How flexible electrification can integrate fluctuating renewables

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ABSTRACT

Supply and demand for electricity are central to the decarbonisation of the energy system. To replace fossil fuels, supply of electricity must shift to wind and solar, but due to their variability, fully renewable supply poses a challenge. On the other hand, additional demand for electricity arises to cut emissions in the heating, transport, or industry sector. We analyze how additional demand from these sectors can be flexible to support the integration of fluctuating renewables on the supply-side. The analysis builds on a macro-energy system model with an extensive scope to cover all sectors and high spatio-temporal detail to capture the variability of renewables. Results show that flexible electrification can efficiently provide a major share of system flexibility if incentivized by regulation. Especially electricity demand for the production of hydrogen is flexible, if hydrogen pipelines and storages are deployed to match production with final consumption.

1. Context and Scale

Objectives of the Paris Climate Agreement require to transform the supply and demand for electricity. On the supply-side, wind and solar must replace fossil fuels, but due to their variability complete substitution remains challenging. At the same time, cutting emissions beyond the power sector requires renewable electricity for battery electric vehicles, production of green hydrogen, or heat-pumps.

We analyze, how the additional demand could adopt to fluctuating generation from wind and photovoltaic to facilitate their integration. Results show that flexible electrification can substitute supply-side solutions, like storage, and efficiently provide a major share of system flexibility. Especially electricity demand for the production of hydrogen is flexible, if hydrogen pipelines and storages are deployed to match production with final consumption. Flexible charging of battery electric vehicles can balance out a substantial share of daily fluctuations.

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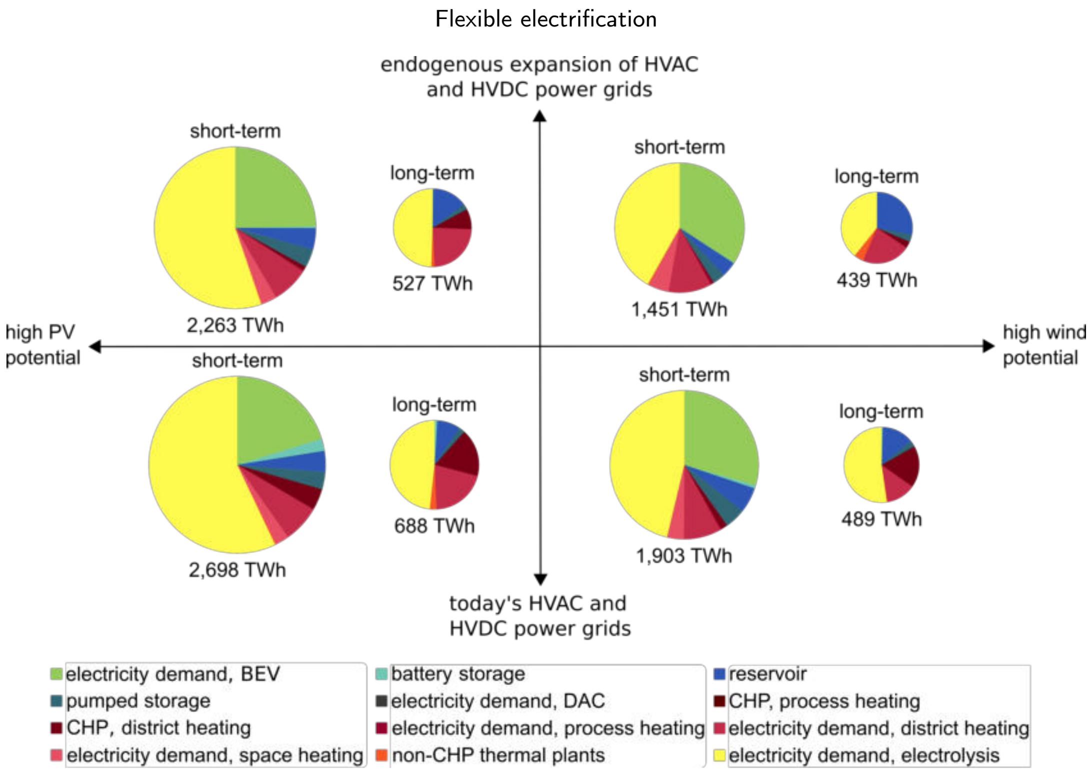

Figure 1: Graphical abstract, Flexible electricity supply and demand by timescale and scenario

2. Introduction

In the Paris Climate Agreement 196 countries commit to keeping global warming *"well below 2 degrees [...] compared to pre-industrial levels"* requiring to decarbonize and transform the global economy [1]. The supply and demand for electricity will play a pivotal role in this transformation.

On the supply side, renewable electricity must replace generation from fossil fuels. Especially wind and photovoltaic (PV) power offer a great global technical potential ranging from 1,585 to 50,580 EJ, at least three times 2019's primary consumption, and declined in levelized costs by 70% and 90% in the last ten years, respectively [2, 3]. Consequently, power generation from wind and PV is rising and in some countries already constitutes a major share: In 2020, wind and PV amounted to 60% of total generation in Denmark or 32% in Germany [4]. However, further increasing these shares and fully decarbonizing power supply remains a challenge, because wind and PV power are weather dependent and fluctuate over time and location. As a result, higher shares require complementary technologies that can be deployed more flexibly, for example storage systems, carbon-neutral thermal plants, or transmission infrastructure [5, 6].

At the same time, decarbonization will also have a profound effect on the demand for electricity. Mitigating emissions beyond the power sector in heating, industry, and transport requires renewable electricity as a primary source of energy, either directly or indirectly using synthetic fuels produced from electricity [7, 8]. In space heating, direct electrification involves electric heat pumps or resistive heating whereas indirect electrification implies to replace oil and gas with synthetic heating fuels. In process heating, the same technologies can substitute industrial boilers and furnaces, although their respective potential highly depends on the specific application and temperature level. In transport, direct electrification involves battery electric vehicles (or electric overhead lines for heavy-duty vehicles), while fuel cell (FC) vehicles or combustion of synthetic fuels create an indirect demand for electricity. Non-electric options for decarbonization in these sectors are scarce since the sustainable potential of biomass (BM) as a primary source of energy is estimated between 100 and 300 EJ and far from sufficient to satisfy global demand [2]. Carbon capturing, if available, will be limited to industrial scale and not applicable in space heating or individual transport.

All strategies to decarbonize heating, industry, and transport entail close integration with the power sector. But the strategies differ in how they affect the total level, the pattern, and the elasticity of electricity demand—all factors decisively shaping the need for flexibility in renewable systems [9]. For instance, temperature-dependent efficiency of electric heat pumps drives up consumption in winter, when PV generation is lowest [10]. Therefore, compared to the use of synthetic heating fuels, electric heat pumps require a shift from PV to wind generation or additional seasonal storage. Based on patterns of PV generation, ambient temperature, and consumption patterns, flexibility needs can be distinguished on two specific timescales, each with different supply- and demand-side options to address them:

- *Short-term flexibility driven by daily patterns:* On the supply-side, battery storage, for instance, can provide short-term flexibility by shifting midday generation from PV to the evening hours, when demand peaks. Corresponding short-term adjustments on the demand-side are encompassed by the term demand-side management (DSM). Today the potential of DSM is limited, but could increase substantially, if electrification adds more flexible demand, for instance, from battery electric vehicles or electric heat pumps.

- *Long-term flexibility driven by seasonal patterns:* One supply-side option for long-term flexibility is seasonal energy storage, like hydrogen produced from excess PV generation in summer, stored and re-converted into electricity during the winter months. The need for such flexibility in the power sector again depends on how heating, industry, and transport are decarbonized. For example, synthetic heating fuels or seasonal heat storage can mitigate peaks of electricity consumption from heat pumps in winter.

Overall, the potential interactions and synergies highlight that system planning must consider both, electricity supply and demand, for the provision of flexibility. Yet, existing analyses of decarbonized power systems are predominantly focused on the supply side. Several studies assess the interplay of fluctuating renewables with different storage systems, thermal power plants, and interconnection to achieve a reliable and decarbonized supply of electricity, but the assumed level, profile, and elasticity of demand are based on historical data and do not reflect decarbonization beyond the power sector [11, 12, 13, 14]. Other studies do consider changing demand, but still assume it to be an exogenous factor, focusing their analysis on the supply side. Often these studies also only account for changes in electricity demand from decarbonizing one specific sector, like space heating [15] or transport [16, 17], some have a more comprehensive perspective and include hydrogen in their supply-side analysis [18, 19].

In very few studies on flexibility and integration of fluctuating renewables, electricity demand is endogenous to the analysis to identify synergies across sectors, for instance, seasonal storage of heat substituting thermal backup plants in the power sector. In all these studies, endogenous consideration of demand is limited to space heating, either omitting transport completely [20, 21] or again resorting to exogenous assumptions [22]. Furthermore, these studies neglect the operational restrictions individual heating systems are subject to on the one hand, but on the other do not account for their flexibility from thermal inertia either.

Extending the existing literature on the integration of fluctuating renewables, this paper transcends the focus on supply-side options in the power sector and instead establishes a broader perspective on the entire energy system to fully include the demand for electricity into the analysis. To achieve this, decarbonization of space heating and, in addition to former research, process heating and transport are endogenous, and their operational restrictions and flexibilities are carefully considered in the applied model. Accordingly, only final demand for electricity remains fixed, while secondary demand from heating or transport can adapt to the composition of supply in terms of overall quantities, profile, and elasticity. The quantitative analysis is conducted for a fully renewable system since the investigated effects can expected to be most pronounced in this setup. We apply a macro-energy system planning model that optimizes expansion and operation of technologies to satisfy final demand by minimizing total costs [23]. The model deploys a graph-based formulation specifically developed to model high shares of fluctuating renewables and sector integration, which is capable to vary temporal and spatial resolution within a model [24]. Thanks to this feature, high resolutions can be applied where the system is sensitive to small imbalances of supply and demand—for instance, in the power sector, while more inert parts, like transmission of gas or hydrogen, are modeled at a coarser resolution. The choice of resolution for final transport or heating demands implicitly reflects the inherent flexibility, or elasticity, of electricity demand from these sectors, in space heating, for example, due to the thermal inertia of buildings, and provides an alternative to including demand-side management as an explicit technology. For further details on the graph-based formulation see section 5.3 of the Experimental Procedures and Göke [24].

In total, the applied model includes 22 distinct energy carriers that can be stored and converted into one another by 120 different technologies to satisfy final demand and transported by four different types of transmission infrastructure. The choice of technologies is based on reports of the Danish Energy Agency [25], except for transport where we resort to Robinius et al. [26]. To introduce the interrelations of carriers and technologies we rely on directed graphs, to keep

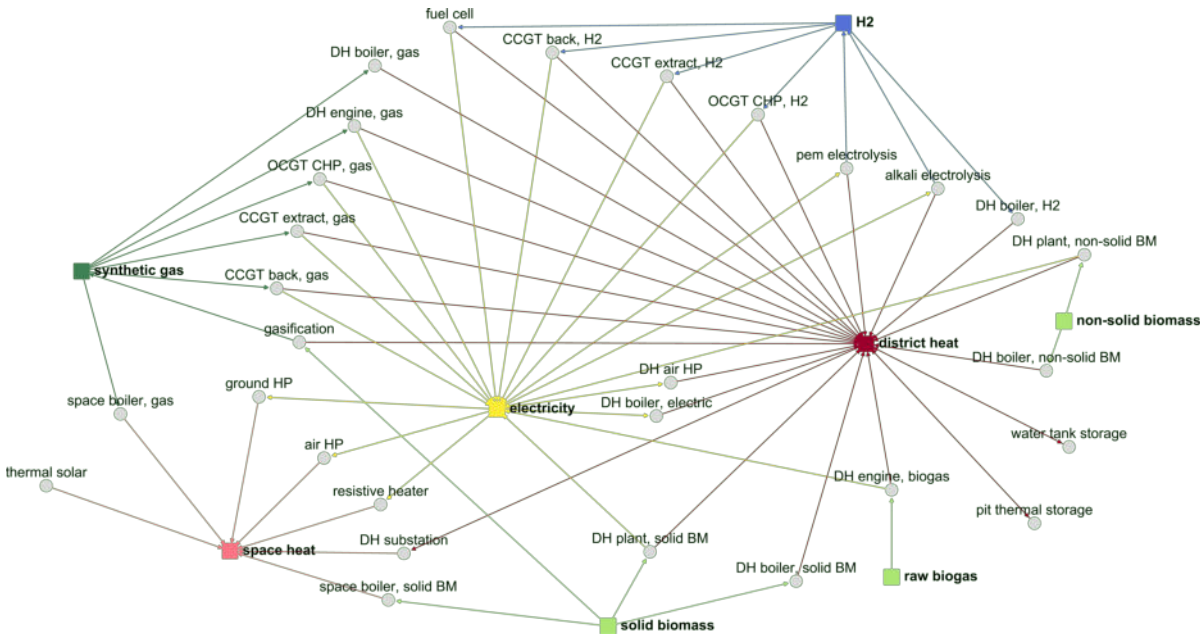

Figure 2: Subgraph for supply of space and district heating

complexity manageable especially on sub-graphs of the full model.[1] Vertices in these graphs either represent carriers, depicted as colored squares, or technologies, depicted as gray circles. Entering edges of technologies refer to input carriers; outgoing edges refer to outputs.

Fig. 2 provides an overview of the technologies capable to supply space and district heat (DH) including their respective input carriers or additional outputs. To take into account that individual heating systems are not embedded into larger networks, like the transmission grid or heating networks, the output of each technology supplying space heat is restricted to be proportional to the level of demand, as section 5.2 of the Experimental Procedure details. The section also describes how both heat pumps (HP) and resistive heaters can be paired with heat storage to mitigate peaks in electricity demand. Supply for district heat includes air heat pumps, different boilers, two distinct storage systems, and a broad range of combined-heat-power (CHP) technologies, some of which, like combined-cycle extraction turbines, can be operated flexibly and–within limits–increase their electricity output at the cost of reduced total efficiency. In addition, excess heat from electrolysis or gasifying solid biomass can be utilized as well. Demand for district heat is fully endogenous and induced by other technologies, for example, substations supplying space heat. Fig. 3 depicts the transport sector graphing all the carriers of final demand for transport, technologies available to satisfy demand, and the inputs these technologies require. For all types of road transport, these include battery electric vehicles (BEV), internal combustion engines (ICE), and electric cars powered by fuel-cells (FC). In addition, trucks powered by electric overhead lines and compressed natural gas (CNG) vehicles in private transport are included. Transport services beyond the road and rail transport are considered by an exogenous fuel demand not included in the graph. Analogous graphs in section 5.5 of the Experimental Procedures provide an overview of technologies for the supply of process heat, electricity, and synthetic fuels.

The temporal scope of the model covers one year with resolutions varying by energy carrier: Electricity uses a full hourly resolution. The same applies to all types of transportation that can incur a direct grid-bound demand for electricity, like heavy road and both types of rail transport. All other types of transport use a daily resolution to account for the flexibility from BEVs. Charging of BEVs is constrained by an hourly profile reflecting when vehicles are plugged in but is flexible on how to satisfy daily demand within this profile. Following the same concept, space, district, and process heat are modeled at a four-hour resolution to account for the thermal inertia of buildings and the potential to shift industrial processes; hydrogen and gas use a daily resolution.

[1] For illustrative purposes Fig. 12 in section 5.5 of the Experimental Procedures shows the full model graph.

Flexible electrification

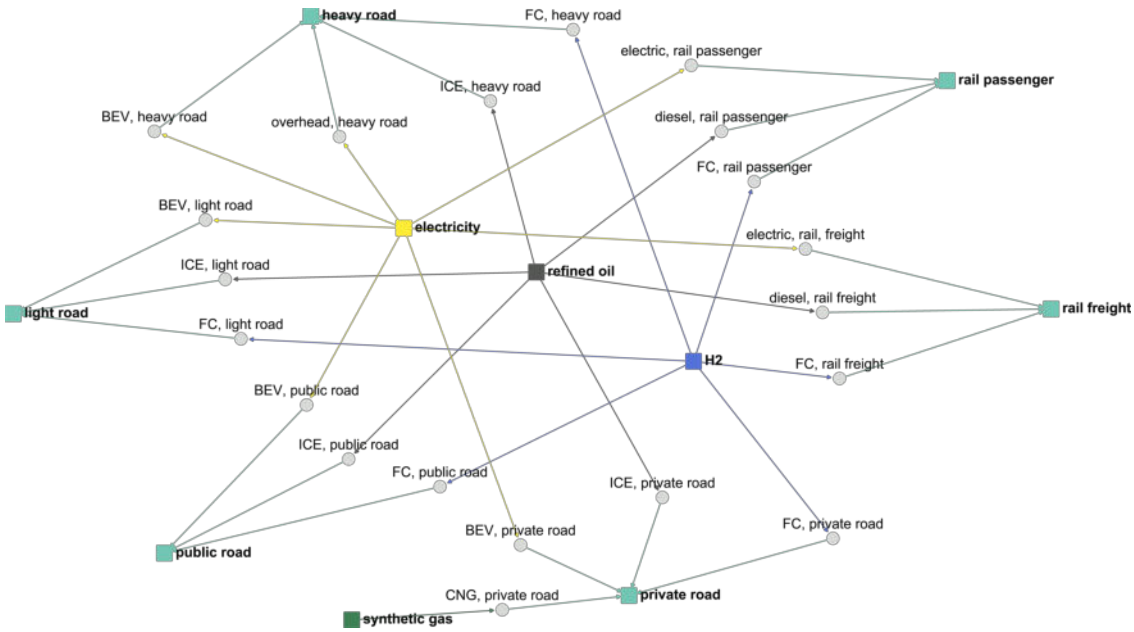

Figure 3: Subgraph of the transport sector

Spatially the model covers the European continent subdivided into 96 regions. A large spatial scope and resolution are essential to capture how transmission infrastructure can smooth local variations of wind and PV generation and add flexibility to the system [27]. The representation of transmission infrastructure in the model includes high-voltage alternating current (HVAC) and direct current (HVDC) lines as well as gas and hydrogen pipelines. Further details on the assumed resolutions and the representation of transmission infrastructure are provided in the Experimental Procedures.

The extensive scope and fine resolution of the model necessitate some simplifying assumptions. Due to the social planner perspective characteristic of bottom-up planning models, we assume all agents behave in a way that minimizes total system costs. In the case of consumers, this implies comprehensive adoption of smart metering and real-time pricing to incentivize flexible demand. In addition, the model is fully deterministic neglecting errors in forecasting supply and demand and the resulting need for balancing services. Finally, the model does not consider unit commitment and abstracts from the operational restrictions of individual units. These restrictions are most relevant for plants using large steam turbines, like coal or nuclear plants, not included due to our focus on renewable energy systems anyway.

To study the interactions between electrification of demand and fluctuating renewable supply, the paper compares four different scenarios depicted in Fig. 4. The scenarios vary two assumptions that shape the need for flexibility but are also subject to considerable uncertainty: the energy potential of fluctuating renewables and the upper limit of power grid expansion. Estimates of PV and wind potentials are difficult and vary substantially, since they must reflect technical constraints on land availability and societal constraints on public acceptance. At the same time, PV and wind have very distinct short- and long-term generation profiles, PV peaking in summer and wind in winter, which will affect flexibility needs differently. Transmission infrastructure is a key option to provide flexibility but is met with public opposition as well. Therefore, its capacity is either limited to today's capacities or can be further expanded by the model. The quantitative assumptions on renewable potential and grid expansion were derived from dedicated literature and are discussed in sections 5.5 and 5.4, respectively.

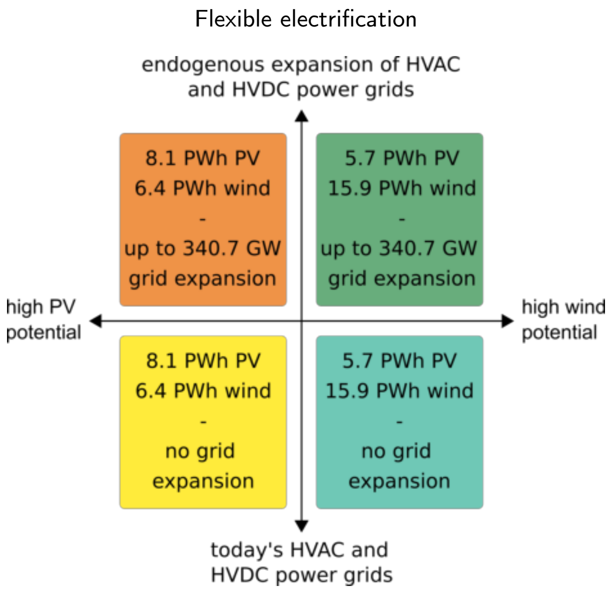

Figure 4: Scenario matrix

3. Results

In light of our research question, analysis of model results focuses on flexibility needs and provision rather than total quantities of supply and demand.[2] To quantify the provision of flexibility from different technologies, we extend the approach introduced in Heggarty et al. [9]. Its basic idea is to visualize the modulation of technology operation around its average, for instance by time of day as in Fig. 5. Positive values indicate total generation for a given hour is above the yearly average; negative values below. A technology generating at constant capacity throughout the whole year would not be visible in the graph and considered perfectly inflexible. By this definition, although restricted by its technical characteristics, flexibility and modulation of a technology are ultimately system attributes determined by the interaction of different technologies, similar to full-load hours.

In Heggarty et al. [9] analysis is limited to the flexibility of supply. As a result, graphs only show modulation of dispatchable generators and take the shape of the residual load curve, the electricity demand minus generation of fluctuating renewables. To extend this metric to the demand side, we define the modulation of electricity consumption to be the difference between actual and perfectly inflexible consumption. Analogously to generators, for electrolysis, inflexible consumption corresponds to operating at constant capacity. For space and process heat, inflexible consumption is the electricity needed to satisfy demand at an hourly instead of a four-hour resolution without local heat storage. For technologies generating district heat, inflexible electricity consumption is proportional to the respective consumption of district heat that satisfies final demand for space and process heat. For BEVs, inflexible consumption is proportional to the hourly profile constraining charging. Final demand for electricity itself and consumption from rail transport or overhead trucks, all represented at an hourly resolution in the model, are a priori inflexible.

The daily modulation profiles in Fig. 5 report need and provision of short-term flexibility by scenario. All profiles clearly exhibit the daily profile of solar generation peaking at noon. The peak of demand in the late evening is observable as well, but not particularly pronounced, because inflexible final demand for electricity on average only accounts for 37 to 40% of total generation depending on the scenario. Lacking a characteristic daily profile, the effect of wind generation is negligible. Correspondingly, the required short-term flexibility is closely correlated with PV generation, which expectedly increases for the high-PV scenarios, but also if grid expansion is prohibited. For quantification of total flexibility needs, we sum all areas in the modulation graph. For the high-wind scenario, these amount to 1,451 TWh with grid expansion and to 1,903 TWh without; for the high PV potential to 2,263 and 2,698 TWh with and without grid expansion, respectively. The correlation coefficient of these values with PV generation is 0.95.

The major source of short-term flexibility is electricity demand from electrolysis, exclusively alkali electrolysis in all scenarios, that closely adapts to the profile of solar generation. Of all technologies, flexibility of electrolysis

[2] Section 5.6 provides detailed energy balances reporting supply and demand by energy carrier for each scenario.

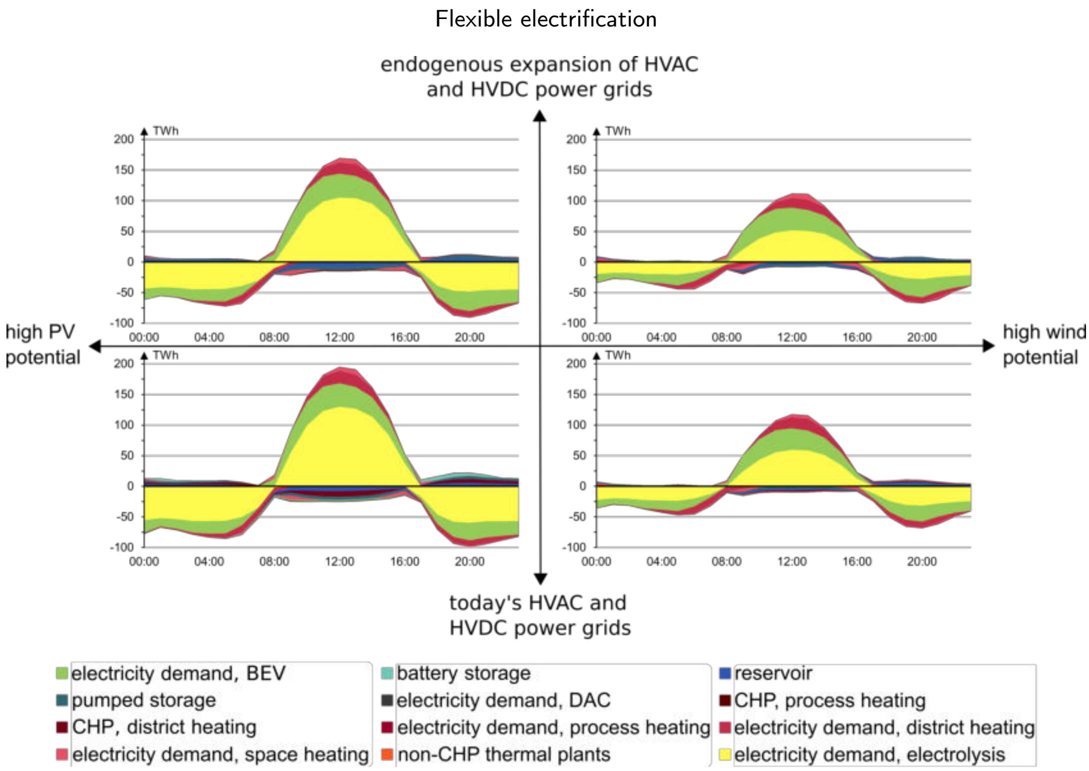

Figure 5: Daily modulation profile

is also most elastic to the total need for flexibility across scenarios increasing from 607 TW for the high-wind and grid scenario to 1,539 TWh for high-PV and no-grid. Three technological factors enable this increase: First, the total hydrogen demand and as a result also the electricity demand for electrolysis increases. As we will elaborate on when discussing long-term flexibility, a high PV potential and no grid expansion make hydrogen less unfavorable to inflexible electrification, for instance in process heating. Second, electrolyzer capacity rises disproportionately to hydrogen demand and consumes a greater share of excess generation from renewables, like a demand-side counterpart to peak-load plants. Accordingly, full load hours of electrolyzers decrease from 3,640 for the high-wind and grid scenario to 2,940 hours for high-PV and no-grid. Finally, added storage and grid infrastructure for hydrogen decouples demand from supply and makes electricity demand from electrolysis more flexible. Energy capacity of cavern storage increasing from 52 TWh for the high-wind and grid scenario to 226 TWh for high-PV and no-grid reflects this. Capacities of grid infrastructure for hydrogen transport rise from 11,615 to 77,118 GWkm.

Flexible loading of BEVs is the next most important source of short-term flexibility on average amounting to 540 TWh with a share of 90 % from private passenger transport. Restricted by the exogenous demand for transport services, short-term flexibility from BEVs is inelastic to the total demand for flexibility.

Electricity demand from district and space heat on average provide 166 and 70 TWh of short-term flexibility, respectively. Flexibility from district heating increases from 156 for the high-wind and grid scenario to 183 TWh for low-PV and no-grid, while flexibility from space heating decreases slightly. The shift towards short-term flexibility from district heat can be explained by synergies with provision of long-term flexibility discussed later. The energy capacity of water tanks used for short-term storage of district heat rises from 84 to 2,800 GWh, while capacity for local storage of space heat, almost exclusively paired with resistive heaters, does not change significantly.

On the supply side, flexibility from battery storage and CHP plants for district heat is highly sensitive to the respective scenario. For the high-wind and grid scenario their contribution is negligible. If high PV potentials and restrictions on grid expansion drive-up flexibility needs, provision increases up to 60 TWh for battery storage and to 101 TWh for CHP plants for district heating in the high-PV and no-grid scenario. Added flexibility from CHP plants, entirely fueled by hydrogen, relates to a steep increase of their total generation enabled by the rise of hydrogen production discussed previously.

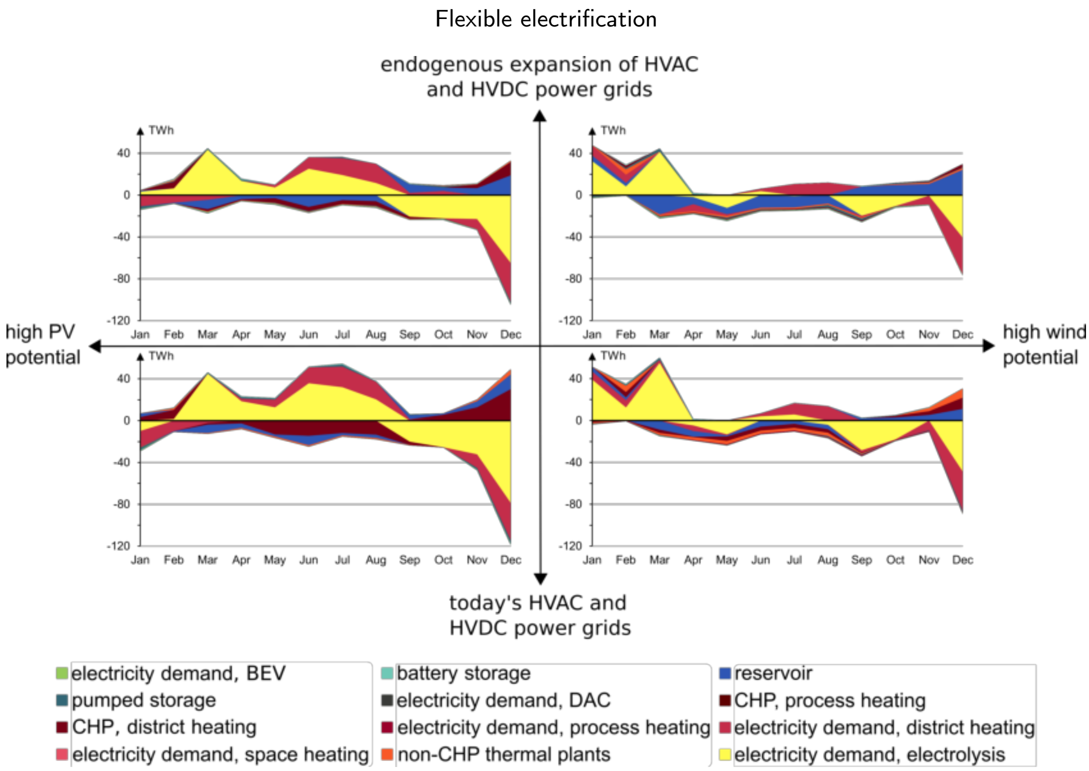

Figure 6: Yearly modulation profile

In addition, hydro reservoirs and pumped storage provide significant flexibility amounting to 55 and 44 TWh for the high-wind and grid scenario. For all other scenarios, flexibility from these technologies almost exactly doubles and reaches an upper limit imposed by fixed capacities.

The yearly modulation plotted in Fig. 6 shows need and provision of long-term flexibility by scenario. Overall, yearly profiles are not as smooth as daily profiles and subject to pronounced outliers, for instance in March, resulting from the characteristics of the underlying climatic year. Daily profiles do not show such outliers since they average out over all days of the modeled year. Nevertheless, all profiles exhibit an increase in consumption during the summer due to peaking PV generation, especially in the high-PV scenarios. In the high-wind scenarios, this effect is offset because wind generation peaks during winter, although the seasonal profile is not as pronounced as for PV. Supply peaks during winter reflect an increase in final demand for space heat and electricity. The total need for long-term flexibility increases from 439 TWh in the high-wind and grid scenario to 688 TWh for high-PV and no-grid, which is less pronounced than the rise of short-term flexibility demand across scenarios. Again, the most important driver of flexibility needs is PV generation correlated with a coefficient of 0.94.

The predominant source of long-term flexibility is electricity demand from electrolysis amounting up to 332 TWh. Similar to the short-term, flexibility from electrolysis is highly elastic to the overall demand for flexibility doubling across scenarios. As a result, corresponding investments into electrolyzer capacity, hydrogen storage and pipelines occur, as discussed earlier. In the high-wind scenarios, the profile is mostly driven by wind generation, which peaks at the beginning of the year, particularly in March, for the respective climatic year. In the high-PV scenarios, there is also a significant increase during the summer.

Electricity consumption from district heating on average provides 100 TWh of flexibility. The specific amount is closely related to the level of investment in pit thermal storage used for seasonal storage. The profiles show how these are mostly charged in late summer and discharged in early winter to minimize losses from self-discharging.

Other types of consumption, like space heating or BEVs, that provided significant amounts of short-term flexibility are not relevant in the long-term, because they are technically incapable to shift demand over an extended period.

Contrary to the short-term, provision of long-term flexibility also significantly relies on supply-side technologies. In the high-wind and grid scenario supply-side flexibility is mostly supplied by reservoirs, but in the other scenarios with greater flexibility needs, provision from reservoirs shifts from long- to short-term. Here CHP plants for district heating, exclusively fueled by hydrogen, contribute significant amounts of long-term flexibility instead amounting up to 120 TWh in the high-PV and no-grid scenario. In this case, a high PV potential and no grid expansion make electricity more scarce during winter, when final heat and electricity demand peak, and as a result combined generation more favourable. At the same time, hydrogen can be produced at lower costs, because higher PV potentials cause excess supply in summer. For thermal plants without CHP mechanics are similar, but their role is negligible.

4. Discussion and conclusions

Overall results demonstrate how electrification of final demand can support the transition towards renewable energy supply. Electrolyzers and BEVs are capable to cover a great majority of daily fluctuations in renewable generation and final demand; electrolyzers and flexible district heating a majority of seasonal fluctuations. The investigated scenarios show that restricting power grid expansion and shifting supply from wind to PV drive-up flexibility needs.[3] Both effects are particularly pronounced for short-term flexibility covering daily fluctuations. A more flexible and an overall increasing hydrogen generation covers a large proportion of additional short- and long-term needs in the respective scenarios. Furthermore, more seasonal storage of district heat and more CHP generation fueled by hydrogen provide additional long-term flexibility.

These results show that neglecting demand-side capabilities to integrate fluctuating renewables will overstate system costs and reliance on flexible supply-side technologies. For instance, our results suggest battery storage is neither required nor cost-efficient to match peaks of PV generation with consumption. Similarly, the need for thermal backup plants to cover peaks of electricity and heat demand in winter is substantially reduced compared to similar studies. In line with previous studies, we find the overall potential of demand-side management in the industry sector to be limited.

The key to flexible electrification are synergies between the different sectors of the energy system. In our analysis, seasonal storages for district heat are for example charged with excess PV generation in summer and discharged when electricity is scare in winter. Realizing these synergies in practice will require coordinated operation and planning of technologies across sectors. While public policy increasingly embraces electrification to achieve climate targets, it should equally address resulting interactions and potential synergies between sectors. This is especially important since uncoordinated electrification will have the opposite effect and drive up flexibility needs, for instance, if inflexible electric heating further increases peak demand for electricity.

Nevertheless, a regulatory framework that fully achieves cost-efficient coordination of the power, heat, transport, and industry sector is likely overly complex and unrealistic. Against this background, our results suggest to give first priority to the coordination of power systems and supply of synthetic fuels, in particular hydrogen. Location and time of electricity consumption for electrolysis should be price-sensitive and consider hydrogen grids and storage to match supply with demand. Similarly, flexible loading of BEVs and flexible operation in district heating networks should be incentivized.

In addition to sectoral synergies, integration of renewables also benefits from the extensive spatial scope of our analysis. Even in the scenarios without grid expansion and today's NTC capacities, exchanged quantities increase significantly to balance local mismatches of demand and renewable supply. In all scenarios, hydro generation—two thirds concentrated in Scandinavia— provides a substantial amount of flexibility to the whole European system. From a policy perspective, this suggests that beyond coordination of energy sectors, integrating renewables also calls for closer coordination of national energy systems.

Our analysis deploys high spatio-temporal detail to account for fluctuations of wind and PV generation and capture the resulting flexibility needs. On the other hand, it also includes a broad range of options to cover these needs. Nevertheless, the analysis could benefit from further extending the representation of flexibility needs and options. Like similar studies, our model is limited to a single climatic year with average characteristics but inevitable outliers, apparent in the seasonal flexibility profile in Fig. 6. Extending the analysis to multiple climatic years could achieve a more robust representation of flexibility needs. On the other hand, promising options for the provision of flexibility could not be included due to a lack of reliable data on their cost and potential. Most prominently, geothermal energy holds considerable potential for flexible supply of both electricity and heat, but estimates of regional potentials are scarce [28]. The same applies to the utilization of excess heat from industrial processes in district heating networks.

[3] This does not necessarily imply wind generation is more cost-efficient than PV, since costs of flexibility must be weighted against generation costs.

5. Experimental procedures

5.1. Resource availability

5.1.1. Lead contact

For further information on resources and materials please refer to the Lead Contact, Leonard Göke lgo@wip.tu-berlin.de.

5.1.2. Materials availability

No materials were used in this study.

5.1.3. Data and code availability

The model data and script is available on GitHub: https://github.com/leonardgoeke/EuSysMod/releases/tag/flexibleElectrificationWorkingPaper.

The applied model uses the open AnyMOD.jl modeling framework [29]. The applied version of the framework is available here: https://github.com/leonardgoeke/AnyMOD.jl/releases/tag/flexibleElectrificationWorking

All files used to derive the model's wide range of quantitative inputs are shared on Zenodo [30]: https://doi.org/10.5281/zenodo.6481534

5.2. Concepts of technology deployment

Since the scope of analysis extended to the demand side, the model includes two very distinct types of assets: first, assets that feed their generation into larger networks and typically operate on an industrial scale, and second, small-scale technologies that are not part of a network and must independently match demand. For instance, thermal plants and renewables both feed into the power grid and at time of low renewable generation thermal plant can increase production to meet demand. But for residential heating this concept does not apply, because each building will only have a single heating technology installed to meet demand.[4].

To account for these differences, the model introduces two distinct concepts for technology deployment termed "merit-order" and "must-run". The "merit-order" refers to the standard representation in energy or power system models and is described by equations 1a and 1b.[5] The concept consists of an energy balance that ensures the summed output Out from all technologies i equals the demand dem at each time-step t and a capacity constraint that limits the output of each technology to the installed capacity $Capa$ in each time-step t. In the model, technologies providing electricity, district heat, hydrogen and synthetic gas apply the merit-order concept.

$$\sum_{i \in I} Out_{i,t} = dem_t \qquad \forall t \in T \tag{1a}$$

$$Out_{i,t} \leq Capa_i \quad \forall t \in T, i \in I \tag{1b}$$

Opposed to the merit-order, the "must-run" concept in equations 2a and 2b, enforces a capacity balance that ensures the installed capacity can meet peak demand $peak$ and fixes the relative output in each time-step to the ratio of current demand to peak demand. In the model, technologies for space heat, any level of process heat, or transport apply the must-run concept.

$$\sum_{i \in I} Capa_i = peak \tag{2a}$$

$$Out_{i,t} = \frac{dem_t}{peak} \cdot Capa_i \quad \forall t \in T, i \in I \tag{2b}$$

Figure 7 illustrates the difference between both deployment concepts. In the merit-order concept, the next cost-efficient technology is deployed until its capacity limit is reached, while in the must-run implementation relative deployment is equal among all technologies. As a result, modeling sectors like residential heating in the merit-order way overestimates utilization of technologies with small variable costs, in this example heat pumps, and underestimates the output of expensive technologies, effectively rendering them as "peak-load" technologies.

There are characteristics of the must-run formulation that are worth mentioning. First, since it replaces an energy balance for each time-step with a single capacity balance, it reduces model size and thus computational complexity.

[4] To see how district heating is accounted for in this context see section 5.5

[5] In all equations variables are written in upper- and parameters in lower-case letters.

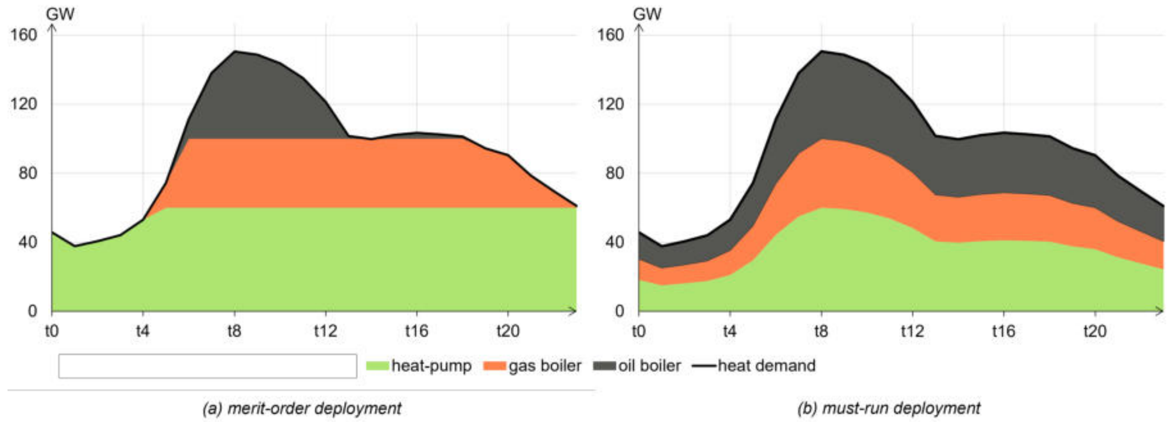

Figure 7: Illustration of deployment concepts

Second, even if within the considered time-frame peak demand does not occur, there will be sufficient capacity to meet it thanks to equation 2a. Practically, this means we can ensure enough heating capacity for an extremely cold climatic year, even if the time-series data in the analysis is based on an average year. However, the method cannot guarantee the operation of this capacity in climatic years not considered.

The applied model additionally implements refinements to the must-run deployment that allow for some operational flexibility of the subjected technologies. All electric and solar thermal heating technologies can be paired with a storage system that exclusively operates with the respective heating technology as displayed in Fig. 8. As a result, the output controlled in Equation 2b must not strictly equal generated heat but the sum of generated and discharged heat instead. For CHP plants providing process heat with a variable power-to-heat ratio, the maximum heating capacity is only an upper bound and not necessarily equal to the capacity that equations 2a and 2b are enforced on. This way investment in these plants can exceed what is strictly required for heating if the added operational flexibility benefits the overall system.

5.3. Graph-based method

As mentioned in the introduction, the model applies a graph-based modeling approach to vary temporal resolution by energy carrier and account for the inert flexibility within certain sectors of the energy system. As an added benefit, this method sensibly reduces computational complexity enabling a more detailed representation of fluctuating renewables [24].

To clarify the mechanics of this method, Figure 8 illustrates the representation of a technology that converts energy carriers of different temporal resolutions, namely a heat pump converting electricity to space heat. Since space heat is modeled at four-hour steps and electricity hourly, the ratio between electricity input and heat output given by the coefficient of performance (COP) is only enforced for the electricity use summed over all four hours. Nevertheless, the constraint restricting the electricity input to not exceed the heat pump's capacity is still enforced separately for each hour limiting the operational flexibility. Analogously, for a CHP plant that converts gas modeled at a daily resolution to heat and electricity, the ratio between inputs and outputs given by the overall efficiency is only enforced daily. Yet, installed capacities limit the output of electricity in each hour and the output of electricity and heat in each four-hour step.

In the model, hydrogen and synthetic gas use a daily resolution to account for their physical inertia. This resolution is consistent with macro models exclusively dedicated to the gas sector and plausible considering gas is also being traded daily [31]. For space and district heating, a four-hour resolution is assumed to account for the thermal inertia of buildings and networks. In process heating, the same resolution is applied to account for the potential of demand-side management in industrial processes. Electricity is modeled hourly to accurately capture fluctuations of renewables and the sensitivity of transmission infrastructure to mismatches of supply and demand. All types of transport that can incur a direct grid-bound demand for electricity, like heavy road and both types of rail transport use an hourly resolution as well; all other types use a daily resolution to account for the flexibility from BEVs. Biomass, carbon, and all liquids are modeled at a yearly resolution since they can be stored comparatively easily.

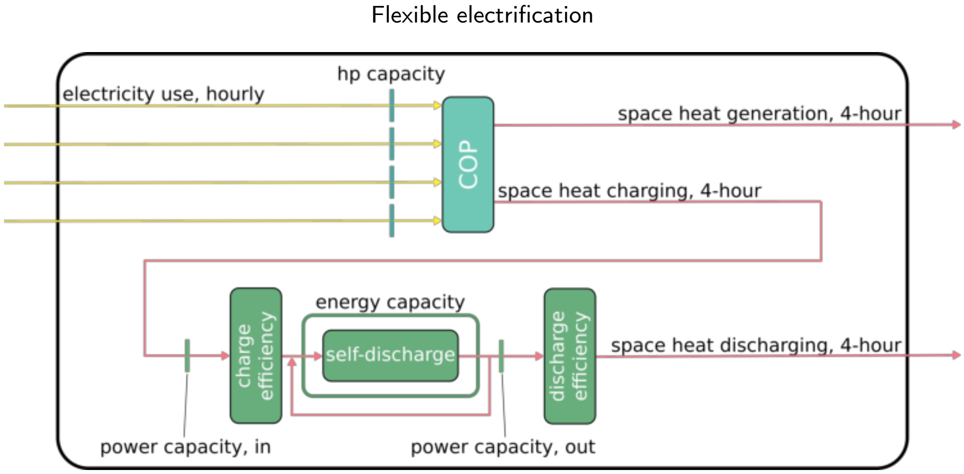

Figure 8: Representation of residential heat-pump

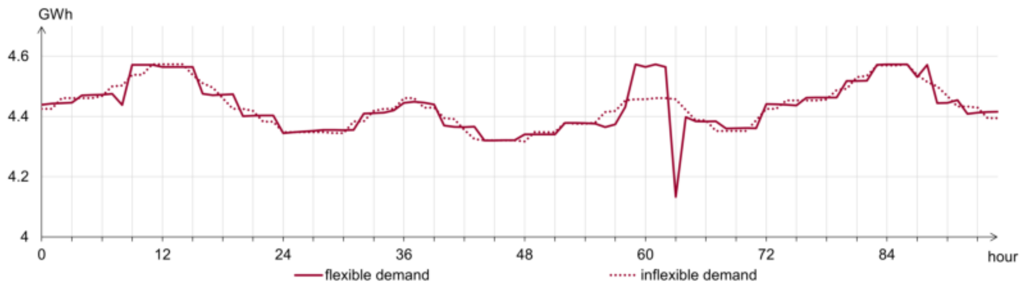

Figure 9: Comparison of electricity demand depending on resolution

It should be noted that the mechanics of the graph-based method restrict flexibility more than the use of a certain resolution might initially suggest, especially when paired with the must-run concept introduced in the previous section. For instance, in a four-hour step with 97.5% of relative demand, a system would have to produce at full capacity for three hours just to reduce demand to 90% in the fourth. For demonstration, Fig. 9 compares electricity demand of electric boilers providing medium temperature process heat in Spain for the scenario with high wind potential and grid expansion for the first four days of the year. The solid line shows hourly electricity demand according to model results when assuming a four-hour resolution for process heat; the dashed line the hypothetical electricity demand for an hourly resolution of process heat. Considering the scale, the comparison reveals only minor differences between both profiles, even in the most extreme case of the four-hour step from 60 to 64.

5.4. Transmission infrastructure

This section gives an overview of the modeled infrastructures for the exchange of energy carriers between regions. All transmission infrastructures are represented as a transport problem, meaning the amount of energy exchanged between regions is only constrained by the available transmission capacity. Analogously to technologies, the model decides on expansion of these capacities and, analogously to temporal resolution, the spatial resolution of exchange is varied by energy carrier.

For electricity, transmission infrastructure includes HVAC and HVDC)lines and applies a spatial resolution that corresponds to European balancing zones. As a result, net-transfer capacities (NTCs) of the existing grid can be based on public ENTSO-E data [32]. The corresponding capacities are displayed in Fig. 10, with HVAC in yellow and HVDC in orange, and are available in the model without additional investment. Grid expansion builds on ENTSO-E data providing costs and capacity for conceivable expansion projects [33]. As an example, Fig. 11 illustrates the resulting capacity-cost curve for expanding the NTC capacity between Germany and the Netherlands. In this case, specific investment costs of the NTC discretely increase from 200 to 3,700 Mil. € per GW and expansion is subject to an upper

[7] If NTCs between two zones differ by direction, the map shows their average, but the model applies distinct values.

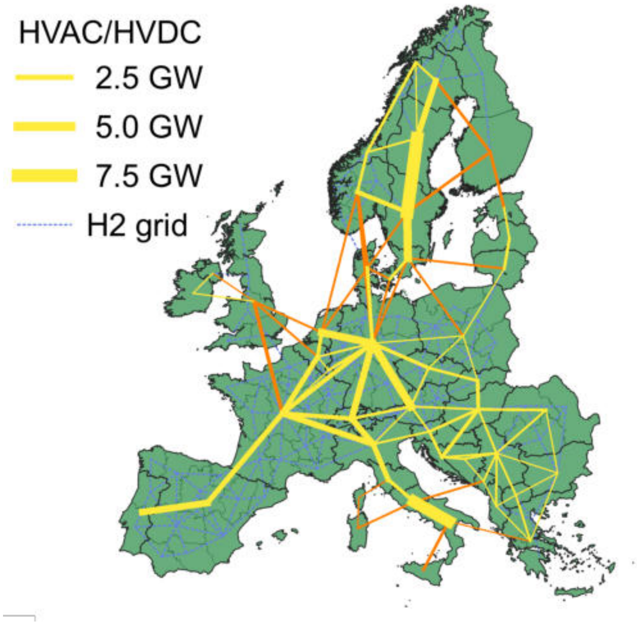

Figure 10: NTCs of existing transmission infrastructure[7]

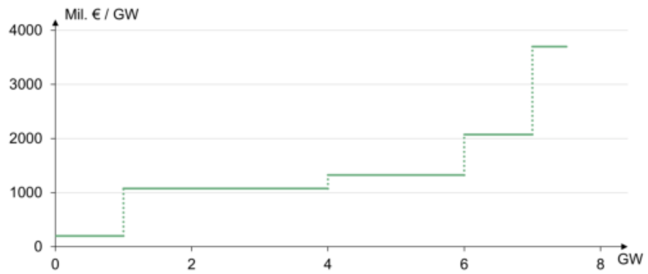

Figure 11: Exemplary capacity-cost curve for NTCs between Germany and the Netherlands

limit of 7.5 GW. Note that due to the strictly linear nature of the optimization problem, actual expansion does not necessarily coincide with the steps of the curve. Transmission losses amount to 5% and 3% per 1,000 km for HVAC and HVDC, respectively [34].

On the one hand, a grid resolution based on balancing zones is comparatively coarse and may underestimate grid restrictions [27]. But on the other hand, using NTCs that already account for inter-zonal congestion and power flows instead of physical grid capacities can be expected to greatly mitigate this effect. Nevertheless, the used NTCs still face the drawback of being computed for load flows in today's system that might substantially deviate from the system we are modeling. On the upside, using a spatial resolution based on balancing zones enables the described approach to model grid expansion based on detailed ENTSO-E data. More detailed resolutions typically must rely on less specific and arbitrary assumptions that are solely based on distance and can range from 400 to 1,000 EUR per MW and km [35, 36].

Transmission infrastructure for hydrogen uses a spatial resolution subdividing Europe into 96 clusters as displayed in Fig. 10. Transmission capacities can be newly built between neighboring clusters and in plausible cases overseas at a general cost of 0.4 Mil. EUR per GW and km [25]. The transport is subject to losses of 2.44% per 1,000 km [25].

In the addition to transmission infrastructures for electricity, synthetic gas, and hydrogen, neighboring countries can exchange solid biomass and refined oil. In contrast, this exchange is not constrained by endogenous capacities, but is subject to variable costs instead [37].

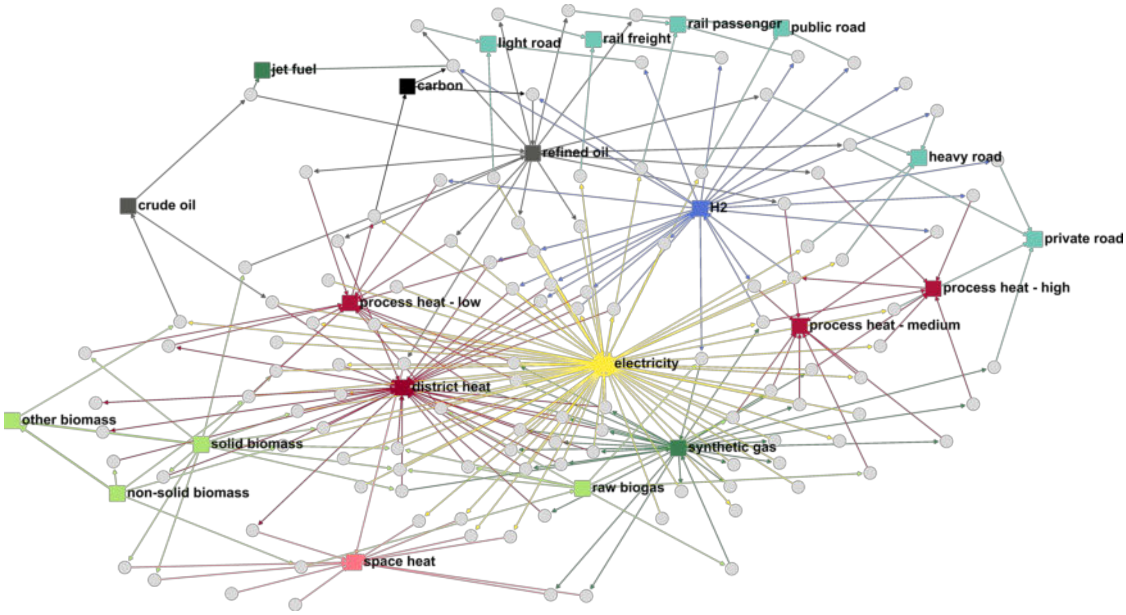

Figure 12: Full graph of model carriers and technologies

5.5. Technology overview

This section provides a comprehensive overview of all technologies and energy carriers considered in the model based on graphs. In these graphs, vertices either represent energy carriers, depicted as colored squares, or technologies, depicted as gray circles. Entering edges of technologies refer to input carriers; outgoing edges refer to outputs. For illustrative purposes, Fig 12 shows the graph of all carriers and technologies. In the following, subgraphs of this graph are used to go into further detail. If not noted otherwise, the choice and parameterization of technologies are based on reports of the Danish Energy Agency [25] using data for the year 2040.

Fig. 13 shows all technologies supplying heat for industrial processes, which are differentiated into three temperature levels. Low temperature heat ranges up to 100°C, medium temperature from 100 to 500°C, and high temperature covers everything above 500°C. Heating requirements within the same temperature category can greatly vary by process and as a result one technology might not be able to satisfy the entire demand of a certain category. For instance, not the entire heating demand above 500°C is eligible for electrification, because steel production in blast furnaces requires fuel combustion. To account for such limits, heat supply from district heating, engines and combined-cycle gas turbines is limited to today's level as a conservative estimate. The potential for electrification was specifically computed based on technology properties and regional data on industry structure.

All technologies generating electricity are presented in Fig. 14. All extraction turbines and biomass plants can be operated flexibly decreasing their heat-to-power ratio at the cost of reduced total efficiency. Since the used technology reports do not provide specific data on hydrogen- instead of methane-based gas plants, hydrogen-based plants adopt the same assumptions. Reservoirs, pumped-storage, and run-of-river cannot be expanded beyond today's capacities which are based on Bourmaud et al. [38]. Reservoirs and pumped storage both operate as storage but charging of reservoirs is based on an exogenous time series while pumped storage must be charged from the overall energy balance.

The capacity and energy potential of PV and wind are differentiated according to the 96 clusters displayed in Fig. 10. In addition, openspace PV and onshore wind are further broken down into three categories with different full load hours for each cluster to reflect different site qualities; rooftop PV and offshore wind are broken into two further categories. Capacity limits are scaled to comply with the overall energy potential for each country reported in Auer et al. [39], for the high-wind scenarios, or Tröndle et al. [40], for the high-PV scenarios, as displayed in Fig. 15. Time-series data for capacity factors is, like all time-series data, based on the climatic year 2008.

Ultimately, Fig. 16 provides an overview of all technologies relevant for the generation and conversion of synthetic fuels. Thanks to the comprehensive sectoral perspective of our model, we are capable to consider the feed-in of excess heat from electrolysis or gasification into heating networks, but also the heat demand from processes like solid oxide

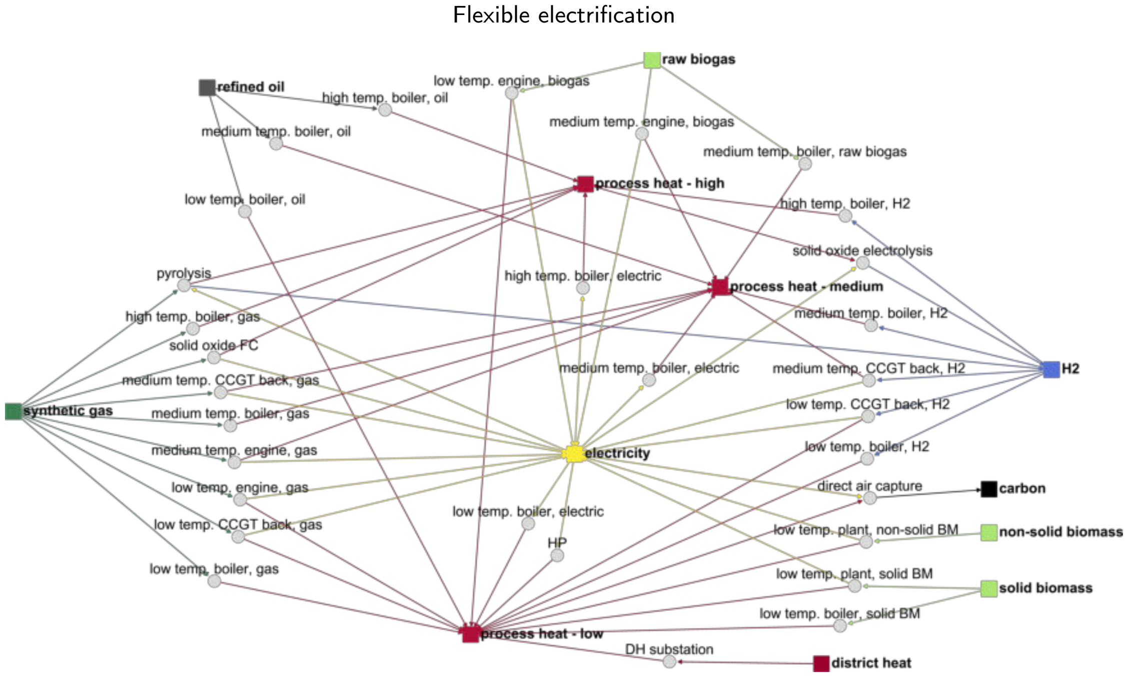

Figure 13: Subgraph for process heat

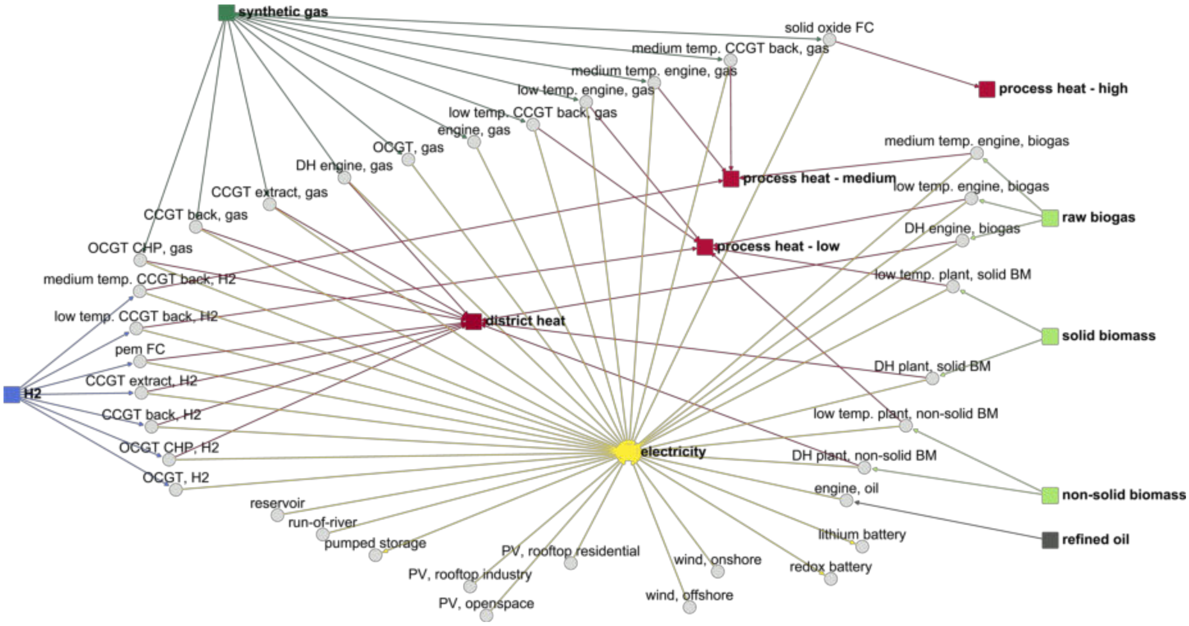

Figure 14: Subgraph for electricity supply

electrolysis and direct air capture (DAC). For cavern storage of hydrogen regional capacity limits reflect that technology requires certain geological conditions. Hydrogen cannot only be generated within the system, but also bought from an external market at a price of 127 EUR/MWh [41]. The use of solid and non-solid biomass is subject to an upper limit reflecting the sustainable potential of 1,266 TWh minus 206 TWh assumed as feedstock for the chemical industry [42, 43]. Crude oil can be generated from biomass or hydrogen and converted into different oil products using refineries. Refinery capacities are fixed to today's values.

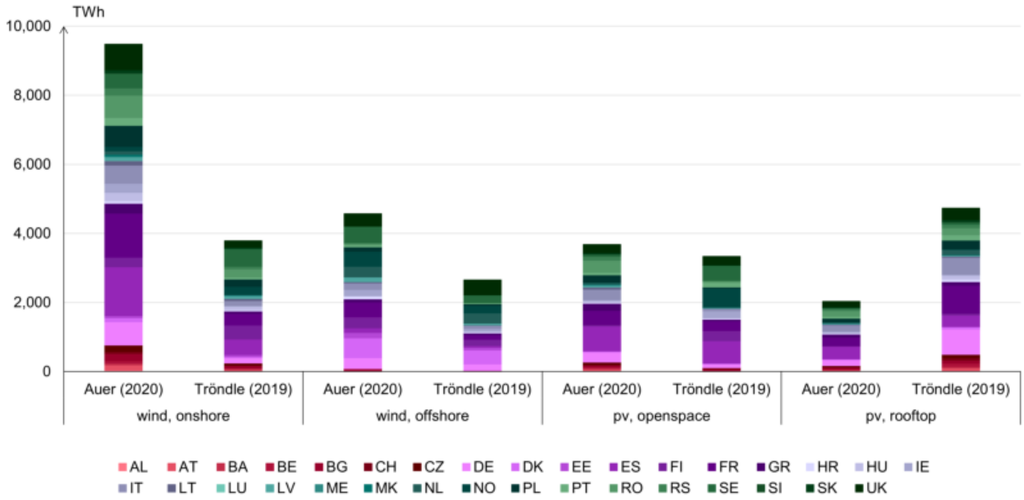

Figure 15: Comparison of assumed renewable potential

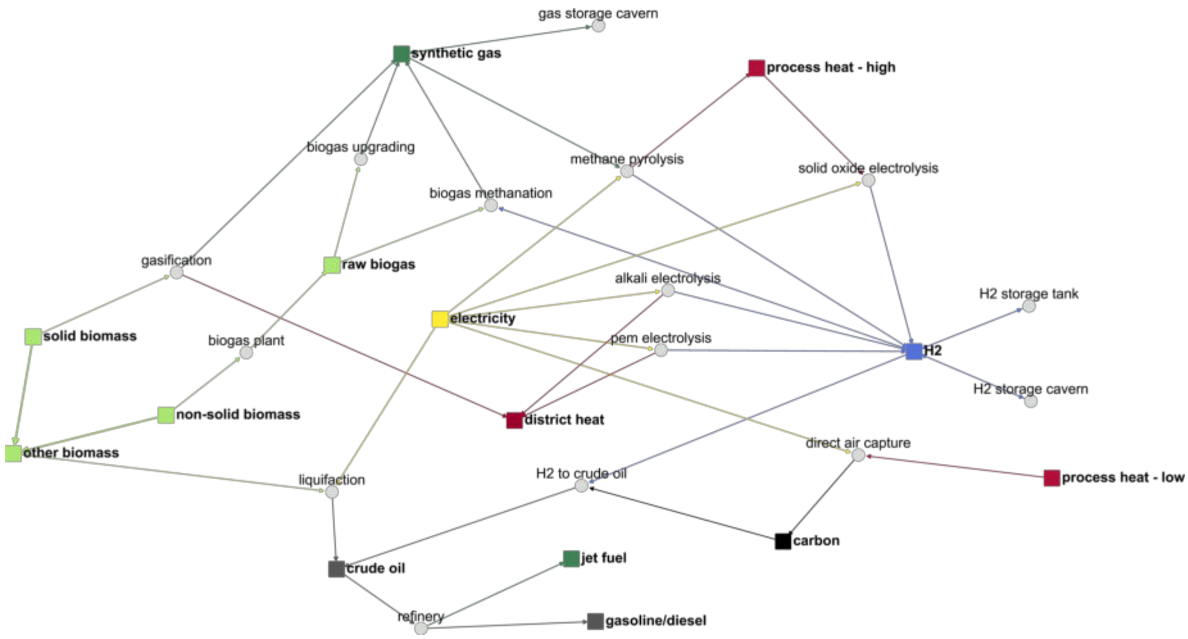

Figure 16: Subgraph for conversion of synthetic fuels

5.6. Energy balances

Since the paper discusses model results with regard to flexibility, this section provides a detailed overview of supply and demand in absolute quantities. For details on the computation process for all inputs discussed in this section see the data material linked in section 5.1.3.

Energy balances in Fig. 17 show supply and demand for electricity by scenario. In all scenarios supply is heavily dominated by generation from fluctuating renewables, namely wind, PV, and run-of-river. The highest share of 94.8% is achieved in the high-PV and grid scenario, the scenario with the smallest flexibility needs. Vice-versa, the high-PV and no-grid scenario with the highest flexibility needs has the lowest share of 92%. The role of electricity generation from thermal plants is negligible for high-wind and grid but increases up to 3.5%. in high-PV and no-grid. In this scenario, 27% of thermal generation relates to open-cycle gas turbines (OCGT) and 62% to combine-cycle gas turbines (CCGT)

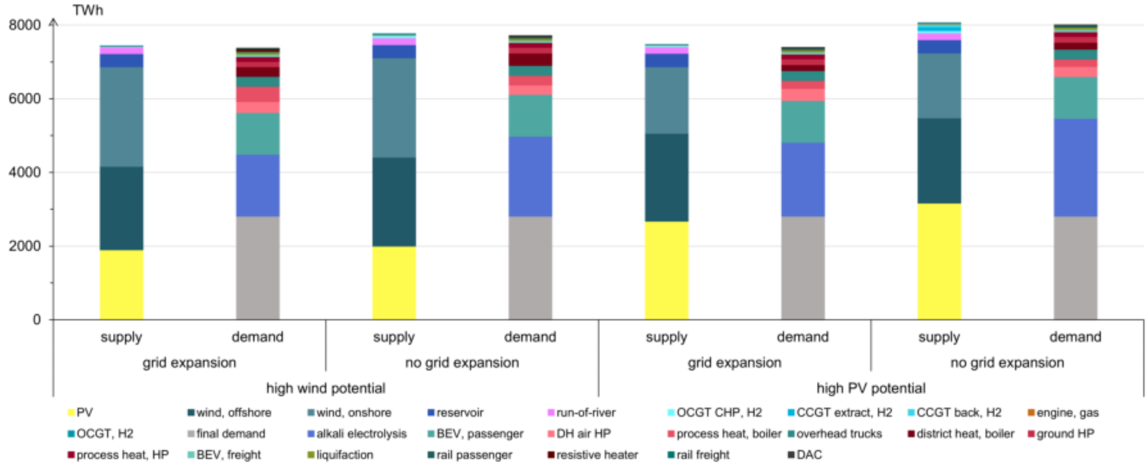

Figure 17: Supply and demand for electricity by scenario

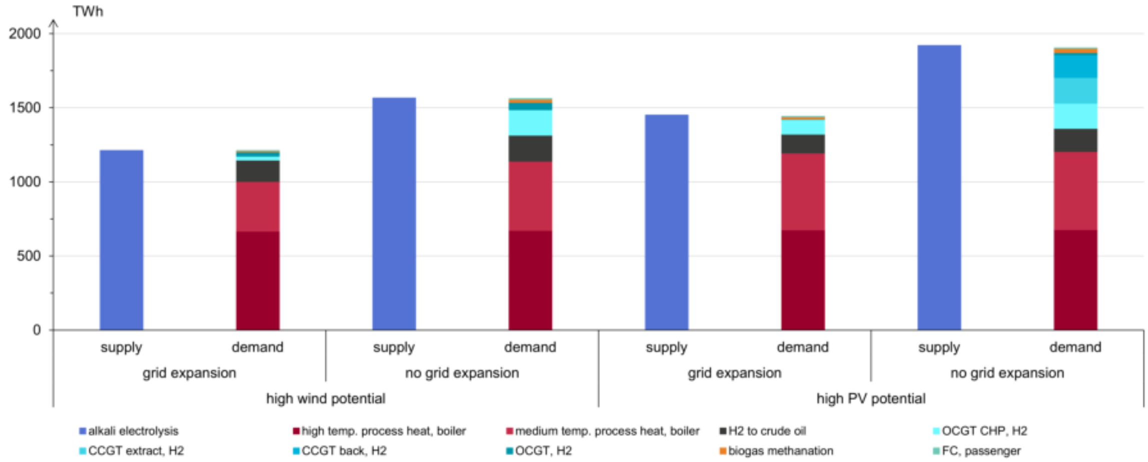

Figure 18: Supply and demand for hydrogen by scenario

plants, all fueled by hydrogen. The remaining share provide engines running on synthetic fuels created from local surpluses of biomass. CHP units make up 93% of electricity generated by thermal plants. Hydro reservoirs produce the remaining share of electricity generation. Total electricity demand varies little and only consumption from electrolyzers differs significantly by scenario, as already discussed in the main body of the paper. Final demand is by definition constant. Demand from BEVs and rail transport is endogenous to the model, but constant as well. Across scenarios, some variations occur in demand from the heating sector and heavy road transport. The difference of total electricity supply and demand reflects storage and transmission losses.

Fig. 18 compares supply and demand for hydrogen across scenarios. In all scenarios, hydrogen is exclusively produced domestically by alkali electrolysis and not imported from outside Europe. Industrial heating at higher temperatures makes up the biggest share of demand. Predominantly this demand is limited to processes not suited for electrical heating. Since electrical heating is more efficient but less flexible, at high PV potentials hydrogen demand for process heating increases slightly due to excess electricity in summer but scarcity in winter. In all scenarios, an almost constant share of hydrogen is used to create crude oil for jet fuel, although the major share of jet fuel originates from biomass. The use of hydrogen within thermal plants reflects the results already discussed above.

The supply and demand of district heating are summarized in Fig. 19. Air heat pumps consistently provide the largest share of district heat, while electric boilers with lower efficiency serve as peak-load capacity. Thermal heating

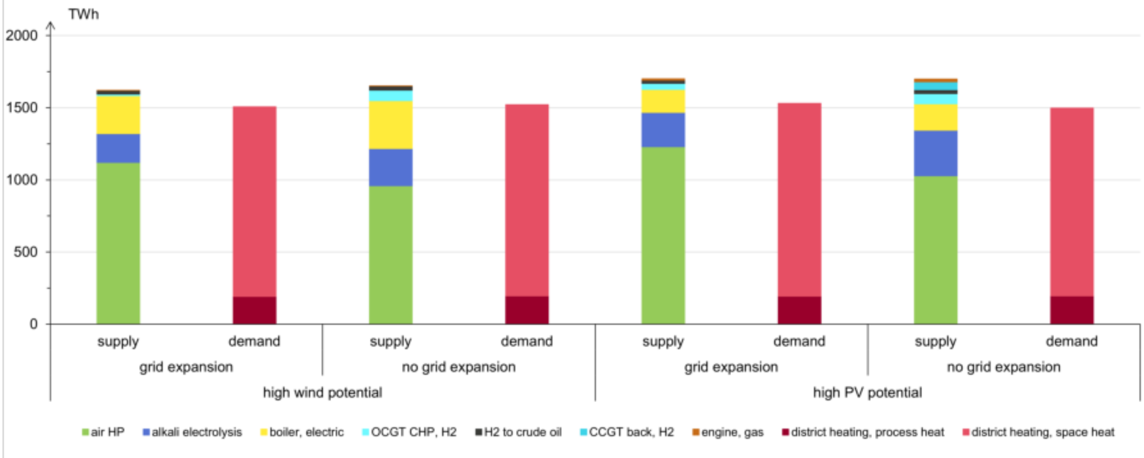

Figure 19: Supply and demand for district heat by scenario

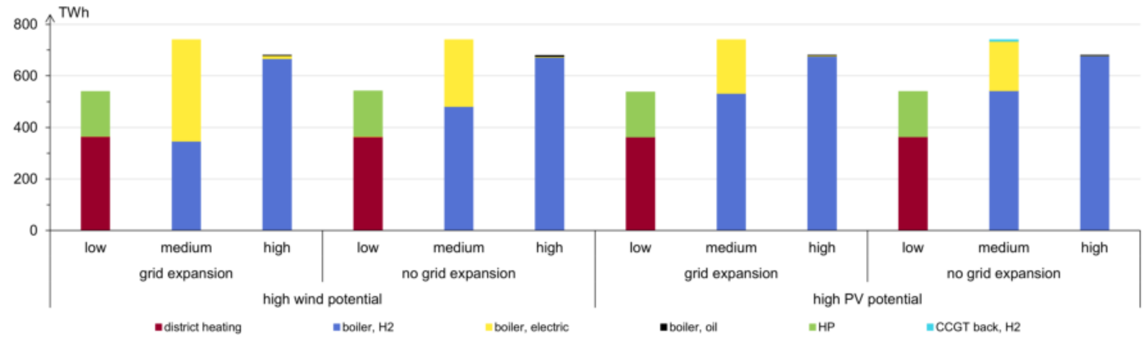

Figure 20: Supply of process heat by scenario

plants provide further peak-load capacity. In addition, a significant amount of exhaust heat from alkali electrolyzers is fed into district heating networks. About 87% of the demand for district heat is used for space heating, the remaining share for low temperature process heat. Differences of total supply and demand reflect heat losses resulting from heat transmission and storage. Accordingly, the greatest losses occur in the high-PV and no-grid scenario that has the highest levels of seasonal storage.

Fig. 20 shows how supply covers the final demand for process heat at different temperature levels. The overall demand by temperature level and country builds on Heat Roadmap Europe [44] and uses indicators on industrial activity for a break down to the regional level. District heating is restricted to low temperatures and subject to an upper limit that due to a lack of appropriate data corresponds to current levels as a conservative estimate. Upper limits also restrict electric heating at medium and high temperatures. These limits are estimated based on process characteristics and regional indicators for industrial activity. District heating supplies the majority of low temperature heat and is at or close to its upper limit in most regions. Medium and high temperature heat are almost exclusively provided by hydrogen and electric boilers depending on capacity limits and effects discussed previously. Due to its inflexibility, the role of CHP units in process heating is negligible.

Fig. 19 reports supply of space heat by scenario. Final demand for space heat builds on Heat Roadmap Europe [44] as well, but assumes a 35% reduction until 2040 [45]. To further regionalize demand, we use NUTS3 level data directly provided by the Heat Roadmap Europe project and assume future reductions are proportional to the average age of the building stock. To estimate the regional potential of district heating, air-source heat pumps and ground-source heat-pumps for the whole of Europe, we use NUTS3 level data on the degree of urbanisation. Although the resulting estimates are plausible, they are rather indicative nature and cannot ensure high accuracy. Supply of space heat shows little variation across scenarios. The dominant source is district heating followed by ground source heat-pumps. Besides

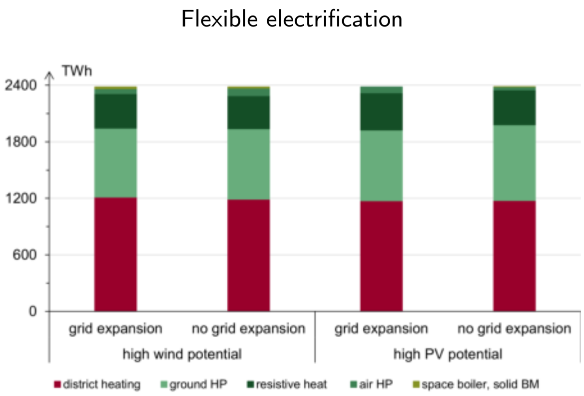

Figure 21: Supply of space heat by scenario

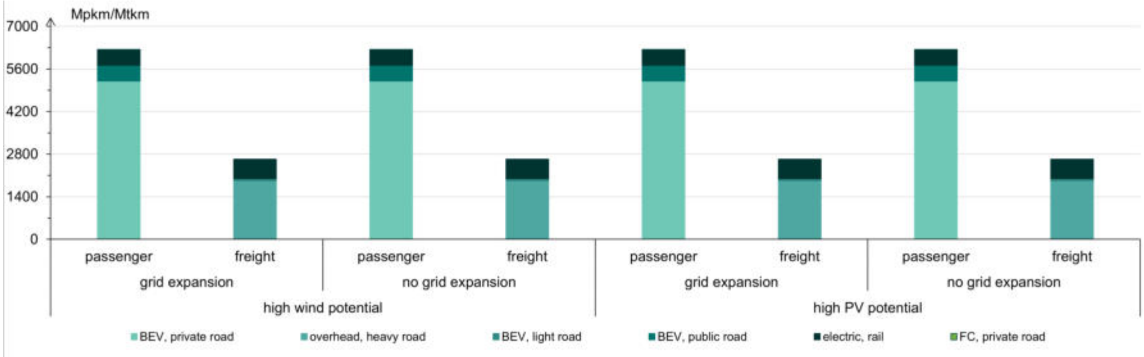

Figure 22: Supply of transport services by scenario

regional potentials, results are driven by cost-differences of heating technologies resulting from the regional structure of the building stock. In addition, some regions use local surpluses of biomass for space heating.

Finally, Fig. 22 compares the provision of transport services across scenarios. Final demand for transport services is split into public road, private road, and rail transport for passengers and heavy road, light road, and rail transport for freight. Demand for each of these is fixed not considering any modal shifts and estimated based on the existing number of vehicles and their driving performance. To account for air and naval transport, the model also includes a final demand for synthetic transport fuels. Results show no variation across scenarios with electric options overall dominating the supply.

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