The role of sector coupling in the green transition: A least-cost energy system development in North Europe towards 2050

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Abstract

This paper analyses the role of sector coupling towards 2050 in the energy system of North Europe when pursuing the green transition. Impacts of restricted onshore wind potential and transmission expansion are considered. Optimisation of the capacity development and operation of the energy system towards 2050 is performed with the energy system model Balmorel. Generation, storage, transmission expansion, district heating, carbon capture and storage, and synthetic gas units compete with each other. The results show how sector coupling leads to a change of paradigm: The electricity system moves from a system where generation adapts to inflexible demand, to a system where flexible demand adapts to variable generation. Sector coupling increases electricity demand, variable renewable energy, heat storage, and electricity and district heating transmission expansion towards 2050. Allowing investments in onshore wind and electricity transmission reduces emissions and costs considerably (especially with high sector coupling) with savings of 78.7€₂₀₁₆/person/year. Investments in electricity-to-heat units are key to reduce costs and emissions in the heat sector. The scenarios with the highest sector coupling achieve the highest emission reduction by 2045: 76% greenhouse gases reduction with respect to 1990 levels, which highlights the value of sector coupling to achieve the green transition.

Keywords: Sector coupling, optimisation, green transition, energy system, modelling, flexibility

1. Introduction

1.1. Motivation

The urgency in terms of limiting global warming by reducing emissions of greenhouse gases (GHG) lead to the Paris Agreement in 2015 [1]. To stay well below a temperature increase of 2°C, it will be necessary to rely on carbon neutral energy supply by 2050 [2]. Wind power and solar photovoltaic (PV) power are becoming competitive with fossil generation technologies in terms of the cost per kWh [3]. This is reflected in global power generation investments, where more investments are being made in renewable energy power than in fossil and nuclear since 2007 [4]. To integrate large shares of fluctuating variable renewable energy (VRE) such as wind and solar power, flexibility is needed in the system. Overall, flexibility can come from dispatchable generation plants, flexible consumption, storage or transmission. Coupling of sectors can provide flexibility by converting electricity to heat (P2H), gas or liquid fuels, thereby providing flexible consumption, fuel substitution, and storage as well as increased possibilities of transmission and flexible power generation if converting back from e.g. gas to electricity [5]. Sector coupling can thereby facilitate a green transition with integration of VRE sources at low cost [6].

Recently, several articles have focused on the potentials of exploiting synergies through sector coupling facilitating lower costs of the energy transition [7]. Thellufsen [8] investigated the value of electricity cross-border and cross-sector coupling, showing that both approaches benefit the system, but that cross-sector coupling leads to higher benefits. However, the spatial resolution used in the study was small and the synergies between the two strategies were not investigated. Brown [6] went a step further, by analysing the synergies of sector coupling and transmission reinforcement performing cost optimisation of a European electric system linked to the individual users' heating sector, road transport, and power-to-gas. They conclude that sector coupling and transmission expansion leads to lower costs, but also that the two options compete. The modelling optimises energy supply for all of Europe in one year hour-by-hour, however with only one node per country and without including industry nor non-road transport. Victoria [9] used the same model to show the benefit of different types of storage, concluding that electric vehicles (EV) may assist in balancing the system in the short term, while large-scale thermal storage may assist in balancing at a seasonal level. Hedegaard [10] showed that electric cars with grid-to-vehicle and vehicle-to-grid facilitate larger wind power investments. Helgeson [11] illustrated the benefit of coupling and co-optimising the electricity and transport sectors, and Schiebahn [12] investigated the techno-economic feasibility of power-to-gas in a case study in Germany, concluding that the costs of the

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related technologies need to decrease to become attractive.

Local resistance and resulting policy constrain important technologies for the green transition such as onshore wind and electricity transmission and lead to increased costs and lower VRE penetration ([13], [14], [15]). The local resistance to wind power has been demonstrated in a range of articles ([16], [17], [18], [19], [20], [21]) with consequences ranging from lack of generalised support to delays and losses. Similarly, overhead transmission lines are experiencing local resistance resulting in barriers to network development [22]. The influence of policy constraints in the energy system is analysed by Schlachtberger [23] and Bolwig [24]. However, while Schlachtberger does not include the heat sector at all, Bolwig only includes district heating (DH).

All these studies show the importance of modelling a wide array of possible sector couplings, the competition with electricity transmission, and the influence of policy constraints.

1.2. Contribution to literature

The role of sector coupling towards 2050 with a case analysis of North Europe pursuing the green transition is investigated in this paper with the open source energy system model Balmorel. The influence of sector coupling on the development and operation of the system, and its potential benefits to reduce costs and emissions, are analysed in the modelled scenarios. The main contributions to the existing literature are explained below.

This study models the demand for electricity, heat (DH, individual heating, and industry), and transport (road, maritime, and aviation) with a regional geographical resolution. Therefore, the synergies across all these sectors can be identified. Previous studies lacked part of the system ([6], [9], [10], [11]), or used a very low geographical representation [8]. By leaving out one or several sectors one might overestimate the importance of the one that is being modeled. As shown by e.g. [6], interconnectors are not as important when also modelling sector coupling.

The existing literature that includes electricity, heat and transport demand has focused on analysing a single scenario year ([6], [8], [9]). This paper models the transition of the energy system towards 2050 by optimising capacity development and operation in ten-year steps from 2025 to 2045. This approach captures the influence of investment decisions in early years on later years.

This paper puts in competition multiple generation and storage units, as well as transmission expansion, DH, carbon capture and storage (CCS), and synthetic gas units. Allowing competition for all these options is important to achieve a cost-effective green transition. Previous studies do not optimise investments in, for instance, CCS units ([6], [8], [9], [10],[11]), or transmission expansion [11].

As there may be resistance to both onshore wind and electricity transmission expansion, scenarios with restricted onshore wind, and transmission investments are modelled and compared in this paper. Previous studies have not analysed the influence

of these constraints in scenarios with high degree of sector coupling ([23], [24]), and hence underestimating the total need for new VRE electricity and their related resistance issues.

1.3. Structure of the paper

This paper is structured as follows. Section 2 presents the methodology, and then, the input data are explained in section 3. Section 4 describes the scenarios. In section 5, the results are presented. Section 6 discusses the limitations of the study, and section 7 concludes the paper.

2. Methodology

This section describes the Balmorel energy-system model, and the optimisation approach used in this paper.

2.1. Balmorel

2.1.1. General description

Balmorel [25] is an open-source [26], bottom-up, deterministic, flexible-structure, energy-system model. It is used in this paper to perform cost-minimisation runs to satisfy the heat and electricity demand of the system towards 2050 from a socio-economic perspective.

The time resolution in Balmorel consists of three hierarchical layers: scenario years y , seasons s , and terms t . Seasons can mean months, weeks, days, etc, whereas terms can be hours, minutes, etc.

The geographical resolution is composed of countries, which contain regions r , which contain areas a . Electricity flow is allowed across regions and heat flow is allowed across areas. The geographical resolution is illustrated in Figure 1.

Figure 1: Geographical resolution.

Inspired from [27], the modelling of solar PV and wind technologies is based on resource grades (RG) to represent that wind and solar resources are not uniform inside each modelled region. Detailed description of this modelling, as well as other technologies can be found in Appendix A.

2.1.2. Objective function

The objective function in Balmorel [25] is to minimise discounted system costs (Eq. 1) while satisfying the electricity and heat demand. The costs can be grouped in investment costs c_y^{inv} , variable costs c_y^{vom} , and fixed costs c_y^{fom} . Costs are annualised

Figure 2: Flow chart illustrating the modelling of the heat sector. Each yellow box represents an area in the model.

so different technologies can be compared. Variable costs include fuel costs, operation costs, and CO₂ tax. When unit commitment is introduced, start-up, shut-down and online costs are also included. Fixed annual costs are linked to installed capacity and can be avoided with decommissioning (in this paper meaning mothballing). Dismantling costs are not considered. The discount factor DF_y weights downs the costs of future years to represent the socio-economic value of time.

$$\min_{c_y^{inv}, c_y^{fom}, c_y^{vom}} \sum_y DF_y \cdot (c_y^{inv} + c_y^{fom} + c_y^{vom}) \quad (1)$$

2.1.3. Electricity sector

The electricity balance is the main equation to be satisfied in the electricity sector and is defined for every region (Eq. 2).

$$g_{r,y,s,t}^{el} = d_{r,y,s,t}^{el} + \sum_{r'} x_{r',r,y,s,t}^{el} - x_{r,r',y,s,t}^{el} \cdot (1 - x_{r',r}^{el,loss}) \quad \forall r, y, s, t \quad (2)$$

In this equation, electricity generation $g_{r,y,s,t}^{el}$, demand $d_{r,y,s,t}^{el}$, transmission flow $x_{r',r,y,s,t}^{el}$, and transmission losses $x_{r',r}^{el,loss}$ need to be in balance in every time step. Distributions losses, as well as flexible electricity demand (storage loading, P2H, etc.) and inflexible electricity demand, are included in $d_{r,y,s,t}^{el}$. Flow with net transfer capacity is assumed [28] and transmission losses are calculated using the distance between regional centroids.

The technologies involved in the electricity sector are transmission lines, dispatchable technologies such as combined-heat-and-power (CHP) and non-CHP units with or without CCS (steam turbines, gas turbines, combined cycle, or engines), P2H technologies, geothermal power, EVs, electrolyzers, fuel cells, methanation-Direct Air Capture (DAC) units, long-term hydro storage with seasonal inflow, or short-term storage (hydro pumping and batteries), and non-dispatchable technologies (solar, wind and hydro run-of-river). Distribution losses for gener-

ation and storage technologies are defined depending on which part of the electric grid they are located.

Ancillary services include minimum frequency containment reserves and automatic frequency restoration reserves [29].

2.1.4. Heat sector

The heat balance is the main equation to be satisfied in the heat sector and is defined for each area (Eq. 3).

$$g_{a,y,s,t}^h = d_{a,y,s,t}^h + \sum_{a'} x_{a,a',y,s,t}^h - x_{a',a,y,s,t}^h \cdot (1 - x_{a',a}^{h,loss}) \quad \forall a, y, s, t \quad (3)$$

In this equation, heat generation $g_{r,y,s,t}^h$, demand $d_{a,y,s,t}^h$, DH flows $x_{a,a',y,s,t}^h$, and distribution losses $x_{a',a}^{h,loss}$ need to be in balance in each time step. Flexible and inflexible heat demand is included in $d_{a,y,s,t}^h$.

The heat sector is divided into DH, individual users, and industry. An illustration of how the heat subsectors have been modelled, as well as how they are linked, is shown in Figure 2. DH modelling is based on network scales based on [30]. The modelling of individual users considers the end purpose of heat demand. Inspired from [31] and [32], heat demand modelling in industry is based on temperature needs.

Technologies involved are DH network, heat pumps, electric and fuel boilers, solar heating, methanation-DAC units, short-term storage (water tanks), long-term storage (pit), and CHP with and without CCS. Not all technologies are capable of satisfying all types of heat demands.

Detailed description on the modelling of the heat subsectors, is explained in Appendix B.

2.1.5. Synthetic gas sector

The synthetic gas sector modelling is inspired by the work presented in [6] and [33] and includes the possibility to produce, store, and consume two additional energy commodities which can be used as long-term energy storage (Fig. 3). These

commodities are the electrofuels hydrogen (H_2) and synthetic natural gas (SNG). The H_2 balance in every time step is defined as a regional market without the possibility to trade among regions. The costs and limitations of transporting H_2 inside each region are not considered. H_2 production is allowed by using alkaline electrolyzers, and it can be either stored in long-term steel tanks, or be used to produce electricity through solid-oxide fuel cells, or to be input to generate SNG in the methanation-DAC units. The SNG balance is modelled as an international annual market without trading costs. SNG generation is allowed with methanation-DAC units using the Sabatier process as modelled in [6], and it can be used as replacement of fossil-based natural gas. The Sabatier process uses as input H_2 , heat ($250-400^\circ\text{C}$) and electricity, and hence, not requiring biomass as source of carbon. It is assumed that SNG can be directly injected to the natural gas network with no storage limitation.

Figure 3: Synthetic gas modelling.

2.1.6. Transport sector

The transport sector modelling is split into private electric vehicles and other transport.

Private electric vehicles. The private electric vehicle (EV) fleet is represented in the model as a virtual storage. The modelling includes the electricity consumed for charging, a representation of the battery storage in the EV fleet, and limits to charging and discharging related to usage patterns. A distinction is made between battery EVs and plug-in hybrid EVs. Time dependent input parameters to the model have been generated through bottom-up modelling of driving patterns. Inflexible charging limits charging downward, whereas the charger capacity limits charging upwards. In addition, lower and upper limits to state of charge are time dependent and based on assumptions to when vehicles are at charging stations (Figure 4). Further description of the modelling setup can be found in [34]. EV charging is penalised with a charger loss and distribution grid losses. EV costs are not included.

Other transport. The remaining transport sector includes 1) additional rail electrification, and 2) electricity demand from synthetic fuel generation for aviation, shipping, and road transport. Additional rail electrification is modelled as an inflexible regional constant hourly demand. Electricity-to-synthetic fuel demand is modelled in a simplified way by introducing two new constraints. The first constraint requires that the aggregated annual electricity demand of this sector in the studied countries needs to be satisfied. When and where this demand is covered is only restricted by the second constraint, which limits

Figure 4: Modelling of available state of charge of EVs [34].

the peak-to-average ratio of this demand in each region. Since the costs of the technologies behind this additional electricity demand are not included, the peak-to-average ratio is used as proxy to model them. This factor is equivalent to defining a minimum average capacity factor per region.

2.2. Optimisation approach

Inspired from [25], the optimisation approach consists of two steps: 1) Capacity development optimisation, and 2) Long-term operational decisions optimisation. These optimisations are performed for three representative scenario years, in this case 2025, 2035, and 2045, which represent ten-year periods.

2.2.1. Capacity development optimisation

The purpose of this optimisation is to obtain cost-optimised development for the different technologies of the system. Investments and operation of numerous generation and/or storage technologies, electric grid reinforcement, and DH expansion are optimised. Decommissioning is also optimised for almost all generation and storage technologies, although part of it is forced to take place due to life time expectancy. The development of hydro reservoirs without pumping, hydro run-of-river, nuclear power, EVs, and other transport is not optimised, but provided exogenously as part of the scenarios (see section 3). The optimised peak of electricity-to-synthetic fuel demand of the transport sector in each region is saved as a proxy for the installed capacity of synthetic gas units behind this demand.

The optimisation is performed with limited intertemporal foresight, following a two-year rolling horizon approach. This means that when planning 2025, 2035 is known, and so on.

Due to the complexity of the optimisation, a reduced amount of time steps (in this case 16 spread-over-the-year weeks, taking Thursday, Friday, Saturday but only 1 every 3 hours) are selected using the approach described in [27]. To keep the annual statistical properties of the time series, these are scaled using the method described in [27], except for seasonal hydro inflow that is scaled linearly with respect to average annual inflow, and EV profiles, whose values correspond to the average of three-consecutive-hour time steps.

Unit-commitment constraints and variables (start-up, shut-down, minimum time off/on, ramping, minimum operation, on-line costs) as well as ancillary-services constraints are not included. The impact on investments of this simplification is

likely to be limited due to the large number of flexibility options included in the model [35].

2.2.2. Long-term operational decisions optimisation

Taking as exogenous the development obtained in the capacity development optimisation, this run simulates in more detail the market operation during the full year by optimising long-term operational decisions such as planned maintenance or storage use. Unit-commitment constraints and variables, as well as ancillary-services requirements, are included. The optimisation consists of full-year runs with perfect foresight. To avoid infeasibilities due to lack of installed capacity, back-up capacity is introduced. The use of this back-up capacity relates to the adequacy of the selected time steps in the capacity development optimisation. Due to the complexity of the problem, integer variables are relaxed and for each day, only 1 every 4 hours is used. More details about this method are shown in [36].

3. Input data

This section describes key input data. The full data set is available at [37]. Further data assumptions as well as detailed source description can be found in Appendix C.

Geographical scope. The studied countries are the UK, Belgium, Netherlands, Germany, Poland, Finland, Sweden, Norway, and Denmark. Sweden, Norway, and Denmark are split into regions based on existing bidding zones. Germany is split into four regions to capture internal bottlenecks [33]. The rest of the countries are defined with a unique region.

Fuel prices and CO₂ tax. Fuel price development is taken from [38], except for biofuel data, which are assumed to be carbon neutral and based on [39].

CO₂ tax levels correspond to 29.79, 90.42, 120.55 €₂₀₁₆/ton in 2025, 2035, and 2045 respectively and are taken from [38].

Technology costs. Most generation and storage data come from [31]. Figure 5 shows annualised investment costs assumptions towards 2050 for representative large-scale generation technologies, whereas storage data are shown in Table 1. Offshore-wind investments further from the shore have higher investment costs, but also generally higher capacity factors [40]. The discount factor used to calculate the annuities, which is the same used in the objective function, is 4% [31]. Electricity transmission expansion costs are based on [38], whereas DH expansion costs (400 M€₂₀₁₆/MW) are taken from [41], both technologies with lifetimes of 40 years.

Wind and solar PV data. Wind and solar PV time series are simulated with the CorRES model [42]. For onshore and offshore wind, a time series is simulated for each RG of each region. More details are given in Appendix A. For solar PV, the time series of the different RGs are scaled using data from [43], utilizing a single time series simulated for each region. The weather year used for the time series corresponds to 2012; the same weather year used for all load time series.

Figure 5: Annualised investment cost per commodity for representative large-scale generation technologies (M€₂₀₁₆/MW). Wind-offshore costs are for the North Sea side of Denmark. Per MW refers to the commodity on the left of the graph. Solar PV costs corresponds to MW_{peak}.

Table 1: Storage units data assumptions.

Commodity	Technology	Annualised investment cost (M€ ₂₀₁₆ /MWh)			Hours to unload per MWh	Hours to load per MWh
		2025	2035	2045		
Electricity	Battery	0.03159	0.02527	0.01896	4.0	4.0
	Hydro-pumping	0.01288	0.01288	0.01288	12.0	13.0
Heat	Water-tank-small	0.00029	0.00029	0.00029	2.0	2.0
	Water-tank-large	0.00015	0.00015	0.00015	60.0	60.0
	Pit-central	0.00011	0.00010	0.00010	82.5	110.0
	Pit-decentral	0.00003	0.00003	0.00003	192.6	192.6
H ₂	Steel-tank	0.00366	0.00261	0.00156	0.5	0.5

Resource technical potentials are taken from several sources. Offshore-wind potentials for the RGs are based on [38] and [44]. National large-scale solar PV potentials come from [45], whereas onshore-wind national potentials are based on the median of multiple sources ([38], [46], [47], [48], [49], [50]). These national potentials are then split into the regions of each country, which are then further split in RGs (see Appendix A).

Two scenarios for onshore-wind potential are defined to illustrate the impact of possible burdens on onshore-wind development. The scenario with high potential corresponds to the data and process previously explained, and defines onshore-wind potentials per region and RG. The scenario with low potential uses the minimum value of the previous sources to add a maximum national potential to the model. The resulting aggregated maximum onshore-wind potential is 1546 and 336 GW for the high and low scenarios, respectively.

Table 2: Scenarios run in this paper. "+" means included, and "-" not included. "REST" stands for restricted, "TRANS" for transmission, "TRP" for transport, "P2H" for power-to-heat, and "SG" for synthetic gas.

Scenario	Transmission investments	High onshore wind potential	P2H investments	Transport sector	Biomass units investments	Synthetic gas investments
REST	-	-	+	+	-	+
TRANS	+	-	+	+	-	+
WIND	-	+	+	+	-	+
FREE	+	+	+	+	-	+
REST_NOTRP	-	-	+	-	+	+
FREE_NOTRP	+	+	+	-	+	+
REST_NOP2H	-	-	-	+	-	+
FREE_NOP2H	+	+	-	+	-	+
REST_NOP2HNOTRP	-	-	-	-	+	+
FREE_NOP2HNOTRP	+	+	-	-	+	+
REST_NOSG	-	-	+	+	-	-
FREE_NOSG	+	+	+	+	-	-

Figure 6: Scenario for other transport (TWh).

Private electric vehicles. Data for private EVs are described in detail in [34]. The demand for electricity use in EVs is calculated based on vehicle stock projections for each modelled country. The projections in [34] have been doubled to represent roughly a scenario where all private vehicles in the studied countries are either plug-in hybrid (73 million cars) or battery EVs (114 million cars) by 2050. A charging (and also discharging for battery EVs) capacity of 10, 15, and 20 kW is assumed per car by 2025, 2035, and 2045 respectively. These assumptions lead to the existence of a large and powerful storage capacity with increasing size towards 2050. By 2045, the energy storage capacity is 6.4 TWh. The hourly availability of this storage depends on the EV pattern assumptions.

Other transport. The electricity demand associated to the decarbonisation of the remaining transport sector by 2050, which includes synthetic fuels production and rail electrification, is taken from [51]. The demand development scenario is shown in Figure 6. The peak-to-average demand ratio per region is assumed to be 1.5, which leads to a minimum average capacity factor of 2/3. This assumes that technologies behind this demand are a bit flexible.

4. Scenarios

To understand the role of sector coupling, and the value of electricity transmission expansion and onshore wind, 12 different scenarios are created (Table 2). The scenarios differ from each other by combinations of 1) allowing or not allowing investments in P2H, electricity transmission, synthetic gas units, or biomass units, 2) including or not including the transport sector, and 3) using high or low onshore-wind potential scenario. As a result, the scenarios play with factors that influence the degree of sector coupling and flexibility in the system. Scenario **FREE** represents the highest degree of possible sector coupling, and scenario **REST** adds restrictions on transmission expansion and onshore wind. It is worth mentioning that biomass investments are only allowed in the scenarios without the transport sector, based on the assumptions that all the biomass in the system would be required in the production of synthetic fuels for transport towards 2050 [52].

5. Results

This section presents the results from the simulations. The results for the scenarios **REST_NOSG** and **FREE_NOSG** are identical to scenarios **REST** and **FREE** respectively, and hence, not shown.

5.1. Sector coupling increases electricity demand

The electricity demand of the scenarios where P2H investments and/or the transport sector are included experience a considerable increase towards 2050 (Figure 7). In scenario **FREE**, by 2045 32% of the electricity demand is linked to P2H and 39% to the transport sector. The total demand in that year is 4.1 times higher than the inflexible demand in 2025, which is similar to today's consumption.

P2H and electricity-to-synthetic fuel transport demand show a strong seasonality. P2H demand peaks during the winter and decreases towards the summer, which is linked to heat demand

Figure 7: Electricity demand development (TWh). Rail transport demand is included as inflexible demand.

Figure 8: Development of electricity generation capacity (unloading capacity for storage) (GW). Long-term storage includes hydro reservoirs. Discharging capacity for EVs is not included.

for space heating, whereas the transport demand is highest during summer and autumn. The combination of both demands reduces the seasonality of the resulting additional demand. When P2H investments are not allowed, the seasonality of transport demand decreases. Likewise, not including the transport sector reduces the seasonality of P2H demand.

Hourly-wise the demand for P2H and electricity-to-synthetic fuel transport is higher during the day than during night. This difference is more pronounced for P2H. EV demand is much higher during the night than during the day, which is highly influenced by the availability pattern assumption (Figure 4).

5.2. Sector coupling increases VRE penetration

The increase in electricity demand due to sector coupling leads to large investments in solar PV and wind technologies (Figure 8). Roughly, the installed electricity capacity doubles in 2035 and triples in 2045 with respect to 2025 when P2H investments and the transport sector are included.

Wind-dominated VRE gradually replace fossil generation towards 2050 even in the scenarios with less sector coupling (see

Appendix D for more details). This is a result of the increase in CO₂ tax and the reduction of VRE costs towards 2050.

Sector coupling not only increases VRE production, but it also improves VRE integration. As shown in Table 3, the scenarios with sector coupling show significant increase in VRE generation without considerably affecting the share of curtailment. By 2045, the scenario with the highest VRE generation (**FREE**) shows 5.3 more VRE generation than the scenario with the lowest VRE generation (**REST_NOPHNOTRP**), while its share of curtailment is even lower (4% compared to 4.6%). P2H investments have a high impact on VRE curtailment.

5.3. Sector coupling increases transmission expansion

Sector coupling leads to increased transmission expansion in the scenarios where this possibility exists (Figure 9), which is linked to VRE penetration, and a consequence of the increase in electricity demand. By 2045, the installed transmission capacity in scenario **FREE** results in 2.6 times the assumed existing transmission capacity by 2025.

Table 3: Curtailment analysis for aggregated solar PV and wind production.

Type	Year	REST	TRANS	WIND	FREE	REST_NOP2H	FREE_NOP2H	REST_NOP2H	FREE_NOP2H	REST_NOP2HNTRP	FREE_NOP2HNTRP
Ratio of production with respect to scenario REST_NOP2HNTRP	2025	1.6	1.6	1.8	1.9	1.4	1.7	1.1	1.3	1.0	1.1
	2035	3.1	3.4	3.5	3.7	1.8	2.3	1.9	2.1	1.0	1.0
	2045	4.6	4.9	5.0	5.3	2.1	2.6	3.4	3.4	1.0	1.1
Share of curtailment with respect to available production	2025	0.2%	0.1%	0.6%	0.8%	0.1%	0.3%	0.1%	0.5%	0.0%	0.0%
	2035	4.0%	3.4%	3.9%	2.5%	2.2%	2.4%	5.3%	4.0%	2.4%	2.0%
	2045	4.5%	4.9%	4.9%	4.0%	2.9%	2.5%	8.0%	6.0%	4.6%	4.4%

Figure 9: Electrical transmission capacity development in scenarios where transmission investments are allowed (TWkm).

5.4. P2H is a cost-effective way of decarbonising most of the heat sector

The results show that P2H is a cost-effective way to decarbonise most of the heat sector, replacing thermal generation gradually towards 2050 (Figure 10). Results per sector are shown in Appendix D.

Heat pumps are the most attractive P2H technology. In the scenarios where P2H investments are allowed, heat pump generation accounts for 48-56% of total heat production. Air-to-air heat pumps are the largest contributor and cover 77-87% of space heating demand in the individual user's sector.

P2H increases the electricity load but also provides flexibility when combined with heat storage, facilitating the integration of VRE. If P2H investments are restricted, then solar heating and biomass units play a bigger role in the heat sector and lead to stronger DH expansion, especially to connect individual users. Solar heating seems to be the last alternative to decarbonise the heat sector, since it relies strongly on short-term and long-term heat storage (Figure 11). In the scenarios with P2H investments, by 2045 the share of individual user's heat demand covered with DH ranges between 27-32%, however not including P2H increases this share to 55-87%, being highest in the scenarios without P2H investments and with biomass investments.

5.5. Heat storage increases the flexibility of the energy system

Heat storage is a key source of flexibility in the energy system. It is used to reduce DH capacity investments and to deal with the seasonality and variability of VRE, facilitating their integration in the system, especially when P2H investments are

Table 4: Ratio between energy capacity and generation of short-term heat storage.

Scenario	2025	2035	2045
Average of scenarios with P2H investments	63.5	71.9	78
Average of scenarios without P2H investments	42.4	42.3	47

allowed. P2H penetration leads to a more intensive use of both short-term (Table 4) and long-term heat storage (Figure 12) towards 2050. Long-term heat storage shows a clear seasonality though, which is linked to heat demand for space heating.

5.6. Sector coupling impacts the use of hydro storage

Sector coupling influences the operation of long-term hydro storage (Figure 12). The difference between the maximum and minimum levels achieved in the reservoirs during the year is higher when P2H investments are allowed. This higher difference means that more energy is saved during the year to be used during cold months via P2H. Including the transport sector decreases this difference.

5.7. Sector coupling decreases costs in the heat sector

Sector coupling between the heat and electricity sectors through P2H considerably reduces the average annual costs of the system (Figure 13). The possibility to invest in P2H units leads to annual savings of around 30%, which are a result of reduced fuel consumption and lower emissions in the heat sector. The value of P2H investments is affected by restrictions in onshore wind and transmission expansion. The difference in average costs between scenario **REST** and **REST_NOP2H** is 63 b€₂₀₁₆/year, whereas the difference between scenario **FREE** and **FREE_NOP2H** is 75 b€₂₀₁₆/year, i.e. 20% higher savings.

5.8. Sector coupling decreases emissions

The results show how the energy system gradually reduces its emissions towards 2050 (Figure 14), with the CO₂ tax assumptions being mainly responsible for this development. The scenarios with higher degree of sector coupling, i.e. those with P2H investments and the transport sector, achieve the highest GHG reduction by 2045: on average 92% with respect to 1990 GHG in the energy sector and 76% with respect to total GHG emissions. Without sector coupling, these figures are 71% and 60%, respectively. Not including P2H investments challenges the decarbonisation of the heat sector if investments in biomass units are also not allowed. Emissions for heat and electricity production are lowest in the scenarios that exclude the transport sector and include P2H investments, although their total

Figure 10: Heat generation development (TWh).

Figure 11: Development of the energy capacity per sector of short-term heat storage (left) and long-term heat storage (right) (TWh).

emissions are high because of the non-decarbonisation of the transport sector.

In the scenarios with P2H investments and the transport sector, most of the emissions for heat and electricity generation are linked to natural gas consumption in the industry sector. In the scenario **FREE**, the one with the least total CO₂ emissions, the emissions in the industry sector are 73% of the total, with 84% of this share coming from high-temperature process heat production, which is the most challenging part of the heat sector to decarbonise.

The CO₂ emissions from the transport sector not included in the model, in the graph ALL FUELS - TRANSPORT, are calculated based on [53]. This source is also applied to estimate the GHG emissions using the CO₂ emissions from the runs. The GHG of the sectors not included in the model are assumed constant and equal to 670 Mton/year [53], i.e. the emissions of 2015 in the studied countries.

5.9. Synthetic gas complements P2H

Investments in synthetic gas units are only found optimal when the transport sector is not included and only in 2045. Investments in H₂ storage or fuel cells do not take place, which means that all the H₂ is directly converted to SNG. The energy volumes of synthetic gas generation are much higher when P2H investments are allowed (Table 5), which is influenced by the strong seasonality of P2H demand, which leads to excess VRE generation in months with low heat demand that is used for synthetic gas production. The synthetic gas produced is mostly

Table 5: Synthetic gas analysis in 2045.

Scenario	H ₂ production (TWh)	SNG production (TWh)	Average capacity factor
REST_NOTRP	155	124	75%
FREE_NOTRP	187	149	72%
REST_NOP2HNOTRP	17	13	84%
FREE_NOP2HNOTRP	18	14	76%

consumed in the winter. Particularly in scenario **FREE**, SNG almost completely replaces natural gas use in 2045.

5.10. Limited electricity short-term storage

Even though sector coupling considerably increases electricity demand and VRE generation, investments in short-term electricity storage are limited, only take place by 2045 in the form of electric batteries, and mostly in scenarios with restricted transmission expansion. The investments in electric batteries vary from 0.01 to 0.43 TWh in the different scenarios, sizes that are small compared to the assumed long-term hydro reservoir energy capacity (125 TWh). Even in the scenario with the lowest VRE penetration and the highest restrictions, i.e. **REST_NOP2HNOTRP**, flexibility coming from power-to-gas is preferred over electric batteries. This shows a limited role of electric batteries to move large energy volumes.

5.11. Restricted transmission and onshore wind reduce the benefits of sector coupling

Restricting onshore-wind potential and/or transmission expansion leads to higher costs (Figure 13), more emissions (Fig-

Figure 12: Usage development of long-term heat storage (up) and long-term hydro storage (bottom). Influence of sector coupling.

Figure 13: Average cost difference with respect to scenario **REST** (b€₂₀₁₆/year). Scenarios without the transport sector seem cheaper because transport costs are not included.

ure 14), and less penetration of VRE (Figure 8). The higher the degree of sector coupling, the higher the impact of these restrictions.

Particularly, restricting onshore wind considerably influences offshore-wind development.

The synergies between onshore wind and transmission expansion are also important. Compared to **REST** scenario, not restricting onshore wind (**WIND** scenario) leads to average annual savings of 16.9 b€₂₀₁₆; not restricting transmission expansion (**TRANS** scenario) to 4.6 b€₂₀₁₆; and not restricting both technologies (**FREE** scenario) 21.4 b€₂₀₁₆. This means that the average savings in scenario **FREE** are 14% higher than the sum of the average savings of scenarios **WIND** and **TRANS**.

6. Discussion

This section discusses key assumptions, results, and limitations of the paper. Results are compared to other studies.

6.1. Discussion of assumptions and results

The scenarios rely on high CO₂ tax increase towards 2050. Given that the current market CO₂ price in Europe is around 25 € per ton and that the assumed CO₂ price by 2025 is 29.79 €₂₀₁₆ per ton, it seems like the results could be close to reality for the 2020 decade. However, the considerable increase

in CO₂ tax assumed for 2035 (90.42 €₂₀₁₆ per ton) and 2045 (120.55 €₂₀₁₆ per ton) can be questioned. Nevertheless, the results show that, without sector coupling or any additional measures applied in the sectors not included in this paper, the 2030 European target of 40% GHG reduction [54] seems reachable under the CO₂ price assumption of this study. However, the carbon neutrality European target for 2050 [54] seems endangered without sector coupling.

The results show that P2H is the most cost-effective way of decarbonising the heat sector. In [6], P2H was found to be the preferred option to decarbonise the heat demand from individual users, which is in line with this paper. However, current grid tariffs and taxes are important barriers to this development [55], which suggests that they should be reconsidered.

In [8], it was suggested that sector coupling should be prioritised over transmission expansion. This paper finds this statement questionable since the value of transmission expansion seems to be highly dependent on the combination of assumptions undertaken, and as shown in [56], the benefits of transmission expansion are highly non-linear. Therefore, this paper suggests that both sector coupling and transmission expansion should be encouraged.

Even though the results show that both onshore wind and transmission expansion benefit the system, as discussed in [24] social opposition may trump this development. Not restricting these technologies leads to average savings of 24.4 b€₂₀₁₆, which divided by the existing population of the studied countries results in 78.7 €₂₀₁₆ per person per year. Part of these savings could be used as compensation schemes to decrease social opposition.

The scenarios with the transport sector assume a gradual decarbonisation of this sector towards 2050. However, there is big uncertainty around this because the technologies that would enable this process are currently expensive. In the scenarios of this paper, investments in synthetic gas units only take place in 2045 due to the large cost reduction assumed. Furthermore, the costs of the scenarios without the transport sector (Figure 13) are not directly comparable to the others because the costs associated to the transport scenario are not included. However, the high CO₂ price increase assumption together with the increase of efficiency of the private vehicle fleet could compensate the

Figure 14: Development of annual CO₂ emissions in the energy sector (left vertical axis) and GHG reduction with respect to 1990 total levels (right vertical axis).

higher capital expenditure. On the other hand, the decarbonisation of the transport sector should be optimised and not assumed to have consistent scenarios.

Short-term electricity storage plays a limited role in the results of this paper. Similar to [35] and [6], it is found that the more flexibility there is in the system, the less need for electric batteries. As suggested in [57], capacity deferral is where electric batteries have the highest value, but further costs reductions are needed to exploit this value. Introducing ramping constraints and increasing time resolution could have increased the value of electric batteries.

Even though wind energy accounts for the largest share of electricity generation in the scenarios, the contribution of solar PV in northern countries like the UK is non-negligible. In [6], solar PV was only found optimal in some of the northern countries when restricting transmission expansion. The detailed modelling of solar PV and wind resources of this paper is likely to be responsible for this difference. Two facts support this conclusion: 1) solar PV assumptions by 2030 lead to almost identical annuities when compared with [6], and 2) investments in UK take place already in 2025 in this paper. This highlights the importance of detailed VRE modelling in energy systems, since it also influences sector coupling.

Investment in CCS technologies are limited and only found optimal when restricting P2H and biomass investments. CCS high capital expenditure is responsible for this result.

There is also growing concern about the carbon neutrality of biofuels [58], which is the assumption made in this paper.

6.2. Limitations of the modelling

The simplifications undertaken to maintain the tractability of the runs are responsible for many of the limitations of this work.

The assumptions of 1) perfect markets, 2) economic rationality, and 3) perfect foresight within the year are some of the main limitations of the model.

The installed capacity in the system may have been underestimated due to data aggregation. In the industry sector, not disaggregating it into types of industries may have overestimated

Table 6: Back-up use in full-year runs. Impact of P2H.

	Commodity	FREE_NOP2HNTRP			FREE_NOTRP		
		2025	2035	2045	2025	2035	2045
Missing energy (TWh)	Heat	27.2	9.1	10.0	16.1	12.6	10.9
	Electricity	0.4	30.4	66.7	0.5	1.5	2.4
Missing capacity (GW)	Heat	135.7	128.5	102.6	179.6	98.0	95.9
	Electricity	34.4	83.9	102.6	6.4	11.0	16.0

the potential for electrification in this sector. The underestimation of capacity in the system is increased due to using limited amount of time steps in the capacity development optimisation. Even though energy-wise the time step selection are found to be a relatively accurate representation of the full weather year used, capacity wise the results are slightly worse. The results show that sector coupling might increase the adequacy of the energy system, especially in the electric sector (Table 6). This conclusion should be tested with different weather years. On the other hand, stochastic optimisation would likely reduce the back-up issue, at the expense of increasing complexity.

In the paper, a unique expansion cost is used for DH investments. However, these costs are sensitive to the location, as exemplified by the differences in labour costs for DH expansion as applied by [59] and [60].

The large increase of distributed electricity generation and demand due to sector coupling could require reinforcement of the distribution network. By 2045 in scenario **FREE_NOP2HNTRP**, the peak electricity demand of the studied system is 309 GW, whereas in scenario **FREE** it is 1247 GW, which is roughly 4 times higher. The reinforcement costs of distribution systems and intra-region transmission system are not included in the optimisation. However, other studies suggest that the costs associated to all electricity grid reinforcement costs would represent 10-15% of total electricity generation costs (a review is presented in [61]). Furthermore, the increase in peak demand might not necessarily lead to reinforcement of the grid. For instance, power-to-gas facilities could be located close to VRE units.

Natural gas grid constraints and markets are not represented

in the model. The first limitation is not likely to impact results given that in 2019 3211 TWh of natural gas were consumed in the studied countries [62], whereas in the runs the maximum yearly natural gas consumption is 3035 TWh. However, given that the scenarios show large differences in natural gas use towards 2050, from almost the consumption of today towards zero, not modelling the natural gas market could have underestimated its use.

The flexibility of the electricity-to-synthetic fuel demand of the transport sector may have been overestimated. The modelling could be improved by introducing the costs and characteristics of the technologies behind the electricity demand assumed. However, it is worth noting that the average capacity factor of the technologies producing H₂ and SNG in the scenario with the highest synthetic fuel production is 72% (Table 5), which means that the peak-to-average ratio assumption in the transport sector of 1.5, i.e. 2/3 capacity factor, could have been a fair approximation.

The speed at which individual users can switch from gas-to-heat to P2H may have been overestimated. The results show that P2H becomes the largest source of heat production in the individual users' sector already by 2025 when investments in P2H are allowed.

The possibility to build meshed grids in the sea and hub connected offshore-wind farms is not considered in this paper. However, as shown in [27] and [40], meshed grids decrease costs and increase the value of offshore wind and transmission, which could influence sector coupling.

7. Conclusions

This article analyses the role of sector coupling towards 2050 when pursuing the green transition to satisfy electricity and heat demand, with a case study of North Europe using the energy system model Balmorel. Potential social resistance towards electricity transmission and wind power is considered. The heat sector studied includes industry, individual heating and DH. Electrification of the transport sector is assumed. Expansion of the electricity grid and DH, generation and storage units, CCS, and synthetic gas units are put in competition in the optimisation of the capacity development and operation of the energy system towards 2050.

A change of paradigm takes place due to sector coupling: The electricity system moves from a system where generation adapts to demand, to a system where demand adapts to generation. This occurs because VRE generation and the share of flexible electricity demand considerably increase towards 2050. The share of inflexible electricity demand by 2045 is lower than 29% in the scenarios with higher degree of sector coupling.

The results show how sector coupling increases electricity demand, VRE integration, heat storage, and electricity and DH transmission expansion towards 2050. The installed stationary electricity capacity in 2045 roughly triples compared to 2025 in the scenarios with P2H investments and transport demand. Investments in electricity storage and synthetic gas technologies are very limited and only take place in 2045.

P2H is the preferred option to decarbonise and reduce costs in the heat sector and considerably influences the use of storage along the year. Decarbonising the industry sector is the biggest challenge, especially when P2H investments are not allowed.

Not restricting onshore-wind potential and/or electricity transmission expansion lead to lower emissions and costs. The impact is greater with higher sector coupling, leading to average savings of 78.7€₂₀₁₆ per person per year.

The scenarios with the transport sector and P2H investments achieve the highest emission reduction with respect to 1990 levels by 2045, 92% GHG reduction in the energy sector, and 76% GHG reduction when including all the sectors.

The results rely on high CO₂ tax growth towards 2050 and highlight the value of sector coupling in the green transition.

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Appendix A. Technology and resource modelling

This appendix describes the modelling behind the generation and storage technologies and fuels used in the model that are not described in the main part of the paper. The modelling has as starting point [25]. The code can be found in [26].

Generic technology constraints. The installed capacity of the technologies with the availability factor limit the maximum generation (or loading of storage, or transmission flow) of the technologies in each time step. For VRE technologies the availability factor is linked to the available energy production.

When activating unit commitment, minimum up/down time and ramping limits are introduced per unit, and the number of units online limit the maximum/minimum production.

When planned maintenance is optimised, the units will be forced to be inoperative during a specific amount of consecutive time steps. More details can be found in [36].

CHP units modelling. CHP units are split into back-pressure and extraction ones. The option of turbine bypassing is allowed for steam-turbines CHP units. All invested steam-turbine CHP units are assumed to have the bypass option. This option considerably increases their flexibility since now the units can produce heat without having to produce electricity. An illustrative example of the different operational range of different CHP units without minimum production constraints is shown in Figure A.15.

Figure A.15: Operational range of steam-turbine CHP units with and without turbine bypass. The blue area defines the operational range. Back-pressure units without bypass have a fixed electricity-heat ratio.

Storage units modelling. Storage is a source of flexibility to the system and can be used to move energy over time. Two types of generic storage are defined in the model: short-term and long-term. Short-term storage is defined with a seasonal cycle, which means that it has the constraint that the storage content at the beginning of each season needs to equal the one at the end, whereas for long-term storage the cycle is considered to be a year. Losses are accounted when loading.

Wind and solar modelling. To represent that the wind and solar resources are not uniform inside a region, different RGs are defined. The RGs can differ in costs, capacity factor, time series and investable potential.

For offshore wind, RGs are linked to distance to shore and grid-connection technology, with RG1 meaning near shore,

RG2 AC-connected far offshore, and RG3 DC-connected far offshore [40]. RG3 has higher costs than RG1 or RG2, but also higher capacity factor, as wind speeds are generally higher further offshore.

For onshore wind and solar PV, RGs only affect potentials, capacity factors, and time series; costs are assumed equal for all RGs. Wind onshore is defined with three RGs: RG1 consists of the 10% highest mean wind speed locations, RG2 of the second best 40%, and the final 50% are for the RG3. The shares define the split of the technical potential to the RGs: 10% of the total technical potential can be placed in RG1, and so forth. Solar PV is modelled similar to onshore wind. However, for relatively small modelled regions, i.e. all regions except the ones in UK and France, only two RGs are used, with the resource potential split equally. The regions with three RGs are UK and France. Solar PV shows generally differences between the capacity factors of the RGs compared to wind [44].

National technical potentials for solar PV and onshore wind are split on the different regions based on area size.

The time series and consequently capacity factors for wind and solar PV are generated using the CorRES model [42]. CorRES is based on tens of years of pan-European meteorological data [63], with the influence of wind technology developments (higher hub height and lower specific power) also modelled [64]. Assumed VRE technology development towards 2050 is taken from [31].

The modelling of solar heating time series and capacity factor is taken from [65]. A unique RG is used, and no potential limit is defined.

Curtailment for VRE is allowed in the model.

CCS units modelling. The possibility to build new generation units with CCS is allowed only for large-scale CHP and non-CHP units due to the large influence of economies of scale for CCS. Building CCS modules for existing generation units is not allowed. It is assumed that the CCS module is always activated, which means that every time the unit consumes fuel, CO₂ will be absorbed. The amount of CCS absorbed with respect to the one generated is defined with the efficiency of the CCS process. Additional electricity consumption is required for this process too, which reduces the net efficiency of the unit. The absorbed CO₂ is assumed to be transported and stored, increasing the operational costs of the units. No constraints are assumed for transporting and storing CO₂.

Hydro. Three types of technologies that use hydro resources are modelled: hydro pumping, hydro run-of-river, and hydro reservoir with seasonal inflow. Hydro pumping is modelled as a short-term electricity storage. Hydro run-of-river is modelled with a time series per region. Hydro reservoir with seasonal inflow is modelled as a long-term seasonal storage, but with seasonal energy inflow (rain, ice melting, etc.) and the possibility for pumping.

Biofuels. Step-wise price functions are defined for biofuel to model that their costs are very sensitive to their demand. This is a proxy for modelling the biofuel balance.

Similar to [66], wood chips, straw, biogas, and wood pellets are defined with three price levels and corresponding annual potential, whereas the rest of the biofuels, e.g. wood waste or wood, are defined with a unique price-annual potential level. Municipal solid waste is an exception and its potential is defined seasonally. Biogas can be used to replace natural gas although with lower efficiency.

Appendix B. Heat sector modelling

This appendix describes in detail the modelling of the different heat subsectors and it is illustrated in Figure 2.

Industry sector. The modelling of the heat demand of industry is performed by aggregating industries based on temperature levels of heat demand and on current connection to DH. The temperature split is inspired from [31] and [32]. With this setup, for each region in the model, six areas are introduced: high temperature (HT), medium temperature (MT), and low temperature (LT) with or without DH existing connections.

HT areas aggregate the industries with heat demand requiring temperatures above 500°C, e.g. metallurgic industries. It is assumed that only direct firing units can satisfy this demand.

MT areas represent those industries with heat demand requiring temperatures between 100°C and 500°C, e.g. steam use in chemical industries. It is assumed that this heat can be provided by CHP units, and electric and fuel boilers.

LT areas represent those industries demanding temperatures below 100°C. This demand can be both for space heating purposes, or for LT process heat in for example the food industry. It is assumed that air-to-water heat pumps and short-term water tanks can operate in these areas.

Based on the assumptions regarding the technologies allowed to satisfy the different types of heat demand, unlimited heat exchange is allowed from MT areas to LT ones. Heat exchange from HT to MT areas is not allowed since using direct firing for other purposes than HT process heat might be more complex and expensive. Furthermore, heat exchange between large-scale DH network areas and LT industrial areas is allowed, as long as there is heat transmission capacity. This simplification assumes that industries are located relatively close to large concentration of people. The use of excess heat is not considered in this paper. CHP with CCS is not allowed in industry due to economies of scale assumptions.

Individual users' sector. The modelling of the heat needs of individual users is done by splitting users in two types in each region of the model depending on whether they are currently connected to DH or not.

Currently-connected-to-DH individual users are further split into different aggregated areas depending on the demand size of the DH network they are in. The size of the network impacts economies of scale of the technologies, land availability, and costs, among others. Each of these areas has associated a time series of inflexible demand for space heating and hot water that needs to be satisfied through DH, i.e. unidirectional flow. The possibility for individual users currently connected to DH to

cover their demand with other technologies than through DH is not modelled.

On the other hand, individual users currently without DH are modelled by aggregating their demand in two areas based on the end purpose: space heating or hot water. Unlimited heat exchange is allowed to move energy from hot-water areas to space-heating areas with the assumption that hot-water demand is satisfied through technologies that could be used not only to deliver hot water to the user but also for space-heating purposes. These technologies are solar heating, air-to-water and ground-to-water heat pumps, electric radiators, fuel boilers, and short-term hot-water tanks storage. The only technology allowed in space-heating areas is air-to-air heat pumps, with the assumption that they can't cover hot-water demand. Furthermore, DH expansion between hot-water areas and large-scale DH areas is allowed. This assumes that all individual users not currently connected to DH can be connected to large-scale DH areas. Heat flow in this case is allowed to go in both ways, i.e. bidirectional. Space-heating areas are not allowed to send energy to the DH network, but they can receive heat indirectly through hot-water areas.

District heating. The modelling of the DH sector is based on scales of DH networks and technologies and is inspired from [30]. Technologies included in this sector are fuel and electric boilers, air-to-water and ground-to-water heat pumps, CHP units, electrolyzers, methanation-DAC units, short-term hot-water tank storage, and long-term pit heat storage. CHP with CCS is allowed but only in large-scale DH areas. DH losses are accounted when moving energy from the DH network to either industry or individual users' areas to avoid double counting. H₂ related technologies, and methanation-DAC units are only allowed in large-scale DH areas to benefit from economies of scale. In these areas, methanation-DAC units are assumed to be built connected to CHP units or boilers, since they can satisfy the temperature needs of the Sabatier process (250-400°C).

Appendix C. Input data

This appendix provides further information on data assumptions. All the data can be found in [37].

Generation and storage technology generic data. Most technological data are directly taken from [31]. Unit commitment data are complemented with data based on [67], [68], and [69].

Economies of scale are reflected in the costs and efficiencies of the units depending on where they are located, e.g. the cost per MW of a heat pump is larger if installed in the individual users' sector than in DH.

CCS costs are estimated by increasing 95% the capital expenditure of the unit without CCS based on [31]. This is done for large CHP and non-CHP units (above 100 MW). Large CHP units are only allowed for investments in large DH networks. CCS absorption efficiency is 90% and transport and storage cost is 20 €/2016/ton [31]. The efficiency penalty is applied with an added electricity demand of 371 MWh per ton captured [70].

Electric battery costs are based on [71]. A linear decrease in battery cost towards 2050 is assumed reaching a 60% decrease compared to 2016.

Methanation-DAC data are taken from [6] and is assumed constant for all years.

Lifetime expectancy is used to calculate the existing generation and storage unit development towards 2050, which forces part of the decommissioning that takes place in the model.

COP time series are based on [72], where missing Nordic countries are assumed to have the same profile as Poland.

Hydro pumping storage potentials are taken from [73], whereas solar heating time series are taken from [65].

Specific data for the electricity sector. Existing generation and storage capacities development is taken from [39] with the updates included in [66].

Electricity demand and distribution losses are obtained from Eurostat [74]. Electricity consumption from processes modelled endogenously in the model, such as pumped hydro storage and heat pumps, is deducted. This exogenous demand is assumed constant towards 2050, except for the demand in Denmark, which adds increasing consumption from data centers based on [75].

Modelled technologies consuming electricity in areas linked to the individual users' sector are assumed to incur into distribution losses.

Existing and planned transmission capacities towards 2050, which correspond to net transfer capacities, are taken from [76]. Investments in transmission are allowed as in [38], from which costs are also taken. The losses per 1000 km used are 7% for HVAC and 4% for HVDC [77]. HVAC is assumed for interconnector of synchronous regions through land, and HVDC for the rest. Transmission losses for wind offshore are considered for the different RGs based on [78]. The losses assumed are 1% for RG1, 1.5% for RG2, and 2% for RG3. Existing wind-offshore farms are assumed to be part of RG1.

Ancillary service requirements are taken from [29].

Specific data for the district heating sector. Annual demand, time series, generation capacity and storage capacity development for existing DH networks are taken from [39], which are based on [38]. The scenario assumes a slight decrease of their demand towards 2050 due to energy efficiency measures.

DH losses for new networks are assumed to be 10% based on typical values. In [79], 12% losses are assumed.

Specific data for the industry sector. Time series for the different heat processes and space-heating demand are taken from [80], whereas annual demand and remaining industrial data are based on data from [32]. The national heat demand split across regions is based on the electricity demand shares. Annual demand is assumed constant through time.

Existing capacities per fuel are based on annual heat demand and corresponding fuel shares.

The split between currently-connected-to-DH industry and non-currently-connected-to-DH industries is based on the share of heat demand covered by DH in industry.

Specific data for the individual users' sector. Individual users' data aggregate the residential sector and tertiary sector.

Annual residential space-heating and water-heating demands are derived from household's final energy consumption in [81], excluding derived heat, divided by assumed fuel efficiencies - 100% for electricity, 90% for gas, 76% for solid fuels, 90% for oil and 80% for renewable energy and wastes.

For the tertiary sector, the share of final energy demand between residential and tertiary sectors is derived in each country from [82] and applied to the residential data in [81]. The fuel shares in [81] are also applied as the technology share of 2016 existing capacities.

Electricity is divided to heat pumps and other electric heating with the share found in [83]. Gas and oil are used for boilers, solid fuels are assumed to be used for coal boilers, renewable energy and wastes are assumed to be used for wood pellet boilers. The above data of Sweden, Finland, UK and Germany are replaced by their national statistics, which include both residential and tertiary sectors and better details.

The national heat demand split across regions is based on electricity demand of each region. Heating demand time series are based on the methodology in [72], using hourly temperature to get heating demand hourly profile over a year. Using the heating demand profile and annual heat demand, the maximum heat load within a year is found and it is defined as the total installed heating capacity. Annual demand is assumed constant towards 2050.

Existing capacities are the total installed heating capacities multiplied by 2016 technology shares.

Appendix D. Supplementary results

This appendix complements the results of the paper by showing more details on the heat and electricity generation development per sector in the scenarios (Figure D.16).

Electricity generation. Sector coupling increases VRE generation towards 2050, replacing fossil fuels. Roughly, in the scenarios with P2H investments and transport sector, the generation in 2045 triples the one in 2025.

Wind is the largest source of clean energy. The share of wind energy production in scenario **FREE** is 43%, 62% and 65% in 2025, 2035, and 2045, respectively, whereas the share of non-renewable sources (nuclear and fossil fuels) in the same years is 31%, 9% and 5%, respectively.

Heat generation per sector. P2H dominates the decarbonisation of the heat sector when P2H investments are allowed. Individual users switch to P2H as early as 2025, whereas industry and DH show a gradual transition. P2H in the industry sector is highly affected by restrictions on onshore wind and transmission expansion, especially the latter.

Generation in the DH sector increases towards 2050 and becomes more important when P2H is not allowed, especially to send energy to individual users. This is reflected in the lower generation of heat in the individual users' sector in scenarios **REST_NOP2HNOTRP** and **FREE_NOP2HNOTRP**.

Figure D.16: Generation development of heat and electricity per sector, technology type, and fuel (TWh).