Impact of climatic, technical and economic uncertainties on the optimal design of a CO₂-neutral electricity, heating and cooling system in Europe

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Abstract

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Designing large-scale energy system through techno-economical optimisation model depends on specific input parameters, in particular, climatic, technical and economic assumptions. In this paper, European electricity, heating and cooling coupled system is modelled in one-node-per-country, hourly-resolved network under technical constraints. Variable renewable energy sources (VRES), storage, synthetic gas and transmission cooperate together to achieve a CO₂-neutral system. Temperature increases and heat savings, which mimic the global warming and potential retrofitting, would reduce the heating and cooling demand (HCD) significantly, thus lowering the system costs but not the levelised cost of energy (LCOE). Demand-side management through buildings’ thermal inertia could shape the heat demand, yet has modest impact on the system configuration. Cost reductions of VRES manage to bring down the system costs and LCOE the most, followed by heating technologies, but both are suffering from the rebound effect. Storage cost reductions have modest impact to the cost, yet altering the wind/solar photovoltaic (PV) mix and weakening the benefits of interconnection. The results obtained by combining scenarios reveal the independence of impact between temperature increases and renewable cost reductions. A considerable robustness is observed in terms of VRES penetration, curtailment and wind/solar photovoltaic (PV) mix for most of the scenarios. By contrary, the heating and cooling sector is strongly affected, due to either more flexible HCD or cost reductions from renewable and heating technologies.

Keywords: Energy system design; Sector coupling; Climate change; Heating saving; Demand-side management; Heating and cooling

1. Introduction

The special report on global warming of 1.5 °C (SR15)\textsuperscript{[1]} published by the Intergovernmental Panel on Climate Change (IPCC) stated that meeting 1.5 °C is possible, yet requires deep and rapid decarbonisation in all sectors. The global anthropogenic greenhouse gas (GHG) emissions are required to undergo an unprecedented reduction in this century, reaching net zero by 2050. As a response, the European Commission released its long-term strategy \textsuperscript{[2]} towards a CO₂-neutral Europe by 2050, in line with the Paris Agreement objective to limit the temperature increase well below 2 °C and pursue efforts to 1.5 °C. Available mature low-carbon energy technologies, in particular wind and solar photovoltaic (PV) power plants, are capable to supply electricity at a large scale. Other sectors apart from electricity, such as transportation, industry, heating and cooling still lack a clear decarbonisation strategy. The far-reaching emission reduction demands a fully sector-coupled energy system in order to exploit the synergies among sectors.

However, whether human being manage to limit the temperature increase to 1.5 °C by the end of century or not, climate change still plays an inevitable role in the weather-dependent energy system to some extent. Kozarcgin et al. \textsuperscript{[3]} use weather-driven modelling to investigate the impact of climate change on highly renewable electricity system for three distinctive scenarios. They find that climate change could modify the need for dispatchable electricity up to 20%, but barely affects the benefits of transmission and storage, which change only by 5%. Schlott et al. \textsuperscript{[4]} explore the effect of climate change to the European electricity system by cost optimisation, assuming no emission reductions. It is found that climate change would increase the correlation length from wind generation, hence PV becomes more important as well as the need for balancing rises. Furthermore, climate change might have a greater influence on other sectors, particularly heating and cooling in two folds, supply and demand. One the one hand, the output of variable renewable energy source (VRES) depend on the weather, which further in-
fluences electrified heating and cooling supply in highly renewable systems. Hdidouan and Staffell [5] propose a framework to assess the cost of wind energy taking climate change into account. They demonstrate this framework by evaluating the British wind resource up to 2100. It is concluded that climate change would result in capacity factors increase in some regions but decrease in others. On the other hand, potential temperature increase would very likely decrease overall heat demand while raising cooling demand. In the light of changing climate, understanding to what extent temperature increase affects the coupled electricity-heating system is important. Staffell and Pfenninger [7] evaluate the impact of weather on the electricity demand and supply in Britain. Due to heat electrification at a large scale, the electricity system is rapidly moving into unprecedented territory, where intermittent renewable output exceeding demand as early as 2021 in UK.

Heating and cooling demand (HCD) would also undergo a substantial change due to expected heat savings in the future. Lund et al. [8] explore the relation between heat savings and supply, in order to identify the least-cost heating strategy for Denmark. It is found that the cost-optimal strategy includes 35% to 53% savings due to building retrofitting compared to the current level. Similarly, Hansen et al. [9] attempt to analyse the balance between investing in heat saving and supplying heat for various European countries and quantify the economically feasible saving levels between 30% and 50% taking sectoral dynamics into account. Similarly, [10] predicts final energy demand falls by 44 per cent by 2050 relative to 2011 in the German building sector. Despite the fact that heat saving deployment is still underdeveloped currently, it has huge potential to facilitate energy system transition in the future. Since there is no essential obstacle, neither technical nor economic, to hinder the progress of heat saving, it is believed that heat saving at a large scale could be accomplished under necessary ‘legislation and control’ [11].

Demand-side management (DSM) could alter the shape of consumers’ pattern, in order to decrease the demand at peak times. Among various implementations of DSM, installing additional equipment, e.g., thermal storage, turns out to be highly efficient [12, 13]. Long-term thermal storage represented by large water tanks in district heating shapes the seasonal variation of HCD and short-term as individual water tanks could smooth out the daily variation [14–16]. However, additional equipment require space and investment, making it less attractive though. An alternative solution is to utilise the buildings’ structure itself, exploiting the potential of thermal mass without sacrificing thermal comfort. Reynders et al. [17] analyse the potential of structure thermal mass for DSM in order to avoid strong mismatch between electricity production and consumption in residential buildings. Huge potential is found in using the thermal mass as short-term storage to shift the peak electricity demand. In [18], the flexibility potential are accessed through increase or decrease the set-point temperature in two different types of buildings. The time constant in the poorly-insulated building is found to be very short (2-5 hours), whereas the well-insulated buildings can endure a complete switch-off for 24 hours.

Previously, some authors have examined the different aspects of uncertainties. Schlachtberger et al. [19] investigate the influence of weather data, cost parameters and policy constraints on a highly renewable European electricity system. A considerable robustness of system costs to weather data and cost assumptions is observed. Collins et al. [20] find out that the impact of long-term weather patterns on European electricity system is significant. A 5-fold increase has been revealed in terms of inter-
annual variability of CO$_2$ emissions and total generation costs from 2015 to 2030.

Compared to electricity demand, HCD has a larger seasonal variation, which would decrease the benefits of high-efficiency but high capital cost technologies, such as heat pumps. In [15], we focus on the role of CO$_2$ prices for a highly decarbonised coupled electricity and heating system in Europe. We find out that not only a renewable target is necessary, but also a CO$_2$ tax is required to incentivise the cost-optimal system configuration. For the cost optimal configuration with 95% CO$_2$ reductions relative to 1990, most investments go into VRES and power-to-heat (PtH) installations, and heating sector is supplied mostly by heat pumps. As mentioned previously, HCD could be influenced by three causes: temperature increase because of climate change, heating saving from building retrofit and demand-side management through buildings’ thermal inertia. Based on the main findings from [15], this study evaluates the impact of climatic, technical and economic uncertainties, in order to address the following research questions:

- Under the circumstances of probable temperature increases, heat savings or peak shaping by DSM, how does a different HCD alter the optimal system configuration?
- What will be the impact of cost reductions of the key components to the decarbonised electricity, heating and cooling system in Europe?

The paper is organised as follows. Section 2 describes the model concisely and introduces the definitions of different scenarios. More mathematical details can be found in Appendix A. Section 3 presents the results of this study and the subsequent Section 4 discusses the main findings as well as the limitations of this analysis. Finally, Section 5 draws the main conclusions and opens up potential future extensions.

2. Methods

2.1. Model

The model is implemented as a linear techno-economical optimisation assuming perfect foresight and long-term market equilibrium, which ensures that the costs of optimised technologies are exactly recovered by market revenues. Appendix A describes the model with details and mathematical formulations.

The objective function is expressed as the total annualised system costs including capital and marginal costs, Equation A.1. Technical and physical constraints, Equations A.2 – A.10 such as hourly supply of inelastic demand and CO$_2$ emissions, are imposed. The VRES generation follow a self-sufficient layout for each individual country, implying all European countries share the same VRES penetration yet deploying its own favourable wind/solar PV mix according to diverse renewable resource, i.e., Equation A.10. It depicts a plausible future circumstance where the European countries need to be relatively self-sufficient in terms of renewable supply [15]. A CO$_2$-neutral system only allows consuming synthetic gas after it has been produced, which can be translated into Equation A.8. The corresponding Lagrange multiplier indicates the necessary CO$_2$ tax to obtain the net-zero emission in an open market. Since a CO$_2$-neutral energy system is considered to be at far future, the currently existing generators are not included in this model.

Each of the 30 European countries is represented by a single node, and neighbouring countries are connected through cross-border high voltage direct current (HVDC) lines, see Figure 2. The transmission capacities are freely optimised given investment costs. Within each country,
electricity, heating and cooling sectors are coupled, as shown in Figure 1.

![Electricity, heating, and cooling sectors coupling diagram](image1)

Figure 1: Coupling of electricity, heating, and cooling sectors.

The inelastic electricity demand is taken from historical values of 2015 provided by the European Network of Transmission System Operators for Electricity (ENTSO-e). The load is mainly met by renewable generators, i.e., wind, solar PV and hydro. Rather than natural gas as the dispatchable backup in [15], synthetic gas is produced first then being consumed to balance the residual load together with storage.

Turning to heating sector, only residential and commercial sectors are considered, which can be further divided into space heating and hot water demand. The profiles of space heating are approximated by heating degree hour (HDH), assuming the demand rises linearly according to ambient temperature $T_{am}^i$ below a threshold $T_{th}^i$ in country $i$

$$HDH_i = \sum_t (T_{th}^i - T_{am}^i)^+, \forall i$$

where the sign ‘+’ indicates that only positive values are counted, and the threshold temperature is assumed to be 17 °C. The time series is then scaled based on the annual demand for domestic space heating in 2015 [21]. A country-specific constant hourly value for the hot water consumption, obtained from the same database, is added to compute the total heating demand time series representative for every country. Heating demand can be supplied by PtH, i.e., heat pumps and resistive heaters, and dispatchable backup, i.e., gas boilers and CHP heat powered by synthetic gas. In order to capture the low performance in winter, the coefficients of performance (COP) of heat pumps vary with ambient temperature. The synthetic gas is created through Sabatier process from hydrogen and CO$_2$ with direct air capture (DAC). The source of CO$_2$ could potentially come from other cheaper carbon sources, such as industry sector, but the option is not considered in this paper. Power-to-gas (PtG), in this paper, refers to both processes using electricity to produce gas, whether hydrogen or synthetic gas. Long-term thermal storage is activated in the area with high population density, whereas

Table 1: Cost, efficiency and lifetime assumptions for the key technologies

| Technology                  | Overnight cost[€] | Unit       | FOM$^a$[%/a] | Lifetime[a] | CF/Efficiency$^b$ |
|-----------------------------|-------------------|------------|--------------|-------------|-------------------|
| Onshore wind$^c$            | 910               | kW$_{el}$  | 3.3          | 30          | 0.23[0.70-0.33]   |
| Offshore wind$^c$           | 2506              | kW$_{el}$  | 3            | 25          | 0.31[0.09-0.51]   |
| Solar PV$^c$                | 575               | kW$_{el}$  | 2.5          | 25          | 0.13[0.06-0.19]   |
| OCGT$^d$                    | 560               | kW$_{el}$  | 3.3          | 25          | 0.39              |
| CHP$^d$                     | 600               | kW$_{th}$  | 3.0          | 25          | 0.47              |
| Gas boiler$^{d,e}$          | 175/63            | kW$_{th}$  | 1.5          | 20          | 0.9               |
| Methanation+DAC             | 1000              | kW$_{th}$  | 3            | 25          | 0.6               |
| Resistive heater            | 100               | kW$_{th}$  | 2            | 20          | 0.9               |
| Heat pump$^c$               | 1400/933          | kW$_{th}$  | 3.5          | 20          | [3.03-3.79]/[2.73-3.04] |
| Battery storage$^f$         | 144.6             | kWh        | 0            | 15          | -                 |
| Hydrogen storage$^f$        | 8.4               | kWh        | 0            | 20          | -                 |
| Hot water tank$^{c,e,f}$    | 860/30            | m$^3$      | 1            | 20/40       | 3/180 days        |
| HVDC lines                  | 400               | MWkm       | 2            | 40          | 1                 |

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

$^b$ Capacity Factor (CF) only applies to renewables, while efficiency only to generators and converters.

$^c$ Capacity Factor varies in different countries due to weather condition. The number in front indicates the average of CF weighted by demand, while the numbers in brackets show the range of CF for different countries. Solar PV is split 50-50% between rooftop and utility-scaled power plants. The impacts of this assumption is limited as discussed in [15].

$^d$ OCGT, CHP and gas boiler all consume synthetic gas generated from methanation.

$^e$ Gas boilers, heat pumps and hot water tanks have different costs and time constant $\tau$ for decentralised (numbers in front) and centralised (numbers behind) systems. The efficiency of heat pumps, also known as the coefficient of performance, varies with temperature.

$^f$ The overnight costs of storage in the table only include the costs of energy capacity.
short-term for low population density area.

Instead of aggregating the cooling demand into electricity in [15], it is now treated as a separate bus in order to capture its potential rise due to temperature increase. The cooling demand only consists of space cooling, and the profiles are modelled through cooling degree hour (CDH), assuming the demand rises linearly according to ambient temperature $T^{am}$ above a threshold $T^{th}$

$$CDH_i = \sum_{t} (T^{am}_{i,t} - T^{th}_{i,t})^+, \quad \forall i$$

where the threshold temperature is assumed to be 24 °C. Likewise, the time series is scaled according to annual cooling demand in 2015. Cooling can only be provided by reversing heat pumps into cooling mode according to [22], with a fixed COP of 3 due to simplicity.

In order to acknowledge potential cost decreasing, particularly for wind and solar PV, while avoiding uncertainties of long-term projection, the cost assumptions (see Table 1) are taken from the predictions for 2030, assuming a discount rate of 7% for the annualised overnight cost. The model is implemented in the open-source framework python for power system analysis (PyPSA) [23] and the PyPSA-Eur-Sec-30 model introduced in [14].

2.2. Scenarios

The ‘Base’ refers to the baseline scenario without incorporating other climatic, technical and economic changes as described below. It must be noted that changes introduced in one scenario are not valid in another scenario.

Climatic

To investigate the impact of climate change to the energy system, a simplified approach is introduced: assuming ambient temperature increases (TI) homogeneously both in space and time, i.e., certain degrees $\Delta T$ are added to all the countries for all the hours. The resulting ambient temperature would be,

$$T^{am}_{i,t} + \Delta T, \quad \forall i, t$$

where $\Delta T$ is chosen among 1, 2, 3, 4, 5 K, and the corresponding scenarios are denoted as ‘TI1’ to ‘TI5’. Since space heating and cooling demand are modelled by HDH/CDH approximation, Equations 1 and 2, temperature increases would lead towards lower heating demand and higher cooling demand. The solid lines in Figure 3 provide an overview of how total heating and cooling demand increases would lead towards lower heating demand and higher cooling demand. The dashed lines in Figure 3 present the effects of heat savings as well as temporally, forming into new heating demand time series for all the countries, reduction level of 10%, 20%, 30%, 40% and 50% are considered in this paper, and the scenarios are denoted as ‘HS10’ to ‘HS50’. It must be noted that the expenses of heat savings are not taken into account in this paper.

Technical

The technical aspect is investigated in two scenarios: heat savings (HS) and demand-side management (DSM).

To model the heat savings due to potential improve of energy efficiency in buildings, homogeneous reduction levels $\Delta H$ are applied on space heating and cooling demand from ‘Base’ spatially as well as temporally, forming into new heating demand time series for all the countries,

$$(100% - \Delta H) \cdot d_{n,t}, \quad n \in \text{space heating&cooling}, \forall t$$

Reduction level of 10%, 20%, 30%, 40% and 50% are considered in this paper, and the scenarios are denoted as ‘HS10’ to ‘HS50’. It must be noted that the expenses of heat savings are not taken into account in this paper. The dashed lines in Figure 3 present the effects of heat savings to heating and cooling demand.

Figure 4 shows the one-week-smoothed hourly profiles of HCD for ‘Base’, ‘TI5’ and ‘HS50’. The impact of temperature increases on the HCD are mixed: the demand de-
creases for most of the hours, apart from a few weeks during the summer due to cooling demand rises. The mixed impact is more obvious when looking at the normalised demand duration curve from the inset of Figure 4. Temperature increases deviate the duration curve substantially from the ‘Base’, resulting in a flatter tail. Comparatively, heat savings modify the space heating and cooling demand uniformly, hence preserving the profile of HCD for most of the time. Temperature increases and heat savings do not only change the total HCD, but also modify the seasonal variation to some extent.

Among various methods for demand-side management for the heating sector, this paper introduces a simple way by utilising buildings’ thermal mass as short-term storage without sacrificing the indoor comfort. A zero-cost, capacity-fixed thermal storage is attached to each heat bus, which allows charging extra heating during off-peak hours and discharging for the peak. The power capacity \( G_{n,s} \) is assumed to be the average heating demand in each heat bus, and the energy capacity \( E_{n,s} \) is obtained by multiplying power capacity with certain hours \( \tau \), i.e., 2, 4, 6, 8 and 10 hours,

\[
E_{n,s} = \tau \cdot G_{n,s}, \quad s \in \text{DSM storage}
\]

where \( n \) refers to either urban or rural heat bus. Likewise, scenarios are denoted as ‘DSM2’ to ‘DSM10’ correspondingly.

**Economic**

The economic aspect is analysed in terms of three key components in supplying heating and cooling demand, i.e., heat pumps (HP), resistive heaters (RH) and power-to-gas (PtG).

Being the high-efficient heating technology as seen from \[^{[15]}\], heat pumps provide the most thermal energy among all the heating suppliers. Therefore, the annualised capital costs of heat pumps play a vital role in the \( \text{CO}_2 \)-neutral electricity, heating and cooling coupled system. Certain reduction rates \( \Delta C_{HP} \) are assumed for heat pumps, resulting in new annualised capital costs as,

\[
(100\% - \Delta C_{HP}) \cdot c_{n,s}, \quad s \in \text{heat pumps}
\]

Reduction rates of 10%, 20%, 30%, 40% and 50% are taken into account in this study, with the corresponding notations as ‘HPC10’ to ‘HPC50’.

The competitor of heat pumps, resistive heaters are much cheaper to install but with lower efficiencies. In a similar manner, the cost reductions, \( \Delta C_{RH} \), are applied to annualised capital costs of resistive heaters,

\[
(100\% - \Delta C_{RH}) \cdot c_{n,s}, \quad s \in \text{resistive heaters}
\]

Reduction rates of 10%, 20%, 30%, 40% and 50% form into corresponding scenarios as ‘RHC10’ to ‘RHC50’.

Apart from heat pumps and resistive heaters, dispatchable backup using natural gas plays an important role in supplying heating during peak hours \[^{[15]}\], but replaced by synthetic gas in this paper. Cost reduction levels are applied to capital costs linked to the PtG, i.e., electrolysis and methanation,

\[
(100\% - \Delta C_{\text{PtG}}) \cdot c_{n,s}, \quad s \in \text{PtG technologies}
\]

Again, reduction rates of 10%, 20%, 30%, 40% and 50% are considered in this study, and the corresponding scenarios are denoted as ‘PtGC10’ to ‘PtGC50’.

**2.3. Key metrics**

The impact of climatic, technical and economic uncertainties is evaluated in terms of a few key metrics. The first key metric is the economy, defined as system cost and LCOE. This metric tells if the net-zero emission system is affordable or not. The system cost is the objective function of techno-economical optimisation, i.e., Equation \[^{[A.1]}\] and LCOE is calculated as system cost divided by the total energy demand. The second key metric looks at the system configuration, i.e., technology composition, VRES penetration \( \gamma \), wind/solar PV mix \( \alpha \) at country- and European-level, required \( \text{CO}_2 \) tax to reach net-zero emissions in Equation \[^{[A.S]}\]. Since ‘TI’ and ‘HS’ both modify the HCD, thermal supply capacity and penetrations of different thermal technologies are also worth investigation. Thermal penetrations are defined similar to VRES penetrations, but in terms of heating and cooling provided by certain thermal technology. For instance, thermal penetration of technology \( s \) can be found as:

\[
\frac{\text{Thermal energy}_{\text{in total}}}{\text{Thermal energy}_{s}}, \quad s \in \text{thermal technologies}
\]

Thermal penetrations indicate how much of heating and cooling is covered by a certain technology \( s \). The last key metric investigates the operation of coupled system, such as heating and cooling supply time series, VRES curtailment, utilisation factor. It provides a more detailed and practical overview about how different components collaborate.

**3. Results**

![Figure 5: System cost (left) and thermal supply capacity (right) compositions for scenario ‘Base’. The white numbers indicate percentage shares for different technologies.](image-url)
### 3.1. Base

The coupled system of electricity, heating and cooling cost 422 billion € annually, and the compositions are shown in terms of percentage shares by the left plot in Figure 5. Being the main energy suppliers of the system, the sum of wind and solar PV accounts for more than half of the system cost, where wind turbines generate 71% (3505 out of 4940 TWh\textsubscript{el}) and solar PV 19% (962 out of 4940 TWh\textsubscript{el}) of electricity annually, see Figure 6. The annual VRES curtailment is kept to a considerably low level, less than 1% of total VRES production. The remaining 10% of primary energy is contributed by hydro inflow and run of river. Roughly a quarter of total expenditure goes to power-to-heat technologies, i.e., heat pumps and resistive heaters. The rest spending is mainly for balancing supply and demand spatially by transmission and temporally through storage.

The thermal supply capacities are shown by the right plot in Figure 5. Despite being the most expensive among heating technologies, heat pumps account for approximately 40% of total thermal supply capacities (2322 GW\textsubscript{th}), and convert 1059 TWh\textsubscript{el} electricity into 3349 and 70 TWh\textsubscript{th}, of heating and cooling, respectively. Thanks to the high-efficiency, at overall COP of more than 3, heat pumps are the most cost-effective among thermal technologies, hence supplying the majority of heating and cooling for all the European countries, see Figure 7. Compared to the north, southern countries have higher thermal penetrations of heat pumps, mainly due to the fact that northern countries have higher variations in HCD compared to the south. For instance, thermal penetration of heat pumps is 0.95 for Spain, while 0.68 for Norway. The HCD duration curve of Spain, plotted by the blue curve in the inset of Figure 7 shows a flatter tail compared to Norway in Figure 12.

Higher variations of HCD requires other thermal technologies, such as inexpensive resistive heaters, yet with low efficiency. Compared to heat pumps, resistive heaters hold roughly half of thermal supply capacities, but only providing less than one seventh of heating. Although CO\textsubscript{2} emissions are kept net-zero in the model, gas-to-heat technologies, i.e., gas boilers and CHP heat, still account for about 10% of the thermal supply capacities and provide 172 TWh\textsubscript{th} of heating, implying strong need of dispatchable backup for heating. Thermal storage is able to smooth out temporal variations in a few days or even seasonal, contributing the remaining one third of thermal supply capacities.

Figure 8 shows the heating supply time series during a cold winter week for two heat buses in Germany. Heat pumps supply the most heating at a rather constant output for both buses. For urban area, the residual load

![Figure 6: Energy flow for 'Base'. Synthetic gas only refers to the part where power is converted to heating in the end.](image-url)
surprisingly. The system costs, plotted by the red dashed line, drop almost linearly since total demand falls down. Temperature increases do not result in low-priced energy, but reduce the system costs due to diminished demand in heating.

The roles of wind and solar PV have been strengthened as the VRES penetrations rise by a small margin. Even though the wind/solar PV mixes at the Europe level remain almost constant, temperature increases alter the mixes at country-level, especially the southern countries favour more solar PV. For instance, the wind/solar PV mix of Italy drops from 0.53 to 0.48. For high cooling demand during the daytime, solar PV is very likely to produce electricity at high capacity factors, see Figure 10. Such strong correlations between cooling demand and solar PV generations, also seen in [25], favours solar PV more as temperature increases, particularly in the southern Europe.

As expected, temperature increases have stronger effects on the thermal units, whose supply capacities undergo a substantial reduction, see Figure 11. Among thermal

3.2. Temperature increases

As temperature increases, the compositions and sum of LCOE remain almost the same compared to ‘Base’, see Figure 9. In spite of much lower heating demand, see Figure 3, the LCOE of power-to-heat does not decrease

Figure 8: Heating supply output during a winter week in Germany for two heat buses of ‘Base’, urban (left) and rural (right) area.

Figure 9: LCOE compositions for temperature increases (TI) up to 5K, where the red dashed line indicates the annualised system costs.

Figure 10: Time series of cooling demand and solar PV generation during a summer week in Italy for the scenario of temperature increase by 5 K.

Figure 11: Thermal supply capacity compositions for temperature increases (TI) up to 5K.
units, supply capacity from synthetic gas drops the most, over a quarter for ‘TI5’ compared to ‘Base’. As mentioned above, synthetic gas plays the role in bridging the gap between extreme situations, hence less supply capacity is required. Followed by synthetic gas, thermal capacity supplied by heat pumps goes down by a quarter comparing ‘TI5’ to ‘Base’. Resistive heaters, however, only decrease by 10% in terms of thermal supply capacity, thanks to its low capital cost and flexibility.

Figure 12: Changes of thermal penetrations of heat pumps comparing ‘TI5’ to ‘Base’. The inset shows normalised demand duration curve for Norway comparing ‘TI5’ to ‘Base’.

Figure 12 exhibits the changes of thermal penetrations of heat pumps comparing ‘TI5’ to ‘Base’ on the country level. Most northern countries see negative changes as a result of temperature increase of 5 K. For instance, thermal penetrations of heat pump in Norway, whose HCD duration curve has been plotted by the inset in Figure 12, decrease from 68% for ‘Base’ to 45% for ‘TI5’. The decrement is mainly due to two reasons: firstly, lower total amount of heating and cooling load is required due to temperature increases, which disfavours using efficient but expensive heat pumps; second is because much lower values of HCD are observed at the tail of Norway HCD duration curve for ‘TI5’ compared to ‘Base’. By contrast, a few southern counties have almost the same thermal penetrations or even more for heat pumps. The inset in Figure 7 shows the HCD duration curve in Spain, where a similar tail has been observed for ‘TI5’ compared to ‘Base’. Even though the total demand of heating and cooling still drops for southern countries, temperature increases results in higher cooling demand, hence requiring more heat pumps for cooling mode.

Comparatively, thermal penetrations of resistive heaters increase among most of European countries, and the increments are more pronounced in the north. Since thermal penetrations of heat pumps drop for most of the countries, utilisation factors also decline significantly at the continent-level, 0.62 for ‘Base’ down to 0.55 for ‘TI5’. By contrast, resistive heaters maintain the utilisation factors around 0.13 regardless of temperature increases. Due to lower total heating and cooling demand, the combination of using more electricity and low-efficient resistive heaters prevail over high-efficient heat pumps which consume less electricity.

3.3. Heat savings

Heat savings have similar effects in HCD compared to temperature increases, apart from cooling demand. However, the sum of LCOE decrease from 65 down to 62 €/MWh for 50% heat saving, and the decrement is mainly contributed from less expenditure of power-to-heat technologies, see Figure 13. Lower LCOE and diminished total demand result in a substantial decline in system cost, shown by the dashed line. Note that the expenses of heat savings are not included in the model, which could potentially raise the LCOE and system costs.

Heat savings lead to higher VRES penetrations, but the wind/solar PV mixes remain almost constant. Comparatively, heat savings have stronger impact on the heating and cooling sector as expected. The sum of thermal supply capacities drop significantly, at a slope of 9% per 10% of heat saving, see Figure 14. Compared to other thermal technologies, resistive heaters do not decrease as much, only at a slope of 2%. In contrast to temperature increases, heat pumps operate at higher full load hours due to the homogeneous reduction effect. In general, heat savings lead towards a similar picture compared to temperature increase. Both cases lower the HCD, resulting in less heat pumps significantly, but not as much as resistive heaters. The VRES layouts, however, are only affected to a marginal extent.
Figure 14: Thermal supply capacity compositions for heat savings (HS) up to 50% reduction.

Figure 15: Changes of thermal penetrations of heat pumps comparing ‘HS50’ to ‘Base’. The inset shows the normalised demand duration curve for Norway comparing ‘HS50’ to ‘Base’.

Figure 16: Changes of energy capacities for individual thermal storage, utilising 6 hours of buildings inertia (‘DM6’) compared to ‘Base’.

3.4. Demand-side management

Even though few differences have been found in terms of system costs and configurations, demand-side management utilising buildings inertia does reduce the need for thermal storage, particularly for the rural area as cheap large water tanks are not available. Figure 16 shows the changes of energy capacities for short-term thermal storage, i.e., individual water tanks, comparing ‘DM6’ to ‘Base’. The reductions are more pronounced in the northern Europe since the peak shaping could be more effective due to higher diurnal variations of HCD. The benefits of utilising buildings inertia have been compromised due to several reasons. To sustain the indoor thermal comfort, the over-heating hours or switch-off the heaters can not exceed a certain period, limiting the allowed thermal storage capacity. In addition, the extra heating stored in the buildings mass has high heat loss. Last but not least, cheap and well-insulated water tanks already exist in the urban area from district heating. Nevertheless, this way of peak demand shaping could be potentially efficient for the places where external thermal storage is unavailable or costly.

3.5. Thermal technology cost reductions

As the costs of heat pumps go down, the system costs decline significantly, see the left plot in Figure 17, since heat pumps account for more than 80% of total heating and cooling generations. The majority of decrement comes from lower heat pumps expenditure, while a small extent is contributed by diminishing wind and solar PV installations, since the coupled system requires less electricity as more available heat pumps. Consequently, the thermal penetrations of heat pumps increase as cost goes
Figure 17: Impact of heat pumps (left), resistive heaters (middle) and power-to-gas (right) cost reductions on the thermal penetrations (left axis) and system costs (right axis).

down, reaching more than 90% for 50% cost reduction. By contrast, resistive heaters see substantial drop in terms of supply capacities and thermal penetrations, while dispatchable backup are barely affected. Cheaper heat pumps have huge impact on the competitors, resistive heaters, but not as much to gas boilers and CHP heat, which are still needed to balance seasonal variations.

However, system costs barely decrease due to cost reductions of resistive heaters, see the middle plot in Figure 17. Half-priced resistive heaters only save less than 1% of annual system cost. Despite the thermal supply capacities of resistive heaters increase considerably, up to 25% comparing 50% cost reduction to ‘Base’, the thermal penetrations only rise from 11% to 12%. Cost reductions do not enable resistive heaters to be cost-efficient compared to heat pumps, since the latter have much higher COP.

As power-to-gas costs go down, expenditure of solar PV increases while wind decreases more, resulting in system costs decline slightly, see the right plot in Figure 17. The primary energy generated by wind/solar PV has changed from 3506/963 TWh for ‘Base’ to 3384/1173 TWh for ‘PtGC50’. The main reason is that large amount of storage is needed to fully utilise solar PV generation due to its high diurnal variations, hence cheaper power-to-gas technologies enable storing surplus solar PV into synthetic gas cost-efficiently. Spatial wind/solar PV mixes reduce among the countries where solar PV have been deployed in ‘Base’, but not in wind-only countries. For instance, Germany has a wind/solar PV mix of 0.58 for ‘Base’, while the number changes to 0.44 for ‘PtGC50’; but its neighbour, Poland has mix of 1.0 for both scenarios.

Thanks to cheaper power-to-gas technologies, thermal supply capacities of heat pumps, resistive heaters and storage all decrease. Since dispatchable energy becomes more cost-competitive, thermal penetrations of gas boilers increase from 4% for ‘Base’ up to 6% for 50% cost reduction, and the corresponding decrement comes from resistive heaters. It is also observed that heat loss due to storage decreases by 25% comparing 50% reduction to ‘Base’. Cost reductions of power-to-gas technologies impact resistive heaters and thermal storage to a larger extent compared to heat pumps.

4. Discussions

The ‘Base’ scenario in this paper is taken from [15] with a few modifications. The net-zero emission system costs 422 billion € annually and LCOE is 65 €/MWh, respectively 19% and 17% higher compared to the scenario of 95% CO₂ reduction. VRES and PtH installations account for the most of increment, while the expenditure for gas has dropped significantly due to stricter emission constraint. The last 5% of emission drives up the system cost, also seen in [24], indicating the difficulty of achieving CO₂-neutral system, yet feasible.

The impact of climatic, technical and economic uncertainties are analysed on top of ‘Base’ scenario. It must be noted that the investigations are not carried out for alternative models, where different methodologies, including additional energy sectors, other CO₂-neutral technologies, or finer spatial/temporal resolutions may result in dissimilar uncertainties.

To investigate the impact of climate change, a simplified approach with homogeneous temperature increases has been introduced in this paper, rather than comprehensive climate models in [3, 27]. Similarly, assuming a uniform building retrofitting for the whole Europe may overlook the spatial characteristics among different countries. The uncertainties caused by cost assumptions are investigated in three categories, i.e., heat pumps, resistive heaters and power-to-gas technologies, while a same reduction rate has been applied on different technologies within
one category. It would be interesting to adopt a more comprehensive sensitivity analysis on the cost assumptions to further understand the synergy among various technologies.

Our model assumes perfect foresight and market equilibrium in the long term and minimises the system cost including capacity and dispatch expenditures, in order to maximise social welfare. Using different approaches, e.g., synchronised dispatch scheme [25] or rule based [29], would very likely have an inevitable impact on the results drew in section 5. Likewise, estimating wind/solar PV capacity factors or geographical potentials in different manners might lead to distinct optimal VRES configurations throughout Europe.

To pursue efforts of below 1.5°C temperature increases by 2050, European countries demand net-zero GHG for the whole energy sector. Coupling to additional sectors, particularly transportation and industry, brings unprecedented challenges humans have ever seen; but it also provides more flexibility and probably reveals extra synergies among different sectors. For instance, highly electrified transport sector could eliminate the need for costly electric storage [10] on the one hand. Potential demand-side management of charging electric vehicles could facilitate to shape the electricity load on the other hand, not to mention that vehicle-to-grid could potentially rewrite the significance of electric storage units [14].

A more comprehensive selection of technologies, in particular renewable resources such as biofuels, solar thermal, geothermal, or concentrated solar power, would facilitate to decarbonise the energy system. Extensive choices of mature low-carbon technologies could offer additional flexibilities to the existing model, hence bringing system costs further down. Alternative non-renewable technologies, e.g., nuclear or carbon capture and storage, could pave a different pathway rather than relying heavily on wind and solar PV.

A coarse-grained network is implemented for the model, where each country is aggregated into one single node. This simplification may neglect transmission bottlenecks, as well as spatial variations of VRES within individual country. Moreover, the simulations are carried out for only one year, where the demand profiles and VRES capacity factors are fixed to today's values.

5. Conclusions

To evaluate the impact of climatic, technical and economic uncertainties on the design of electricity, heating and cooling coupled system in Europe, an hourly-resolved, one-node-per-country network model with net-zero emission constraint has been introduced in this paper. On top of it, synthetic temperature increases, heating savings, demand-side management and cost reductions of key components are applied to quantify the impact of uncertainties.

System cost of net-zero emission scenario is dominated by wind, solar PV and power-to-heat installations, while the remaining is spent for balancing spatially by transmission and temporally through storage. Heat pumps provide most of heating and cooling at a rather constant output thanks to high efficiency. Urban area relies heavily on long-term thermal storage, while rural area consumes synthetic gas through dispatchable backup. In spite of an arduous journey to fossil-free, the synergy between long-term storage provided by synthetic gas and large water tanks, inexpensive resistive heaters and high-efficient heat pumps manage to carry out a CO₂-neutral electricity, heating and cooling coupled system.

Temperature increases do not result in lower LCOE, but cut system costs down almost linearly due to diminishing heating demand. Even though temperature increases barely affect VRES penetrations and wind/solar PV mixes at the Europe level, southern countries prefer more solar PV due to strong correlations between generations and cooling demand. Due to less total amount of HCD and changes of profiles, thermal penetrations of heat pumps decrease at different levels spatially while resistive heaters increase.

Compared to temperature increases, heat savings have similar effects in HCD, however, the system costs and LCOE both decrease linearly. Lower heating and cooling demand make surplus electricity more abundant, hence favouring inexpensive technologies more than heat pumps, therefore, corresponding thermal penetrations decrease considerably for most of the countries. Even though demand-side management through buildings' thermal inertia barely influences the system cost and configuration, the need for decentralised thermal storage has been brought down, particularly in the northern Europe. Nevertheless, the high heat loss assumed in the model underlines benefits of having free short-term storage and other forms of thermal storage are sufficiently cheap and more flexible.

Economic uncertainties are evaluated through three aspects: cost reductions in heat pumps, resistive heaters and power-to-heat technologies. Since heat pumps deliver the majority of heating and cooling among thermal units, its cost reductions lower the system costs considerably. By contrast, cheaper resistive heaters and power-to-gas barely cut down system costs, yet the latter one would reduce thermal storage loss. Low-cost of heat pumps decrease the need for resistive heaters substantially, but cost reductions of resistive heaters have insignificant impact on heat pumps. As power-to-gas technologies become less expensive, more dispatchable synthetic gas is available, not only could store more surplus energy from solar PV, but also enabling smoothing out seasonal variations to some degree.

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The model is implemented as a techno-economical optimisation problem, which minimises the total system costs expressed as a linear function (Eq. (A.1)) subject to technical and physical constraints (Eqs. (A.2) - (A.10)), assuming perfect competition and foresight. The open-source framework PyPSA [23] and the PyPSA-Eur-Sec-30 model introduced in [14], are used. Each of the 30 European countries covered by the model is aggregated into one node, which consists of one electricity bus, two heat buses for urban and rural areas, and one cooling bus (see in Figure 1). Neighbouring countries are connected through cross-border transmission lines, including existing and under construction lines (see Figure 2). High Voltage Direct Current (HVDC) is assumed for the transmission lines, whose capacities can be expanded by the model if it is cost-effective. Within each country, different buses are connected by energy converters as shown in Figure 4.

The model runs over a full year of hourly data. The inelastic loads of electricity, heating which includes the ratio between urban and rural heating, and cooling, are exogenous to the model and not optimised, as well as for hydroelectricity, i.e., hydro reservoir, run-of-river generators, and pumped-hydro storage, where fixed capacities are assumed due to environmental concerns. By contrast, VRES generator capacities, i.e., onshore wind, offshore wind, and solar PV, conventional generator capacities, i.e., open cycle gas turbines (OCGT), combined heat and power (CHP), gas boilers, converter capacities, i.e., heat pumps and resistive heaters, storage power and energy capacities, i.e., batteries and hydrogen for electricity and hot water tanks for heating, and transmission capacities are all optimised. In addition, the hourly operational dispatch of generators, converters, and storage units are subject to optimisation as well.

Appendix A. PyPSA-Eur-Sec-30 Model

As mentioned in Section 2, each country \( i \) has four buses labelled by \( n \). Generators and storage technologies by denoted by \( s \), hour of the year by \( t \), and bus connectors by \( \ell \), which include both transmission lines and converters. The total annual system cost consists of fixed annualised costs \( \bar{c}_{n,s} \) for generator and storage power capacity \( G_{n,s} \), fixed annualised costs \( \bar{c}_{n,s} \) for storage energy capacity \( E_{n,s} \), fixed annualised costs \( c_{\ell} \) for bus connectors \( F_{\ell} \), variable costs, for generation and storage dispatch \( g_{n,s,t} \). The total annual system cost is minimised by:

\[
\min_{G_{n,s},E_{n,s},F_{\ell},g_{n,s,t}} \left\{ \sum_{n,s} c_{n,s} \cdot G_{n,s} + \sum_{n,s} \bar{c}_{n,s} \cdot E_{n,s} + \sum_{\ell} c_{\ell} \cdot F_{\ell} + \sum_{n,s,t} a_{n,s,t} \cdot g_{n,s,t} \right\}
\tag{A.1}
\]
Appendix A.2. Constraints

The demand $d_{n,t}$ of bus $n$ at hour $t$ is met by VRES generation, hydroelectricity, conventional backup (OCGT, CHP, gas boiler), storage discharge, converters (heat pump, resistive heater) and HVDC transmission across border.

$$\sum_s g_{n,s,t} + \sum_l \alpha_{n,l,t} \cdot f_{l,t} = d_{n,t} \iff \lambda_{n,t} \ \forall n,t \quad (A.2)$$

where $f_{l,t}$ refers to energy flow on the link $l$ and $\alpha_{n,l,t}$ indicates both the direction and the efficiency of flow on the bus connectors; it can be time-dependent such as heat pumps. The Lagrange/Karush-Kuhn-Tucker (KKT) multiplier $\lambda_{n,t}$ associated with the demand constraint represents the local marginal price of the energy carrier.

The dispatch of generators and storage is bounded by the product between installed capacity $G_{n,s}$ and availabilities $\bar{g}_{n,s,t}$:

$$g_{n,s,t} \cdot G_{n,s} \leq \bar{g}_{n,s,t} \leq \bar{g}_{n,s,t} \cdot G_{n,s} \quad \forall n,s,t \quad (A.3)$$

$g_{n,s,t}$ and $\bar{g}_{n,s,t}$ are time-dependent lower and upper bounds due to e.g., VRES weather-dependent availability. For instance, for wind generators, $g_{n,s,t}$ is zero and $\bar{g}_{n,s,t}$ refers to the capacity factor at time $t$. $G_{n,s}$ is the installed power capacity for generators, limited by installable potentials $\bar{G}_{n,s}$ due to, e.g., geographical constraints:

$$0 \leq G_{n,s} \leq \bar{G}_{n,s} \quad \forall n,s \quad (A.4)$$

Similarly, the dispatch of converters has to fulfil the following constraints

$$f_{l,t} \cdot F_{l} \leq f_{l,t} \cdot F_{l} \leq f_{l,t} \cdot F_{l} \quad \forall \ell,t \quad (A.5)$$

For a unidirectional converter, e.g., a heat pump, $f_{l,t} = 0$ and $f_{l,t} = 1$ since a heat pump can only convert electricity into heating. For transmission links, $f_{l,t} = -1$ and $f_{l,t} = 1$, which allows both import and export between neighbouring countries. In particular, the inter-connection transmission can be limited by a global constraint

$$\sum_{l} l_{\ell} \cdot F_{l} \leq \text{CAP}_{LV} \iff \mu_{LV} \quad (A.6)$$

where the sum of transmission capacities $F_{l}$ multiplied by the lengths $l_{\ell}$ is bounded by a transmission volume cap $\text{CAP}_{LV}$. The KKT multiplier $\mu_{LV}$ associated with the transmission volume constraint indicates the shadow price of an increase in transmission volume to the system.

The state of charge $e_{n,s,t}$ of every storage has to be consistent with charging and discharging in each hour, and is limited by the energy capacity of the storage $E_{n,s}$

$$e_{n,s,t} = e_{n,s,t-1} + \eta_1 |g_{n,s,t}^+| - \eta_2 |g_{n,s,t}|$$

$$+ g_{n,s,t,\text{inflow}} - g_{n,s,t,\text{spillage}}, \quad 0 \leq e_{n,s,t} \leq E_{n,s} \quad \forall n,s,t \quad (A.7)$$

The storage has a standing loss $\eta_0$, a charging efficiency $\eta_1$ and rate $g_{n,s,t}^+$, a discharging efficiency $\eta_2$ and rate $g_{n,s,t}$, possible inflow and spillage which are subject to Equation (A.3). The storage energy capacity $E_{n,s}$ can be optimised independently of the storage power capacity $G_{n,s}$.

To enforce the decarbonisation of the energy system, a net-zero emission is imposed to the model, which means only synthetic gas is allowed to be consumed as dispatchable backup for OCGT, CHP and gas boiler, and the sum of initial filling level ($e_{n,s,t=0}$) for gas storage has to be equal to the ending level ($e_{n,s,t=T}$)

$$\sum_{n,s} (e_{n,s,t=0} - e_{n,s,t=T}) = 0 \iff \mu_{\text{CO}_2} \quad (A.8)$$

The KKT multiplier $\mu_{\text{CO}_2}$ indicates the necessary carbon emission tax to fulfil this constraint in an open market.

Appendix A.3. VRES layout

For every country $i$, the annual available VRES generation is denoted by $g_{i,VRES}$, representing the energy that can be potentially generated, that is, before curtailment.

$$g_{i,VRES} = \sum_{t,s\in VRES} g_{n,s,t} \cdot G_{n,s} \quad (A.9)$$

The VRES penetration $\gamma_i$ is defined as the ratio of VRES generation to the total demand in country $i$, which is the sum of electricity, heating and cooling demand

$$g_{i,VRES} = \gamma_i \sum_{t,n\in EU} d_{n,t} \quad (A.9)$$

The VRES generation consists of wind generation $g_{i,W}$ and solar $g_{i,S}$,

$$g_{i,VRES} = g_{i,W} + g_{i,S}$$

The wind/solar mix parameter $\alpha_i$ determines the ratio between available wind and VRES

$$g_{i,W} = \alpha_i \cdot g_{i,VRES} \quad (A.10)$$

The VRES mix of the whole system $\alpha_{EU}$ can be found by

$$\sum_{i} g_{i,W} = \alpha_{EU} \cdot \sum_{i} g_{i,VRES}$$

where $\alpha_{EU}$ expresses the overall VRES layout tendency towards wind or solar dominance.

To utilise different VRES resources over the continent, a weakly homogeneous layout is introduced, where ‘homogeneous’ indicates that the share $\gamma_i$ of each country is the same, thus shortened to $\gamma$, and ‘weakly’ suggests that the mix $\alpha_i$ of each country is optimised.

$$\gamma_i = \gamma, \quad \alpha_i \text{ subject to opt} \quad (A.10)$$

This layout ensures that each country is VRES self-sufficient to a certain extent, and the optimisation seeks the optimal wind/solar mix in each country.