, have not yet been achieved on average by major producers such as Russia and the US [10]. Viable biomass feedstock for low-carbon hydrogen production includes biogenic waste and biomass residues as well as forest from sustainable forestry. Induced land use changes need to be avoided, as those can be associated with substantial impacts on climate change due to, e.g., release of CO_2 and other greenhouse gases from decomposing biomass in soils. If viable biomass in combination with CCS is used, CO_2 can be permanently removed from the atmosphere [54,55] and such pathways can be considered as carbon dioxide removal options [58].

Using the LCA results of some of these hydrogen production pathways, life-cycle greenhouse emissions of an 18-ton truck for urban delivery with different drivetrains and fuel supply options today per ton-km of freight transport where quantified [59]. The resulting comparison is presented in Fig. 8. In practice, only minor reductions compared to conventional diesel trucks can be achieved with FCEV (Fuel Cell Electric Vehicle) using hydrogen from SMR (equivalent to the FCEV with "fossil fuel"). However, using hydrogen from an ATR with CCS allows for a GHG emission reduction of more than 50%, similar to FCEV using hydrogen from solar PV powered electrolysis. Using hydrogen from wood gasification in FCEV as well as BEV (Battery Electric Vehicle) charged with renewable electricity leads even to a slightly higher reduction of GHG emissions. The lowest life cycle greenhouse gases are generated by FCEV trucks using hydrogen from biomass-based hydrogen production chains with CCS. However, limited biomass resources and competing use options need to be considered in this context [60].

3. Adaptation of hydrogen and CCS value chains to seize national opportunities

3.1. Key drivers of the emerging hydrogen market and common features of opportunities for hydrogen and CCS value chains

Hydrogen is appealing for decarbonisation of the energy system as it can be used in all sectors and has no end use CO_2 emissions. However, an inherent challenge is the need for establishment of an infrastructure for hydrogen production, distribution, and storage where economies of scale can reduce investment costs. Hence, first movers are needed to establish initial deployment at scale. Our experience from undertaking studies in Germany, the Netherlands, the UK, Switzerland and Norway

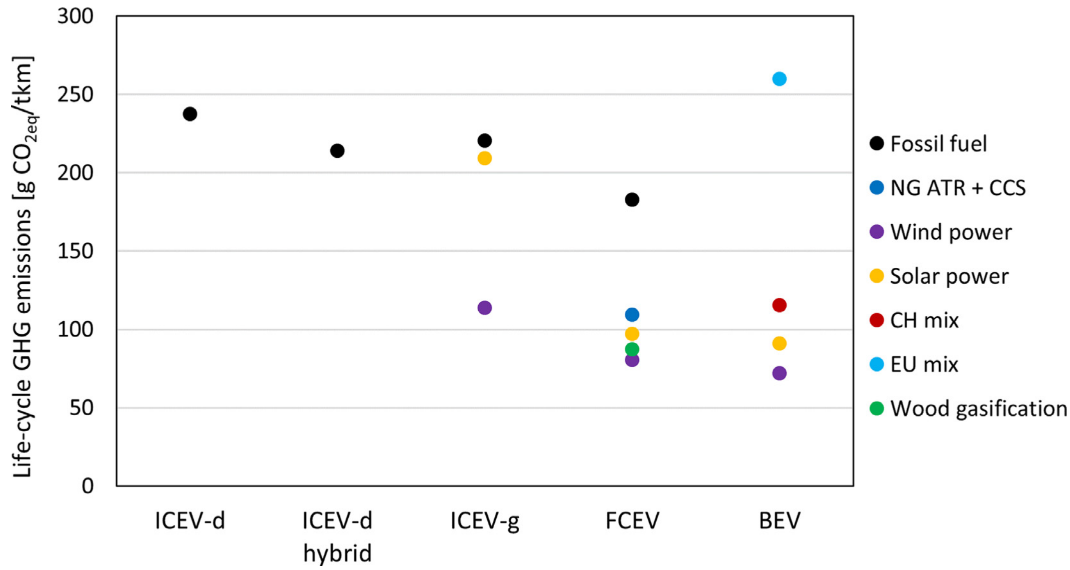

Fig. 8. Life-cycle GHG emissions of an 18-ton truck with different powertrains and across different fuel supply pathways for urban delivery today per ton-km, based on [59]. FCEV: Fuel Cell Electric Vehicle; BEV: Battery Electric Vehicle; ATR: Autothermal Reforming; CCS: Carbon Capture and Storage; ICEV: Internal Combustion Engine Vehicle; -d: diesel; -g: gas; CH and EU mix: average electricity supply in Switzerland and the EU.

is that the key sectors for use of hydrogen are, to a large degree, determined by national conditions.

- The industrial demand for decarbonization with corresponding cost competitive hydrogen-based solutions are key drivers in the Dutch, British, German and Swiss studies.
- In the UK, decarbonisation of domestic and commercial heating is a central driver since 85% of the buildings are connected to the gas network. This is a sector with inherent need for energy storage and flexibility to accommodate seasonal variation in energy demand, which must be addressed by the developed hydrogen infrastructure.
- In Switzerland, the freight transport sector is the second key sector for hydrogen market development. Conversely, industrial demand for hydrogen as a low-carbon fuel could pave the way for hydrogen use in the transport sector in Germany.
- Hydrogen also has an important role in the seasonal balancing of the Swiss power system via Power-to-X options.
- The Norwegian energy system has a high share of hydro power and extensive domestic electrification. Export of hydrogen, to Europe and beyond, is thus a key driver for hydrogen production based on domestically produced natural gas.

A more comprehensive overview of the national studies can be found in Appendix B.

Common observations among the studies are that:

- Hydrogen production via natural gas reforming with integrated CCS enables cost-efficient deployment of large-scale transport infrastructure for hydrogen and CO_2.
- Integrated hydrogen and CCS infrastructures enables permanent storage of CO_2 captured from the air or from biomass and hence facilitates compensation for emissions that are almost impossible to avoid.
- Collaboration across international borders is in many cases necessary for the realization of national business cases.

The low regret deployment scheme for large-scale hydrogen and CO_2 infrastructure in the UK study was a phased approach where the first phase included deployment of a modular ATR at scale with integrated CCS. The produced hydrogen would be used in domestic appliances upgraded to handle up to 20% hydrogen admixture in the natural gas grid, in industrial clusters with replacement of natural gas with minimum CAPEX (Capital Expenditure) and in Combined Cycle Gas Turbines (CCGTs) adapted to combustion of up to 90% hydrogen blended with natural gas. In the Netherlands, re-use of a gas infrastructure for low-calorific gas poses a possibility for establishing a national hydrogen backbone [61]. The backbone could be used to transport hydrogen produced from both natural gas with CCS and offshore wind via electrolysis. Decarbonization of the German gas infrastructure is recommended to be initiated by establishing a dedicated hydrogen pipeline infrastructure connecting areas with large hydrogen demands [39]. The hydrogen pipeline will initially primarily transport hydrogen imported from Norway which is produced from natural gas in plants with integrated capture of CO_2 and permanent underground storage in the North Sea Basin. The dedicated hydrogen infrastructure would facilitate the distribution of hydrogen produced domestically from renewable sources as it increases in volume.

True net-zero greenhouse gas emission economies rely on technologies that can remove CO_2 from the atmosphere in order to compensate for emissions that are almost impossible to avoid, for instance in agriculture. Removing CO_2 from the atmosphere can be achieved by applying carbon dioxide removal (CDR) technologies such as Direct Air Capture with subsequent permanent storage of the CO_2 (DACCS) or by appropriate processing of biomass, for example via combustion and post-combustion CO_2 capture, fermentation of biogenic waste to biogas or biomass gasification with subsequent reforming and CO_2 capture. All four technologies rely on transport and permanent storage of CO_2. The latter two options further necessitate infrastructure for hydrogen distribution and appliances. The establishment of integrated H_2 - CCS value chains thus facilitates deployment of CDR technologies, including hydrogen production using biogenic feedstock combined with CCS.

Cross-border collaboration was identified as essential in the Swiss study owing to the need for CO_2 transport to storage sites beyond Switzerland, for example to the North Sea basin storage sites, at the early stages of hydrogen deployment. Offshore storage in the North Sea basin is also highly relevant in the German context, and in the current study permanent storage on the Dutch continental shelf was considered. Further, hydrogen imported from Norway is assumed to supply the dedicated hydrogen pipeline in Germany.

3.2. Observed main challenges for establishing hydrogen and CCS value chains

A common finding of the case studies is that the development of the hydrogen market will require government intervention at country and EU levels. Infrastructures for distribution and use of hydrogen, as well as for transport and storage of CO_2, cannot be deployed in incremental steps and are investments with long time-horizons of more than 20 years. There is a clear expressed need for coordinated planning, governance, and decision-making frameworks.

A key recommendation from the UK perspective is to establish a delivery body/organization with a clear mandate to co-ordinate the national system-wide business case; all regions and sectors to use the principles of low regrets and creation of real options characterised by flexibility to follow different investment pathways and technologies as the markets and system evolve. All decarbonization investment projects must be assessed against the contribution to net zero emissions at system level, and the establishment of a hydrogen market will provide solutions for all sectors of the energy system. [62]

A macroeconomic assessment of options for decarbonizing the German gas infrastructure showed that deployment of CO_2 pipelines for transport of CO_2 from German onshore point source emitters to offshore storage sites depends strongly on involvement of political decision makers and societal acceptance. This to a much higher degree than the options of blending hydrogen into existing natural gas pipelines and transporting hydrogen in dedicated pipelines. The latter option was seen to primarily depend upon a suitable legal regime for hydrogen pipelines and industry hot spots that created infrastructure synergies [39].

A review of the Swiss conditions identified key system-level investment barriers were related to policies and regulations. Despite the existence of a technology-neutral climate policy framework with carbon pricing since 2008, a set of limitations in the framework must be overcome to incentivise the use of hydrogen and CCS chains. These limitations include: the legal basis for permitting technical CO_2 sinks such as geological permanent storage; qualification of the sources of hydrogen for domestic environmental added value compensation; sufficient carbon levy and ETS price levels to incentivize hydrogen production with CCS [63].

Investigation of the technical and financial feasibility of deployment of hydrogen production with CCS to decarbonize industry in the Rotterdam port area showed that long-term uncertainties in the commodity and greenhouse gas emissions prices significantly impact the business case. Further, public support, such as contracts for differences, risk-bearing loans or subsidies, were found necessary [64].

An EU-wide effort is needed to simplify the legislative pathway for hydrogen and CCS value chains [39]. Issues of high importance are:

- The provisional application of the 2009 amendment to the London Protocol.
- Ordinance of pipeline safety and major accidents for CO_2 pipelines.
- Clarification of the relationship between the EU CO_2 Emission Trading System and transport by shipping.
- Regulation of the hydrogen market should be developed at an early stage.
- If guarantees of origin for hydrogen produced from renewable sources are implemented, similar incentives should be considered for hydrogen from natural gas with associated CO_2 emissions, of comparable value to renewably based hydrogen.
- For dedicated hydrogen pipelines the demarcation of other regimes, such as for natural gas and power storage, should be clarified.
- A legally reliable financing framework for dedicated hydrogen pipelines should be created.
- For re-purposing of natural gas pipelines to transport hydrogen a legal mechanism to facilitate the handling of existing legal relationships must be established.

4. Conclusions

The urgency to achieve net-zero CO_2 emissions, as first presented by the IPCC special report on 1.5 °C Global Warming, has spurred renewed interest in hydrogen to complement electrification for widespread decarbonization across all energy sectors. The potential use of hydrogen, and inherent benefit of establishing linked hydrogen-CCS value chains, is thus best assessed in the context of energy system transformation to reach net-zero climate targets. The business case opportunities rely on the public governing bodies playing an active role in facilitating the creation of a hydrogen market and the required infrastructure. Hydrogen and CCS systems are highly attractive in the context of reaching climate neutrality by 2050, and can be seen as complementary to hydrogen production by electrolysis. However, under current policy and regulatory frameworks the business cases are fragile. There is also a need for an EU-wide effort to simplify the regulatory pathway for hydrogen and CCS value chains.

Deployment of linked infrastructure requires substantial up-front investment with long term benefits, which necessitates centralised national coordination. The business case further relies on sufficient scale and cost-optimal infrastructure deployment and utilization. In this context, hydrogen production through methane reforming (ATR/GHR) combined with CCS for large scale deployment in the industrial sector is at the heart of business cases across Europe. Furthermore, hydrogen is predicted to become important for the transport sector in the longer term. Detailed assessment of techno-economic conditions is essential to address the timeline for transition and hydrogen demand for industry clusters and transport applications. Regional conditions and the long-term need for carbon dioxide removal technologies could similarly be essential to identify optimal deployment pathways for hydrogen and CCS infrastructure. Further, collaboration across international borders has been identified as important for successful implementation of national business cases.

Based on these findings we suggest prioritizing the following points in future work:

- Enhance methodologies and tools for detailed integration analysis and optimization of hydrogen applications and production units and hydrogen and CO_2 infrastructure at industrial clusters. Such clusters constitute key opportunities for hydrogen and CCS value chains but tend to be complex owing to the wide variety of component processes and plants.
- Convert the transport sector away from fossil fuels to hydrogen, which is of particular interest for the transport of heavy-goods. There is a need to establish increased understanding of the transport sector energy demand at high geospatial and time-resolutions, optimal infrastructure for supply of hydrogen and electricity and efficient integration into an overall energy system.
- Investigate the role of hydrogen value chains beyond short-term energy markets to, for example, assess the importance of seasonal energy storage.
- Address the key challenge of insufficient economic investment incentives by surveying the requirements for financial support policies to attract private- and public-sector investments in hydrogen and CCS value chains.

Appendix A. A system business model for the H21 North of England

Appendix B. Approaching opportunities for hydrogen and CCS in the Netherlands, Germany, Switzerland, the United Kingdom and Norway

In the following we provide an overview of the business opportunities for hydrogen and CCS chains that have been explored for cases in the Netherlands, Germany, Switzerland, the United Kingdom and Norway.

The objective of the Dutch case study was to identify how the Rotterdam industry can be significantly decarbonized through the introduction of clean H_2 as raw material and energy carrier for its base industries and utilities, CO_2 capture at large single point emitters, CO_2 offshore storage and CO_2 utilization. The Port of Rotterdam is the largest seaport in Europe and its industrial cluster mainly includes oil refining, (petro)chemical and power industries, all energy- and CO_2-intensive. At national level, the CO_2 emission reduction targets for 2030 is set at 49% compared to 1990, which poses a significant challenge for the industry sector to develop towards CO_2 neutrality. For the oil refining and (petro)chemical industries the use of hydrogen for high temperature heating is attractive. Hydrogen will substitute the use of refinery associated gases and fuels, which can be transformed into hydrogen with low related emissions if the produced CO_2 is captured. The proposed approach constitutes a significant part of the business case for hydrogen in the Rotterdam port. In the business case development, early assessment of the factors that are needed for a sound business case was essential. The assessment included the project scoping and ownership structure, public perception, changing economics, emission reduction, and CAPEX estimates and was carried out in the H-vision project spun out from the case study. The identified risks in all phases of the project approach were categorized using the ELEGANCY business case development and assessment methodology, and mitigations were proposed. Especially the long-term uncertainties about commodity and CO_2 emission prices constitute a significant obstacle to get the Dutch case study in Rotterdam started. They have a substantial impact on the business cases for low-carbon hydrogen, and switching from the traditional CO_2 intensive energy feedstocks is expensive and with significant risks. Furthermore, hydrogen production and distribution infrastructure are capital intensive, and such investments are difficult to rationalize without a long-term outlook on hydrogen demand. A public-private collaboration was thus proposed to mitigate risks.

The German gas infrastructure is well developed and serves the industry, power, residential and commercial sectors. As a contribution to decarbonization of the gas infrastructure, the German case study has assessed different infrastructure options for an integrated H_2 - CCS chain. The first option is to establish a CO_2 network for offshore CO_2 storage in the Netherlands. For transport of hydrogen two options are considered: blending of hydrogen into the natural gas grid and the creation of a dedicated hydrogen pipeline system. An analysis of the three options was carried out that included technical, macroeconomic, legal and sociological aspects. The technical analysis describes the modelling of infrastructure options and shows the CO_2 avoidance and costs. In total, with all three options combined in a best case over 100 $MtCO_2/yr.$ can be abated. From a macroeconomic perspective, the infrastructure options are assessed in terms of their economic and political feasibility focusing on (1) complexity, (2) non-economic aspects, (3) uncertainty, and (4) stakeholders. By doing so, factors that foster or hinder a successful implementation of a German infrastructure are identified. The legal framework for the infrastructure options was analysed with a focus on the provisions for the construction and operation of the respective pipelines, the interaction between infrastructure, law and markets as well as the overall quality of the legal regime. Based on this analysis, the legal research identified the risk and hurdles for the infrastructure options that are connected to the legal framework and discussed possible remedies and their feasibility. From a sociological perspective, social acceptance of the options as well as of hydrogen and CCS technologies were examined. To analyse acceptance, qualitative interviews with relevant stakeholders and a quantitative survey with people living in Germany were performed. The results indicate that there is a high potential for acceptance, but this depends on factors such as fields of application, energy sources and procedures, which should be considered in the implementation phase.

The Swiss case study has clearly shown that the ambition to reduce its GHG emissions to net-zero by the middle of the century – as announced by Federal Council in 2019 – can only be achieved by (i) decarbonizing the demand sectors and (ii) deploying CCS. Hydrogen plays a dual role: it can be a clean energy vector for the freight transport sector, industrial heat and power generation, and it allows to generate negative CO_2 emissions when produced from bio-gas reforming or biomass gasification. The annual volume of CO_2 storage will be more than 9 Mt by the middle of the century. Studies whether a substantial part of this can be stored in Switzerland are inconclusive at this point. A connection to a European CO_2 transport and storage infrastructure is therefore of paramount importance.

Decarbonization of building stock heating has been the main focus in the UK case study. Appraisal of UK greenhouse gas emissions reduction by conversion of residential and commercial heating to combustion of hydrogen was recognised as an option in 2018 [65]. In 2016, large-scale conversion of the gas supply network to 100% hydrogen was investi-

Table 1
Example system business model for the first phase of the H21 North of England Roadmap (see also [57]).

	Conceptual System Business Model	Asset & Rights Ownership	Capital Sourcing	Market Development		Physical Delivery	
				Responsibility	Remuneration	Responsibility	Business Structure
H_2 INFRASTRUCTURE	H_2 Production with Integrated CO_2 Capture	Private	Private	Public	Targeted Revenue Support	Private	Free Market Enterprise
	H_2 Transmission	Private	Private	Public	Price Regulated Revenue + Construction Support	Private	Regulated Asset Base (New)
	H_2 Distribution	Private	Private	Public	Price Regulated Revenue	Private	Regulated Asset Base (Existing)
	H_2 Storage	Public	Private	Public	Performance Based Revenue	Private	Public Concession (Design-Build-Finance-Operate)
CO_2 INFRASTRUCTURE	CO_2 Transmission	Joint	Joint	Public	Price Regulated Revenue	Private	Joint Venture
	CO_2 Storage	Joint	Joint	Public	Price Regulated Revenue	Private	Joint Venture
H_2 END USE MARKETS	Industry	Private	Private	Public	Targeted Revenue Support	Private	Free Market Enterprise
	Centralised Heat & Power	Private	Private	Public	Targeted Revenue Support	Private	Free Market Enterprise

gated and found to be feasible for three large UK cities with the first phase conversion using steam methane reformers sited at Teesside [48]. In 2018 the H21 North of England industry project [47] progressed detailed planning and outlined concepts and designs for decarbonisation across the north of England as preparation for establishing a longer term hydrogen-based decarbonisation pathway. The updated H21 plans are intended to supply 14% of UK heat from natural gas-based hydrogen production at Teesside, with 8 TWh of hydrogen storage and operate a CO_2 transport and storage network at up to 20 Mt CO_2/yr. The ambition for industry CO_2 emissions reduction by CCS has also increased both at the Teesside [66] and nearby Humberside [67] industrial clusters. The UK case study anticipated the requirement for greater CO_2 storage capacity by plotting industry aspirations for decarbonisation of heating by hydrogen reformation with CCS for two industrial clusters. Storage options were identified, and injection operations were simulated to securely contain CO_2 for the H21 North of England Project and industrial decarbonisation at Teesside. Furthermore, the operation of multiple CO_2 injection sites operated by two or more CCS projects within the same offshore hydraulically connected formation were investigated. A first provision of the UK theoretical potential capacity for hydrogen storage in new salt caverns was estimated and found to significantly exceed the projected storage requirements for the gas industry H21 Projects [47,48]. A UK-wide least-cost infrastructure was modelled, integrating the hydrogen and CO_2 storage capacity estimates, and a cost-optimal technology mix. Finally, the ELEGANCY business case tools were applied to the first phase of the H21 North of England Roadmap.

Due to the small size of the Norwegian domestic energy system, the main possibility for hydrogen from a Norwegian perspective is for export to Europe by nearly an order magnitude, although a certain domestic potential exist for the decarbonisation of offshore oil and gas platforms. Analyses were carried out to understand how hydrogen, produced based on Norwegian natural gas with CCS, should be delivered to the European market. The techno-economic optimisation of hydrogen with CCS deployment for different scenarios highlight that producing hydrogen in Norway is, in general, cheaper and that hydrogen transport to Europe via pipeline, especially if natural gas pipeline can be reused, is more cost-efficient. The techno-economic optimisation approach adopted allow to better identify robust strategies for development of H_2 - CCS value chains and what impact them. However, it is also important that these approaches are heavily dependent on the quality of input data considered and that detailed evaluations may also be required to provide enough accuracy for meaningful decision support in some cases.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

A subset of data and models are open/can be made available upon request.

CRediT authorship contribution statement

Gunhild A. Reigstad: Conceptualization, Funding acquisition, Project administration, Writing – original draft, Writing – review & editing. **Simon Roussanaly:** Conceptualization, Formal analysis, Supervision, Validation, Writing – original draft, Writing – review & editing. **Julian Straus:** Conceptualization, Formal analysis, Methodology, Software, Validation, Visualization, Writing – original draft, Writing – review & editing. **Rahul Anantharaman:** Conceptualization, Formal analysis, Funding acquisition, Supervision, Writing – review & editing. **Robert de Kler:** Conceptualization, Data curation, Investigation, Methodology, Project administration, Writing – original draft. **Maxine Akhurst:** Conceptualization, Funding acquisition, Project administration, Writing – original draft, Writing – original draft, Writing – review & editing. **Nixon Sunny:** Data curation, Formal analysis, Investigation, Methodology, Software, Validation, Writing – review & editing. **Ward Goldthorpe:** Writing – original draft, Writing – review & editing. **Lionel Avignon:** Writing – original draft, Writing – review & editing. **Jonathan Pearce:** Formal analysis, Investigation. **Stefan Flamme:** Investigation, Methodology, Visualization, Writing – original draft, Writing – review & editing. **Gianfranco Guidati:** Writing – original draft. **Evangelos Panos:** Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Writing – review & editing. **Christian Bauer:** Formal analysis, Funding acquisition, Project administration, Resources, Visualization, Writing – original draft.

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