Speed of technological transformations required in Europe to achieve different climate goals

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Abstract

Europe’s contribution to global warming will be determined by the cumulative emissions until climate neutrality is achieved. In this paper, we investigate alternative transition paths under carbon budgets corresponding to temperature increases between 1.5 and 2°C. We use PyPSA-Eur-Sec, an open model of the sector-coupled European energy system with high spatial and temporal resolution. All the paths entail similar technological transformations, but the timing of the scale-up of important technologies like water electrolysis, carbon capture and hydrogen networks differs in the model. In our results, solar PV, onshore and offshore wind become the cornerstone of a net-zero energy system enabling the decarbonisation of other sectors via direct electrification (e.g. heat pumps and electric vehicles) or indirect electrification (e.g. using synthetic fuels). Under the cost and performance assumptions applied, for a social cost of carbon (SCC) of 120\texteuro}/tCO\textsubscript{2}, transition paths under 1.5 and 1.6 °C budgets are, respectively, 8%, and 1% more expensive than the 2°C-budget because building assets earlier costs more. These pathways also see a faster ramp-up of new technologies before 2035. Under these assumptions, the 1.5°C-budget is cost-optimal in our model, if SCC of at least 300 Euros are considered. Moreover, we discuss the strong implications of the SCC and discount rate assumed when comparing alternative paths. We also analyse the consequences of different assumptions on the cost and potential of CO\textsubscript{2} sequestration.

1. Introduction

Sustained high global annual CO\textsubscript{2} emissions are quickly depleting our carbon budget, i.e., the cumulative emissions that will enable us to remain below a specific temperature increase. On top of that, estimating the carbon budget is subject to substantial uncertainties in the evaluation of the transient climate response to cumulative emissions or the potential impacts of Earth system feedbacks such as permafrost thawing [1]. An environmentally cautious approach would entail reducing emissions as fast as possible. In Europe, climate ambition has risen in recent years with examples such as the 55% greenhouse gas (GHG) reduction commitment of the European Union for 2030 [2], the European Green Deal [3], and aggressive reduction targets in some member states [4, 5]. Still, a large gap exists between globally committed emissions reductions and those necessary to fulfil the Paris Agreement [6].

On the one hand, Integrated Assessment Models (IAMs) have traditionally been used to assess transition paths under strict carbon budgets [7–11]. The term IAM covers a wide variety of models including a global representation of energy, economy, climate and land. Generally, IAMs suffer from a low spatial and temporal resolution that prevents the representation of energy networks and the variability of wind and solar, although some efforts to improve these limitations are ongoing [12–14]. On the other hand, Energy System Models (ESMs) with higher spatial and temporal resolution, as well as detailed representations of power networks [15–22] and storage [23–26] are used to investigate power system transformations, but by focusing on regions and particular years, they miss long-term global interactions with climate and technological learning. Recently, some ESMs have been extended to include other sectors [27–31] resulting in alternative transition paths that are characterized by a higher contribution from wind and solar photovoltaics (PV) than IAMs scenarios, together with high electrification of other sectors [32, 33].

Some of the authors have recently shown that, for a carbon budget corresponding to 1.75°C temperature increase, it is less expensive to follow an early and steady decarbonisation path in Europe, in which emissions are strongly reduced before 2030, compared to delayed action that requires more abrupt and expensive transformations mid-century [29]. Here, we go one step further by investigating the consequences of transforming the full sector-coupled European energy system with different cumulative
emissions corresponding to various temperature increases. There are two main consequences of Europe achieving net-zero emissions while using a lower carbon budget. First, ceteris paribus, the probability to remain below a certain temperature increase is higher, or the associated temperature increase is lower, see Fig. 1. Second, for the same global budget, reducing cumulative emissions in Europe enables higher emissions in other regions compensating for Europe’s higher historical emissions.

In this work, we use PyPSA-Eur-Sec[36], an open model of the sector-coupled European energy system with uninterrupted 3-hourly resolution for a full year and a 37-nodes network, Fig. 2. The model comprises the electricity, heating and land transport sectors used in [27, 29]. Moreover, it is extended to include the transformation of industry, industrial feedstocks, shipping and aviation, the use of biomass and a detailed accounting of carbon capture, use, and storage (CCUS), as well as demand-side efficiency improvements in buildings. Our model includes higher time and spatial resolution than most IAMs. This captures the variability of wind and solar, the presence of heating demand peaks and dark doldrums (i.e., periods with low wind and solar generation), and the role of storage at different time scales. This, together with detailed modelling of electricity and hydrogen grids, is crucial to estimate flexibility needs to balance variable renewable generation. Moreover, we include a more detailed breakdown of industry by sector, including for example the option of direct reduced iron (DRI) in steel manufacturing.

We model the transformation of the European energy system using a myopic approach in 5-years steps from 2020 to 2050 assuming different carbon budgets. This paper focuses on two main research questions which can be stated as: What are the economic consequences of different climate ambitions for Europe? When do key new technologies emerge under distinct budgets with a common set of cost and performance assumptions? We show that, regardless of the budget, similar technological transformations take place, but for the 1.5 and 1.6°C budgets it is cost-optimal for most of them to take place already by 2035. We extend the existing literature by providing three main novelties. First, the use of a highly resolved model. Second, the comparative analysis of transition paths for Europe under carbon budgets corresponding to temperature increases discretised by a tenth of a degree. Third, the inclusion of a sensitivity analysis to the cost and potential of CO₂ sequestration.

Figure 1: Temperature increase for distinct carbon dioxide budgets in Europe from 2020 (6.4% of global emissions allocated to Europe based on an equal per-capita distribution). Confidence intervals are indicated by different shadings. For 1.7°C and 67% confidence interval, the figure also shows the European budgets assuming a equitable distribution that compensates for historical emissions, and an inequitable distribution that assumes the prevalence of historical splits among regions (5.5% [34] and 11% [35] of global emissions allocated to Europe, respectively).

Figure 2: The networked model comprises 37 nodes, one per region of countries belonging to separate synchronous zone. The size of the circles represents today’s electricity demand in the residential and services sector. HVAC/HVDC transmission capacities among countries are shown in grey/red. Renewable resources are aggregated to the smaller regions shown on the map. The green shades represent the annual capacity factor for onshore wind in the different regions. Equivalent information for solar PV and offshore wind is depicted in Fig. S2-3.

2. Methods

2.1. Baseline model setup

We model the transformation of the European energy system under six different carbon budgets corresponding to a temperature increase between 1.5 and 2°C, with 67% confidence, see [37] and Supplemental Materials. The share of the global carbon budget allocated to Europe is estimated assuming an equal-per capita distribution [34, 35]. Fig. 1 shows alternative relations between Europe carbon budget and temperature increase when (i) the historical
responsibilities of every region are taken into account [34], (ii) splitting is proportional to historical emissions in every region [35], and (iii) different confidence intervals for temperature increase are considered [37].

While the use of uninterrupted hourly resolution has proven to be key to estimate the flexibility needs for highly renewable energy systems [27, 32], several analyses have proven that minor differences are found when using 3-hour instead of 1-hour time steps [38–40]. This is due to the fact that 3-hourly resolution is enough to capture the solar daily fluctuations and estimate the required short-term storage. Hence, we select 3-hour time steps to enable a high spatial resolution, network modelling and detailed technology description while reducing computational requirements. For every year in one transition path, the model including 37-nodes network, 370 regions representing renewable resources and full sector coupled is solved in approximately 4 hours using 30GB RAM.

Exogenous assumptions in the model include the path of electrification of land transport, conversion of shipping to H2 and some transformations in the industry. Each of these exogenous assumptions is discussed in more detail below. The model determines endogenously the technologies to produce electricity and heating, the origin of H2 (electrolytic or by steam methane reforming with or without carbon capture), and the origin of methane and naphtha (fossil or synthetically produced) that are used in land transport and shipping, in aviation and for energy consumption and feedstock in the industry. The sectors are described in detail in the Supplemental Materials and a summary is provided below.

Electricity can be produced by solar PV, onshore wind, open (OCGT) and combined-cycle gas turbines (CCGT), nuclear, coal, lignite power plants, and combined heat and power (CHP) units using biomass or gas. The solar and wind resource are represented by 370 regions, each of which is connected to one of the 37 nodes in the network. Electricity can be stored in batteries or H2 storage (underground in salt caverns or overground in steel tanks). Reservoir, run-of-river hydro and pumped hydro storage (PHS) capacities are fixed exogenously based on existing facilities. The existing and planned transmission capacities are modelled using linear power flow. H2 can be produced using electrolyser and by steam methane reforming (SMR) with or without carbon capture. A H2 network can be built to connect countries if it is cost-effective. The impact of disallowing the H2 network is evaluated in a sensitivity analysis.

Heating demand can be supplied by heat pumps, heat resistors and gas boilers and stored in thermal energy storage. Costs and properties of these technologies vary depending on if they are installed in a high-density population area, where district heating systems are assumed, or in low-density population areas where only individual solutions are considered. In the former, heat can also be provided by CHP plants. Efficiency gains due to build-
CO\textsubscript{2} can be captured from exhaust gases (CHP plants, SMR or process emissions in the industry) or by direct air capture (DAC). Captured CO\textsubscript{2} can be used to produced synthetic methane via the Sabatier reaction or synthetic hydrocarbons via the Fischer-Tropsch process. It can also be sequestered underground with a maximum potential of 200 MtCO\textsubscript{2}/a, which is conservative but enough for capturing process emissions. Cost assumptions for different technologies are taken from DEA [42]. Future cost evolution of different technologies is exogenous to the model [42], see Note S12. Efficiencies, lifetimes, and maximum potential for renewable technologies are described in the Supplemental Materials. Based on the JRC database [43], we follow a conservative approach in which only biomass that is not competing with crops is accounted as solid-biomass potential and can be used in the industry or burnt in CHP plants with our without carbon capture. A sensitivity analysis disallowing biomass with carbon capture is performed. Biogas is upgraded into biomethane.

In the industry sector, the production of materials (such as steel, cement, chemicals) in every node is assumed to remain constant. A detailed analysis is carried out in every industrial subsector to model the most probable transformations. The general approach includes the electrification of some industrial process, and the use of methane and biomass for high and mid-temperature process heat, respectively. A comprehensive description of all the industrial transformations assumed is included in the Supplemental Materials. In every time step, the percentage of steel that is produced via direct reduced iron (DRI) is fixed exogenously and so is the supply of aluminium from scrap metal. The model determines endogenously how the hydrogen demand is supplied (either using electrolyser, SMR or SMR with CC) and whether the methane and hydrocarbons have fossil, synthetic or biogas origin. All hydrocarbon feedstocks are also accounted for in the model.

Road and rail transport transformation is exogenously fixed using a path that ends with 85% of land transport electrified and 15% using fuel cells in 2050. These assumptions are fixed exogenously because we expect consumer choice, government support and stock turnover inertia to be more decisive than pure cost optimisation. Half of the existing EVs in every time step are assumed to do smart charging and enable vehicle-to-grid operation. Shipping transformation is also exogenous and follows a path that entails full conversion to hydrogen in 2050. Aviation consumes kerosene whose origin (fossil vs. synthetic) is endogenously determined. The possibility of importing synthetic fuels to Europe is not modelled. The agriculture sector is not included in the model and it is assumed that emissions from this sector are offset by the LULUCF sector.

2.2. Sensitivity analysis

There are many uncertain input assumptions that flow into the optimisation model. Uncertain inputs could overwhelm any signal in the results. To explore how the results depend on the inputs, we perform several sensitivity analyses: varying the most important cost assumptions, leaving cost and technology assumptions fixed at 2020 values throughout the pathway, varying the carbon sequestration costs and volumes, endogenising building efficiency measures, removing the hydrogen network and excluding biomass with CCS.

3. Results

3.1. The timing of key technology transformations

Fig. 4 gathers the occurrence of some key transformations under distinct carbon budgets. Our scenario assumptions, which include exogenously determined CO\textsubscript{2} emissions paths, imply that lower carbon budgets reach net-zero emissions earlier, see also Fig. S1. The CO\textsubscript{2} emissions path corresponding to 1.5°C carbon budget reduces emission in year 2040 to less than 5% of 1990 level. The time step at which electricity generation is almost fully renewable precedes the system-wide decarbonisation by 5 to 15 years. For 1.5 and 1.6°C-budgets, it would be optimal to fully decarbonise the electricity generation already in 2030, which highlights how challenging the low-emissions budgets are. Electricity generation is the first sector to undergo a deep transformation, see also Fig. S7. This was expected since renewable technologies, mainly solar PV, onshore and offshore wind are already competitive on a levelised basis with fossil-fueled generators [44, 45]. Regardless of the budget, all the paths entail strong electrification of other sectors with non-biomass renewable electricity supplying more than 55% of final energy demand in 2050. The pathways for 1.5 and 1.6°C-budgets achieve more than 40% of renewable primary energy in 2030, a target that has been recently proposed by the European Commission [46]. However, those two budgets see a dramatic ramp-up of technologies, particularly solar PV, wind and electrolysis, between 2025 and 2035, see Fig. S5 and S6. In particular, for the 1.5°C budget, the model install around 500 GW/a of new wind and solar in that period. The model finds it cost-effective to build a hydrogen network that enables exchanges among countries, Fig. S30.

Our results show three strategies to decarbonise the heating sector. First, heat pumps and electric resistors are used to supply heating demand. Second, in urban areas, district heating systems enable the use of large heat pumps together with biomass CHP units and gas boilers to ensure heating supply in the winter. When the system approaches net-zero emissions, waste heat output from the Fischer-Tropsch process dumped into district heating systems can
Figure 4: Occurrence of key transformations for distinct carbon budgets. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5° and 2°C. When the bar corresponding to a carbon budget is hidden by another color, this indicates that the timeline for the technological transformation is the same for both budgets. See Fig. S30, S34-44 for sensitivity analysis of these results.

cover up to 20% of the demand in those areas. Third, in regions without district heating systems, gas boilers are used at peak demand times to backup the heat pumps that cover the main supply. The share of consumed gas that has fossil, biogas or synthetic origin evolves throughout the transition paths, Fig. S17. The share of technologies providing heat in every time step are shown in Fig. S11-15.

Between 2030 and 2040, substantial production of electrolytic H₂ is cost-effective for scenarios below 1.9°C. Initially, the production of H₂ is used for seasonal balancing of power generation, see Fig S32. As the Fischer-Tropsch technology is installed, H₂ is consumed to produce synthetic hydrocarbons reaching a demand of 1700 TWhH₂/a when all the hydrocarbons consumed in the model are synthetically produced. None of the transition paths installs capacity to produce blue H₂ via steam methane reforming with carbon capture (SMR-CC), see Fig. S25. The production of H₂ switches straight from SMR to electrolysis. The production of synthetic hydrocarbons starts as soon as the electricity generation is fully decarbonised in every budget.

Direct air capture (DAC) capacity is only installed for carbon budgets corresponding to temperature increase below 1.7°C. The model finds it more cost-effective to capture CO₂ from (i) process emissions (which in 2050 represents 155MtCO₂/a, Note S10), (ii) biomass and methane used in the industry, and (iii) biomass combusted in CHP units, see also Fig. 5. With the reference cost assumptions, sequestering CO₂ underground is economically preferable and it occurs earlier than building Fischer-Tropsch capacities that transform the captured CO₂ into synthetic hydrocarbons. The 200MtCO₂/a potential for CO₂ sequestration assumed for Europe is fully utilised as soon as it becomes cost-effective. A sensitivity analysis for CO₂ sequestration is conducted in Section 3.6.

The CO₂ emissions paths for the 1.5 and 1.6 °C budgets are assumed to reduce emissions below 5% of 1990 by 2040 and 2045 respectively. However, the exogenously defined transformation of land transport and shipping still include substantial emissions at that time. This result in the model including a large deployment of Negative Emissions Technologies (NETs) between 2030 and 2045 for those scenarios. This example illustrates the consequences for the system if the decarbonisation of some sectors lags behind the global CO₂ reduction targets.

In 2015, Europe imported 6000 TWh/a of oil [47]. More stringent carbon budgets reduce Europe’s external dependency earlier. The reasons are twofold: first, efficiency measurements and direct-electrification reduces the demand for oil and methane; second, as CO₂ emissions are constrained, the upgrade of biogas into methane and the production of synthetic oil become cost-effective, see Fig. S17-S18.

3.2. Sectoral emissions and CO₂ price

In all the alternative transition paths, the order of sectoral emissions reductions is maintained, see Fig. S8. Electricity generation is decarbonised first, followed by the heating and industry sectors, and finally, aviation. In our analyses, the shares of road transport and shipping that gets electrified or transformed into using hydrogen are exogenously fixed, Note S11.
The required CO₂ price, also known as the marginal abatement cost, is an output of the model. It increases as CO₂ emissions allowance are reduced, see Fig. 6. For the 1.5°C-budget, a sharp increase of the CO₂ price, reaching 370 €/tCO₂, is required to incentivise the extremely fast build-up of a carbon-neutral system by 2035. The 1.6°C carbon budget requires a smoother ramp-up in CO₂ price that stabilizes towards the end of the transition at around 270 €/tCO₂. Higher carbon budgets require an increase of CO₂ price in 2050 to force carbon neutrality. Compared to our previous analysis [29], we found that similar CO₂ prices are required by mid-century, even though in this work we included a broader representation in the model of NETs such as carbon capture in the industry and CHP units, carbon sequestration, and carbon use in the Fischer-Tropsch process. The assumed cost and potential of CO₂ sequestration also affect the required CO₂ price, as discussed in Section 3.6. It is important to realize that, by setting up a CO₂ cap in every time step, instead of assuming a CO₂ price that steadily increases throughout the transition, the model avoids the large use of carbon dioxide removal as discussed by Strefler et al. [48].

3.3. Net-present-value of system costs

Figure 7 depicts the net-present-value (NPV) of system costs for transition paths using distinct carbon budgets and social discount rates. The assumed social discount rate has a higher impact on the calculation than the carbon budget in every path. As expected, the net-present-value of future costs is lower with higher discount rates. Fig. 7 also shows that the required investments for distinct climate ambitions are not that different. Lower budgets require an earlier build-up of new assets, which due to the exogenous evolution of costs assumed, results in a more expensive transition. For a detailed description of cost components throughout the system transformation see Fig. S4.

For a 2% discount rate, the 1.5 and 1.6°C budgets are, respectively, 8% and 1% more expensive than the 2°C budget. These percentages are 5% and -1% when a 6% discount rate is used. The implications of the assumed discount rate have been extensively discussed by other authors, see [49–51] and Supplemental Materials. For transition paths with perfect foresight and negative emissions, Emmerling et al. [50] found that reducing the discount rate from 5% to 2% more than doubles the required CO₂ price in 2020, more than halves the carbon budget overshoot and increases substantially the investments in renewable energy. In our analysis, the assumed discount
rate does not change the timing of different technologies because we use a myopic approach in which the CO₂ emissions paths are set exogenously and not by imposing a single carbon budget constraint. Still, this parameter has a large influence when computing the net-present-value of system costs. The selection of a discount rate higher than zero is based on the assumption that economic growth will continue. Based on this, historical growth rates are typically assumed. Temporal preferences are also claimed as an argument to support high discount rates. However, it is important to recognize the impacts in terms of inter-generational burden-sharing of this argument, as mitigation and adaptation costs in the short and long term will be paid by different groups of people.

3.4. Including climate damage costs

So far we have considered only the cost of mitigation given defined CO₂ budgets. Including the costs saved by avoided climate damages could favour scenarios with tighter budgets, but there is a high uncertainty associated with the assessment of the economic impact of climate change [52–58]. In this section we illustrate the potential impact on our results of including different assessments of climate damages quantified through the social cost of carbon (SCC). The costs of mitigation for tighter CO₂ budgets are compared with the reduced climate damage costs.

The social cost of carbon (SCC) represents the economic cost caused by an additional tonne of carbon dioxide emissions or its equivalent. SCC is different from the marginal abatement cost discussed in Section 3.2. On the one hand, SCC is typically employed in cost-benefit analysis, aiming at evaluating to what extent the cost of climate mitigation compensates for the avoided climate change impacts. On the other hand, the CO₂ marginal abatement cost is employed in cost-effectiveness analyses, i.e., when estimating the most cost-effective strategy to attain a climate target. Arguments in favor of using marginal abatement cost [59] and SCC [60] have been put forward, and some authors argue for using a welfare-optimal carbon price calculated as the sum of both [61].

In our analysis, the marginal abatement cost is an output of the model, determined as the Lagrange/KKT multiplier of the emissions cap constraint imposed every year, which in turn has been exogenously determined to make sure that the carbon budget is not exceeded. For instance, for the 2.0°C transition path, the marginal abatement cost takes care of ensuring that cumulative emissions correspond to a temperature increase of 2.0°C. The marginal abatement cost depends on the transition path and the year, Fig. 6.

On top of that, when we compare the NPV of system costs for different carbon budgets, we want to include the fact that the 2°C budget is expected to have stronger economic impacts caused by climate change than the 1.5°C budget. To take that into account, when estimating the NPV, we add a term that is calculated as the SCC multiplied by the additional emissions of every transition relative to the 1.5°C-budget. In this way, we limit warming to a temperature threshold (different for every carbon budget) using the marginal abatement costs, and also account for the damages occurring below that threshold via the SCC.

Widespread SCC estimations can be found in the literature caused by the uncertainties associated with climate change and duration of impacts, together with the high sensitivity to some modelling assumptions [52–58]. We have considered here a SCC of 120 €/tCO₂ [62]. For simplicity and easy comparison of the scenarios, we assume that the SCC is constant in time. Fig. S9 and S10.
show, respectively, the cumulative system cost for a SCC of 75 and 300 €/tCO₂ and we use the same SCC regardless of the discount rate used in our calculations, despite the fact that the SCC itself depends on the discount rate. The former represents the recommendations by the Danish Economic Council of Environmental Economics [63]. For the latter, the transition under 1.5°C already results less expensive than for the 2°C budget. It must be noted that a SCC of 300 €/tCO₂ is lower than the SCC estimated by the German Environmental Agency with 0% time preference (680 €/tCO₂) [64] and similar to recent recommendations by the European Commission (250 and 800 €/tCO₂ in 2030 and 2050 respectively) [65]. Moreover, considering the risk associated with climate tipping points could increase the SCC by up to a factor of two [66]. On top of that, the co-benefits of reducing CO₂ emissions in Europe due to avoided premature mortality and morbidity caused by air pollution, reduced lost workdays and increased crop yields are estimated in the range of 125–425 €/tCO₂ [67].

We believe that Fig. 7 provides a useful decision map where the costs of distinct climate ambitions in Europe are compared including not only those cost components associated with a profound transformation of our energy system but also those related to the avoided CO₂ emissions. Together with Fig. 1, it enables comparing the alternative budgets related to different temperature increases, confidence intervals and Europe’s share of global emissions, while not losing sight of the strong impacts of exogenous assumptions such as the discount rate or the SCC.

### 3.5. Sensitivity 1: Costs and technological performance

The sensitivity to some of the main assumptions is evaluated through three sets of analyses. First, the sensitivity to cost assumptions for selected technologies is described in the Supplemental Materials. Assuming variations of ±20% of the costs of the main technologies do not have any substantial impact on the date for key transformations, Fig. S34-S41. We found the difference in NPV of system cost among different budgets, the use of solar and wind as main energy generators, and the selection of electrolytic-H₂ over the production via SMR-CC to be robust for all the cost variations, Fig. S29.

Moreover, to evaluate the impact of the assumed exogenous cost evolution, a sensitivity run is implemented in which costs and technologies performance are kept fixed at values corresponding to 2020. This produces no major impact on the timeline for key transformations, Fig. S30, the use of NETs, Fig. S31 and the production of H₂ and synthetic fuels, Fig. S29. However, neglecting the potential costs evolution translates into a higher contribution from wind and nuclear compensating lower solar generation, Fig. S29, higher CO₂ prices, Fig. S32, higher NPV of system costs, Fig. S33, and slightly higher cost differences between the transition paths with lower carbon budgets and 2.0°C, Fig. S29.

### 3.6. Sensitivity 2: CO₂ sequestration cost and potential

So far, we have assumed a CO₂ sequestration potential for Europe of 200 MtCO₂/a, and a cost for sequestration and transport of 20€/tCO₂. The high uncertainties associated with those assumptions and the full deployment of the potential shown in Fig. 5 motivates a sensitivity analysis specifically focused on CO₂ sequestration. We conduct it here for the 1.7°C-budget. Fig. 8 shows the amount of CO₂ sequestered in 2050 under different assumptions. As the potential is increased, the system finds it optimal to sequester up to around 950MtCO₂/a. It is important to realized that this value is far below the technical potential for CO₂ sequestration in Europe, estimated at 126 GtCO₂/a [68]. This could reduce the annualised system cost by 10%, and it would also impact the required CO₂ price, see Fig. S19 and S20.

Besides underground sequestering, the alternative uses of captured CO₂ in the model are to produce synthetic methane or synthetic oil. The former is not part of the solution for most of the sensitivity cases, see Fig. S21, so we can consider the absence of methanation in the optimal system a robust result. Conversely, the production of synthetic liquid fuels strongly depends on the CO₂ underground sequestering potential, Fig. S21, S23. In short, when underground sequestering is hampered by high cost or limited potential, more synthetic fuel is produced via Fischer-Tropsch, as this is the second most cost-effective option.

When lower costs are assumed for CO₂ sequestration, the rate increases slightly up to 1,150MtCO₂/a, still much below the estimated physical potential. It is also interesting to realize that, when the model selects a high CO₂ sequestration rate, additional CO₂ capture technologies like gas CHP with carbon capture are installed, although this technology was not part of the optimal solution under the reference potential of 200 MtCO₂/a, Fig. S23. Hydrogen production via steam methane reforming with carbon capture (SMR CC) is only part of the solution when the sequestration potential is extended to 1000 MtCO₂/a, Fig. S22-S23. Even with a extremely low cost assumption for CO₂ sequestration (2 €/tCO₂) the use of SMR CC is limited to 220 TWh/a.

If we look now at the opposite scenario, that is, one where the transport and sequestration of CO₂ ends up being more expensive than initially estimated, this results in a lower optimal sequestration rate, e.g., for a hundred-fold increase in cost, the maximum CO₂ sequestration rate is approximately 127MtCO₂/a. As previously mentioned, the lower CO₂ sequestration rate is compensated by a higher production of synthetic oil, Fig S21.
3.7. Sensitivity 3: \( H_2 \) network, building retrofitting, biomass with carbon capture

In this section, we briefly evaluate some additional assumptions. We start by discussing the constraints on the networks expansion. The previous analysis assumed no expansion of transmission links among countries, besides those already existing. The build-up of a greenfield hydrogen network among countries, which was cost-effective in all the transition paths, was also included, see Fig. S24. On the one side, for the 1.7°C-budget, allowing the expansion of the power grid up to twice today’s volume reduces the system cumulative cost by 2%. As previously shown, the cost benefits of grid expansion [17] are reduced when the additional local flexibility provided by sector coupling is included in the model [27]. On the other side, disabling the build-up of the hydrogen network (i.e., hydrogen is produced and consumed locally) only increases the cumulative system cost by 0.5% and does not result in substantial changes on the key transformation indicators, Fig. S42.

Previous analyses assumed exogenous reduction in space heating due to building retrofitting whose cost is not included. To evaluate this assumption, we implemented a sensitivity run where the extension of investment in building retrofitting is endogenously calculated as described in [41]. For the 1.7 °C, this strategy is gradually implemented throughout the path as it becomes cost-effective, see Fig. S28.

\( H_2 \) capture on biomass burnt in CHP plants or the industry sector shows substantial deployment when the system approaches net-zero emissions, Fig 5, but this technology is controversial due to the uncertain costs, land use and environmental impacts [8, 69, 70]. We run a sensitivity analysis disallowing \( H_2 \) capture from biomass. The cumulative system cost is roughly the same, but the system deploys direct air capture to achieve the required negative emissions, Fig. S25 and S44.

3.8. Limitations of this analysis

Before concluding, we briefly mention the main limitations of our study in this section. First, we have assumed an exogenous transformation of land transport and shipping. Regarding land transport, we expect stock turnover, government support as well as public perception of new technology to be a stronger determinant of new vehicle shares that pure cost optimisation. Regarding shipping, we assumed a conservative transition since there is inertia in stock turnover that limit the transformation speed. This has important implications, particularly for the 1.5°C and 1.6°C budgets, which require offsetting the emissions from these sectors when net-zero emissions are imposed.

Second, we have assumed that the cost evolution of different technologies is exogenous based on pathways forecast by the Danish Energy Agency, i.e., no endogenous learning effects are considered. By doing that, we are assuming that global learning, driven by globally installed capacities, will determine the future costs of technologies, but we do not represent possible local learning. We have evaluated the implications of the assumed costs evolution via sensitivity analyses.

Detailed analyses of the near-optimum solution space for the European power system have been recently presented [71–74]. In general terms, they found that the optimal solution space is quite “flat,” meaning that alternative solutions, in which the deployment of some technologies is different, can still achieve a cost close to the minimum. In this paper, we have not investigated the near-optimal solutions for the alternative transition paths, which could allow certain technology transitions to take place earlier or later. This remains a topic for further research.

3.9. Results Summary

In this work, we have investigated the transformation of the European energy system between 2020 and 2050 under distinct carbon budgets corresponding to various temperature increases between 1.5°C and 2°C. We found that all the transition paths experience similar technological transformations, but they occur at different points in the future. The system begins decarbonising electricity generation by installing solar PV, onshore and offshore wind capacities. This triggers strong electrification of other sectors such as heating, where large capacities of heat pumps are installed. Renewable electricity is also used to produce hydrogen via electrolysis, displacing the current production via steam methane reforming (SMR). A hydrogen network interconnecting the countries, co-optimised with the rest of the system, appears after 2035. Only for \( H_2 \) sequestration potential higher than 1000 MtCO\(_2\)/a and low cost, the model installs limited capacities of SMR with carbon capture, casting doubts on the relevance, from a system perspective, on the blue hydrogen strategy. When the system approaches net-zero emissions, electricity is also used...
to produced synthetic oil via the Fischer-Tropsch process, enabling the decarbonisation of the aviation and industry sectors. Carbon budgets corresponding to 1.5°C and 1.6°C result in cost-optimal solutions where the most substantial technological transformations are fully accomplished by 2030, which shows how challenging these budgets are.

The system installs negative emission technologies (NETs) to offset process emissions from the industry. NETs are also needed when the transformations of land and maritime transport lag behind the CO₂ reduction targets. First and foremost, CO₂ is captured from point-source emitters including process emissions and biomass burnt in the industry and CHP units. For the 1.5 and 1.6°C-budget, direct air captured is also extensively used. The 200 MtCO₂/a assumed as CO₂ sequestration potential is completely deployed when the system approaches net-zero emissions. After that, the Fischer-Tropsch process is used to convert CO₂ into synthetic fuel. The impacts of uncertainties in CO₂ cost and potential have been investigated via sensitivity analysis. For optimistic cost and potential assumptions, up to 1,150 Mt CO₂/a are used, which is far below the estimated physical potential of CO₂ sequestration in Europe (126 GtCO₂/a) [68]. When the cost of CO₂ transport and sequestration is assumed to be higher, the use of CO₂ sequestration is reduced, and the full potential is not deployed. It is relevant to notice that under extremely high-cost assumptions (2,000 €/tCO₂), it is still cost effective to sequester 127 MtCO₂/a. This partially compensates for the industry process emissions, which account for 155 MtCO₂/a in 2050, and results in a marginal abatement cost of approximately 2,100 €/tCO₂. Hence, our results indicate that the lack of a small potential of CO₂ sequestration at a reasonable cost makes the net-zero CO₂ system very challenging.

4. Discussion

After presenting the main results of our analysis and its limitations, we discuss three main implications for the transformation of the European energy system.

The need for high CO₂ prices. Although only large emitters are currently included in the European Emissions Trading System (ETS), extending this mechanism to other sectors has also been proposed [46, 75]. Based on our results, for low-carbon budgets, ETS-sectors tend to reduce emissions earlier than non-ETS sectors, see Fig. S7. In particular, reducing emissions in the heating sector is expensive, mainly due to the strong seasonality in heating demand, see Fig. S27, and the fact that only in district heating systems (and not in individual systems) seasonal storage can be used for balancing. The need for stronger incentives to reduce emissions in the heating and industry sector is indicated in our results by the high CO₂ price required towards the end of the transition paths, Fig 6.

Having a single CO₂ price in Europe for all the sectors and countries can create tensions. For instance, the ETS CO₂ price has reached values higher than 80€/tCO₂ in 2021. For the electricity sector, the substitution of coal by gas power plants was already triggered at much lower CO₂ prices. The CO₂ price surge has increased the marginal cost of gas, which together with the rise in gas price, triggered an unprecedented period of high electricity prices in Europe. This has triggered some discussion on the negative effect of such high CO₂ prices for the electricity sector, but we can see that historical values are still much lower than those required in our model when approaching net-zero CO₂ emissions. This is one of the examples of the challenges for policy to reconcile the use of a single CO₂ price for sectors that required very different policy pressure. Similarly, a certain CO₂ price can represent a strong incentive for some European countries while not being strong enough to incentivize transformations in others [76, 77]. Although the need for external action is indicated in our model by high CO₂ prices, in reality, high CO₂ prices may lead to negative distributional impacts and uncertainty if prices are volatile. Other policy implementations may be preferred, such as subsidies for emissions-free technologies and transformation deadlines including banning of emitting technologies.

Large wind and solar PV deployment together with negative emissions technologies. Our results show, consistently for all the carbon budgets and sensitivities, a strong deployment of wind and solar PV that become the cornerstone of the energy supply. This confirms previous works that emphasize the need for using up-to-date costs assumptions for wind and solar and proper modelling of balancing strategies to avoid downplaying this decarbonisation strategy [10, 32, 78].

We found that at least a small amount of CO₂ sequestration, in the order of 200 MtCO₂/a, at a reasonable price, is needed to ease the operation of the fully decarbonized system. Nevertheless, we found that that it is possible to attain net-zero CO₂ emissions while using conservative assumptions for biomass potential and CO₂ sequestration. In essence, by avoiding common assumptions that are known to favour NETs we found cost-effective solutions that make limited use of them. The avoided pitfalls include (i) a poor representation of the balancing options and/or costs of renewable energy sources [32], (ii) perfect foresight optimisation with high discount rates which is known to result in large contribution from NETs [50, 79], (iii) assumptions of an exogenous exponential increase of the CO₂ price [48]. Conversely, in our model, we use a myopic approach and set up an emissions cap in every time step.

Low carbon budgets are economically beneficial but require a dramatic increase in wind and solar capacities. When comparing alternative climate ambi-
tions, the cumulative system cost is typically employed to assess the alternatives. However, the high impact of uncertain exogenous assumptions, such as the social cost of carbon (SCC) or the discount rate, on those estimations requires careful evaluation. Here, we found that for a 2% discount rate and SCC of 120 €/tCO₂, the 1.5°C and 1.6°C-budgets are 8% and 1% more expensive respectively, relative to the 2°C budget. However, for a SCC of 300 €/tCO₂, the 1.5°C budget is cost-optimal. In essence, our results show that the main challenge for low-carbon budgets is not the increase in the investments but the required dramatic ramp-ups of technologies, particularly solar PV, wind and electrolysis, between 2025 and 2035, see Fig. S5. In particular, for the 1.5°C budget, the model install around 500 GW/a of new wind and solar in that period.

It is difficult to assess whether this dramatic development will be feasible in light of historical building rates. Technological transitions are known to be nonlinear and are better described by S-curves [80, 81]. Cherp and co-authors [82] evaluated historical data on wind and solar deployment in different countries and, by using an S-curve approximation, concluded that the maximum annual rate is expected to be 0.9% and 1.1% of the electricity supply for solar and onshore wind respectively. For the current EU annual electricity consumption of 2850 TWh/a, and assuming 1,200 and 2,000 full-load hours for wind and solar respectively, this translates into 35 GW/a, a much lower figure than the requirements in our model. However, as argued by other authors [81, 83], it is likely that the historical development rates, which were highly determined by policy support are not a good indicator of the feasible development speed for wind and solar once these technologies have become competitive and in many locations the lowest-cost option.

As a final remark, our simulations suggest there is only a small cost to ambitious emissions reduction. In this case, following the precautionary principle and pursuing an ambitious path, given the high uncertainty about the potential impact of climate change, would come with little cost penalty. This would not only allow a lower contribution of Europe to temperature increase but could also offset higher emissions in other world regions, compensating for inequitable historical emissions.

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**Supplemental Materials : Speed of technological transformations required in Europe to achieve different climate goals**

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**Supplemental experimental procedures.**

**S1. Carbon budgets and temperature increases**

Following the methodology described in [1] and the estimations in [2], summarized below, the global carbon budget $B_{\text{global}}$ as a function of the temperature increase $T_{\text{lim}}$ is estimated using Eq. 1.

$$
B_{\text{global}} = \frac{T_{\text{lim}} - T_{\text{hist}} - T_{\text{nonCO}_2} - T_{ZEC} - E_{\text{Esfb}}}{\text{TCRE}}
$$

The historical human-induced warming to date is assumed to be $T_{\text{hist}}=0.94^\circ C$ until 2006–2015 relative to the preindustrial level (1850–1900). The non-CO$_2$ contribution to future temperature $T_{\text{nonCO}_2}$ is estimated to be between 0.1 and 0.2$^\circ C$ [1, 2]. The zero-emissions commitment $T_{ZEC}$ represents the additional contribution to peak warming that is still to be expected after a complete cessation of CO$_2$ emissions and is assumed to be zero. The Transient Climate Response to Cumulative Emissions (TCRE) is assumed to be normally distributed at 0.45$^\circ C$ (1$\sigma$ range 0.27-0.63$^\circ C$) per 1000Gt CO$_2$ [2]. Finally, subtracting the warming associated with Earth system feedback $E_{\text{Esfb}}$, such as the permafrost thawing, and global CO$_2$ emissions since 2011, the global carbon budgets from 2020 onwards are shown in table.

Global carbon budgets (Gt CO$_2$) and Europe carbon budgets assuming an equal per-capita distribution.

| $T$(\degree C) | 33rd | 50th | 67th | 33rd | 50th | 67th |
|-------|------|------|------|------|------|------|
| 1.50  | 650  | 500  | 400  | 41.8 | 32.2 | 25.7 |
| 1.60  | 850  | 650  | 550  | 54.7 | 41.8 | 35.4 |
| 1.70  | 1050 | 850  | 700  | 67.5 | 54.7 | 45.0 |
| 1.80  | 1250 | 1000 | 850  | 80.4 | 64.3 | 54.7 |
| 1.90  | 1450 | 1200 | 1000 | 93.2 | 77.2 | 64.3 |
| 2.00  | 1700 | 1350 | 1150 | 109.3| 86.8 | 73.9 |

Global carbon budgets are converted to European budgets assuming equal-per capita distribution which translates into a 6.43% share for Europe [3, 4]. This share is 5.5% when the historical responsibilities

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of each region are taken into account (starting from 1992, the year in which the text of UNFCCC was approved) [4]. Assuming the prevalence of historical emissions the share would be 11% [3].

The carbon budgets are distributed throughout the transition paths assuming an exponential decay, following [3]. Emissions $e(t)$ in every year $t$ are limited by

$$e(t) = e_0(1 + (r + m)t)e^{-mt}$$  \hspace{1cm} (2)

where $r$ is the initial linear growth rate, which here is assumed to be $r=0$, and the decay parameter $m$ is determined by imposing the integral of the path to be equal to the budget for Europe $B_E$.

$$B_E = \int_{t_0}^{\infty} e_0(1 + (r + m)t)e^{-mt}dt$$

$$m = \frac{1}{B_E} \sqrt{1 + \frac{r B_E}{e_0}}$$ \hspace{1cm} (3)

On top of that, net CO$_2$ emissions in 2050 are forced to be zero.

Europe carbon budgets are distributed in time assuming an exponential decay.

**S2. PyPSA-Eur-Sec: model description**

PyPSA-Eur-Sec builds upon the model from [5], 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, and industry, aviation and shipping on the demand side. Unavoidable process emissions, as well as the need for feedstocks for the chemicals industry and dense hydrocarbon fuels for aviation, necessitate careful management of the carbon cycle, including carbon capture from industry, biomass combustion and directly from the air. The overall circulation of energy and carbon is shown in figure. A brief mathematical formulation of the model is provided in Section S15.
S3. Power sector

S3.1. Electricity demand

Hourly electricity demand for every country is retrieved from EU Network Transmission System Operators of Electricity (ENTSO-E) via the convenient dataset prepared by the Open Power System Data (OPSD) initiative [6]. Existing electrified heating is subtracted from the existing electricity demand since that heating demand is taken into consideration in the heating sector.

S3.2. Electricity supply

In every country, electricity can be generated by solar photovoltaics (rooftop and utility-scale installations), onshore wind, offshore wind, Open Cycle Gas Turbines (OCGT), Combined Cycle Gas Turbines (CCGT), coal, lignite, and nuclear power plants and Combined Heat and Power (CHP) units using either gas, coal or biomass. Their costs, lifetimes and efficiencies are shown in Tables S1 and S2.

Wind and solar energy resources are aggregated to 370 clusters in Europe, see Figure 2 in the main text and Figures S2 and S3. After that, the power network is clustered to 37 nodes, one per country. This means that in every country a variable number of renewable regions exist, depending on the size of the country. This approach enables representing different wind and solar resources within every country while keeping a short computational time. See a more detailed description of the benefits and limitations of this
approach in [7]. Onshore and offshore wind capacity factor time series are modelled by converting wind velocity from ERA5 reanalysis [8] into wind generation, following the methodology described in [9]. ERA5 database comprises hourly resolution and 30 km spatial resolution. For every region, a capacity layout proportional to the wind resource is assumed. Time series representing the hourly capacity factors for solar PV are obtained by converting satellite irradiance (SARAH) data [10] into solar electricity generation. The open-source package atlite [11] is used for the generation of renewable time series.

The maximum capacity for onshore wind, offshore wind, and solar PV that can be installed in every region is limited by the estimated potentials. Those are determined by summing the available land in every reanalysis grid cell, which in turn is calculated by considering only the suitable land for every technology, according to the Corine Land Cover (CLC) database [12] and subtracting Natura 2000 protected areas [13]. The bathymetric dataset GEBCO [14] is used to estimate offshore wind potentials. Only areas whose sea depth is lower than 50 m are considered valid. For near-shore locations (distance < 30 km) offshore wind turbines with AC connection are considered. For far-shore locations, DC-connected offshore turbines (including AC-DC converter costs) are assumed.

Conversion factors of 10 MW/km² and 50 MW/km² are considered for wind and utility-scale solar PV respectively. For onshore and offshore wind, the potential $Potential_{n,\text{wind}}$ is calculated as 20% of the available land. For utility-scale solar PV, 9% of the available land is used for estimating the potential $Potential_{n,PV}$. For rooftop PV, the potential is estimated based on the population density assuming 0.1 kW/m² and 10 m²/person.

$$ Potential_{n,PV} = \sum_i 0.09 (A_{i,\text{CLC,PV}}^{PV} - A_{i,\text{Natura2000}}^{PV}) \quad \text{for} \quad i \in n $$ (4)

where $A_{i,\text{CLC,PV}}^{PV}$ is the area of the grid cell belonging to PV categories in the CLC database and $A_{i,\text{Natura2000}}^{PV}$ is the area of the grid cell protected by the Natura 2000 network.

$$ Potential_{n,\text{wind}} = \sum_i 0.2 (A_{i,\text{CLC,wind}}^{wind} - A_{i,\text{Natura2000}}^{wind}) k_n \quad \text{for} \quad i \in n $$ (5)

For wind, $k_n$ is a coefficient calculated by imposing the condition that in none of the grid cells the installed capacity surpasses the potential. This represents a conservative approach. Higher potentials could be attained if the assumed capacity layout is not proportional to the wind resource.

Land types considered suitable for every technology. Categories in Corine Land Cover database [12] are selected following [15].

| Technology    | Categories                                                                 |
|---------------|---------------------------------------------------------------------------|
| Solar PV      | artificial surfaces (1-11), agriculture land except for those areas already occupied by agriculture with significant natural vegetation and agro-forestry areas (12-20), natural grasslands (26), bare rocks (31), and sparsely vegetated areas (32) |
| Onshore wind  | agriculture areas (12-22), forests (23-25), scrubs and herbaceous vegetation associations (26-29), bare rocks (31), and sparsely vegetated areas (32) |
| Offshore wind | sea and ocean (44)                                                        |

Reservoir hydropower and run-of-river capacities are exogenously fixed at their values in 2015. Hourly inflow is modelled using atlite [11] based on runoff data from ERA5 and scaled using the EIA annual hydropower generation statistics [16]. CHP units are modelled as back-pressure plants whose heat production is proportional to electricity output.

S3.3. Electricity storage and transport

Electricity can be stored in static batteries, hydrogen storage and Pumped Hydro Storage (PHS). The capacity of the latter in every country is exogenously fixed at 2015 values. The H₂ supply is described in
Section S5.2. Hydrogen can be stored in overground steel tanks or underground salt caverns, see details in Section S5.3.

The modelling of transmission grids is based on PyPSA-Eur \cite{17}. PyPSA-Eur uses as input all the existing high voltage alternating current (HVAC) and direct current (HVDC) lines in the European system. The 4,973 nodes in the initial network are clustered using the k-means algorithm into a variable number of nodes \cite{7}. In this work, we use 37 nodes, i.e., one for every region of European countries belonging to separate synchronous zones, see Fig. 2 in the main text. The equivalent lines connecting the clustered nodes are calculated by aggregating the previous lines and estimating a weighted cost that takes into consideration the underwater fraction of the lines and adds a 25\% factor to account for the fact that transmission lines cannot be placed as the crow flies due to land use restriction. For the transmission lines capacities, a safety margin of 33\% of the installed capacity is used to satisfy \( n – 1 \) requirement \cite{18}. Linear optimal power flow is applied using Kirchhoff’s formulation \cite{19}. The baseline scenario assumes that transmission capacities are kept fixed. Moreover, a sensitivity analysis enabling the co-optimisation of transmission capacities with the generation, storage and conversion technologies is also discussed in the main text.

S3.4. Distribution grids

Contrary to the transmission grid, the distribution grid topology is not included and only the total capacity from the transmission grid down to the low-voltage level is optimised. Rooftop PV, heat pumps, resistive heater, home batteries and chargers for passenger cars are connected to low-voltage level. The remaining generation and storage technologies are connected to the transmission grid. In practice this means that the distribution grid capacity is only extended if it is necessary to balance the mismatch between local generation and demand. The cost assumption for extending the transmission grids are included in Table S1.

S3.5. Existing power plants and decommissioning

For conventional technologies, i.e. OCGT, CCGT, coal, lignite, nuclear and gas CHP, installed capacities in every country in 2020 and commissioning dates are retrieved from powerplantmatching \cite{20}. For solar PV, onshore and offshore wind, the installed capacities in 2020 and the installation dates were obtained by processing annual installed capacities statistics from \cite{21}. Existing power plants are assumed to be decommissioned at their corresponding commissioning date plus lifetime (Table S2). Since many nuclear power plants in Europe have been retrofitted, an average lifetime of 60 years before decommissioning is assumed.

S4. Heating sector

S4.1. Heating demand

Annual heat demands for European countries are retrieved from JRC-IDEES \cite{22}. They are converted into daily heat demand based on the population-weighted \cite{23} Heating Degree Day (HDD), that is, heating is assumed to be proportional to the difference between ambient temperature and a threshold temperature. 15\(^\circ\)C is assumed as threshold temperature. Ambient temperature is read from the same reanalysis database \cite{8} used to model wind time series. The daily space heating demand is split in different hours following a daily demand profile that is different for weekdays/weekends and residential and services demand \cite{24}. On top of that, hot water demand, assumed to be constant throughout the day, is added. Total heating demand in Europe is estimated at 3,660 TWh\(_{th}/a\). Although the value is similar to total annual electricity demand, heating demand shows a more pronounced seasonal variation \cite{25}.

For every country, heating demand is split between low-population density areas and high-population density areas. 44.6\% of the European population is estimated to live in the latter \cite{5} where district heating (DH) systems can be deployed. For Southern European countries (Portugal, Spain, Italy, Greece and
Bulgary), no DH systems are allowed. For the remaining countries, 60% of the heating demand in high-population density areas is assumed to be supplied by district heating systems. 15% losses in district heating systems are assumed. In [25], a sensitivity analysis is conducted in which DH systems are assumed to be extended until they cover 100% of heating demand in high-density population areas. This reduces cumulative system costs by 2.4% but, due to the wide range of cost estimation for DH systems found in the literature, it is difficult to conclude whether the savings would offset the required investments for DH expansion and maintenance.

Cooling demand is currently supplied by electricity so it is included in the electricity demand time series. It is assumed to remain constant throughout the transition paths. For a thorough discussion of the impact of changing cooling demand, the reader is referred to [26].

Space heating demand is reduced due to building retrofitting. For the baseline scenario, this is exogenously fixed, and its cost is not included in the total system cost. In a sensitivity analysis, we investigate the impact of endogenous retrofitting, as described in [27].

S4.2. Heating supply

In densely-populated areas with district heating systems, heating can be supplied by central air-sourced heat pumps, heat resistors, gas boilers, solar collectors, and CHP units using methane or solid biomass. Including only air-sourced heat pumps in urban areas is a conservative assumption since there are many possible sources of low-temperature heat that could be tapped in cities (wastewater, rivers, lakes, seas, ground in some cases, etc.). Methane and biomass CHPs are based on back pressure plants operating with a fixed ratio of electricity to heat output. Their model corresponds to the DEA [28]‘Gas turbine simple cycle (large)’ and ‘09b Wood Pellets Medium’, respectively. Time series for solar collectors heat production are generated based on the reanalysis database [8]. Waste heat from fuel cells, methanation and Fischer-Tropsch plants is also input into the district heating networks. In areas without district heating systems, heating can be supplied by individual heat pumps, heat resistors and gas boilers. Costs, lifetimes, and efficiencies of the different technologies are included in Tables S1 and S2.

The Coefficient of Performance (COP) of heat pumps depends on ambient or ground temperature to capture the lower COP in winter. COP depends on the difference between the source and the sink temperatures $\Delta T = T_{sink} - T_{source}$. For air-sourced heat pumps (ASHP), $COP = 6.81 + 0.121 \Delta T + 0.000630 \Delta T^2$, for ground-sourced heat pumps (GSHP), $COP = 8.77 + 0.150 \Delta T + 0.000734 \Delta T^2$ [29]. The sink water temperature is assumed to be $T_{sink} = 55^\circ C$, the source temperature for air and ground is taken from the same reanalysis database used to estimate heating demand [8].
S4.3. Existing heating capacities and decommissioning

Capacities already existing for technologies supplying heat are retrieved from [30]. For the sake of simplicity, coal, oil and gas boilers capacities are assimilated to gas boilers. Besides that, existing capacities for heat resistors, ASHP, and GSHP are included in the model. For heating capacities, 25% of existing capacities in 2015 are assumed to be decommissioned in every 5-year time step after 2020.

S4.4. Heating storage

Thermal energy can be stored in large water pits associated with district heating systems and individual thermal energy storage (TES), i.e., small water tanks. A thermal energy density of 46.8 kWh/th/m$^3$ is assumed, corresponding to a temperature difference of 40 K. The decay of thermal energy $1 - \exp(-\frac{1}{2\tau})$ is assumed to have a time constant of $\tau=180$ days for central TES and $\tau=3$ days for individual TES. Charging and discharging efficiencies are 90% due to pipe losses.

S5. Hydrogen

S5.1. Hydrogen demand

Hydrogen is consumed in the industry to produce ammonia and direct reduced iron (DRI), see Sections S10.2 and S10.4. Hydrogen is also consumed to produce synthetic methane and hydrocarbons, see Sections S6.2 and S7.2. The consumption of hydrogen for land transport and shipping is exogenously fixed, see Sections S11.1 and S11.3. Stationary fuel cells can be installed and use to convert $H_2$ into electricity if it is cost-effective to balance renewable fluctuations. The waste heat from the stationary fuel cells is used in district-heating systems.

S5.2. Hydrogen supply

Currently, most of the $H_2$ consumed globally is produced using steam methane reforming, SMR ($CH_4 + H_2O \rightarrow CO + 3H_2$ and water-gas shift reaction $CO + H_2O \rightarrow CO_2 + H_2$). PyPSA-Eur-Sec allows the production of $H_2$ via SMR, SMR with CCS or using electrolysers. The costs, lifetimes and efficiencies for every technological option are shown in Tables S1 and S2. Alkaline electrolysers are assumed since they have a lower cost [28] and higher cumulative installed capacity [31] than polymer electrolyte membrane (PEM) electrolysers. The share of different technologies that produce $H_2$ is a result of the optimisation and consequently is impacted by their costs, the price of electricity, the global $CO_2$ constraint, etc.

S5.3. Hydrogen storage and transport

Hydrogen can be stored in overground steel tanks or underground salt caverns [31]. For the latter, energy storage capacities in every country are limited to the potential estimation for onshore salt caverns within 50 km of shore to avoid environmental issues associated with brine solution disposal, see Figure 7 in [32].

A greenfield $H_2$ network connecting the different nodes is built if it is cost-effective.

S6. Methane

S6.1. Methane demand

Methane is used in individual and large-scale gas boilers, CHP plants with or without CCS, and in some industry subsectors, see Section S10.
S6.2. Methane supply

On top of using fossil methane, the model includes three alternative ways of producing methane. First, synthetic methane can be produced in two steps by producing hydrogen and then combining hydrogen and captured CO$_2$ in the Sabatier reaction ($CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$). Second, the single step combined electrolysis and methanation process with efficient integration of heat developed in the HELMETH project is also possible [33]. Third, biogas is upgraded into methane. The share of synthetic, biogas-based, and fossil-based methane used by the model is a result of the optimisation which depends on the technology costs, global CO$_2$ constraints, etc.

S6.3. Methane transport

Methane is assumed to be transported freely between countries using the existing fossil gas network since future demand is predicted to be low and no bottlenecks are expected.

S7. Oil-based products

S7.1. Oil-based products demand

Naphtha is used as a feedstock in the chemicals industry, see Section S10.3. Land transport that is not electrified or converted into using H$_2$-fuel cells also consumes oil-based products, see Section S11.1. Aviation consumes kerosene, see Section S11.2.

S7.2. Oil-based products supply

On top of using fossil oil-based products, they can be synthetically produced by combining H$_2$ and captured CO$_2$ in the Fischer-Tropsch process ($nCO + (2n + 1)H_2 \rightarrow C_nH_{2n+2} + 2nH_2O$) with the costs and efficiency included in Tables S1 and S2. The waste heat from the Fischer-Tropsch process is used in district heating systems. The share of fossil-based and synthetic oil products used by the model is a result of the optimisation which depends on the technology costs, global CO$_2$ constraints, etc.

S7.3. Oil-based transport

Oil-based products are assumed to be transported freely among countries since future demand is predicted to be low and no bottlenecks are expected.

S8. Carbon dioxide capture, usage and sequestration (CCU/S)

CO$_2$ can be captured using direct air capture (DAC), or carbon capture associated with (a) industry process emissions, (b) SMR, (c) methane or biomass used for process heat in the industry or (d) CHP plants using biomass or methane. Costs and efficiencies for the different technologies are included in Tables S1 and S2. DAC includes the adsorption phase where electricity and heat are required to assist the adsorption process and regenerate the adsorbent. It also includes the drying and compression of CO$_2$ prior to storage which consumes electricity and rejects heat. Process emissions are captured assuming 95% capture rate and costs of CO$_2$ capturing corresponding to the cement industry [28]. For SMR, CHP units, and biomass and methane used in the industry, the model includes two options (with or without CCS) with different costs. The capacities and use of each of them are co-optimised with the rest of the elements in the system.

The captured CO$_2$ can be used to produce synthetic methane and synthetic oil products, see Sections S6.2 and S7.2, respectively. Captured CO$_2$ can also be sequestered underground. 20 €/tCO$_2$ are assumed for transport and sequestration. IEA reports cost for pipe transport between 2 and 14 USD/tCO$_2$ and cost for CO$_2$ underground sequestration of 10 USD/tCO$_2$ [34]. A maximum potential of 200 MtCO$_2$/a is considered for Europe, which is very conservative but enough for capturing process emissions. The impact of these assumptions is investigated in the sensitivity analysis.
Biomass classification from the JRC [35], usage in PyPSA-Eur-Sec, and potentials in JRC’s medium availability scenario for 2030.

| Source                                  | JRC code    | use in model | Potential [PJ/a] |
|-----------------------------------------|-------------|--------------|------------------|
| Energy crop: sugar beet bioethanol      | MINBIOCRP21 | not used     | 882.5            |
| Energy crop: rapeseed and other oil crops | MINBIORPS1     | not used     | 949.3            |
| Energy crop: starchy crops              | MINBIOCRP11 | not used     | 288.0            |
| Energy crop: grassy                     | MINBIOCRP31 | not used     | 1777.6           |
| Energy crop: willow                     | MINBIOCRP41 | not used     | 317.7            |
| Energy crop: poplar                     | MINBIOCRP41a| not used     | 96.6             |
| Wet and dry manure                     | MINBIOGAS1  | biogas       | 1237.6           |
| Primary agricultural residues           | MINBIOAGRW1 | solid biomass| 1120.6           |
| Roundwood fuelwood                     | MINBIOWOO   | not used     | 273.2            |
| Roundwood chips and pellets             | MINBIOWOOa  | not used     | 2087.1           |
| Forestry energy residue                 | MINBIOFSR1  | solid biomass| 1955.0           |
| Secondary forestry residues: woodchips  | MINBIOWOO1  | solid biomass| 432.2            |
| Secondary forestry residues: sawdust    | MINBIOWOO1a | solid biomass| 152.0            |
| Forestry residues from landscape care   | MINBIOFSR1a | solid biomass| 320.5            |
| Biodegradable municipal waste           | MINBIOMUN1  | solid biomass| 565.1            |
| Biodegradable sludge                   | MINBIOSLU1  | biogas       | 34.9             |

S8.1. CO₂ transport

CO₂ transport among countries is unconstrained in the model.

S9. Biomass

S9.1. Biomass potentials

Biomass supply potentials for each European country are taken from the JRC database [35, 36]. Only residues from agriculture and forestry as well as biodegradable municipal waste are considered as energy feedstocks. Fuel crops are avoided because they compete with scarce land for food production, while primary wood, as well as wood chips and pellets, are avoided because of concerns about sustainability [37]. The JRC provides potentials in low, medium and high availability scenarios, which depend on supply and competition with other uses of each feedstock. The medium availability scenario for 2030 is used, assuming no biomass import from outside Europe.

Manure and sludge waste are available to the model as biogas (that is upgraded to biomethane), while other wastes and residues are classified as solid biomass and available for combustion in CHP plants and for medium-temperature heat (< 500°C) applications in industry. The technical characteristics for the solid biomass CHP are taken from DEA Technology Database [28] assumptions for a medium-sized back pressure CHP with wood pellet feedstock; this has very similar costs and efficiencies to CHPs with feedstocks of straw and wood chips. A summary of the feedstocks and use in the model is shown in the table. The available potentials to the model are summed up in the table. We briefly compare these assumptions to other sources. In 2015, the EU28 energy usage was 180 TWh of biogas, 1063 TWh of solid biofuels, 109 TWh of renewable municipal waste and 159 TWh of liquid biofuels. Our model contains roughly a doubling of the biogas production from 2015 and similar amounts of solid biofuels, but a shift from energy crops and primary wood to residues and wastes. Since most liquid biofuels come from energy crops today, these do not appear in PyPSA-Eur-Sec. Zappa et al (2019) [38] uses the same JRC database but in addition to the feedstocks we use, they also allow roundwood chips and pellets, as well as grassy, willow and poplar energy crops.
S9.2. Biomass demand
Solid biomass is used to provide process heat up to 500°C in the industry, see Section S10. It can also be burnt in CHP plants associated with district heating systems.

S9.3. Biomass transport
Solid biomass and biogas products are assumed to be transported freely among countries. This is a limitation of the model but it is not expected to have a large impact since most of the countries have a biomass demand for the industry lower than their domestic potential.

S10. Industry
The industry sector comprises many different subsectors with specific energy demands, processes emitting CO₂, as well as existing and under-development mitigation strategies. Section S10.1 provides a general description of the modelling approach for the industry in PyPSA-Eur-Sec. The following subsections include, for every industry subsector, a description of: (a) the current energy demands, (b) the mitigation strategies, (c) whether the mitigation is exogenously fixed or co-optimised with the rest of the elements in the model.

S10.1. General Overview
Greenhouse gas emissions associated with industry can be classified into energy-related and process-related emissions. The former can be curbed by using low-emission energy sources. The only option to reduce the latter is by substituting or reducing material usage, by using alternative manufacturing process or by assuming a certain rate of recycling so that a lower amount of virgin material is needed. In 2015, the sectors with the largest final energy consumption in Europe were Iron and steel, Chemicals Industry, Non-metallic mineral products, Pulp, paper and printing, Food, beverages and tobacco, and Non-ferrous Metals.

The modelling procedure can be described as follows. First, the energy demands and process emissions for every unit of material output are estimated based on 2015 data from the JRC-IDEES database [22] and for the future new technology processes described below. Second, the energy demands and process emissions are calculated using the per-unit-of-material ratios and the production of materials in every country in 2015. The latter are assumed to remain constant in the future. Material output per country are retrieved from the JRC-IDEES database [22], ammonia production statistics [39], Eurostat energy-balances [40], and national statistics from Switzerland [41].

As a general rule for all the industry subsectors, the cross-cutting technologies demand that is currently supplied with electricity (i.e., lighting, air compressors, motor drives, fans and pumps, etc.), as well as the low-enthalpy heat demand, are directly added to the electricity and heat buses. Low enthalpy heat demand can be supplied via district heating systems or is added to services heat demand. This means that it can also be supplied by other processes producing heat as a bi-product such as DAC or Fischer-Tropsch. Besides low-temperature heat, the industry sector also demands process heat at higher temperatures. For EU-28 plus Norway, Switzerland, and Iceland, Rehfelt et al. [42] estimated that, from the 2015 industrial heat demand, 45% corresponds to \( T > 500°C \), 30% to 100-500°C, and 25% to \( T < 100°C \). Naegler et al.
[43] did a similar analysis for the year 2012 using slightly different categories, i.e. $>400^\circ$C / $100-400^\circ$C / $<100^\circ$C, and obtained similar shares (48/27/25%). The high share of high-temperature process heat demand led us to discard the use of solar thermal or geothermal to supply process heat. For every specific subsector, process heat is assumed to be supplied by methane, biomass or electricity depending on the specific characteristics.

The figure in this section depict: (i) the final consumption of energy and non-energy feedstock in the industry today and in 2050 when all the transformation described below have been implemented, and (ii) the process emissions from different subsectors. The latter are captured and, for net-zero emissions scenarios, need to be compensated by negative emissions, see Section S8.
Two alternative processing routes are used today to manufacture steel in Europe. The primary route, also known as integrated steelworks, represents 60% of the steel production, while the secondary route, based on electric arc furnaces, represents the remaining 40% [22]. The primary route uses blast furnaces in which coke is used to reduce iron ore into molten iron ($\text{Fe}_2\text{O}_3 + 3\text{CO} \rightarrow 2\text{Fe} + 3\text{CO}_2$ and $\text{FeO} + 3\text{CO} \rightarrow \text{Fe} + 3\text{CO}_2$) which is then converted to steel in a basic oxygen furnace. This route implies large process emissions (0.22 tCO$_2$/t steel). Alternatively, in the secondary route, electric arc furnaces are used to melt scrap metal, limiting the direct CO$_2$ emissions to the burning of graphite electrodes [44] and significantly reducing them (0.03 tCO$_2$/t steel). Integrated steelworks can be replaced by direct reduced iron, DRI ($\text{Fe}_2\text{O}_3 + \text{H}_2 \rightarrow 2\text{FeO} + \text{H}_2\text{O}$ and $\text{FeO} + \text{H}_2 \rightarrow \text{Fe} + \text{H}_2\text{O}$) and its processing in an electric arc furnace, avoiding the associated process emissions from reduction. Currently, DRI uses methane as a reduction agent but we assume here that it is substituted with hydrogen requiring 1.7 MWh H$_2$/t steel [45] and electricity 0.322 MWh$_{elec}$/t steel [46]. Hydrogen-based DRI is being explored in H2Future, HYBRIT, and SALCOS projects.

The share of steel produced by hydrogen-based DRI is exogenous to the model. The consumed hydrogen is produced via SMR, SMR+CCS or electrolysis, see Section S5.2. In 2050, DRI represents 30% of steel production. The remaining 70% is obtained following the secondary route using scrap metal. According to [47], circular economy practices have the potential of expanding the share of the secondary route to 85% just by increasing the amount and quality of scrap metal, but we follow a conservative approach and limit the secondary route to 70%.
The share of steel produced by direct reduced iron (DRI) and secondary route (scrap metal recycling) is exogenously fixed in the model.

For the remaining subprocesses in this sector, the following transformations are assumed. Methane is used to provide energy for the smelting process. The activities associated with furnaces, refining and rolling, and product finishing, are electrified assuming the current efficiency values for these cases. All the transformations described in this paragraph are already implemented at the beginning of the transition path. Although this is a limitation of the model, its impact is limited in the light of Figure S1.

S10.3. Chemicals Industry

The chemicals industry includes a wide range of diverse industries ranging from the production of basic organic (olefins, alcohols, aromatics) and inorganic (ammonia, chlorine) compounds to polymer (plastics) and end-user products (cosmetics, pharmaceutics). Ammonia is described in detail in Section S10.4.

The chemicals industry consumes large amounts of fossil-fuel based products as feedstock [48]. Synthetic methane and naphtha can be produced in the model, see Sections S6.2 and S7.2, respectively. For methane and naphtha, the share of synthetic vs fossil-based feedstock used by the model is a result of the optimisation, which, in turn, depends on the technology costs, global CO$_2$ constraints, etc. We assimilate all the demand for liquid hydrocarbons in the chemicals industry included in the JRC-IDEES database [22] (i.e. liquid petroleum gas -LPG-, diesel oil and residual fuel oil) to naphtha. Moreover, we assume the following transformations for the energy-consuming processes comprised in the chemicals industry: (a) All the final energy consumption in the steam processing is converted to methane since it requires temperatures higher than 500°C [42]. (b) The remaining processes in the chemicals industry are electrified using the current efficiency of microwave for high-enthalpy heat processing, electric furnaces, electric process cooling, and electric generic processes. Transformations (a) and (b) are already implemented at the beginning of the transition path. Although this is a limitation of the model, its impact is limited in the light of Figure S1.

Process emissions from feedstock in the chemical industry represent 0.369 tCO$_2$/t ethylene eq. We consider process emissions for all the material output. This is a conservative approach since we are assuming that all the plastic-embedded CO$_2$ will eventually be released into the atmosphere. However, plastic disposal in landfills will avoid, or at least delay, associated CO$_2$ emissions, while carbon dioxide could also be captured from waste to energy facilities (not considered in this model). Finally, circular economy practices could allow the mechanical and chemical recycling of 56% and 11% of total end-of-life of plastic volumes respectively [47]. However, we have followed a conservative approach and do not include any change in recycling rates.
S10.4. Ammonia
Ammonia production for every country in Europe is retrieved from the United States Geological Survey (USGS) statistics [39]. Hydrogen can be combined with Nitrogen to obtain ammonia in the Haber-Bosch process ($N_2 + 3H_2 \rightarrow 2NH_3$) [48]. Currently, $H_2$ for the ammonia industry in Europe is obtained by SMR. In PyPSA-Eur-Sec, $H_2$ can be produced via SMR, SMR + CCS or using electrolysers, see Section S5.2. The share of different technologies that produce $H_2$ is a result of the optimisation. When electrolytic-$H_2$ is used to produce ammonia, 6.5 MWh $H_2$/t $NH_3$ and 1.17 MWh$_{elec}$/t $NH_3$ are consumed [49].

S10.5. Non-metallic mineral products
This subsector includes the manufacturing of cement, ceramics, and glass.

S10.5.1. Cement
Cement manufacturing involves large process and energy emissions. The calcination of limestone to chemically reactive calcium oxide, also known as lime, ($CaCO_3 \rightarrow CaO + CO_2$) involves process emissions that account for 0.54 tCO$_2$/t cement. Some proposed mitigation strategies (e.g. using new raw materials or recovering unused cement from concrete at the end of life [50]) are currently at a very early development stage and, consequently, have not been considered here. For the cement industry, we assume that the final energy consumption (except current electricity, low-temperature heat and biomass consumption) is supplied by methane which is capable of delivering the required high-temperature heat. This transformation is already implemented at the beginning of the transition path. Although this is a limitation of the model, its impact is limited in the light of Figure S1. The share of fossil vs. synthetic methane consumed is a result of the optimisation, see Section S6.2. Process emissions are capture and, for net-zero emissions scenarios, need to be compensated by negative emissions, see Section S8.

S10.5.2. Ceramics
Complete electrification of this sector is assumed based on the current efficiency of the already electrified processes which include microwave drying and sintering of raw materials, electric kilns for the primary production processes, and electric furnaces for the product finishing. The final electricity consumption, in this case, is 0.44 MWh/t of ceramic. The manufacturing of ceramics includes process emissions which account for 0.03 tCO$_2$/t ceramic.

S10.5.3. Glass
Glass production is assumed to be fully electrified based on the current efficiency of electric melting tanks and electric annealing which represents an electricity demand of 2.07 MWh/t of glass. This agrees with the 2.1 MWh/t reported in [51]. The manufacturing of glass includes process emissions which account for 0.1 tCO$_2$/t glass.

S10.6. Non-ferrous Metals
The non-ferrous metal subsector includes the manufacturing of base metals (aluminium, copper, lead or zinc), precious metals (gold, silver), and technology metals (molybdenum, cobalt, silicon).

The manufacturing of aluminium represents more than half of the final energy consumption of this sector. Two alternative processing routes are used today to manufacture aluminium in Europe. The primary route represents 40% of the aluminium production while the secondary route represents the remaining 60%. The primary route involves two energy-intensive processes: the production of alumina from bauxite (aluminium ore) and the electrolysis to transform alumina into aluminium via the Hall-Héroult process ($2Al_2O_3 + 3C \rightarrow 4Al + 3CO_2$). The primary route requires high-enthalpy heat to produce alumina, which we assume that is supplied by methane, and has associated process emissions of 1.5 tCO$_2$/t aluminium. According to [44], inert anodes might be commercially available in 2030 avoiding process emissions in the primary route, but this has not been considered here. In the secondary route, scrap aluminium is remelted, energy
demand is as low as one-tenth of the primary route and CO$_2$ emissions are avoided. Assuming that all the subprocesses in this route are electrified, 1.7 MWh$_{elec}$/t aluminium are required in the secondary route. The share of aluminium produced via the secondary route is exogenous to the model. In 2050, following [44] and [50], we consider that recycling of aluminium has increased so that up to 80% of the EU28 production is covered by the secondary route.

![Share of Aluminium produced by the primary route. The remaining is produced by scrap metal recycling.](image)

For the other non-ferrous metals, the electrification of the entire manufacturing process is assumed which results in 3.2 MWh/t lead eq. This transformation is already implemented at the beginning of the transition path. Although this is a limitation of the model, its impact is limited in the light of Figure S1.

S10.7. Other industry subsectors

A similar approach is assumed for the remaining industry subsectors which include: (a) Pulp, paper and printing, (b) Food, beverages and tobacco, (c) Textiles and leather, (d) Machinery Equipment, (e) Transport Equipment, (f) Wood and wood products and (g) others. Low- and mid-temperature process heat in these industries is assumed to be supplied by biomass while the remaining processes are electrified. These transformations are already implemented at the beginning of the transition path. Although this is a limitation of the model, its impact is limited in the light of Figure S1. None of these subsectors involves process emissions.

S11. Transport sector

Annual energy demands from road and transport, aviation and navigation for every country are retrieved from JRC-IDEES [22].

S11.1. Land transport

The share of land transport that is converted into using electricity or fuel cell vehicles is exogenously fixed. In 2050, 85% of land transport is electrified and 15% uses H$_2$ fuel cells.

For the electrified land transport, country-specific factors are computed by comparing the current car final energy consumption per km in [22] (average for Europe 0.7 kWh/km) to the 0.18 kWh/km value assumed for battery-to-wheels efficiency in EVs. The characteristic weakly profile provided by the German Federal Highway Research Institute (BAST) [52] is used to obtain hourly time series for European countries taking into account the corresponding local times. Furthermore, a temperature dependence is included in the time series to account for heating/cooling demand in transport. For temperatures below/above 15°C/20°C, temperature coefficients of 0.98%/°C and 0.63%/°C are assumed, see [5] for more details.
At every time step, the internal-combustion vehicles transformed into battery electric vehicles (BEV) are assumed to include a battery with a storage capacity of 50 kWh, charging capacity of 11 kW, and 90% charging efficiency. It is considered that half of the existing BEV can shift their charging time as well as discharge into the grid to facilitate the operation of the system (i.e. vehicle-to-grid services). The BEV state of charge is forced to be higher than 75% at 7 a.m. every day, through $e_{n,s,t}$ in Equation (11), to ensure that the batteries are close to full in the morning peak usage. This also restricts BEV demand to be shifted within a day and prevent EV batteries from becoming seasonal storage. The percentage of BEV connected to the grid at any time is inversely proportional to the transport demand profile, which translates into an average/minimum availability of 80%/62%. This approach is conservative compared to most of the literature. For instance, in [47] the average parking time of the European fleet of vehicles is estimated at 92%. The cost of the EV batteries is not included in the model since it is assumed that EV owners buy them to satisfy their mobility needs.

S11.2. Aviation

Aviation consumes kerosene that can be produced synthetically or have fossil-origin, see Section S7.2.

S11.3. Shipping

Shipping energy demand is converted into hydrogen following an exogenously defined path. The consumed hydrogen can be produced by SMR, SMR+CC or electrolysers, see Section S5.2.
S12. Cost assumptions

Investment and O&M cost assumptions for different technologies, as well as lifetimes, efficiencies and emissions, are retrieved from the PyPSA Technology Data repository v0.2.0 [53]. For the most relevant technologies, the assumptions are shown in Tables S1, S2, and S3.

Table S1: Overnight investment cost assumptions per technology and year. All costs are given in real 2015 money.

| Technology                  | Unit | 2020   | 2025   | 2030   | 2035   | 2040   | 2045   | 2050   | source |
|-----------------------------|------|--------|--------|--------|--------|--------|--------|--------|--------|
| Onshore Wind                | €/kW | 1118   | 1077   | 1035   | 1006   | 977    | 970    | 963    | [28]   |
| Offshore Wind               | €/kW | 1748   | 1660   | 1573   | 1510   | 1447   | 1431   | 1415   | [28]   |
| Solar PV (utility-scale)    | €/kW | 529    | 452    | 376    | 352    | 329    | 315    | 301    | [26]   |
| Solar PV (rooftop)          | €/kW | 1127   | 955    | 784    | 729    | 661    | 600    | 539    | [54]   |
| OCGT                        | €/kW | 453    | 444    | 435    | 429    | 423    | 417    | 411    | [28]   |
| CCGT                        | €/kW | 880    | 855    | 830    | 822    | 815    | 807    | 800    | [28]   |
| Coal power plant            | €/kW | 3845   | 3845   | 3845   | 3845   | 3845   | 3845   | 3845   | [55]   |
| Lignite                     | €/kW | 3845   | 3845   | 3845   | 3845   | 3845   | 3845   | 3845   | [55]   |
| Nuclear                     | €/kW | 7940   | 7940   | 7940   | 7940   | 7940   | 7940   | 7940   | [55]   |
| Run of river                | €/kW | 3312   | 3312   | 3312   | 3312   | 3312   | 3312   | 3312   | [56]   |
| PHS                         | €/kW | 2208   | 2208   | 2208   | 2208   | 2208   | 2208   | 2208   | [56]   |
| Gas CHP                     | €/kW | 590    | 575    | 560    | 550    | 540    | 530    | 520    | [28]   |
| Biomass CHP                 | €/kW | 3381   | 3295   | 3210   | 3135   | 3061   | 3000   | 3000   | [28]   |
| HVDC overhead               | €/MW | 400    | 400    | 400    | 400    | 400    | 400    | 400    | [57]   |
| Batteries storage           | €/kWh| 232    | 187    | 142    | 118    | 94     | 84     | 75     | [28]   |
| Battery inverter            | €/kW | 270    | 215    | 160    | 130    | 100    | 80     | 60     | [28]   |
| Home battery storage        | €/kWh| 323    | 264    | 202    | 169    | 136    | 122    | 108    | [28, 58] |
| Home battery inverter       | €/kW | 377    | 303    | 228    | 186    | 144    | 115    | 87     | [28, 58] |
| Electrolysis                | €/kW | 650    | 550    | 450    | 375    | 300    | 275    | 250    | [26]   |
| Fuel cell                   | €/kW | 1300   | 1200   | 1100   | 1025   | 950    | 875    | 800    | [28]   |
| H₂ storage underground      | €/kWh| 3.0    | 2.5    | 2.0    | 1.8    | 1.5    | 1.4    | 1.2    | [28]   |
| H₂ storage tank             | USD/kWh | 11    | 11     | 11     | 11     | 11     | 11     | 11     | [28, 59] |
| direct air capture          | €/(tCO₂/h) | 700000 | 700000 | 6000000 | 5500000 | 5000000 | 4500000 | 4000000 | [28]   |
| Methanation                 | €/kW | 278    | 278    | 278    | 252    | 226    | 226    | 226    | [60]   |
| Central gas boiler          | €/kW | 60     | 55     | 50     | 50     | 50     | 50     | 50     | [28]   |
| Domestic gas boiler         | €/kW | 312    | 304    | 296    | 289    | 282    | 275    | 268    | [28]   |
| Central resistive heater    | €/kW | 70     | 65     | 60     | 60     | 60     | 60     | 60     | [28]   |
| Domestic resistive heater   | €/kWh | 100    | 100    | 100    | 100    | 100    | 100    | 100    | [61]   |
| Central water tank storage  | €/kWh| 0.6    | 0.6    | 0.5    | 0.5    | 0.5    | 0.5    | 0.5    | [28]   |
| Domestic water tank storage | €/kWh| 18     | 18     | 18     | 18     | 18     | 18     | 18     | [28, 62] |
| Domestic air-sourced heat pump | €/kW | 940   | 895    | 850    | 827    | 805    | 782    | 760    | [28]   |
| Central air-sourced heat pump | €/kW | 951   | 951    | 856    | 856    | 856    | 856    | 856    | [28]   |
| Domestic air-sourced heat pump | €/kW | 1500  | 1450   | 1400   | 1350   | 1300   | 1250   | 1200   | [28]   |
| CO₂ capture in CHP          | €/(tCO₂/h) | 3300000 | 3000000 | 2700000 | 2550000 | 2400000 | 2200000 | 2000000 | [28]   |
| Fischer-Tropsch             | €/kW | 2100   | 1850   | 1600   | 1350   | 1100   | 1000   | 900    | [28]   |
| Steam Methane Reforming     | €/kW | 540    | 540    | 540    | 540    | 540    | 540    | 540    | [63]   |
| Steam Methane Reforming w. CC | €/kW | 1032  | 1032   | 1032   | 1032   | 1032   | 1032   | 1032   | [63]   |
| biomass CHP                 | €/kW | 3006   | 2929   | 2851   | 2817   | 2782   | 2748   | 2714   | [28]   |
| biogas to gas upgrade       | EUR/kW | 423   | 402    | 381    | 371    | 362    | 352    | 343    | [28]   |
Table S2: Efficiency, lifetime and FOM cost per technology (values shown corresponds to 2020).

| Technology                        | FOM\(^b\) [%/a] | Lifetime [a] | Efficiency [%] | Source |
|-----------------------------------|-----------------|--------------|----------------|--------|
| Onshore Wind                      | 1.2             | 27           | 27             | [28]   |
| Offshore Wind                     | 2.3             | 27           | 27             | [28]   |
| Solar PV (utility-scale)          | 1.6             | 35           | 28             |        |
| Solar PV (rooftop)                | 1.2             | 30           | 28             | [54]   |
| OCGT                              | 1.8             | 25           | 40             | [28]   |
| CCGT                              | 3.3             | 25           | 0.56           | [28]   |
| Coal power plant                  | 1.6             | 40           | 0.33           | [55]   |
| Lignite                           | 1.6             | 40           | 0.33           | [55]   |
| Nuclear                           | 1.4             | 60           | 0.33           | [55]   |
| Reservoir hydro                   | 1.0             | 80           | 0.9            | [56]   |
| Run of river                      | 2.0             | 80           | 0.9            | [56]   |
| PHS                               | 1.0             | 80           | 0.75           | [56]   |
| Gas CHP                           | 3.3             | 25           |                | [28]   |
| Biomass CHP                       | 3.6             | 25           |                | [28]   |
| HVDC overhead                     | 2.0             | 40           |                | [57]   |
| HVDC inverter pair                | 2.0             | 40           |                | [57]   |
| Battery storage                   | 20              |              |                | [28]   |
| Battery inverter                  | 0.2             | 10           | 0.95           | [28]   |
| Home battery storage              | 0.2             | 10           | 0.95           | [28, 58]|
| Electrolysis                      | 2.0             | 25           | 0.66           | [28]   |
| Fuel cell                         | 5.0             | 10           | 0.5            | [28]   |
| H\(_2\) storage underground       | 0.0             | 100          |                | [28]   |
| H\(_2\) storage tank              | 20              |              |                | [28, 59]|
| direct air capture                | 5.0             | 20           |                | [28]   |
| Methanation                       | 4.0             | 30           | 0.8            | [60]   |
| Central gas boiler                | 3.2             | 25           | 1.03           | [28]   |
| Domestic gas boiler               | 6.6             | 20           | 0.97           | [28]   |
| Central resistive heater          | 1.5             | 20           | 0.99           | [28]   |
| Domestic resistive heater         | 2.0             | 20           | 0.9            | [61]   |
| Central water tank storage        | 0.5             | 20           |                | [28]   |
| Domestic water tank storage       | 1.0             | 20           |                | [28, 62]|
| Water tank charger/discharger     |                 |              | 0.84           |        |
| Domestic air-sourced heat pump    | 3.0             | 18           |                | [28]   |
| Central air-sourced heat pump     | 0.2             | 25           | 3.4            | [28]   |
| Dom. ground-sourced heat pump     | 1.8             | 20           |                | [28]   |
| CO\(_2\) capture in CHP           | 3.0             | 25           |                | [28]   |
| Fischer-Tropsch                   | 3.0             | 25           | 0.65           | [28]   |
| Steam Methane Reforming           | 5.4             | 25           | 0.74           | [63]   |
| Steam Methane Reforming w. CC     | 5.4             | 25           | 0.67           | [63]   |
| biomass CHP                       | 4.1             | 25           | 0.29           | [28]   |
| biogas to gas upgrade             | 2.5             | 15           |                | [28]   |

\(^a\) Fixed Operation and Maintenance (FOM) costs are given as a percentage of the overnight cost per year.

\(^b\) Hydroelectric facilities are not expanded in this model and are considered to be fully amortized.

\(^c\) Coefficient of performance (COP) of heat pumps is modelled as a function of temperature, as described in the text.
Table S3: Costs and emissions coefficient of fuels.

| Fuel          | Cost [€/MWh\text{th}] | Emissions [tCO\textsubscript{2}/MWh\text{th}] | Source |
|---------------|------------------------|---------------------------------------------|--------|
| coal          | 8.2                    | 0.34                                        | [65]   |
| lignite       | 2.9                    | 0.41                                        | [65]   |
| gas           | 20.1                   | 0.2                                         | [65]   |
| oil           | 50.0                   | 0.27                                        | [65]   |
| nuclear       | 2.6                    | 0                                           | [55]   |
| solid biomass | 25.2                   | 0                                           | [35, 38]|
| biogas        | 59.0                   | 0                                           | [35, 38]|

\textsuperscript{a} Raw biomass fuel cost is assumed as the middle value of the range provided in the references for different European countries and types of sustainable biomass.
\textsuperscript{b} We neglect the contribution from emissions embedded in infrastructure additions as we assume that they are significantly smaller than those coming from fossil-fuels combustion. As the energy system decarbonise the CO\textsubscript{2} embedded in wind turbines and solar panels will be even further reduced.

S13. Investment and social discount rate

It is well known that the assumed discount rates have large implications in cost-benefit analyses of long-term problems such as climate change [67–70]. We consider two types of discount rates. First, the financial discount rate is used to annualise capital costs. It is relevant to notice that a high investment discount rate penalizes capital intensive technologies such as wind and solar with high investment costs in the first year, relative to technologies such as gas power plants where fuel costs occurring every year represent a high share of their total cost. Here, we assume a financial discount rate equal to 7% for all the investments except individual assets such as rooftop PV or individual water tanks for which 4% is assumed. The 7% financial discount rate is assumed for all the countries. Schyska and Kies have assessed the impacts of assuming different costs of capital on the optimal European power system [71].

Second, a social discount rate is used to discount future investment when adding quantities throughout a transition path. By doing that the social discount rate weights the cost of short-term against long-term action. The use of a social discount rate higher than zero is based on preferences or the expectation that economic growth will maintain. A social discount rate of 2% is usually selected. This can be justified by the average growth rate of 1.6% over the past 20 years in the European Union. A further justification is that the 30-year Treasury Bonds in the USA are yielding a return on the order of 2%. It is important to remark that, for climate change mitigation strategies, the selected discount rate has strong inter-generational implications as it weights the short and long-term costs paid by different groups of people. We discuss in the main text the implications of assuming different social discount rates when computing the cumulative system cost throughout the transition.

Financial and social discount rate considered in related works.

|                | Financial discount rate | Social discount rate | Source |
|----------------|-------------------------|----------------------|--------|
| PRIMES         | 10%                     |                      | [50, 72]|
| JRC-EU-TIMES   | 7-18%                   | 5%                   | [73]   |
| Bogdanov 2019  | 7%                      |                      | [74]   |
| Creutzig 2017  | 10%                     |                      | [75]   |
S14. Social Cost of Carbon

The social cost of carbon (SCC) represents the economic cost caused by an additional tonne of carbon dioxide emissions or its equivalent. To compare the cumulative cost of the system throughout the different budgets, the cost associated to SCC is estimated as:

\[ \sum_y \left( \frac{\text{Emissions in budget} - \text{Emissions in 1.5° C-budget}}{(1 + \text{social discount rate})^y} \right) \cdot \text{SCC} \]  

(6)

S15. Mathematical formulation of the model

In every time step, the optimisation objective, that is, the total annualised system cost is calculated as:

\[ \min_{G_{n,s}, E_{n,s}} \left[ \sum_{n,s} c_{n,s} \cdot G_{n,s} + \sum_{n,s} \hat{c}_{n,s} \cdot E_{n,s} + \sum_{\ell} c_{\ell} \cdot F_{\ell} + \sum_{n,s,t} o_{n,s,t} \cdot g_{n,s,t} \right] \]

where \( c_{n,s} \) are the fixed annualised costs for generator and storage power capacity \( G_{n,s} \) of technology \( s \) in every bus \( n \), \( \hat{c}_{n,s} \) are the fixed annualised costs for storage energy capacity \( E_{n,s} \), \( c_{\ell} \) are the fixed annualised costs for bus connectors \( F_{\ell} \), and \( o_{n,s,t} \) are the variable costs for generation and storage dispatch \( g_{n,s,t} \) in every hour \( t \). Bus connectors \( \ell \) include transmission lines but also converters between the buses implemented in every country (see Fig. 6 in the main text), for instance, heat pumps that connect the electricity and heating bus.

The optimisation of the system is subject to several constraints. First, hourly demand \( d_{n,t} \) in every bus \( n \) must be supplied by generators in that bus or imported from other buses. \( f_{\ell,t} \) represents the energy flow on the link \( \ell \) and \( \alpha_{n,\ell,t} \) indicates both the direction and the efficiency of flow on the bus connectors. \( \alpha_{n,\ell,t} \) can be time-dependent such as in the case of heat pumps whose conversion efficiency depends on the ambient temperature.

\[ \sum_s g_{n,s,t} + \sum_{\ell} \alpha_{n,\ell,t} \cdot f_{\ell,t} = d_{n,t} \leftrightarrow \lambda_{n,t} \forall n, t \]  

(7)

The Lagrange multiplier \( \lambda_{n,t} \), also known as Karush-Kuhn-Tucker (KKT), associated with the demand constraint indicates the marginal price of the energy carrier in the bus \( n \), e.g., local marginal electricity price in the electricity bus.

Second, the maximum power flowing through the links is limited by their maximum physical capacity \( F_{\ell} \). For transmission links, \( f_{\ell,t} = -1 \) and \( f_{\ell,t} = 1 \), which allows both import and export between neighbouring countries. For a unidirectional converter e.g., a heat resistor, \( f_{\ell,t} = 0 \) and \( f_{\ell,t} = 1 \) since a heat resistor can only convert electricity into heat.

\[ f_{\ell,t} \cdot F_{\ell} \leq f_{\ell,t} \leq \bar{f}_{\ell,t} \cdot F_{\ell} \quad \forall \ell, t. \]  

(8)

Third, for every hour the maximum capacity that can provide a generator or storage is bounded by the product between installed capacity \( G_{n,s} \) and availabilities \( \bar{g}_{n,s,t}, g_{n,s,t} \). For instance, for solar generators \( \bar{g}_{n,s,t} = 0 \) and \( g_{n,s,t} \) refers to the capacity factor at time \( t \).

\[ \bar{g}_{n,s,t} \cdot G_{n,s} \leq g_{n,s,t} \leq \bar{g}_{n,s,t} \cdot G_{n,s} \quad \forall n, s, t.\]  

(9)

The maximum power capacity for generators is limited by potentials \( \bar{G}_{n,s} \) that are estimated taking into account physical and environmental constraints:

\[ 0 \leq G_{n,s} \leq \bar{G}_{n,s} \quad \forall n, s. \]  

(10)
The storage technologies have a charging efficiency $\eta_{\text{in}}$ and rate $g_{n,s,t}^+$, a discharging efficiency $\eta_{\text{out}}$ and rate $g_{n,s,t}^-$, possible inflow $g_{n,s,t,\text{inflow}}$ and spillage $g_{n,s,t,\text{spillage}}$, and standing loss $\eta_{0}$. The state of charge $e_{n,s,t}$ of every storage has to be consistent with charging and discharging in every hour and is limited by the energy capacity of the storage $E_{n,s}$. It should be remarked that the storage energy capacity $E_{n,s}$ can be optimised independently of the storage power capacity $G_{n,s}$.

\[
e_{n,s,t} = \eta_{0} \cdot e_{n,s,t-1} + \eta_{\text{in}} |g_{n,s,t}^+| - \eta_{\text{out}} |g_{n,s,t}^-| + g_{n,s,t,\text{inflow}} - g_{n,s,t,\text{spillage}} ,
\]

\[
0 \leq e_{n,s,t} \leq E_{n,s} \quad \forall n,s,t .
\]

So far, Equations (7) to (11) represent mainly technical constraints but additional constraints can be imposed to bound the solution.

The interconnecting transmission expansion can be limited by a global constraint

\[
\sum_{\ell} l_{\ell} \cdot F_{\ell} \leq \text{CAP}_{\text{LV}} \quad \leftrightarrow \quad \mu_{\text{LV}} ,
\]

where the sum of transmission capacities $F_{\ell}$ multiplied by the lengths $l_{\ell}$ is bounded by a transmission volume cap $\text{CAP}_{\text{LV}}$. In this case, the Lagrange/KKT multiplier $\mu_{\text{LV}}$ represents the shadow price of a marginal increase in transmission volume.

The maximum CO$_2$ allowed to be emitted by the system $\text{CAP}_{\text{CO}_2}$ can be imposed through the constraint

\[
\sum_{n,s,t} \varepsilon_s \frac{g_{n,s,t}}{\eta_{n,s}} + \sum_{n,s} \varepsilon_s (e_{n,s,t=0} - e_{n,s,t=T}) \leq \text{CAP}_{\text{CO}_2} \quad \leftrightarrow \quad \mu_{\text{CO}_2}
\]

where $\varepsilon_s$ represents the specific emissions in CO$_2$-tonne-per-MWh, of the fuel $s$, $\eta_{n,s}$ the efficiency and $g_{n,s,t}$ the generators dispatch. In this case, the Lagrange/KKT multiplier represents the shadow price of CO$_2$, i.e., the additional price that should be added for every unit of CO$_2$ to achieve the CO$_2$ reduction target in an open market.

S16. Sensitivity 1: Costs and technological performance

To investigate the impact of different assumptions in the model results, we have implemented different sensitivity analyses, described in Table S4 and gathered in three groups. In this first note, we present sensitivity to technology cost assumptions. We re-run the model assuming a variation of $\pm 20\%$ of the cost for selected technologies. The timeline for key technological transformation is not substantially impacted by these variations in costs, see Fig. S34-S39. In addition, Fig. S29 shows the most relevant metrics for the 1.7$^\circ$C-budget in 2050. Most of them are quite robust to cost variations. The relative increase in NPV of system cost for the 1.5 and 1.6$^\circ$C budgets, compared to 2.0$^\circ$C, is also found to be quite stable to cost variations.

One of the main limitations of our analysis is the assumption of exogenous cost evolution. In order to investigate the impact of this assumption, we rerun the analysis while keeping the costs for the different technologies and their technical parameters fixed at their values in 2020 (see Note S12). Equivalent figures as those shown in the main text are produced, Fig. S41, S31, S32, S33, and the main differences are discussed in the main text.
Table S4: Sensitivity scenarios analysed.

| Name                  | Description of sensitivity scenario                                      | CO\textsubscript{2} budgets modeled |
|-----------------------|---------------------------------------------------------------------------|-------------------------------------|
| solar+20              | Cost of solar in every time step increased by 20%                          | all                                 |
| solar-20              | Cost of solar in every time step decreased by 20%                          | all                                 |
| onwind+20             | Cost of onshore wind in every time step increased by 20%                   | all                                 |
| onwind-20             | Cost of onshore wind in every time step decreased by 20%                   | all                                 |
| nuclear+20            | Cost of nuclear in every time step increased by 20%                        | all                                 |
| nuclear-20            | Cost of nuclear in every time step decreased by 20%                        | all                                 |
| battery+20            | Cost of utility-scale battery in every time step increased by 20%          | all                                 |
| battery-20            | Cost of utility-scale battery in every time step decreased by 20%          | all                                 |
| methanation+20        | Cost of methanation in every time step increased by 20%                   | all                                 |
| methanation-20        | Cost of methanation in every time step decreased by 20%                   | all                                 |
| direct air capture+20 | Cost of direct air capture in every time step increased by 20%             | all                                 |
| direct air capture-20 | Cost of direct air capture in every time step decreased by 20%             | all                                 |
| electrolytic H\textsubscript{2}+20 | Cost of electrolytic H\textsubscript{2} in every time step increased by 20% | all                                 |
| electrolytic H\textsubscript{2}-20 | Cost of electrolytic H\textsubscript{2} in every time step decreased by 20% | all                                 |
| SMR CC H\textsubscript{2}+20 | Cost of H\textsubscript{2} produced via SMR-CC in every time step increased by 20% | all                                 |
| SMR CC H\textsubscript{2}-20 | Cost of H\textsubscript{2} produced via SMR-CC in every time step decreased by 20% | all                                 |
| electrolytic H\textsubscript{2}+20 | Cost of electrolytic H\textsubscript{2} in every time step increased by 20% and cost of H\textsubscript{2} produced via SMR-CC in every time step decreased by 20% | all                                 |
| fixed costs           | Costs and performance for every technology are fixed at 2020 values        | all                                 |
| CO\textsubscript{2} sequestration cost and potential | Cost assumption is assumed to be (0.1/0.5/1/5/10/100) of the reference. Potential is assumed to be (1/2/5/10/100) | 1.7°C |
| no H\textsubscript{2}-network | The building of a greenfield H\textsubscript{2} network interconnecting countries is disallowed | 1.7°C |
| endog. build. retro.  | The investments in building retrofitting that reduce heating demand are endogenous to the system, as described in [27] | 1.7°C |
| no biomass with CC    | The use of biomass with carbon captured (in the industry and CHP units) is disallowed | 1.7°C |

S17. Supplemental Figures
Figure S2: The networked model comprises 37 nodes, one per country. The size of the circles represent today's electricity demand. Renewable resources are aggregated to the smaller regions shown in the map. The yellow shades represent the annual capacity factor for solar PV in the different regions.
Figure S3: The networked model comprises 37 nodes, one per country. The size of the circles represent today’s electricity demand. Renewable resources are aggregated to the smaller regions shown in the map. The green shades represent the annual capacity factor for offshore wind in the different regions.
Figure S4: Annualised system cost for throughout the transition paths assuming distinct carbon budgets.
Figure S5: Europe capacities for different technologies throughout the transition paths assuming distinct carbon budgets.
Figure S6: Europe annually installed capacities for different technologies throughout the transition paths assuming distinct carbon budgets.
Figure S7: Emissions per sector for different carbon budgets. The electricity sector includes all the emissions related to electricity generation, regardless of where the electricity is used (i.e., CCGT, OCGT, coal, lignite, and oil power plants). The heating sector comprises gas and oil boilers in every heating bus. Emissions associated with CPH units are split 50/50 to the electricity and heating sector. Industry sector includes process emissions, and emissions associated with SMR, as well as gas and biomass used in the industry. Emissions associated to oil with fossil origin are split between kerosene for aviation and naphtha for industry proportionally to the oil consumed in those sectors. Notice that the evolution of emissions in road transport and shipping are impacted by the exogenous transformation of those sectors.
Figure S8: ETS sector includes electricity generation, industry, aviation and central heating. No-ETS sectors include individual heating, land transport and shipping. It is relevant to mention that, in the context of the ‘Fit for 55’ package [76], heating, land transport and shipping will be part of the ETS.
Figure S9: Net-present-value of system costs for different carbon budgets and transition speeds. A social cost of carbon of 75 €/tCO₂ is assumed. See Fig. 8 in the main manuscript for results assuming a social cost of carbon of 0 and 120 €/tCO₂.
Figure S10: Net-present-value of system costs for different carbon budgets and transition speeds. A social cost of 300 €/tCO\(_2\) is assumed. See Fig. 8 in the main manuscript for results assuming a social cost of carbon of 0 and 120 €/tCO\(_2\).
Figure S11: Heating supply for high-population density areas where district heating systems are installed. Results for distinct carbon budgets are shown.
Figure S12: Heating supply for services demand in high-population density areas without district heating systems. Results for distinct carbon budgets are shown.
Figure S13: Heating supply for residential demand in high-population density areas without district heating systems. Results for distinct carbon budgets are shown.
Figure S14: Heating supply for services demand in low-population density areas. Results for distinct carbon budgets are shown.
Figure S15: Heating supply for residential demand in low-population density areas. Results for distinct carbon budgets are shown.
Figure S16: Production and demand for hydrogen for distinct carbon budgets.
Figure S17: Production and demand for methane for distinct carbon budgets.
Figure S18: Production and demand for oil for distinct carbon budgets.
Figure S19: Sensitivity Analysis: Relative annualised system cost at the end of the transition for the 1.7°C-budget. Results are shown as a function of the assumed CO$_2$ sequestration cost and potential.
Figure S20: Sensitivity Analysis: Required CO$_2$ price at the end of the transition for the 1.7C$^\circ$-budget. Results are shown as a function of the assumed CO$_2$ sequestration cost and potential.
Figure S21: Sensitivity Analysis: Use of CO$_2$ to produce synthetic methane (top) and synthetic liquid fuels (bottom) at the end of the transition for the 1.7C$^\circ$-budget. Results are shown as a function of the assumed CO$_2$ sequestration cost and potential.
Figure S22: Sensitivity Analysis: H$_2$ produced via steam methane reforming with carbon capture, known as blue hydrogen, at the end of the transition for the 1.7C°-budget. Results are shown as a function of the assumed CO$_2$ sequestration cost and potential.
Figure S23: Sensitivity analysis: (left) Technologies capturing CO$_2$ and (right) sequestration and use of CO$_2$ in the system for the 1.7°-C-budget. (first row) reference cost and potential, (second row) hundredfold increase in cost assumption, (third row) hundredfold increase in potential, (fourth row) hundredfold increase in potential while cost is 10% of the reference value.
Figure S24: Electrolysers capacity and hydrogen network for the 1.7°C-budget.
Figure S25: Sensitivity analysis: (left) Technologies capturing CO$_2$ and (right) sequestration and use of CO$_2$ in the system for the 1.7°C-budget. Reference scenario (top) is compared to alternative scenario disabling the use of biomass with carbon capture (bottom).
Figure S26: Daily generation and consumption of electricity throughout the year for the $1.7^\circ$C-budget in 2050.
Figure S27: Daily generation and consumption of heating throughout the year for the 1.7°C-budget in 2050. Power-to-heat includes heat produced by heat pumps and resistive heaters; Power-to-gas includes heat from methanation, and hydrogen production; Gas-to-power/heat includes heat produced in CHP units and gas boilers; Power-to-liquid includes heat from Fischer-Tropsch process.
Figure S28: Annualised system cost (including endogenous building retrofitting to reduce space heating demand) throughout the 1.7°C path.
Figure S29: Sensitivity analysis to costs assumptions. The figure depicts the increase in NPV of system cost for the 1.5 and 1.6°C budgets, relative to 2.0°C, for different sensitivity scenarios, described in Table S4. The main metrics at the end of the transition paths for the 1.7°C budgets are also shown.
Figure S30: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case fixed costs and performance of the technologies (corresponding to 2020) are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S31: (left) Technologies capturing CO$_2$ and (right) sequestration and use of CO$_2$ in the system for the distinct carbon budgets. CC stands for carbon capture. This is an equivalent figure to Fig. 5 in the main text, but in this case fixed costs and performance of the technologies (corresponding to 2020) are assumed.
Figure S32: Required CO\(_2\) price for distinct carbon budgets. The CO\(_2\) price is not an input to the model, but an output calculated as the Lagrange/KKT multiplier associated with the CO\(_2\) cap constraint (equation 13). This is an equivalent figure to Fig. 6 in the main text, but in this case fixed costs and performance of the technologies (corresponding to 2020) are assumed.
Figure S33: Cumulative system cost for different carbon budgets and discount rates (indicated in the legend). A social cost of carbon of $120\text{€/tCO}_2$ is assumed. This is an equivalent figure to Fig. 7 in the main text, but in this case fixed costs and performance of the technologies (corresponding to 2020) are assumed.
Figure S34: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for solar 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S35: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for onshore wind 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S36: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for nuclear 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S37: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for battery 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5° and 2°C.
Figure S38: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for direct air capture (DAC) 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S39: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for methanation 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S40: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for H₂ electrolysis 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S41: Occurrence of key transformations for distinct carbon budgets. This is an equivalent figure to Fig. 4 in the main text, but in this case costs for H₂ produced via Steam Methane Reforming with carbon capture (SMR CC) 20% higher (top) and 20% lower (bottom) of the reference values, Note S12, are assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur for modelled transition paths under carbon budgets corresponding to temperature increase between 1.5°C and 2°C.
Figure S42: Occurrence of key transformations for the 1.7°C carbon budget. This is an equivalent figure to Fig. 4 in the main text, but in this case no build-up of an H₂ network interconnecting European countries is allowed. The bars indicate the period when key technological transformations (described by labels on the left) occur.
Figure S43: Occurrence of key transformations for the 1.7°C carbon budget. This is an equivalent figure to Fig. 4 in the main text, but in this case endogenous investment in building retrofitting is assumed. The bars indicate the period when key technological transformations (described by labels on the left) occur.
Figure S44: Occurrence of key transformations for the 1.7°C carbon budget. This is an equivalent figure to Fig. 4 in the main text, but in this case the possibility of investing in biomass with carbon capture (BECCS) is disallowed. The bars indicate the period when key technological transformations (described by labels on the left) occur.
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