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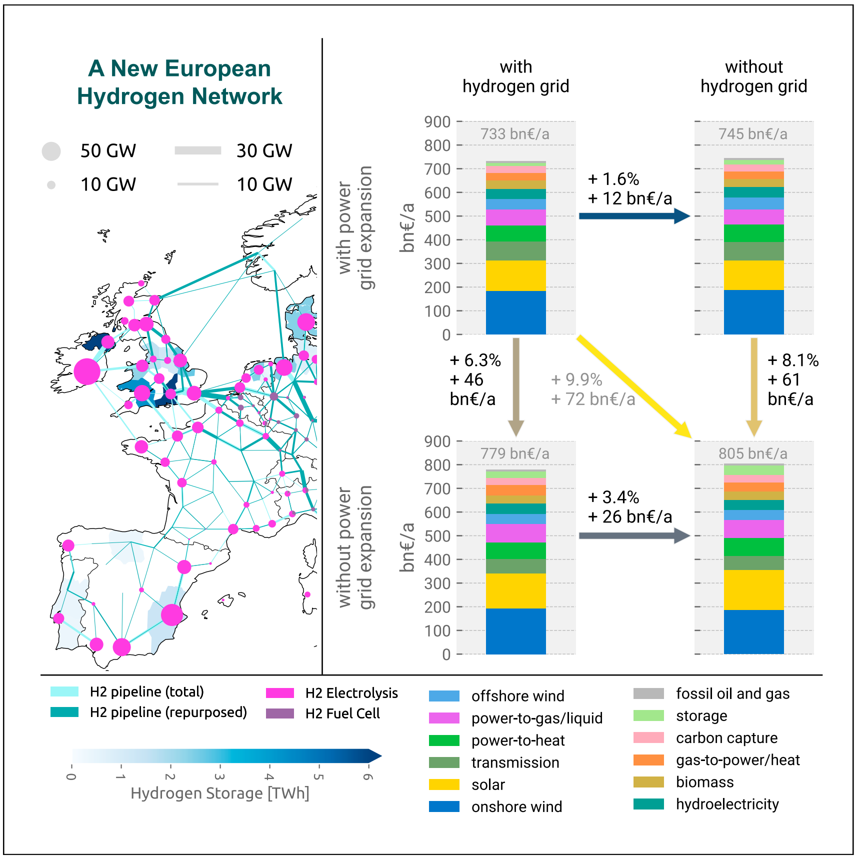

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Highlights

Examination of the cost benefit of a European hydrogen network in net-zero emission scenarios

H_2 network reduces system costs by up to 3.4%, highest without power grid expansion

Between 64% and 69% of the hydrogen network uses retrofitted gas network pipelines

Power grid expansion saves more than hydrogen network, but strongest savings with both

We examine the interplay between a continent-wide hydrogen network and electricity grid expansion in Europe to help balance variations in wind and solar energy supply. By adapting existing natural gas pipelines for hydrogen transport, energy system costs can be reduced, especially when power grid reinforcements are not possible. Both types of transmission infrastructure offer cost-effective options for achieving a European energy system with net-zero CO_2 emissions. However, with a 10% cost increase, it is possible to build neither.

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Article

The potential role of a hydrogen network in Europe

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SUMMARY

Europe's electricity transmission expansion suffers many delays, despite its significance for integrating renewable electricity. A hydrogen network reusing the existing gas network could not only help to supply the demand for low-emission fuels but could also balance variations in wind and solar energies across the continent and thus avoid power grid expansion. Our investigation varies the allowed expansion of electricity and hydrogen grids in net-zero CO_2 scenarios for a sector-coupled European energy system, capturing transmission bottlenecks, renewable supply and demand variability, and pipeline retrofitting and geological storage potentials. We find that a hydrogen network connecting regions with low-cost and abundant renewable potentials to demand centers, electrofuel production, and cavern storage sites reduces system costs by up to 26 bn€/a (3.4%). Although expanding both networks together can achieve the largest cost reductions, by 9.9%, the expansion of neither is essential for a net-zero system as long as higher costs can be accepted and flexibility options allow managing transmission bottlenecks.

CONTEXT & SCALE

Many different combinations of infrastructure could make Europe carbon neutral by mid-century, but not all solutions meet the same level of acceptance. For example, power grid reinforcements have faced many delays, despite their value for integrating renewables. A hydrogen network reusing gas pipelines could substitute for moving cheap but remote renewables across the continent to where demand is.

We study trade-offs between new transmission lines and a hydrogen network in the European energy system with net-zero CO_2 emissions. We find that a hydrogen network consistently reduces system costs and that large parts could reuse gas pipelines. Energy transport as electrons and molecules offers complementary strengths, achieving the highest cost savings together. However, neither is essential as long as the system can be coordinated around the resulting bottlenecks. This reveals many affordable ways to achieve net-zero emissions in Europe, giving policymakers different options to choose from.

INTRODUCTION

There are many different combinations of infrastructure that would allow Europe to reach net-zero greenhouse gas emissions by mid-century.[1] However, not all technologies meet the same level of acceptance among the public. The last few decades have seen public resistance to new and existing nuclear power plants, projects with carbon capture (CC) and sequestration (CCS), onshore wind power plants, and overhead transmission lines.[2–4] The lack of public acceptance can delay the deployment of a technology or even stop its deployment altogether.[5] This may make it harder to reach greenhouse gas reduction targets in time or cause rising costs through substitution with other technologies. In particular, electricity transmission network expansion has suffered many delays in Europe in recent decades, despite its importance for integrating large amounts of renewable electricity and electrifying the transport, building, and industry sectors.[6,7]

Hydrogen has the potential to become a pivotal energy carrier in such a climate-neutral energy system.[8,9] It is needed in industry to produce ammonia for fertilizers and can be used for direct reduced iron for steelmaking.[10,11] It is also a critical feedstock for producing synthetic methane and liquid carbonaceous fuels for use as aviation and shipping fuels and as a precursor to high-value chemicals in industrial production.[12] Hydrogen could also be used for heavy-duty land transport and backup heat and power supply.[13,14]

The limited social acceptance of electricity grid reinforcement and the advancing role of hydrogen raise the question of whether a new hydrogen network could offer a replacement for balancing variable renewable electricity generation and moving energy across the continent.[15] Such a vision for a European Hydrogen Backbone (EHB) has recently been expressed by Europe's gas industry in a series of reports.[16–19] It would offer an alternative to connect remote regions with abundant and cost-effective wind and solar potentials to densely populated and industry-heavy regions with high demand but limited supply options.

Since Europe's sizable natural gas transmission network is set to become increasingly redundant as the system transitions toward climate neutrality, the option to repurpose parts of the network to transport hydrogen instead may enhance the appeal of hydrogen networks further. This is because retrofitting gas pipelines would greatly reduce the development costs of hydrogen pipelines.[20,21] Moreover, repurposed and new pipelines may also meet higher levels of acceptance among the local populations than transmission lines.[22] Unlike transmission towers, pipelines are less visible because they usually run below or near the ground. Particularly where gas pipelines already exist, the perceivable impact would be minimal.

However, few studies have looked into how much building a hydrogen network in Europe could reduce system costs. The industry-oriented EHB reports do not include an assessment based on the co-optimization of energy system components.[16–19] Other sector-coupling studies have not included hydrogen networks at all,[1,23–25] or when they do, they model Europe only at a country-level resolution,[26,27] have a country-specific focus with limited geographical scope or detail outside the focus area,[28] investigate the mid-term role rather than the long-term role of a hydrogen network,[26] or neglect some energy sectors or non-energy demands that involve hydrogen.[15,28,29] However, high resolution at continental scope is needed to understand how a hydrogen network can relieve power grid bottlenecks, where the costs of hydrogen network development can be reduced by retrofitting gas pipelines and where geological sites for hydrogen storage are located. Previous one-node-per-country studies could not have suitably assessed this.

This paper provides the first high-resolution examination of the trade-offs between electricity grid expansion and a new hydrogen network in scenarios involving a European energy system with net-zero carbon dioxide emissions, no energy imports, and high shares of renewable electricity production. By leveraging recent computational advances, we resolve 181 regions to study what role hydrogen infrastructure can play in a future sector-coupled system. This enables us to take account of network bottlenecks inside countries, see more precise locations of demand and supply in the network, and capture the variability of renewable resources. For the first time, such an investigation also considers regional potentials for the repurposing of legacy gas pipelines and the geological storage of hydrogen in salt caverns.

Our analysis covers four main scenarios to examine whether a hydrogen network composed of new and retrofitted pipelines can compensate for a potential lack of power grid expansion. These scenarios differ based on whether electricity and hydrogen grids can be expanded. As supplemental sensitivity analyses, we also evaluate the impact of restricted onshore wind potentials (supplemental information section onshore wind potential elimination), more progressive technology assumptions (supplemental information section using technology and cost projections for 2050), the impact of importing most hydrogen derivatives from outside of Europe on network benefits (supplemental information section importing all liquid carbonaceous fuels), and the use of alternative shipping fuels (supplemental information section liquid hydrogen in shipping).

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For our analysis, we use an open capacity expansion model of the European energy system, PyPSA-Eur-Sec, which, in contrast to the models used in many previous studies,[23,30–38] combines a fully sector-coupled approach with a high spatio-temporal resolution and multi-carrier transmission infrastructure representation so that it can capture the various transport bottlenecks that constrain the cost-effective integration of variable renewable energy.[39] The model co-optimizes the investment and operation of generation, storage, conversion, and transmission infrastructures for the least-cost outcome in a single linear optimization problem, covering 181 regions and a 3-hourly time resolution for a full year. A sensitivity analysis varying the model's spatio-temporal resolution is included in supplemental information sections temporal resolution and spatial resolution. The regional scope comprises the European Union without Cyprus and Malta as well as the United Kingdom, Norway, Switzerland, Albania, Bosnia and Herzegovina, Montenegro, North Macedonia, Serbia, and Kosovo. It incorporates spatially distributed demands of the electricity, industry, building, agriculture, and transport sectors, including dense fuels for shipping and aviation as well as non-energy feedstock demands in the chemicals industry. Primary energy supply comes from wind, solar, biomass, hydro, and limited amounts of fossil oil and gas. The energy flows between the system's energy carriers are modeled by various technologies, including heat pumps, combined heat and power (CHP) plants, thermal storage, electric vehicles, batteries, power-to-X processes, hydrogen fuel cells, and geological potentials of underground hydrogen storage. Data on existing electricity and gas transmission infrastructure are also included to determine grid expansion needs and retrofitting potentials. The model also features detailed management of carbon flows between capture, usage, sequestration, removal from the atmosphere, and emissions into the atmosphere to track carbon through the system. More details on the model are presented in the experimental procedures and supplemental experimental procedures. The model is open source and based on open data (github.com/pypsa/pypsa-eur-sec).

All investigations are conducted with a constraint that carbon dioxide emissions into the atmosphere balance out to zero over the year, disregarding other greenhouse gas emissions. The model can sequester up to 200 $MtCO_2$ per year, allowing it to sequester industry process emissions that have a fossil origin, such as the calcination in cement manufacturing, but restricting the use of negative emission technologies compared with other works.[34] In our scenarios, we also do not consider clean energy imports to Europe, thus assuming that Europe is self-sufficient in electricity and green fuels and feedstocks. We relax this constraint in supplemental information section importing all liquid carbonaceous fuels. Technology assumptions are taken widely from the Danish Energy Agency (DEA) for the year 2030.[40] A sensitivity analysis with technology assumptions for the year 2050 is presented in supplemental information section using technology and cost projections for 2050.

RESULTS

Energy, hydrogen, and carbon balances show key technologies needed to satisfy European energy needs with net-zero emissions

First of all, with the energy balance in Figure 1, we underline the central role of wind and solar electricity supply in all scenarios. Hydroelectricity, biomass, and the recovery of ambient heat through heat pumps further support the energy supply, whereas fossil oil and gas only play a small role, since carbon dioxide removal options to offset their unabated emissions are limited by the assumed sequestration potentials. Electricity demand for industrial processes, electrified transport, and the residential sector, alongside heat for hot water provision, space heating, and industrial processes, dominates the energy consumption. Conversion losses of power-to-X

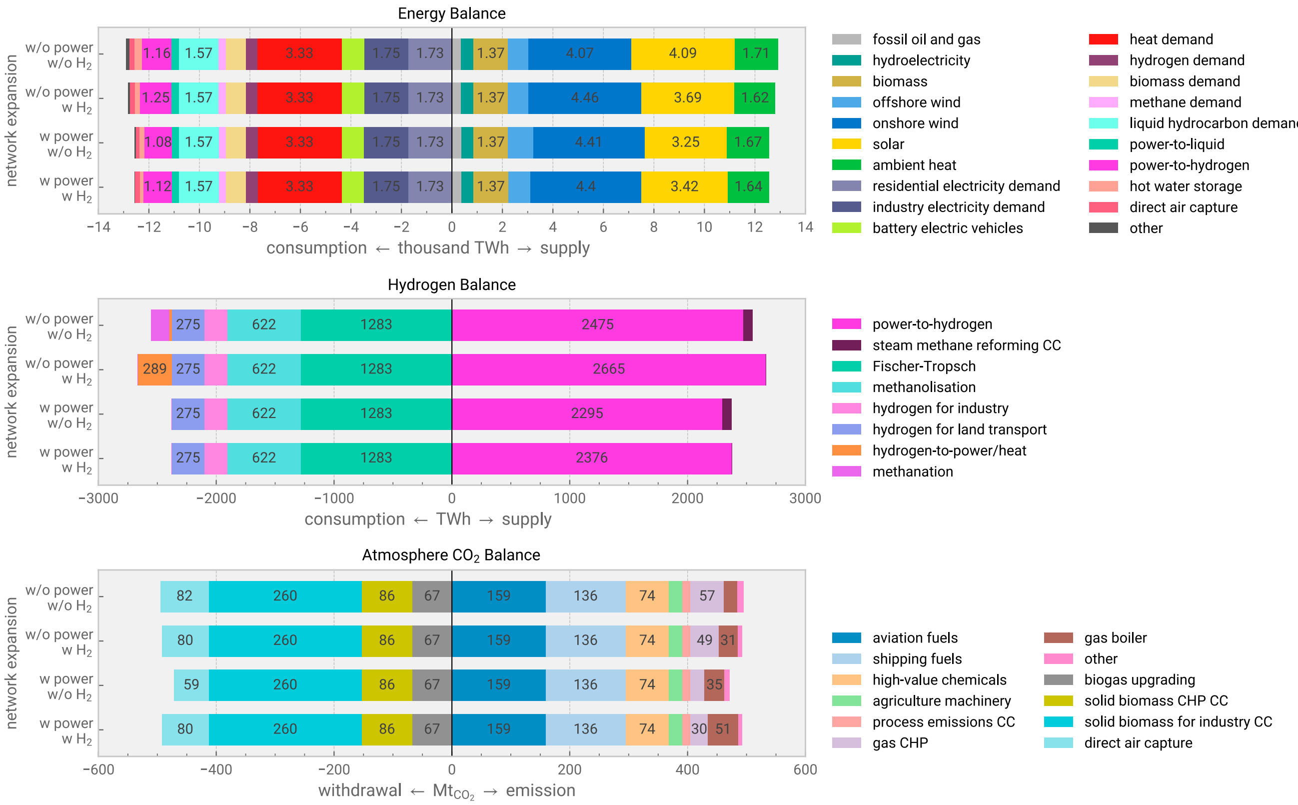

Figure 1. Energy, hydrogen, and carbon dioxide balances across all scenarios
Energy consumption includes final energy and non-energy demands by carrier as well as conversion losses in thermal storage and electrofuel synthesis processes (e.g., power to hydrogen and power to liquid). The ambient heat retrieved by heat pumps is counted as energy supply. A breakdown of final energy and non-energy demands is shown by sector in Figure S2, by time in Figure S3, and by region in Figure S5. For technologies with a carbon capture (CC) option, the carbon dioxide balance shows residual emissions due to imperfect capture rates. For detailed Sankey diagrams of energy and carbon flows, see Figures S39–S41.

processes are also shown in the energy balance and are most pronounced for electrolysis. Overall, differences between the scenarios are small. With restricted network expansion options, the energy supply shifts toward solar photovoltaics (PVs), and the total increases slightly. This rise compensates for the higher heat losses in thermal energy storage and increased handling of added synthetic gas in these scenarios.

Figure 1 also presents the balance of hydrogen consumption and supply. The supply side is dominated by the production of large amounts of green electrolytic hydrogen, between 2,376 and 2,665 TWh/a depending on the scenario. We only observe a limited production of blue hydrogen from steam methane reforming with CC in scenarios without hydrogen network expansion (78 TWh/a). A glance at the demand side reveals that, for the most part, hydrogen is only an intermediate product between electricity and derivative products. There are only a few direct uses of hydrogen; for instance, in the industry sector, it is used for producing ammonia and steel with hydrogen-based direct reduction of iron, as well as for heavy-duty land transport. Most hydrogen is used to produce derivatives such as Fischer-Tropsch fuels, methane, ammonia, and methanol, which are used for dense aviation and shipping fuels, fertilizers, and as a feedstock for producing high-value chemicals.

The production of carbonaceous fuels consumes 1,903 TWh/a of hydrogen, of which 192 TWh/a is usable in the form of waste heat for district heating networks. Around 139 TWh/a of hydrogen is lost during synthetic fuel production. A total of 275 TWh/a of hydrogen is used in land transport, whereas the industry sector consumes 195 TWh/a of hydrogen for ammonia and steel production, excluding the consumption of hydrogen for other industry feedstocks (e.g., for high-value chemicals). If the electricity grid expansion is restricted, but hydrogen can be transported, some more hydrogen is produced to be re-electrified in fuel cells during critical phases of system operation (287 TWh hydrogen). These fuel cells would mostly be built inland in Central Europe (see later section common design features in four net-zero carbon dioxide emission scenarios for Europe), where the lack of a strong grid connection requires local dispatchable heat and power supply as a backup for periods of low renewable feed-in and cold weather. However, in terms of energy consumed, the reconversion of hydrogen to electricity only assumes a secondary role. In all scenarios with network expansion, no synthetic methane is produced for process heat in some industrial applications and as a heating backup for power-to-heat units. This is because the model prefers to use the full potential for biogas (336 TWh/a) and limited amounts of fossil gas (366 TWh/a), which are offset by sequestering biogenic carbon dioxide, over synthetic production.

Only when neither hydrogen nor power network expansion were allowed do we see methanation (H_2-to-CH_4, 152 TWh hydrogen). In this case, despite the associated conversion losses, synthetic methane is used as a transport medium for hydrogen to utilize the existing gas network to bypass the restricted transport options for hydrogen and electricity. Apart from the imperfect capture rate of 90%, which requires supplementing some CO_2, the combination of methanation and carbon-capturing steam methane reforming creates a carbon cycle, provided that the CO_2 is returned to the methanation sites with an appropriate CO_2 transport infrastructure.

The atmospheric CO_2 balance in Figure 1 shows that carbonaceous fuels in shipping, aviation, and the incineration or eventual decay of plastics constitute the major uncaptured carbon dioxide emissions in the system. Some additional CO_2 is emitted through using unabated methane (natural gas, biogas, or synthetic) in gas boilers and CHP plants in the heating sector during the challenging cold winter periods with low renewable energy supply and high space heating demand. Industrial process emissions are largely captured such that owing to imperfect capture rates, only residual emissions are released into the atmosphere. Most carbon dioxide removal is achieved through biomass technologies. For instance, biogenic CO_2 is captured in biomass CHP plants or industrial low-temperature heat applications. Direct air capture was used in all scenarios but takes a much smaller part by supplementing the CO_2 available from biogenic or fossil sources once they are exhausted. Of the CO_2 handled by the system for the synthesis of electrofuels and long-term sequestration, the largest share is of biogenic origin (62%), followed by captured fossil CO_2 emissions from fuel combustion and process emissions (25%). Direct air capture has the smallest share with 58–82 Mt $_{CO_2}$/a (13%). The broad availability of captured CO_2 from industrial processes and biofuel combustion is advantageous for the system, as it lowers the cost of fuel synthesis by avoiding costly and energy-intensive direct air capture.

For a comprehensive overview of energy and carbon flows between carriers in each scenario, see Figures S39 and S40, which can be interactively explored at h2-network.streamlit.app.

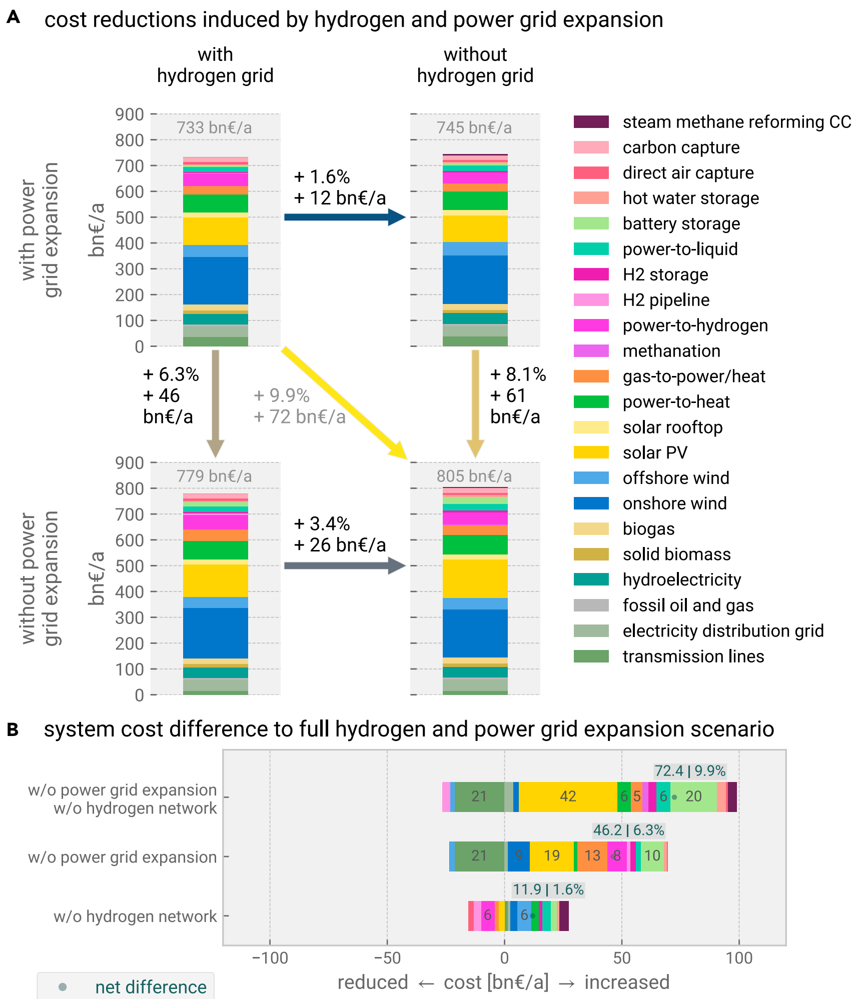

Figure 2. Cost reductions achieved by developing electricity and hydrogen network infrastructure

(A) Comparison of four scenarios with and without expansion of a hydrogen network (left to right) and the electricity grid (top to bottom). Each bar depicts the total system cost of one scenario alongside its cost composition. Arrows between the bars indicate absolute and relative cost increases as network infrastructures are successively restricted.

(B) System cost difference of grid expansion restrictions relative to the least-cost solution with full hydrogen and power grid expansion. For similar graphics in different settings, e.g., more optimistic cost assumptions, imports of carbonaceous fuels, liquid hydrogen as shipping fuel, intermediate levels of power grid expansion, and onshore wind availability, see Figures S21–S29.

Cost benefit of hydrogen network is consistent and strongest without power grid expansion

In Figure 2, we first compare the total energy system costs and their compositions between the four main scenarios, which vary in whether the power grid can be expanded beyond today's levels and whether a hydrogen network based on new and retrofitted pipelines can be built. Across all scenarios, the total costs are dominated by investments in wind and solar capacities, power-to-heat applications (primarily heat pumps), electrolyzers, and electrofuel synthesis plants (for transport fuels and as a feedstock for the chemicals industry). Total energy system costs vary between 733 and 805 bn€/a, depending on the available network expansion options.

Overall, we find that energy system costs are not overly affected by restrictions on the development of electricity or hydrogen transmission infrastructure, and systems without grid expansion appear as equally feasible alternatives. Nonetheless, realizable cost savings range in the order of tens of billions of euros per year. The combined net benefit of hydrogen and electricity grid expansion beyond today's levels is 72 bn€/a; a system with no further network expansion would be around 9.9% more expensive. This limited cost increase can be attributed to the high level of synthetic fuel production for industry, transport, and backup electricity and heating applications. The option for a flexible operation of conversion plants, inexpensive energy storage, and low-cost energy transport as carbonaceous fuels between regions offer sufficient leeway to manage electricity and hydrogen transport restrictions effectively (see common design features in four net-zero carbon dioxide emission scenarios for Europe). However, regulatory changes would be needed in order to manage the network bottlenecks (see derivation of policy implications from regional and operational insights).

The total net benefit of power grid expansion is between 46 and 61 bn€/a (6.3%–8.1%), compared with costs for transmission reinforcements between 15.1 and 37.9 bn€/a. System costs decrease despite the increasing investments in electricity transmission infrastructure. Power grid reinforcements enable renewable resources with higher capacity factors to be integrated from further away, resulting in lower capacity needs for solar and wind. The electricity grid also allows renewable variations to be smoothed in space and facilitates the integration of offshore wind, resulting in lower hydrogen demand for balancing power and heat and less hydrogen infrastructure (comprising electrolysis, cavern storage, reconversion, and pipelines). Restrictions on power grid expansion conversely raise costs by forcing more local production from solar PVs and increased hydrogen production. As a hydrogen network could compensate for the lack of grid capacity to transport energy over long distances, the benefit of electricity grid reinforcements is strongest if no hydrogen network can be developed. Supplemental information section electricity grid reinforcement restrictions presents in more detail the progression of system cost changes in intermediate steps between a doubling of power grid capacity and no grid expansion.

The presence of a new hydrogen network can reduce system costs by up to 3.4%. The net benefit between 12 and 26 bn€/a (1.6%–3.4%) largely exceeds the cost of the hydrogen network, which is between 3.2 and 4.6 bn€/a. The hydrogen network offers an alternative for bulk energy transport from the windiest and sunniest regions in Europe's periphery to low-cost geological storage sites and the industrial clusters in Central Europe with high energy demand but less attractive and more constrained renewable potentials (see hydrogen network takes over role of bulk energy transport). We find that its system cost benefit is strongest when the electricity grid is not expanded. However, even with high levels of power grid expansion, the hydrogen network is still a beneficial infrastructure.

Although power grid reinforcements provide higher cost reductions, hydrogen and electricity networks are stronger together. Around 36% of the combined cost benefit of transmission infrastructure can be achieved solely with a new hydrogen network. In contrast, 84% of the combined cost benefit can be reached by just reinforcing the electricity transmission system. Compared with the combined net benefit of 72 bn€/a, the individual benefits sum up to a value that is only 20.8% higher (61 + 26 = 87 bn€/a). Thus, offered cost reductions are mainly additive.

This also means that a hydrogen network cannot perfectly substitute for power grid reinforcements. It can only partially compensate for the lack of grid expansion, yielding 42.6% of the cost reductions achieved by electricity grid expansion. This is because electricity has more versatile uses in the newly electrified transport, building, and industry sectors. Hydrogen can only be used directly in a few specialized sectors, and if it has to be produced only to be re-electrified later, there will be expensive efficiency losses. A system built exclusively around hydrogen network expansion is just 4.6% more expensive than an alternative system that only allows electricity grid expansion. Overall, our results show that energy transport as electrons and molecules offers complementary strengths. From a system-level perspective, network expansion leads to small cost reductions.

Common design features in four net-zero carbon dioxide emission scenarios for Europe

Across all scenarios, we see 206–245 GW offshore wind, 1,691–1,776 GW onshore wind, and 2,666–3,598 GW solar PVs (Figure S42). The wide range of solar capacities is due to an increased localization of electricity generation through solar PVs when the expansion of transmission infrastructure is limited. As network expansion options are constrained, we see demand for local daily storage with batteries almost quadrupling (from 73 to 272 GW with a typical energy-to-power ratio of 6 h) and doubling for weekly and seasonal storage with hydrogen and thermal storage (from 73 to 141 TWh; see Figures S42 and S49 for state-of-charge profiles per technology). For all scenarios, the capacities of PVs split on average into 16% rooftop PV and 84% utility-scale PV. The offshore share of wind generation capacities varies between 10% and 12% and is highest when networks can be fully expanded.

The spatial distribution of investments per scenario is shown in Figure 3. Although solar capacities are found throughout Europe, especially in the South, onshore and offshore wind capacities are mostly found in the North Sea region and the British Isles. When allowed, new electricity transmission capacity is built where it helps the integration of remote wind production and the transport of electricity to inland demand centers. Consequently, most grid expansion is seen in and between Northwestern and Central Europe. Battery storage pairs with solar generation in Southern Europe, particularly when power grid reinforcement is limited. Besides their wider use overall, battery deployment also progresses northbound in this case.

Furthermore, electrolyzer capacities for power-to-hydrogen conversion see a massive scale-up ranging from 937 to 1,250 GW depending on the scenario. The capacities are lowest when the electricity grid can be expanded. In this case, their locations correlate strongly with wind and solar capacities (Pearson correlation coefficient $R^2 = 0.64$ for each, Figure 3). If no hydrogen or electricity transmission expansion is allowed, the electrolysis correlates more strongly with wind energy ($R^2 = 0.74$) than with solar energy ($R^2 = 0.46$). The build-out of hydrogen production facilities is accompanied by a network of pipelines and underground hydrogen storage in Europe to help balance generation from renewables in time and space.

In space, a new pipeline network transports hydrogen from preferred production sites to the rest of Europe, where hydrogen is consumed by industry (for ammonia, high-value chemicals, and steel production), aviation, and shipping, as well as fuel cell CHPs for combined power and heat backup. Varying in magnitude per scenario, we see major net flows of hydrogen from Great Britain to the Benelux countries, Germany, and Norway; from Northern Germany to the South; and from the East of Spain to Southern France. The favored network topology strongly depends on the

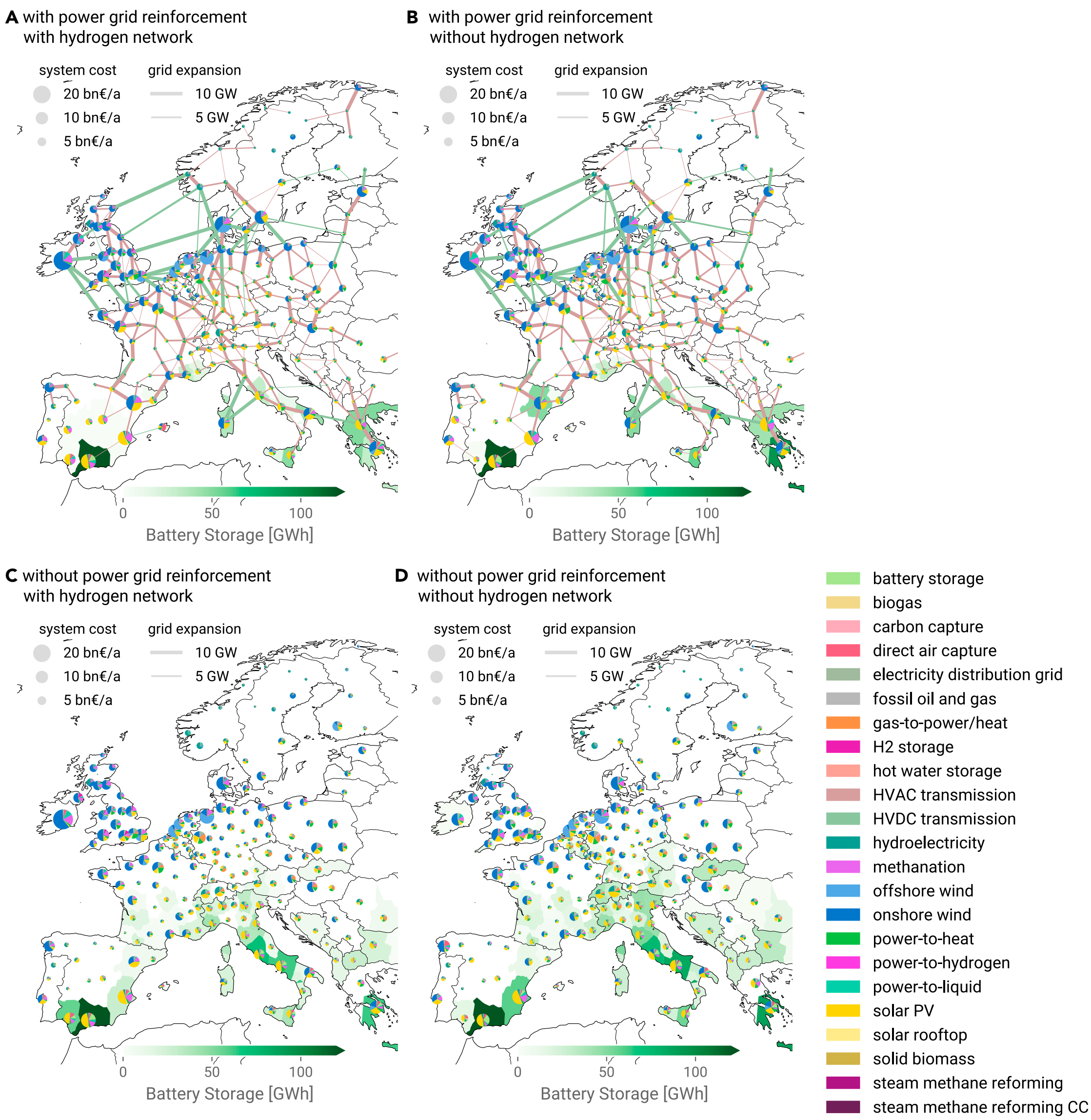

Figure 3. Regional distribution of system costs and electricity grid expansion for scenarios with and without electricity or hydrogen network expansion

The pie charts in each of the network expansion scenarios (A–D) depict the annualized system cost alongside the shares of the various technologies for each region. The line widths depict the level of added grid capacity between two regions, which was capped at 10 GW. For the regional distribution of average electricity and hydrogen prices per scenario, see Figures S34 and S35. Corresponding regionally averaged price time series and price duration curves are shown in Figures S36–S38. Total installed capacities are presented in Figure S42.

potentials for cheap renewable electricity. If onshore wind potentials were restricted, e.g., due to limited social acceptance in Northern Europe, the network infrastructure would be tailored to deliver larger amounts of solar-based hydrogen from Southern Europe to Central Europe. We discuss this supplemental sensitivity analysis in supplemental information sections onshore wind potential elimination and compromises on onshore wind potential restrictions.

The development of a hydrogen network is driven by the fact that (1) spatially fixed hydrogen demand for steelmaking and ammonia industry as well as heavy-duty land transport is located in areas with less attractive renewable potentials (Figure S5B), (2) the best wind and solar potentials are located in the periphery of Europe (Figure S15), (3) bottlenecks in the electricity transmission network give impetus to alternative energy transport options and re-electrification capacities as backup supply in weakly connected areas, and (4) moving hydrogen from production sites to where the geological conditions allow for cheap underground storage is significantly more cost-effective than local storage in steel tanks (Figure S18). Another subsidiary location factor for hydrogen network infrastructure is linked to the siting of electrofuel production. Because we assume that waste heat from these processes can be recovered for district heating networks, urban areas with attractive renewable potentials nearby are preferred sites for fuel synthesis to which the hydrogen needs to be transferred. Since we assume no constraints for the transport of carbonaceous fuels, the spatial distribution of hydrogen consumption for fuel synthesis is not a siting factor that is considered. Similar to the positioning of hydrogen fuel cells, the location of hydrogen consumption for electrofuel production is endogenously optimized. Because we further assume sufficient infrastructure for the transport of captured carbon dioxide, the location of carbon sources and sinks does not influence the siting of fuel synthesis plants either.

The flexible operation of electrolyzers further supports the system integration of variable renewables in time. Hydrogen production leverages periods with exceptionally high wind speeds across Europe by running the electrolysis with average utilization rates between 35% and 41% (see Figures S44, S46, and S48). The produced hydrogen is buffered in salt caverns, which then allows for higher full-load hours of fuel synthesis processes. For Fischer-Tropsch and methanolization plants, we see combined average utilization rates between 59% and 68%, which aligns with the higher upfront investment costs of these processes. Their operation is very steady in the summer months and mostly interrupted in winter periods with low wind speeds and low ambient temperatures to give way to backup heat and power supply options (see Figures S44 and S46). By exploiting periods of peak generation and curbing production in periods of scarcity, high amounts of variable renewable power generation that serves the system's abundant synthetic fuel demands can be incorporated into the system cost-effectively. This ultimately leads to little curtailment of renewables between 2% and 3% (Figure S43) even without grid reinforcements and low levels of firm capacity. In relation to a peak electricity consumption of 2,626 GW_{el}, we observe open-cycle gas turbine (OCGT) and CHP plant capacities between 106 and 218 GW_{el}, most of which are gas CHP plants. The lowest values were attained when additional power transmission could be built.

Hydrogen storage is required to benefit from temporal balancing through flexible electrolyzer operation. We find cost-optimal storage capacities between 26 and 43 TWh with a hydrogen network and 21 and 22 TWh without a hydrogen network while featuring similar filling level patterns throughout the year (Figure S49). Almost all hydrogen is stored in salt caverns, exploiting vast geological potentials across Europe, mostly in Northern Ireland, England, and Denmark. We observe no storage in steel tanks unless both hydrogen and electricity networks cannot be expanded. In this case, we see up to 1 TWh of steel tank capacity, which represents 5% of the total hydrogen storage capacity. If the options for network development are restricted, more hydrogen storage is built to balance renewables in time rather than in space.

Hydrogen network takes over the role of bulk energy transport

Depending on the level of power grid expansion, between 204 and 307 TWkm of hydrogen pipelines are built (Figure 4A). The higher value is obtained when the hydrogen network partially offsets the lack of electricity grid reinforcement. On

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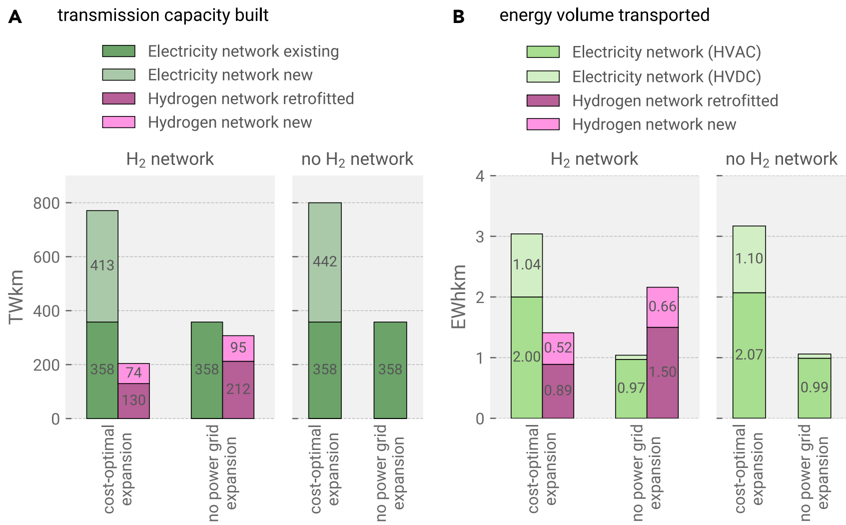

Figure 4. Transmission capacity built and energy volume transported for various network expansion scenarios

(A) shows transmission capacity built, whereas (B) shows energy volume transported. For the hydrogen network, a distinction between retrofitted and new pipelines is made. For the electricity network, a distinction is made between existing and added capacity or how much energy is moved via high-voltage alternating current (HVAC) or high-voltage direct current (HVDC) power lines. Both measures weight capacity (TW) or energy (EWh) by the length (km) of the network connection.

the other hand, restricting hydrogen expansion only has a small effect on cost-optimal levels of power grid expansion. The length-weighted power grid capacity is more than doubled in the least-cost scenario; without a hydrogen network, the cost-optimal power grid capacity is 7% higher.

When both hydrogen and electricity grid expansions are allowed, the hydrogen network transports approximately half the amount of energy transmitted via the electricity network (Figure 4B). This is striking because the hydrogen network capacity is little more than a quarter that of the power grid (Figure 4A). In consequence, the utilization rate of 78% of the hydrogen network is much higher than the utilization rate of 36% of the electricity grid (Figure S50). One plausible explanation for this observation is that the buffering of produced hydrogen in cavern storage allows more coordinated bulk energy transport in hydrogen networks, whereas the power grid directly balances the variability of renewable electricity supply and is subject to linearized power flow physics (Kirchhoff's circuit laws).

When electricity grid expansion is restricted, the hydrogen network plays a dominant role in transporting energy around Europe. In this case, around twice as much energy is moved in the hydrogen network (2.16 EWhkm) than in the electricity network (1.04 EWhkm). Between only power grid expansion and only hydrogen network expansion, the difference in the total volume of energy transported is only 0.9%.

New hydrogen network can leverage repurposed natural gas pipelines

With our assumptions, developing electricity transmission lines is approximately 60% more expensive than building new hydrogen pipelines. We assume costs for a new hydrogen pipeline of 250 €/MW/km, whereas for a new high-voltage transmission line, we assume 400 €/MW/km (see supplemental information section techno-economic assumptions). Despite higher costs, we observe that electricity grid reinforcements are preferred over hydrogen pipelines. Part of the reason is that electricity has more versatile end uses in transport, buildings, and industry in our scenarios with high levels of direct electrification. Hydrogen can only be used directly in a few specialized sectors, and if hydrogen has to be produced only to be re-electrified later, the efficiency losses mean that additional generation capacity would be needed to compensate. This makes energy transport in the form of hydrogen less competitive. However, hydrogen pipelines are particularly attractive where the end-use is hydrogen based.

The appeal of a hydrogen network is further spurred when existing natural gas pipelines are available for retrofitting. Repurposing costs just around half as much as building a new hydrogen pipeline (117 versus 250 €/MW/km; see supplemental information section techno-economic assumptions). For the capacity retrofit, we include costs for required compressor substitutions and assume that for every unit of gas pipeline decommissioned, 60% of its capacity becomes available for hydrogen transport. The 3-fold lower volumetric energy density of hydrogen compared with natural gas is offset by the possibility to attain higher volume flows with hydrogen. In consequence, even detours of the hydrogen network topology may be cost-effective if, through rerouting, more repurposing potentials can be tapped.

As Figure 5 illustrates, the optimized hydrogen network topology is built around supporting flows into the industrial and population centers of Central Europe. We see strong pipeline connections in Northwestern Europe to integrate wind-based hydrogen hubs as well as connections for the transport of solar hydrogen hubs from Spain, Italy, and Greece. Individual pipeline connections between regions have optimized capacities of up to 30 GW. Of the total hydrogen network volume, between 64% and 69% consists of repurposed gas pipelines. The share is highest when the electricity grid is not permitted to be reinforced. Up to a quarter of the existing natural gas network is retrofitted to transport hydrogen instead, leaving large capacities that are used for neither hydrogen nor methane transport. In our scenarios, 29%–42% of retrofittable gas pipelines fully exhaust their conversion potential to hydrogen. The most notable corridors for gas pipeline retrofitting are located offshore across the North Sea and the English Channel and in Great Britain, Germany, Austria, Switzerland, Northern France, and Italy. The most prominent new hydrogen pipelines are built in the British Isles, particularly to connect Ireland, Northern France, and the Netherlands, and in Spain and Portugal. The sizable existing natural gas transmission capacities in Southern Italy and Eastern Europe are largely not repurposed for hydrogen transport in this self-sufficient scenario for Europe.

However, this picture would change if clean energy import options were considered. Since most of the hydrogen is used to produce synthetic carbonaceous fuels and ammonia, much of the hydrogen demand would fall away if these derivatives were imported. In a sensitivity analysis in supplemental information section importing all liquid carbonaceous fuels, we show that the relative cost benefits of hydrogen network expansion are not strongly affected by importing all liquid carbonaceous fuels, even though this action would reduce the cost-optimal extent of hydrogen infrastructure by more than 50%. Moreover, direct hydrogen imports into Europe by pipeline or ship could alter cost-effective network topologies, as new import locations need to be connected rather than domestic production sites. For instance, the network's role might change from distributing energy from North Sea hydrogen hubs to integrating inbound pipelines from North Africa with increased network capacities in Southern Europe.[41]

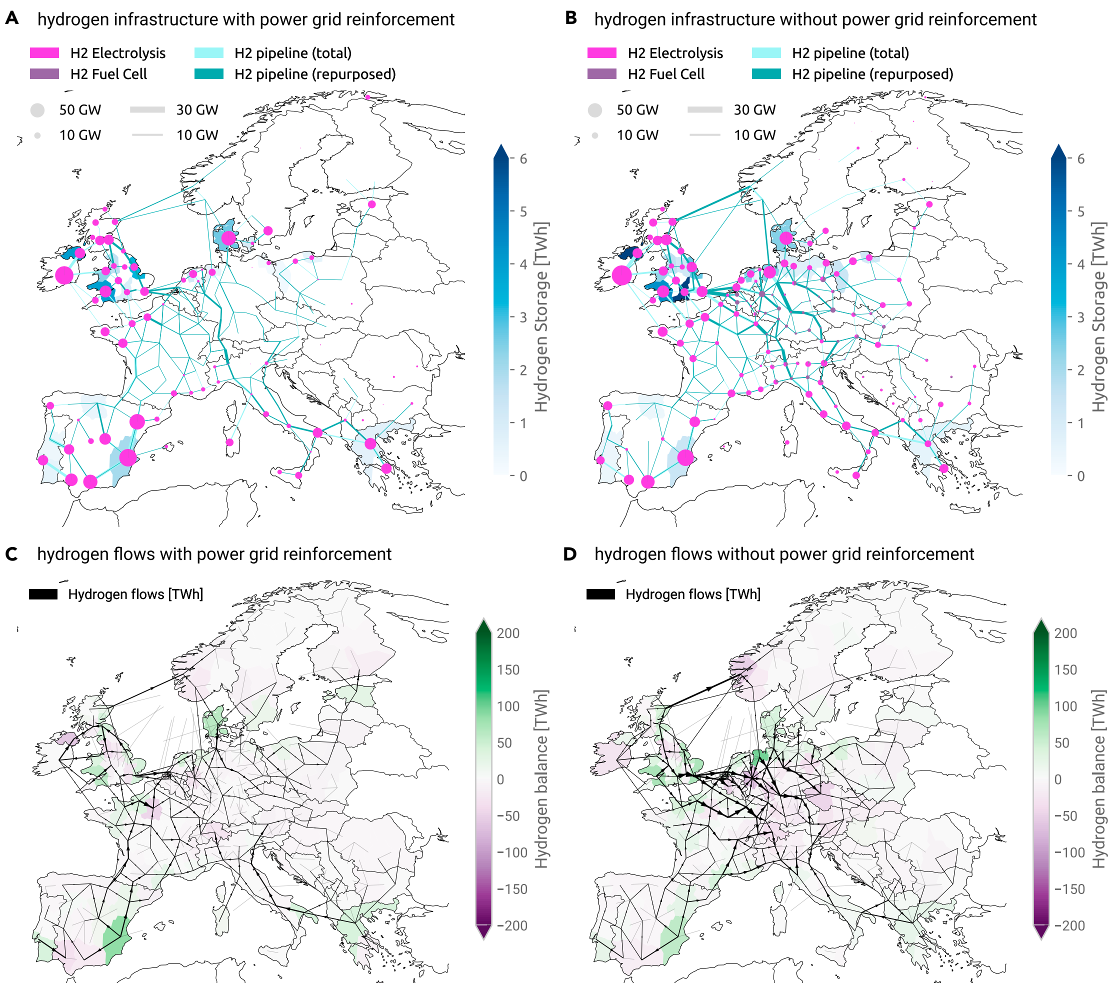

Figure 5. Hydrogen network infrastructure and energy flows

(A and B) Optimized hydrogen network, storage, reconversion, and production sites with and without electricity grid reinforcement. The size of the circles depicts the electrolysis and fuel cell capacities in the respective region. The line widths depict the optimized hydrogen pipeline capacities. The darker shade depicts the share of capacity built from retrofitted gas pipelines. The coloring of the regions indicates installed hydrogen storage capacities.
(C and D) Net flows of hydrogen in the network and the respective energy balance with and without electricity grid reinforcement. Flows larger than 2 TWh are shown with arrow sizes proportional to net flow volume. For a map outlining net power flows in the electricity transmission network, see Figure S33.

Regional imbalance of supply and demand is reinforced by transmission

In line with previously shown capacity expansion plans, energy surplus is found largely in the windy coastal and sunny Southern regions that supply the inland regions of Europe, which have high demands but less attractive renewable potentials (Figure 6). The net energy surplus of individual regions amounts to up to 260 TWh. Examples are Danish offshore wind power exports and large wind-based production sites for synthetic fuels in Ireland. For Denmark, this surplus is more than twice as high as its final energy demand, resulting in a situation where three quarters of Denmark's energy production is exported. Net deficits of single regions can have similarly high values, close to 200 TWh. Examples are, in particular, the industrial cluster between Rotterdam and the Ruhr Valley as well as other European metropolises.

Energy transport infrastructure fuels the uneven regional distribution of supply relative to demand. This is illustrated by the Lorenz curves in Figure 6 for different energy

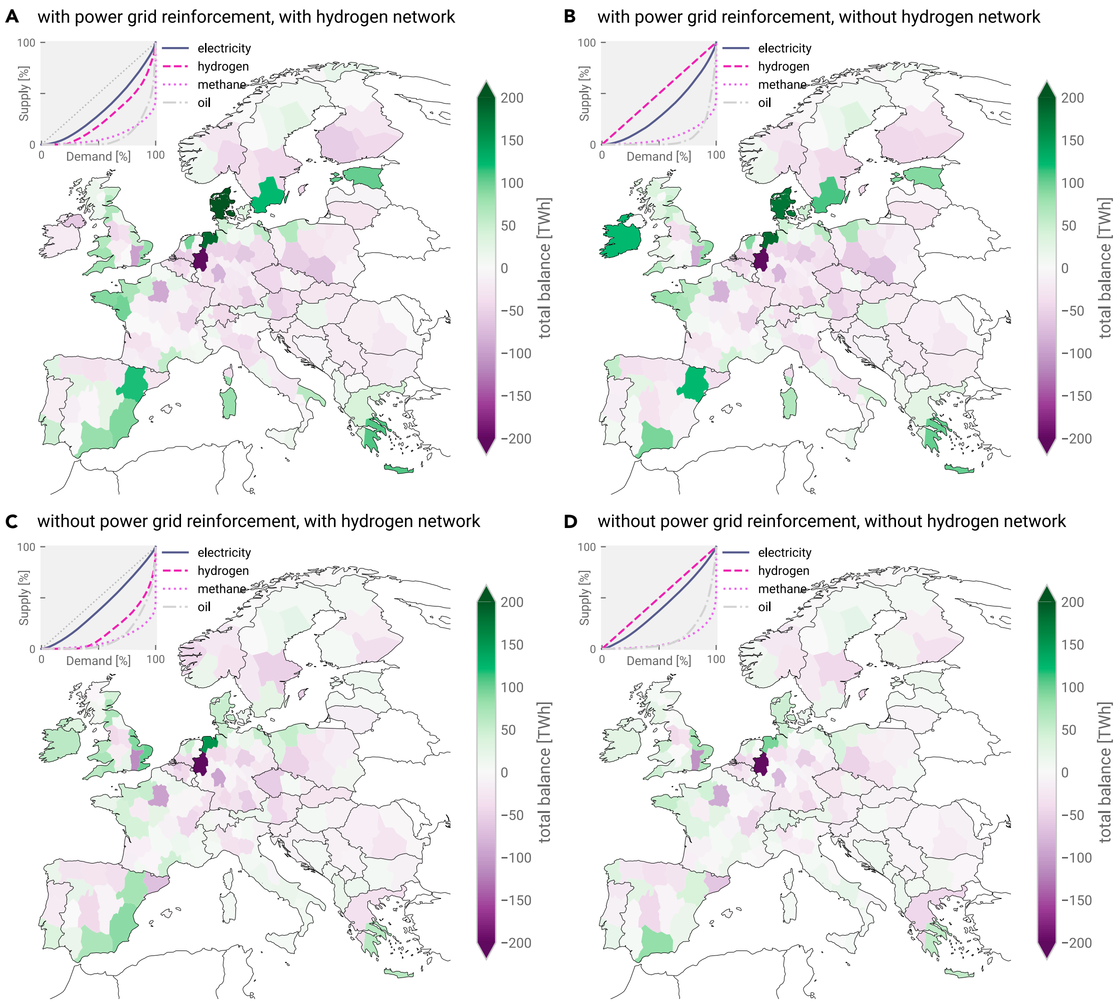

Figure 6. Total energy balances for scenarios with and without electricity or hydrogen network expansion for the 181 model regions

For each scenario (A–D), the maps reveal regions with net energy surpluses and deficits. The Lorenz curves on the upper left of each map depict the regional imbalances of electricity, hydrogen, methane, and liquid hydrocarbon supply relative to demand. Methane and liquid hydrocarbon supply can be of fossil, biogenic, or synthetic origin. If the annual sums of supply and demand are equal in each region, the Lorenz curve resides on the identity line. However, the more imbalanced the regional supply is relative to demand, the further the curve dents into the bottom right corner of the graph.

carriers. The Lorenz curves plot the carrier's cumulative share of supply versus the cumulative share of demand, sorted by the ratio of supply and demand in ascending order. If the annual sums of supply and demand are equal in each region, the Lorenz curve resides on the identity line. However, the more unequal the regional supply is relative to demand, the further the curves dent into the graph's bottom right corner. For the least-cost scenario, Figure 6A highlights that the supply and demand of hydrogen are slightly more regionally imbalanced than those of electricity. Reduced power grid expansion causes more evenly distributed electricity supply (Figures 6C and 6D), and when hydrogen transport is restricted (Figures 6B and 6D), the production of carbonaceous fuels is increased in regions with attractive renewable potentials because they can be transported at low cost.

DISCUSSION

To put our results into a broader perspective, in this section, we compare them with related literature and proposals presented in the gas industry's EHB reports. This is followed by an appraisal of the limitations of our study and a derivation of policy implications based on spatial and operational insights.

Comparison with related literature

Compared with the net-zero scenarios from the European Commission,[35] we see much larger wind and solar electricity generation, reaching beyond 8,600 TWh compared with approximately 5,700 TWh. This is also reflected in the capacities built: wind capacity exceeds 2,000 GW in our scenarios but is only 1,200 GW in the Commission's scenarios, and solar capacity exceeds 3,500 GW but is only 1,000 GW in the Commission's scenarios.[35] In terms of the total electricity produced, our results approximately show a tripling of today's generation compared with an increase by 145% in the Commission's net-zero scenarios.[35] Roughly, one-third goes to regular electricity demand; one-third goes to newly electrified sectors in heating, transport, and industry; and another third goes to hydrogen production (dominated by demand for liquid carbonaceous fuels). The major difference from the Commission's scenarios[35] is caused by their lower electrification rates, a 15% share of nuclear power in the electricity mix, higher biomass usage across all sectors (2,900 TWh/a versus 1,400 TWh/a in our scenarios), and a strong reliance on fossil fuels imports (2,900 TWh/a) for non-energy uses (e.g., plastics and other high-value chemicals). By considering the landfill of plastics as a long-term carbon sequestration option, the Commission's scenarios see little need to produce synthetic hydrocarbons for non-energy feedstocks. On the contrary, our modeling, which assumes that all carbon in waste will be incinerated or eventually decay into the atmosphere and limited sequestration potentials, requires sustainable carbon sources for green electrofuels and precludes the wide-ranging use of fossil oil.

Using pathway optimization, Victoria et al.[27] investigate the timing of when certain technologies become important for the European energy transition and find a hydrogen network consistently appearing after 2035. However, owing to a one-node-per-country resolution in that study, little can be said about subnational network infrastructure needs, retrofitting opportunities for gas pipelines or regional geological storage potentials. Compared with our findings, limited network expansion options affect total energy system costs less in Victoria et al.[27] A doubling of today's transmission volume reduces cumulative system costs between 2020 and 2050 by 2% in Victoria et al.,[27] compared with 8.1% in this study. Disabling hydrogen network expansion increases cumulative costs by 0.5% in Victoria et al.,[27] compared with 3.4% in this study. This discrepancy arises because country-internal transmission bottlenecks are not captured, whereby the integration costs of remote resources such as offshore wind within the countries are neglected.

Caglayan et al.[29] also consider European decarbonization scenarios with both electricity and hydrogen networks but at lower spatial resolution (96 regions) and without the industry, shipping, aviation, agriculture, and non-electrified heating sectors. A similar pattern of hydrogen pipeline expansion toward the British Isles and North Sea is seen; however, lower overall electrolyzer capacities (258 GW compared with 937–1,250 GW in our study) are observed because not all sectors are included. Caglayan et al.[29] also find cost-optimal hydrogen storage of 130 TWh, whereas our scenarios involve just between 21 and 43 TWh owing to the larger flexible hydrogen demand diminishing the need for weekly and monthly balancing.

A large number of cost-effective designs for a climate-neutral European energy system was also presented by Pickering et al.[1] Their 98-region model with 2-hourly resolution likewise includes all energy sectors, including non-energy feedstocks, and also assumes energy self-sufficiency for Europe. However, hydrogen transport options were not considered such that hydrogen must be produced locally. Moreover, geological potentials for low-cost underground hydrogen storage and the option to retrofit gas pipelines are not included. Owing to higher storage cost in steel tanks and fewer assumed end uses of hydrogen and its derivatives, the scenarios involve less hydrogen storage (0–6 TWh versus 21–43 TWh) and lower electrolyzer capacities (290–855 GW versus 937–1,250 GW) than those in our study. Furthermore, whereas our model allows limited use of fossil fuels and with options for CCS, Pickering et al.[1] eliminate the use of fossil energy and only consider direct air capture as a carbon source. Overall, the total energy system costs in Pickering et al.[1], between 730 and 866 bn€/a, are similar to those in our study, between 733 and 805 bn€/a.

Comparison with the European Hydrogen Backbone

Our results are aligned with the European Hydrogen Backbone (EHB).[16–19] Although no detailed modeling lies behind the visions in the EHB reports, we present an analysis based on temporally resolved spatial co-planning of energy infrastructures. We see cost-optimal hydrogen network investments in the range of 3.2–4.6 bn€/a, whereas the EHB report covering 21 countries finds slightly higher costs between 4 and 10 bn€/a.[18,42] The extension to 28 countries reports costs between 7 and 14 bn€/a.[19] Compared with the hydrogen backbone vision presented in the EHB from April 2021,[18,43] our scenarios show a similarly sized hydrogen network with comparable retrofitting shares. Measured by the length-weighted sum of pipeline capacities (TWkm), the 309 TWkm indicated in the EHB report matches the upper end of the range of 204–307 TWkm observed in our scenarios. Likewise, the 69% share of repurposed natural gas pipelines[18] roughly agrees with our findings, where between 63.5% and 69.1% of hydrogen pipelines are retrofitted gas pipelines. In contrast to the EHB reports, we also explore solutions without a hydrogen network, which we find to be feasible as well.

Limitations of the study and scope for future investigations

In our main scenarios, Europe is largely energy self-sufficient. Although limited amounts of fossil gas and oil imports are allowed, no imports of renewable electricity, chemical energy carriers, or commodities from outside of Europe are considered. However, including green imports may change system needs for electricity and hydrogen transmission infrastructure substantially. New hydrogen import hubs might require different bulk transmission routes. The import of large amounts of carbon-based fuels and ammonia would, furthermore, diminish the demand for hydrogen overall and hence the need to transport it. This effect of wide-ranging imports of liquid carbonaceous fuel demand on infrastructure needs is demonstrated in a sensitivity analysis in supplemental information section importing all liquid carbonaceous fuels and should be explored in more detail in future work.[44–46]

Additionally, the very uneven distribution of energy supply in our results may interfere with the level of social acceptance for new infrastructure to an extent that may block a swift energy transition.[47–49] Hence, future investigations should weigh the cost surcharge of increased regionally self-sufficient energy supply against the potential benefit of higher public acceptance and increased resilience.

Previous research has shown that the system design can be changed in many ways with only a small change in total costs.[1,50–52] This breadth of options makes robust statements about specific locational infrastructure needs vaguer. Although we present selected design trade-offs regarding transmission networks and some further sensitivities (supplemental information section sensitivity analysis), a more comprehensive exploration of near-optimal solutions would be prudent, especially in the directions of carbon management infrastructure, biomass usage, the level of energy imports, industry transition and relocation options, more regionally balanced infrastructure, and increased system resilience.

Owing to the absence of pathway optimization, our results cannot offer insights into the required transition steps and how the gradual transformation may restrict certain options toward the final climate-neutral state. For example, our results do not show which parts of gas network could be repurposed first or where the benefit of a hydrogen network might be the highest initially. In the context of multi-horizon planning, we also neglect the dynamics of technological learning by doing.[53–55] The transformation to net-zero emissions requires vast and timely growth rates of power-to-X and carbon dioxide removal technologies to realize anticipated cost reductions,[56] which we assume to be given by assuming fixed technology cost.

The need for high spatial resolution to evaluate the competition between electricity and hydrogen networks required a compromise on the temporal resolution, owing to computational constraints. Even though hourly resolution would have been more desirable and generally viable with the available raw data, our analysis employs a 3-hourly resolution to be able to focus on spatial detail, which is important to resolve transmission bottlenecks and examine what infrastructure options can cost-effectively integrate high-yield generation sites with demand clusters, synthetic fuel production, and geological storage potentials. As quantified in the supplemental sensitivity analysis in supplemental information section temporal resolution, the temporal aggregation, however, tends to underestimate demand peaks, as well as the expansion of offshore wind and battery storage for short-term balancing. Conversely, it will overestimate the development of solar PVs to some extent, as solar feed-in fluctuations are smoothed. Nevertheless, the coarser resolution still captures the dominant intraday, daily, weekly, and seasonal patterns, as well as the investment patterns and interactions of electricity and hydrogen transport, which are the focus of this study. Moreover, the sector-coupled system's numerous demand flexibilities (such as electrolyzers, heat pumps, and electric vehicle batteries) provide a wide range of options for managing hour-to-hour variations partially.

Further limitations include the following: heat demands and the availability of renewables vary considerably year by year such that our restriction to a single year may limit the robustness to interannual weather variability; we do not consider new nuclear power plants; we do not spatially resolve the CO_2 resource and infrastructure; we do not consider secondary benefits of grid expansion for the provision of ancillary services; and for the transport and industry sectors, we make some exogenous assumptions about process switching, drive trains, alternative fuels for industry heat, and recycling rates, which may have turned out differently if they were endogenously optimized.

Derivation of policy implications from regional and operational insights

Regardless of the energy carrier transported, our results highlight that cooperation between European countries is important to reach net-zero CO_2 emissions most cost-effectively. This is because there are significant differences in renewable resources across Europe. The cost differential between supply in Europe's demand centers and periphery outweigh the cost of building new transmission infrastructure. Thus, we see both substantial net importers (e.g., the industry clusters in Ruhr Valley and Rotterdam area) and strong net exporters of energy (e.g., Denmark, Ireland, Spain, and Greece). The option to transport energy around Europe also counteracts incentives for industry relocation. Expanding energy transport infrastructure may be less controversial since it would affect regional development less than the migration of industries.

Regarding hydrogen production, we see both solar-based hubs in Southern Europe and wind-based hubs in Northern Europe using water electrolysis. The regional and technological diversity in electrolytic hydrogen production is the preferred solution, but the impetus for Southern solar-based hubs is greatly affected by the evolution of other system components. Difficulties with installing sufficient onshore wind capacities around the North Sea would reinforce their relevance, although the import of most liquid carbonaceous fuels from outside of Europe would weaken the case for solar-based hubs. Our results also highlight that compared with the amount of electrolytic hydrogen, blue hydrogen from steam methane reforming with CC only plays a marginal role and was only used in our scenarios when no hydrogen network could be developed.

As the general hydrogen network benefit is not dependent on electricity grid reinforcements, both networks could be developed in parallel. Thus, policymaking could focus on options that are most easily achieved and widely accepted. Although the hydrogen network benefit is not affected by alternate technology cost developments or import policies, the network topology is. Lower costs of solar PVs raise the appeal of hydrogen production hubs in Southern Europe, altering the suitable hydrogen network layout. Likewise, wide-ranging hydrogen imports from the Middle East/North Africa (MENA) region would need to be supported with transmission infrastructure in Southern Europe.

The flexible operation of electrolyzers has several advantages for system stability and integrating wind and solar generation cost-effectively and should be incentivized. Fluctuating renewable generation is buffered in geological hydrogen storage primarily in the United Kingdom, Denmark, Spain, and Greece to achieve more continuous production in capital-intensive fuel synthesis plants in accordance with their operational restrictions. This leads to low curtailment rates of renewables and a lower requirement for firm capacity, outlining the benefit of cross-sectoral approaches for reducing CO_2 emissions cost-effectively. Fuel cell CHP plants in Germany can further support grid operation when the power grid cannot be expanded. However, energetically, the re-electrification of hydrogen only plays a minor role in this sector-coupled system.

To reach the net-zero energy systems we have modeled, which feature new transmission networks and leverage various sector-coupling flexibilities, many changes are needed in policy and regulation. Tight coordination between countries and energy sectors is required to achieve low-cost solutions, similar to how the process for the Ten Year Network Development Plan (TYNDP) has moved toward joint planning.[57] To achieve the coordination of dispatch and capacity expansions at the local level around grid bottlenecks, particularly if electricity and hydrogen network expansions are limited, local price signals are required corresponding to our 181 bidding zones (Figures S34 and S35). In our model, electric vehicles and heat pumps operate flexibly, which requires the deployment of smart meters and dynamic electricity tariffs to incentivize grid-supporting behavior. Finally, a sustained rise in the price of CO_2 emission certificates is needed. The results we show are also contingent on adjusted regulations and rules for building infrastructure and developing competitive markets for hydrogen and carbon dioxide.

Conclusions

In this work, we have investigated the potential role of a hydrogen network in net-zero CO_2 scenarios for Europe with high shares of renewables. The analysis was performed using the open sector-coupled energy system model PyPSA-Eur-Sec featuring high spatio-temporal coverage of all energy sectors (electricity, buildings, transport, agriculture, and industry across 181 regions and 3-hourly resolution for a year). With these levels of spatial, temporal, technological, and sectoral resolution, it is possible to represent grid bottlenecks as well as the variability and regional distribution of demand and renewable supply. Thereby, the system's infrastructure needs regarding generation, storage, transmission, and conversion can be assessed. This includes, in particular, trade-offs between electricity grid reinforcement, which has limited public support, and developing a hydrogen network, for which unused gas pipelines can be repurposed.

Besides large-scale renewable expansion of wind turbines in Northern Europe and solar PVs in Southern Europe, the build-out of hydrogen infrastructure is one of the biggest changes seen in our scenarios for the future European energy system. Huge new electrolyzer capacities enter the system and operate flexibly to aid renewables integration. The siting of new hydrogen production hubs is determined by access to excellent wind and solar resources in the broader North Sea region and Spain in particular. Underground storage in salt caverns is developed in the United Kingdom, Denmark, Spain, and Greece for buffering, and a new continent-spanning hydrogen pipeline network is built to connect cheap supply and storage potentials in Europe's periphery with its industrial and population centers. This new hydrogen network is supported by considerable amounts of gas pipeline retrofitting: between 63.5% and 69.1% of the network uses repurposed pipes, especially in Central European countries with existing gas infrastructure.

Our analysis reveals that a hydrogen network can reduce energy system costs by up to 3.4%. Cost reductions are shown to be highest when the expansion of the power grid is restricted. However, hydrogen networks can only partially substitute for grid expansion. We found that in fact both ways of transporting energy and balancing renewable generation complement each other and achieve the highest cost savings of up to 9.9% together. At the same time, these findings also support the interpretation that neither electricity nor hydrogen network expansion are essential for achieving a cost-effective system design if such a cost premium can be accepted to achieve alternative goals.

In conclusion, there appear to be many infrastructure trade-offs regarding how and from where energy is transported across Europe, provided that energy planning and operation can be tightly coordinated. More energy transport capacity reduces costs, but some restrictions on grid expansion have only limited impact on total energy system costs. This should enable policymakers to choose from a wide range of compromise energy system designs with low cost but higher acceptance.

EXPERIMENTAL PROCEDURES

Resource availability

Lead contact

Requests for further information, resources, and materials should be directed to the lead contact, Fabian Neumann (f.neumann@tu-berlin.de).

Materials availability

The study did not generate new materials.

Data and code availability

The code to reproduce the experiments and visualizations is available on GitHub: github.com/fneum/spatial-sector and is archived on Zenodo: https://doi.org/10.5281/zenodo.8005409.

A dataset of the modeling results has been deposited to Zenodo: https://doi.org/10.5281/zenodo.8006612.

An interactive scenario explorer accompanies the paper at h2-network.streamlit.app, with code published on GitHub: github.com/fneum/spatial-sector-dashboard and archived on Zenodo: https://doi.org/10.5281/zenodo.8005327.

Technology data assumptions were taken from github.com/pypsa/technology-data (v0.4.0), which are archived on Zenodo: https://doi.org/10.5281/zenodo.6885392.

We also refer to the documentation of PyPSA (pypsa.readthedocs.io), PyPSA-Eur (pypsa-eur.readthedocs.io), and PyPSA-Eur-Sec (pypsa-eur-sec.readthedocs.io) for technical instructions on how to install and run the model.

Modeling setup

In this section, the core characteristics and assumptions of the model PyPSA-Eur-Sec are presented. More detailed descriptions of specific sectors, energy carriers, renewable potentials, transmission infrastructure modeling, and mathematical problem formulation are covered in the supplemental information sections model overview, electricity sector, transport sector, industry sector, heating sector, renewables, hydrogen, methane, oil-based products, biomass, carbon dioxide capture, usage and sequestration (CCU/S), and mathematical model formulation.

The European sector-coupled energy system model PyPSA-Eur-Sec uses linear optimization to minimize total annual operational and investment costs subject to technical and physical constraints, assuming perfect competition and perfect foresight over one uninterrupted year of 3-hourly operation (see supplemental information section mathematical model formulation for mathematical formulation). In this study, we used the historical year 2013 for weather-dependent inputs. Apart from existing electricity and gas transmission infrastructure and hydroelectric power plants, no other existing assets are assumed (*greenfield optimization* or *overnight scenario*) so that the model assumes a long-term equilibrium in a market with perfect competition and foresight and disregards pathway dependencies. The model is implemented in the free and open software framework PyPSA (Python for Power System Analysis).[58]

PyPSA-Eur-Sec builds upon the model from Brown et al.,[23] which covered electricity, heating in buildings, and ground transport in Europe with one node per country. PyPSA-Eur-Sec adds biomass on the supply side; industry, agriculture, aviation, and shipping on the demand side; and higher spatial resolution to suitably assess infrastructure requirements. In this study, the European continent is divided into 181 regions. Unavoidable process emissions, feedstock demands in the chemicals industry, and the need for dense fuels for aviation and shipping also required the addition of a detailed representation of the carbon cycles, including CC from industry processes, biomass combustion, and directly from the air (DAC).

Figure S1 gives an overview of the supply, transmission, storage, and demand sectors implemented in the model. To render interactions in the sector-coupled energy system, we model the energy carriers electricity, heat, methane, hydrogen, carbon dioxide, and liquid carbonaceous fuels (oil, methanol, and naphtha) across the different energy sectors. Generator capacities (for onshore wind, offshore wind, utility-scale and rooftop solar PVs, biomass, hydroelectricity, oil, and natural gas); heating capacities (for heat pumps, resistive heaters, gas boilers, CHP plants, and solar thermal collector units); synthetic fuel production (electrolyzers, methanation, Fischer-Tropsch, steam methane reforming, and fuel cells); storage capacities (stationary and electric vehicle batteries; hydrogen storage in caverns and steel tanks; pit thermal energy storage; pumped hydro and reservoirs; and carbon-based fuels such as methane, methanol, and Fischer-Tropsch fuels); CC (from industry process emissions, steam methane reforming, CHP plants, and DAC); and transport capacities of electricity transmission lines, new hydrogen pipelines, and repurposed natural gas pipelines are all subject to optimization, as well as the operational dispatch of each unit in each represented hour.

Exogenous demand and supply assumptions
Exogenous demand and supply assumptions in the model include a fully price inelastic and spatially fixed demand for the different materials and energy services in each sector; the extent of land transport electrification; the use of methanol as shipping fuel and kerosene in aviation; process switching in industry; the reuse and recycling rates of steel (70%), aluminum (80%), and plastics (55%) manufacturing; the ratio of district heating to decentralized heating in densely populated regions; efficiency gains of 29% due to building retrofitting; and hydroelectricity capacities (for reservoir and run-of-river generators and pumped hydro storage).

Technology and cost assumptions
For the technology and cost assumptions, we take estimates for the year 2030 for the main scenarios and run a sensitivity analysis with more progressive cost projections for the year 2050 in supplemental information section using technology and cost projections for 2050. We take technology projections for the year 2030 for the main scenarios to account for expected technology cost reductions in the near-term while acknowledging that the gradual transition to climate neutrality implies that much of the infrastructure must be built well in advance of reaching net-zero emissions. Many numbers come from the technology database published by the DEA.[40] A complete referenced list of techno-economic assumptions is compiled in Table S3. Among many other technologies, for overnight costs, we assume 636 €/kW_e for rooftop PV; 487 €/kW_e for utility-scale PV; 142 €/kWh and 160 €/kW for batteries; 1,035 €/kW for onshore wind; 1,524 €/kW for offshore wind; 450 €/kW_e for electrolyzers; 1,100 €/kW_e for fuel cell CHPs; 2 €/kWh for underground hydrogen storage; 0.54 €/kWh for central pit thermal energy storage; 628–651 €/kW_{out} for methanation, methanolization, and Fischer-Tropsch processes; 572 €/kW_{CH_4} for steam methane reforming with CC (i.e., blue hydrogen); and 685 €/t for direct air capture if operated without interruption.

Energy supply
The time series and potentials of variable renewable energy supply (wind, solar, hydro, and ambient heat) are computed from historical weather data (ERA5[59] and SARAH-2[60]). Potentials for wind and solar generation take various land eligibility constraints into account, e.g., suitable land types and exclusion zones around populated and protected areas. As long as emissions can be offset by negative emission technologies and sequestration potentials are not exhausted, limited amounts of

fossil oil and gas can still be used as primary energy supply. Although no assumption about the origin of fossil energy is made, imports of renewables-based products into Europe are only considered in supplemental sensitivity analysis in supplemental information section importing all liquid carbonaceous fuels.

Transmission networks

The full transmission network for European electricity transport is taken from the electricity-only model version, PyPSA-Eur,[61] and is clustered down to 181 representative regions based on the k-means network clustering methodology used in Hörsch and Brown[62] and Frysztacki et al.[39] This level of aggregation reflects, at the upper end, the computational limit to solve a temporally resolved sector-coupled energy system optimization problem and, at the lower end, the requirements to preserve the most important transmission corridors that cause bottlenecks and limit the system integration of renewables. The impacts of spatial aggregation are evaluated in supplemental information section spatial resolution. Power flows are modeled using a cycle-based load flow linearization from Hörsch et al.[63] that significantly improves computational performance. The power flow linearization implies that no transmission losses are considered. Hydrogen pipeline flows assume a simple transport model. This means that while incoming and outbound flows must balance for each region and pipes can transport hydrogen only within their capacity limits, no further physical gaseous flow constraints are applied. The potential for gas pipeline retrofitting is estimated based on consolidated network data from the SciGRID_gas project[64] such that for every unit of gas pipeline decommissioned, 60% of its capacity becomes available for hydrogen transport.[16]

Industry

For industry, we assume that the demand for materials (such as steel, cement, and high-value chemicals) remain constant and disregard options for industry relocation.[65] The assumed industry transformation is characterized by electrification; process switching to low-emission alternatives (e.g., switching to hydrogen for the direct reduction of iron ore[66]); more recycling of steel, plastics and aluminum[67]; fuel switching for high- and mid-temperature process heat to biomass and methane; the use of synthetic fuels for ammonia and organic chemicals; and allowing CC. It is assumed that no plastic or other non-energy product is sequestered in landfill but that all carbon in plastics eventually makes its way back to the atmosphere, either through combustion or decay; this approach is stricter than in other models.[35]

Transport

The transport sector comprises light and heavy road, rail, shipping, and aviation transport. For road and rail, electrification and fuel cell vehicles for heavy-duty transport are available. For shipping, methanol is considered. Aviation consumes kerosene, the origin of which (fossil or synthetic) is endogenously determined. Half of the battery electric vehicle fleet for passenger transport is assumed to engage in demand response schemes as well as vehicle-to-grid operation.

Buildings

The buildings sector includes decentral heat supply in individual housing as well as centralized district heating for urban areas. Heating demand can be met through air- and ground-sourced heat pumps, gas boilers, gas/biomass/hydrogen CHPs, resistive heaters as well as waste heat from synthetic fuel production in district heating networks. For district heating networks, seasonal heat storage options are also available. Efficiency gains from building retrofitting of 29% are exogenous to the model based on Zeyen et al.[68]

Biomass

For biomass, only waste and residues from agriculture and forestry are permitted, using the medium potential estimates from the JRC ENSPRESO database.[69] This results in 336 TWh per year of biogas that can be upgraded and 1,038 TWh per year of solid biomass residues and waste for the whole of Europe. Biomass can be used in combined electricity and heat generation with and without CC, as well as to provide low- to medium-temperature process heat in industry.

Carbon capture

Carbon capture is needed in the model both to capture and sequester process emissions with a fossil origin, such as those from the calcination of fossil limestone in the cement industry, as well as to use carbon for the production of carbonaceous fuels for dense transport fuels and as a chemical feedstock, for example to produce plastic. CO_2 can be captured from exhaust gases (industry process emissions, steam methane reforming, CHP plants) or by direct air capture. Captured CO_2 can be used to produce synthetic carbonaceous fuels via the Sabatier, Fischer-Tropsch, or methanolization process. Up to 200 $MtCO_2$/a may be sequestered underground, which is sufficient to capture process emissions but limits the system's reliance on negative emission technologies. Landfill of plastics is not considered a long-term sequestration option.

SUPPLEMENTAL INFORMATION

Supplemental information can be found online at https://doi.org/10.1016/j.joule.2023.06.016.

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AUTHOR CONTRIBUTIONS

F.N.: conceptualization, data curation, formal analysis, investigation, methodology, software, validation, visualization, writing – original draft, and writing – review & editing; E.Z.: data curation, formal analysis, investigation, software, validation, and writing – review & editing; M.V.: formal analysis, investigation, methodology, software, and writing – review & editing; T.B.: conceptualization, data curation, formal analysis, funding acquisition, investigation, methodology, project administration, resources, software, supervision, writing – original draft, and writing – review & editing.

DECLARATION OF INTERESTS

The authors declare no competing interests.

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