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Different flexibility options for better system integration of wind power

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ABSTRACT

Variable renewable electricity (VRE) will play an important role in future energy systems, but additional flexibility measures will be needed to integrate large-scale VRE into energy systems. Here we investigate the effectiveness of different flexibility options to integrate wind power, using the Finnish energy system as a case. The main flexibility options considered are sector-coupling such as power-to-heat and power-to-gas, energy storages, and electric vehicles. The results indicate that the share of wind power could be increased up to one third of all electricity, limited by the cross-border transmission capacity and the high share of nuclear power in the Finnish case, while simultaneously decreasing annual system costs and carbon emissions. Power-to-heat and wind power curtailment were the most cost-effective flexibility options. Furthermore, combined heat and power (CHP) and nuclear power could form a barrier to cost-effective wind power integration, suggesting that viewing the energy system as a whole provides valuable insight for wind power integration.

1. Introduction

Several future energy scenarios include high shares of variable renewable electricity (VRE) such as wind power as part of climate change mitigation [1]. This will increase power supply variability, imposing major challenges on power system reliability, safety, and electricity markets, calling for additional energy system flexibility measures [2–4]. The options for increasing flexibility are ample, ranging from supply to energy storage and demand side measures [5,6]. Furthermore, considering the energy system as a whole and integrating power, thermal, and transport sectors together (also called sectoral coupling) could considerably improve the integration of large-scale VRE [7].

The literature on wind power integration with flexibility options is extensive. This includes power grid operation [3,8–10], system flexibility requirements [11,12], existing power plants [13–15], and hydro power [16,17], among others. As to different flexibility technologies, power-to-heat [18,19], demand response [20], electric vehicles [21–24], storage [25,26], or a combination of several measures [27–30] have been studied. However, most of the previous studies focus only on one or just a few aspects of system flexibility [6] instead of comparing a wide range of flexibility options, contrary to our approach here.

Finland was chosen as the case study for this paper because of its ambitious climate targets [31] and data availability. Finland's decarbonization strategy is mainly based on nuclear power and bioenergy, but wind power will also play an important role as in the whole EU [32]. Like in many northern countries, combined heat and power (CHP) is important in Finland and represents around one third of all electricity production.

Wind power integration with nuclear and CHP intensive energy systems such as in Finland has been discussed in literature. A high share of nuclear power could constrain wind power use [33]. CHP with thermal storage could be an economical and technically attractive option for balancing wind power [34], but studies indicate that replacing CHP with power-to-heat solutions (heat pumps and electric boilers) and heat storage could be even more economically feasible for wind power integration [13,30,33,35]. A 100% renewable scenario for Finland relying on power-to-gas has also been investigated [36]. In addition, load-shifting [29] and electric vehicles [37] could provide additional system flexibility, especially in combination with power-to-heat solutions [30]. Our analysis differs from the previous studies mainly in that we assess multiple flexibility measures, while considering the national energy system as a whole with all sectors (power, heat, fuel), and considering the effect of CHP.

Three research questions are of particular interest here: 1) to what extent could different flexibility measures cost-effectively be used to integrate large-scale wind power in Finland by 2030, 2) could CHP form a barrier to cost-effective wind power integration, and 3) how will a high share of nuclear power affect wind integration? For this purpose, we employed a national energy system model incorporating all energy sectors to accurately consider the sector couplings and their relation to flexibility measures. The methodology is described in Section 2, the main results are discussed in Section 3, and finally the conclusions are presented in Section 4.

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2. Methodology

2.1. Modelling approach

The analyses are made with a techno-economical energy system simulation and optimization model, which has been developed at Aalto University. The model is implemented in Excel®; a future version will be implemented in MATLAB®. A detailed documentation of the model can be found in Refs. [38,39] and here we just summarize the key points of the model.

The model works with hourly energy balances, which are calculated over a whole year. The model employs a 1-h time step for electricity and heat, while fuel demands are considered on an annual scale due to their inherent storage functionality. The final energy flows (electricity, heat, and fuel) in all sectors of the national energy system are calculated from the primary energy sources. The model seeks for a cost-optimal solution of the energy system against wind power addition and fossil fuels (more details in Section 2.3) while securing the supply-demand balance and meeting all given constraints and system limitations. The energy system composition is thus endogenous to the model. The model also includes advanced conversion options (P2X) between final energy forms linked to flexibility measures with large-scale variable renewable energy and combined heat and power (CHP). An hourly analysis is also important to correctly take into account the energy system dynamics, which is essential when considering variable energy sources and intersectoral coupling through the different energy carriers [5]. A schematic illustration of the model is presented in Fig. 1. Industrial CHP is considered here separately from district heating CHP. Wind power, which is the focus of this study, is considered as an integral part of the whole energy system and as a source of electricity, similarly to other electricity-only production methods in the model.

In the energy balance section of the model, primary energy sources are converted into final energy in a 2-stage conversion process. First, primary energy is converted into electricity and heat by conventional conversion methods. Second, advanced conversion methods are used to match the final energy produced to the actual demands of the different final energy forms (electricity, heat, and fuel). The hourly distribution of conventional conversion is scaled based on historical production data, whereas the advanced conversion is based on control rules [38]. This kind of production distribution scaling has been used e.g. in Ref. [40]. The advanced conversion technologies and flexibility options included in this study are:

1. Power-to-heat (P2H);
2. Power-to-gas (P2G);
3. Smart charging of electric vehicles (EV);
4. Vehicle-to-grid (V2G);
5. Biomass-to-biofuel conversion (B2B);
6. Thermal storage;
7. Electricity storage;
8. Wind power curtailment.

The control rules for the flexibility options simply aim at balancing the unmet demands. For example, power-to-heat (P2H) aims at meeting the heat demand with excess electricity, while power-to-gas (P2G) converts excess electricity to synthetic gas. Heat storage operation aims to minimize wasting heat surplus by filling any free capacity, and electricity storage aims to prevent unnecessary power import or export. Curtailment is used in case transboundary power export capacity is exceeded. Cross-border export and import are regarded as the final option for balancing electricity supply and demand. However, considering in detail the ability of the international power market to absorb the Finnish electricity export was outside the scope of this paper, so the international market is assumed to be able to supply and absorb electricity at all times, limited only by the cross-border transmission capacity. More detailed information on the control rules can be found in Ref. [38].

The whole country (here Finland) is modelled as a single node without regional power and heat flow restrictions, but the overall transmission losses and cross-border power exchange capacities are considered. The power system is connected to one price area (Nordic electricity market, Nordpool) through one transmission corridor with a limited capacity. The imports of power within the transmission capacity limitation and gas are not limited; for export, only electricity is considered. Detailed modeling of the electricity markets with effects from changes in the Finnish power mix was outside the scope of this study, which could cause some uncertainty to the electricity market price used here.

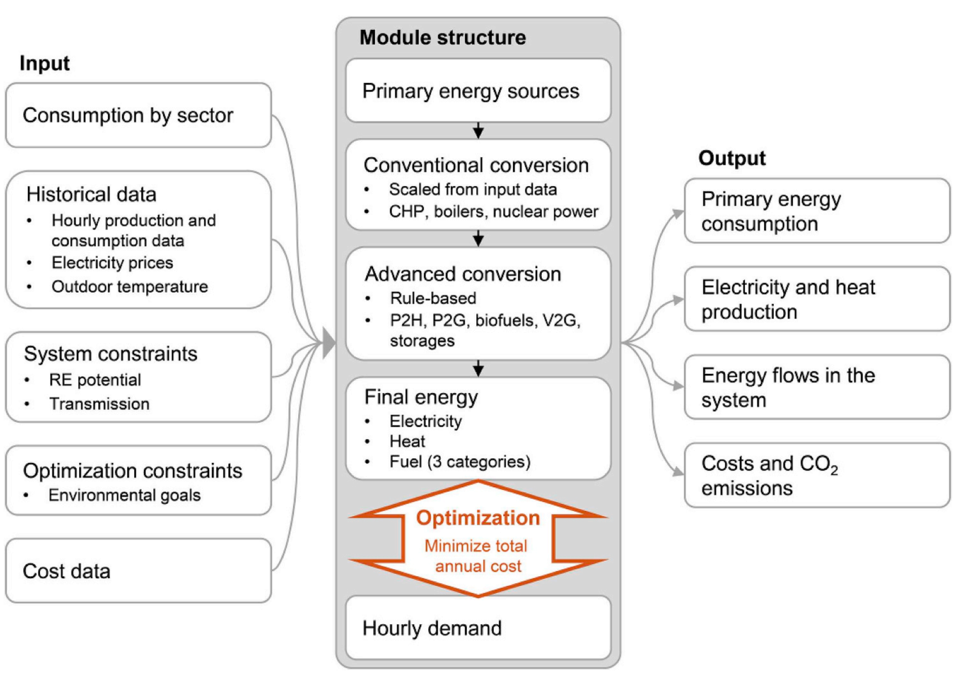

Fig. 1. Schematic of the modelling approach.

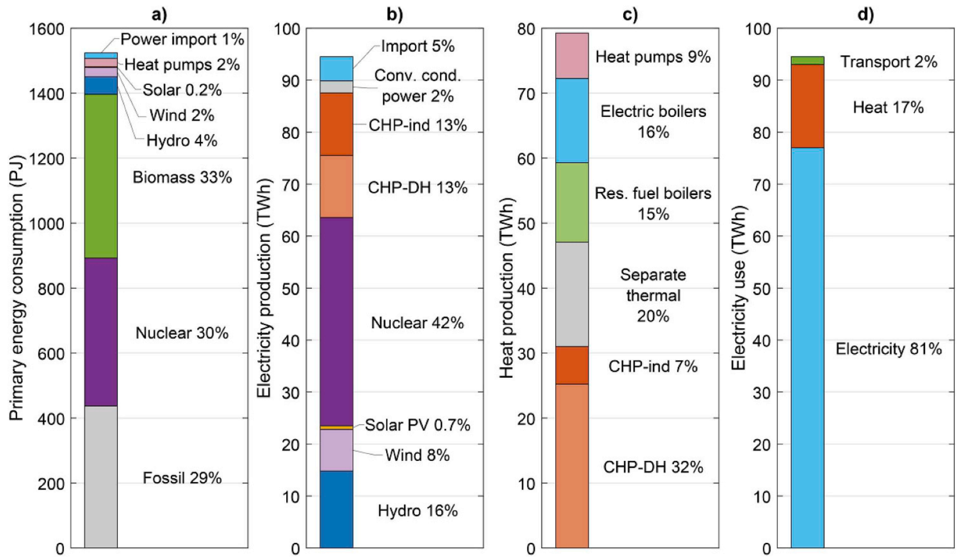

Fig. 2. Reference scenario (Finland 2030) based on the National Energy and Climate Strategy 2030 [31]. (a) Primary energy consumption (b) Electricity production (c) Heat production (d) Electricity use.

The modelling of EVs and V2G is based on reference [22]. We assume here that 50% of the EV fleet will participate in V2G, and the size of the EV fleet is determined based on the annual electricity consumption of the transport sector. The batteries of the EV fleet are modelled as a lumped storage, charged through a line connection and discharged during driving and V2G operation. The driving pattern affects the interaction of the battery with the grid. It is assumed that 70% of all EVs are grid-connected while parked. Smart charging implies that EVs may utilize the grid's excess electricity production if there is free capacity in the battery, while in the V2G mode, two-way operation between the EV battery and the grid is allowed to avoid unnecessary power import, limited only by the hourly power transmission connections, while ensuring adequate storage levels for EV self-use. Without smart charging, the EV batteries are not charged in advance, and the driving pattern of the EVs directly determines the EV consumption without any demand shifting.

The optimization of the energy system is done against the annual system costs. Mathematically the optimization problem can be formulated as

$$\begin{aligned} Min.\ Total\ Annual\ Cost \ = & \sum_{t=1}^{tech} (Investment\ Cost_t + O\&M_t) \\ & + \sum_{f=1}^{fuels} Fuel\ Cost_f \\ & + \ Cost\ of\ imported\ electricity \\ & - Revenues\ of\ exported\ electricity \\ & + Emission\ costs \end{aligned}$$

subject to

a) balance of final energy supply and demand;
b) available primary energy resources;
c) energy system constraints such as cross-border transmission capacities.

The variables used in the optimization are discussed in Section 2.3, whereas the main optimization outputs are the primary energy composition, power and heat production, and the energy balance of the system.

The annual investment cost is calculated as the total investment divided by lifetime, using a real interest rate of 5%. The hourly heat demand is calculated from the outdoor temperature with a 2-component load model, which includes a constant part for the domestic hot water and a temperature-dependent part for the space heating, which is calibrated to match the total annual heat consumption. The hourly heat demand calculation is based on an indoor comfort temperature of 17 °C. More information on the heat load data can be found from Ref. [39]. The total CO_2 emissions are calculated based on the CO_2 content of the primary energy sources, but assuming all bioenergy use CO_2 neutral [41].

2.2. Reference case and input data

We use as the reference year 2030, for which both the EU and Finland have established climate targets. The reference energy system case is based on the scenario calculations presented in the National Energy and Climate Strategy 2030 of the Finnish Government [31]. The overall energy and climate targets in Finland by 2030 are the following [42] (current year 2017 values are shown in brackets [43]):

- Share of renewable energy in final consumption to be increased to 50% (41%);
- Self-sufficiency of final consumption to be increased to 55% (46%, estimated);
- Share of renewable transport fuels to be raised to 40% (19%);
- Coal will no longer be used in energy production (8% of total energy consumption);
- Use of imported oil for the domestic needs will be cut by half (23% of total energy consumption).

Furthermore, Finland follows the EU goals to decrease the greenhouse gas emissions by 40% by 2030.

The main features of the reference scenario are shown in Fig. 2 and Table 1, and the more detailed numerical data of the reference scenario is given in Supplementary Information. Finland's present energy strategy relies on nuclear power and forestry biomass, as well as on combined heat and power (CHP). Primary energy (Fig. 2a) composes mostly of nuclear power, biomass and fossil fuels, each one third of the total. The share of renewables is 40% in primary energy and 50% in final energy consumption. CHP, which is important in the Nordic countries, stands for 39% of the total heat demand (Fig. 2c). The share of wind power of the total electricity consumption in the 2030 strategy is 8% (8 TWh) in 2030, while in 2017 the share was 5.6% (4.8 TWh)

Table 1
Energy consumption in Finland in 2030 (reference scenario) [31].

	Fuel (PJ)	Electricity (TWh)	Heat (TWh)
Industry	380	44.0	17.7
Transport	175	1.5	–
Residential	–	11.3	41.2
Public sector	–	21.0	16.9
Transmission losses	–	3.0	3.4
Total	555	80.8	79.3

[43]. The share of wind power in Finland is increasing rapidly being only 0.3% (0.3 TWh) in 2010 and 2.8% (2.3 TWh) in 2015.

The cost and efficiency assumptions for fuels and the different technologies are given in Appendix A (Tables A1-A3). Furthermore, we assume a carbon price of 60 €/tCO_2 in 2030, based on the IEA's 2DS scenario [1]. For the temporal profiles of demand and production, we use 2013 as the historical reference year, for which supply and demand data is readily available [43,44]. To determine the hourly heat demand we use ambient temperature values from Central Finland [45]. For market price of electricity, historical Nord Pool data for 2013 is used for the temporal price distribution [46], while the annual average price is scaled according to a projected electricity market price average in 2030, 53 €/MWh [47]. Electricity market prices are considered exogenous, as detailed modelling of the electricity market was outside the scope of this paper. The cross-border power transmission capacities in 2030 are assumed 5460 MW for export and 5876 MW for import [48], ca 40% of the Finnish peak electricity consumption in 2017. Finally, the consumption and availability of electric vehicles are calculated based on [22,49,50].

Like other power production, the temporal profile of wind power production is based on historical (year 2013) production data [44]. However, the historical profile is modified based on [33] to reflect a higher wind integration level with more spatial dispersion. The uncertainty of wind power was outside the scope of the model, so here wind production is considered deterministic. The potential of wind power is not considered in this study. However, according to the Finnish Wind Power Association [51], the potential of wind power is estimated as 30 TWh in 2030, and new wind power technologies (e.g. off-shore wind) could enable over 300 TWh annual production, even if only the best wind sites and land-use restrictions were taken into account. The production levels of wind power in this paper fall below the previous values.

2.3. Flexibility cases

The effect of different flexibility options on wind power integration is investigated through case studies, which are listed in Table 2. Each flexibility measure is first considered as a separate case, and then as a combined case with all measures together. In each case, we aim to determine to what extent each flexibility measure could support cost-effective wind power integration, i.e. how much wind power could be added to the cost-optimized energy system with each flexibility measure in place. In each case, the flexibility measure under study is added as an available option for the optimization and the hourly balance calculations in the model.

The *No P2X* case acts as a flexibility reference, as no additional flexibility measures are enabled. In *P2H*, heat pumps and electric boilers are added as variables in the optimization, but the level of heat pump production is limited to one third of the non-industrial heat demand reflecting the diversity in the heating market and the possible limitations in heat source availability during the main heating season in winter. In *P2G*, the option of converting excess electricity to synthetic gas via power-to-gas is allowed, the size of the plant being determined by optimization. Similarly, in *B2B*, the conversion of biomass to biofuel, and bio- and natural gas to liquid fuel, is allowed to provide fuel flexibility to the transport sector, and the level of fuel production is determined by the optimization. The two cases involving electric vehicles (*Smart charging* and *V2G*) explore the possibilities of demand shifting through the EV fleet: smart charging allows EVs to be charged using excess electricity when available, whereas V2G allows directing electricity from the EVs back to the grid if necessary (see also Section 2.1). Without smart charging, the EV electricity demand cannot be shifted and will be defined by the EV driving pattern. The *Heat storage* and *Elec storage* cases add thermal and electricity storages, respectively, as variables to the optimization. The reference level of electricity storage is zero, whereas in all cases, 60 GWh thermal storage is assumed to be already available through the Finnish district heating networks. Finally, the *Curtailment* case allows curtailing excess power production (mainly wind) in case cross-border power export capacity is exceeded. However, this curtailment is limited to 5% of the total annual wind power production, as higher curtailment levels were considered less meaningful in connection with wind power utilization.

In addition to the flexibility options, we investigate the possible lock-in effect of combined heat and power (CHP), important for the Nordic countries. This is achieved by calculating all cases with both constant and variable CHP production. In the constant CHP case, CHP production remains the same as in the reference scenario, whereas in the variable CHP case, CHP production is a variable in the optimization.

The main variables in the cost optimization are the amount of wind power, fossil fuels, and conventional conversion (i.e. CHP and separate fuel-based power and heat production). However, the amount of fossil fuel cannot be higher than in the reference scenario to avoid replacing wind power with fossil fuels, and to avoid breaking the climate targets. The amount of nuclear power is kept constant in the optimization.

3. Results and discussion

In this section, we analyse the effects of the different flexibility options described in Section 2.3 and, particularly, each flexibility

Table 2
Flexibility cases in the study. Each option is limited by the amount of excess electricity production. Each case is run for both constant and variable CHP production (see explanation in the text).

Case	Abbreviation	Notes
No flexibility measures	*No P2X*	
Power-to-heat	*P2H*	Both electric boilers (COP = 1) and heat pumps (COP = 3). Heat pumps max. 1/3 of the non-industrial heat demand.
Power-to-gas	*P2G*	
Smart charging of EVs	*Smart charging*	
Vehicle-to-grid	*V2G*	Includes smart charging.
Biofuels	*B2B*	Biomass-to-biofuel and gas-to-liquid
Thermal storage	*Heat storage*	
Electricity storage	*Elec storage*	
Curtailment		Max. 5% of total annual wind production.
All, no P2G		All above flexibility measures except for P2G.
All, with P2G		All above flexibility measures.

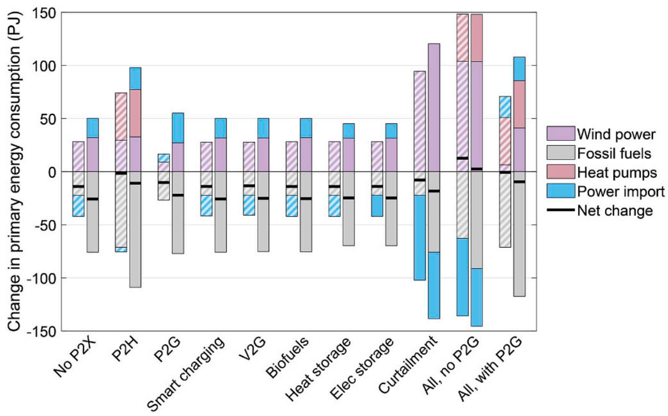

Fig. 3. Change in primary energy compared to the reference case (Finland 2030). The columns on the left (striped) refer to constant CHP, and on the right (solid) to variable CHP.

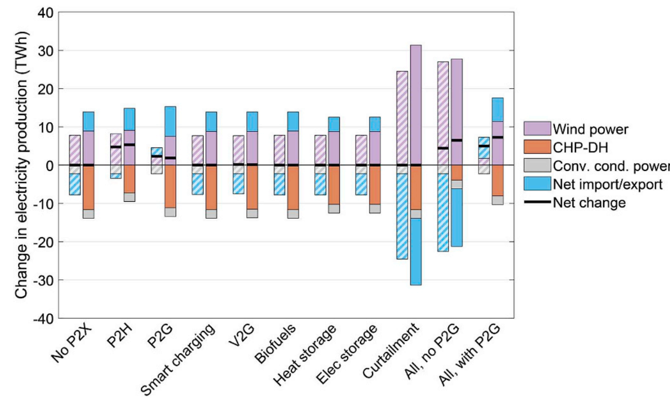

Fig. 4. Change in electricity production compared to the reference case (Finland 2030). The columns on the left (striped) refer to constant CHP, and on the right (solid) to variable CHP.

option's ability to support cost-effective wind power integration. The optimization runs of each case minimized the total system cost, using Finland 2030 as the starting point and reference case (see Fig. 2). The variables in the optimization were the amount of wind power, fossil fuels, and conventional conversion (i.e. CHP and separate fuel-based power and heat production), while the amount of fossil fuel could not be higher than in the reference case to cope with the CO_2 emission targets. The numerical values of the results are shown in Supplementary Information.

3.1. Effects in primary energy

Fig. 3 shows the change in the overall primary energy consumption with the different flexibility options compared to the reference case (see Fig. 2). All cases exhibit replacement of fossil fuels with wind power and/or heat pumps, while the total primary energy consumption decreases by 2% (26 PJ) at most. Changes in primary energy composition are higher (up to 40 PJ) with variable than constant CHP. However, only up to 10% (150 PJ) of the total primary energy is affected by the wind power integration, due to the high amount of biomass and nuclear power present in the system, which were constant in the optimization.

Interestingly several cases gave almost identical outcomes (*No P2X*, *P2G*, *Smart charging*, *V2G*, *B2B*, *Heat storage* and *Elec storage*, see Table 2 for the abbreviations). In these cases, wind power could be added only up to a certain limit (+ 9 TWh), after which the transmission capacity of power export (max. 5460 MW) would constrain increasing wind power. In the 2013 dataset, which we used as historical hourly data, the export peak occurred on Midsummer Eve, when overall electricity consumption is traditionally at lowest in Finland and the heat demand is low, but the weather was this time very windy. During these peak hours, the difference between rigid electricity baseload production and electricity consumption can be as low as 200 MW (less than 10% of the prevailing wind power in the low-wind reference), which indicates that without demand side management high power export would be inevitable. Especially at times of low power demand, the high share of nuclear baseload production (26–83% of the electricity demand, average 43%) poses a limit for effective wind power integration.

3.2. Electricity and heat production

Investigating the changes in final energy use in the different cases is highly relevant for the wind integration analysis, since wind production tends to be oversized in respect to the electricity consumption and the oversupply is often used in the other energy sectors through the inter-sectoral coupling.

Fig. 4 illustrates the differences in electricity production in the scenarios. All in all, 2–31 $TWhyr^{-1}$ of wind power could be cost-optimally added into the energy system with the different flexibility measures, resulting in an 11–37% wind power share of the electricity production. Variable CHP enabled higher amounts of wind power (8–31 TWh wind power added, share of wind power 18–37%) than constant CHP (2–27 TWh and 11–31%, respectively). However, the wind power shares are slightly lower if we only consider the self-use of wind power, obtained by subtracting the amount of exported wind power. With variable CHP, the self-use of wind power increased by 8–16 TWh from the reference case, resulting in a 15–23% share of total electricity consumption; with constant CHP, the corresponding numbers were 3–11 TWh and 10–18%. Curtailment seems to enable the highest wind power addition, as it can overcome the problematic power export during peak periods, resulting in a 29% wind power share of electricity production with constant CHP and 37% with variable CHP.

The dominant form of electricity defined by the policy preferences in Finland is nuclear power, but regardless the share of wind power could be cost-effectively increased up to 37% of all electricity (case *Curtailment,* variable CHP). The increased wind power production would be counterbalanced by increased power export and by decreasing the use of conventional condensing power and especially CHP in the variable CHP case. The decrease in CHP through preferring separate heat production in the scenarios is well demonstrated in Fig. 5: CHP heat production decreases even by 25 $TWhyr^{-1}$ with variable CHP and separate heat production would increase by the same amount. Furthermore, we find that heat pumps are employed to their maximum limit in all cases whenever included. Based on the changes in heat production in the different scenarios in Fig. 5, the order of merit for

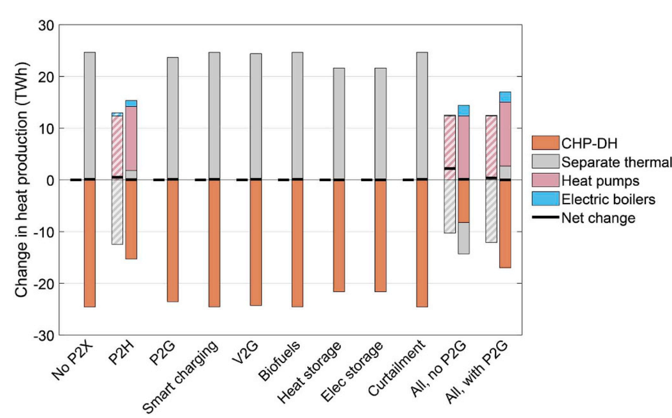

Fig. 5. Change in heat production compared to the reference case (Finland 2030). The columns on the left (striped) refer to constant CHP, and on the right (solid) to variable CHP.

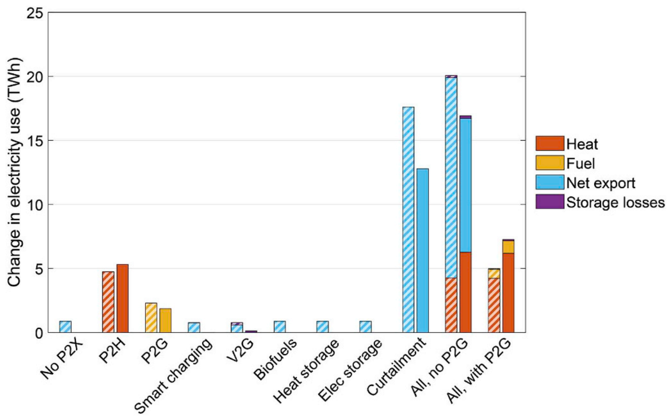

Fig. 6. Change in electricity use compared to the reference case (Finland 2030). The columns on the left (striped) refer to constant CHP, and on the right (solid) to variable CHP.

heating solutions would be 1) heat pumps, 2) separate heat boilers, and 3) CHP, thus allowing more efficient use of low-marginal-cost power sources (wind, solar, nuclear).

The intersectoral coupling of the different flexibility options is illustrated in Fig. 6. In the cases with P2H excess wind power is converted into heat (21–29% of all electricity use), curtailment increases the export of wind power (14–23%), and P2G directs a small amount of excess electricity (1–3%), which would otherwise be exported, to synthetic gas production. The small amount of P2G suggests that P2G may not yet be a cost-effective solution for large-scale wind power integration compared to P2H and curtailment. The storage losses in Fig. 6 refer to the electricity losses in the stationary electricity storage and in the EV batteries due to V2G operation, and their amounts here are relatively negligible.

3.3. Further effects on the power system

Table 3 gives the cost-optimal amounts of flexibility measures compared to the reference case, illustrating also the numerical values of the flexibility measures discussed in the previous sections. The cost-optimal amounts of the flexibility measures suggest that electricity storage is not yet cost-effective, as this option was not added in any of the cases. Furthermore, we found that the demand for heat storage decreases in some cases as CHP is replaced with more flexible separate heat production, such as power-to-heat. Overall, the highest increase in flexibility was found in the case *All, no P2G*, where all measures except for P2G and electricity storage were employed. In addition, the amount of CHP-based heat decreases in all cases with variable CHP, which is also discussed in Section 3.2. The costs and CO_2 emissions are discussed

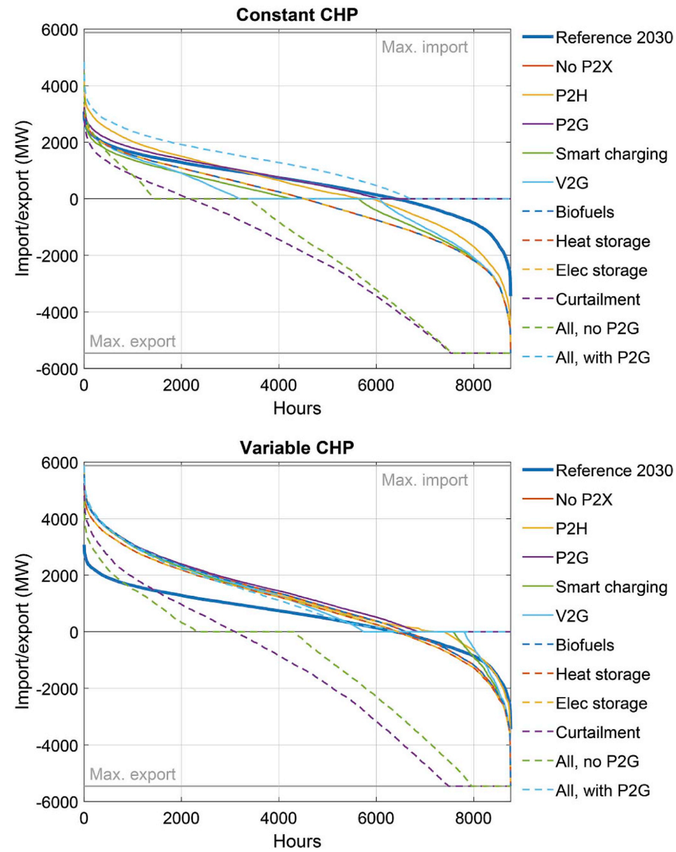

Fig. 7. Duration curve of power import (positive) and export (negative) with the different flexibility measures, with (a) constant CHP and (b) variable CHP.

separately in the next section.

Even though the different flexibility cases may not differ when comparing annual primary energy and electricity supply (Figs. 3 and 4), the effect on the power duration curve is well recognized, illustrated in Fig. 7. Here we present the duration curve of import and export as in our model cross-border export and import are regarded as the final option for balancing electricity supply and demand, thus representing the state of the domestic power system. Firstly, it can be noticed that in the curtailment cases the amount of export was higher than in the other cases: power was exported 65–75% of the hours of the year, whereas the share of export in the other cases was on average 25%. Curtailment allows oversizing of wind power as the peak production conditions can be better managed. However, it should be noted that here the amount of export was limited only by the cross-border transmission capacity;

Table 3

Flexibility additions in the different flexibility cases, compared to the reference case (Finland 2030). The colors visualize flexibility increases (green) and decreases (red) within a category compared to the reference case (shown in the second column).

P2X additions	Reference	No P2X		P2H		P2G		Smart charging		V2G		B2B		Heat storage		Elec storage		Curtail-ment		All, no P2G		All, with P2G	
		consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP	consCHP	varCHP
P2H - electric heating (TWh of heat)	13	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	2
P2H - heat pumps (TWh of heat)	7	0	0	12	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	12	12	12
P2G (PJ of gas)	0	0	0	0	0	5	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2
Biofuel from biomass (PJ)	40	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	21	0	3
Heat storage (GWh)	36	0	0	0	0	0	0	0	0	0	0	0	0	0	-15	0	0	0	0	5	86	42	-29
Elec storage (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
V2G output (TWh)	0	0	0	0	0	0	0	0	0	0.7	0.5	0	0	0	0	0	0	0	0	0.7	0.8	0.2	0.4
Wind curtailment (TWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.7	2.1	1.8	1.0	0	0
CHP heat (TWh)	25	0	-25	0	-15	0	-24	0	-25	0	-24	0	-25	0	-22	0	-22	0	-25	0	-8	0	-17
Wind production (TWh)	8	8	9	8	9	2	8	8	9	8	9	8	9	8	9	8	9	25	31	27	28	2	11
Annual cost (100 = reference)	100	-4%	-6%	-8%	-9%	-1%	-4%	-4%	-6%	-3%	-6%	-4%	-6%	-4%	-6%	-4%	-6%	-7%	-10%	-10%	-10%	-6%	-7%
CO_2 emissions ($MtCO_2$)	33.5	-5%	-16%	-15%	-28%	-6%	-16%	-5%	-16%	-5%	-16%	-5%	-16%	-5%	-15%	-5%	-15%	-5%	-16%	-14%	-20%	-15%	-23%

considering the ability of the international market to absorb Finnish electricity export was outside the scope of this paper. Thus, in reality the export indirectly caused by wind power curtailment may not be as prominent.

Secondly, smart charging (SC) of electric vehicles and vehicle-to-grid mitigate small imbalances in demand, as there are significant periods of the year without any cross-border power exchange (13–16% of the hours of the year with SC, 24–33% with V2G). This results in a 'zigzag' shape of the duration curve: instead of the smoothly descending duration curve of other scenarios, with SC and V2G there is a plateau in the curve. Thirdly, P2G directs all potential export to gas synthesis, but this is due to the operational rules.

The cases with variable CHP had on average 51% higher peak import than constant CHP, due to the increased import seen in Fig. 4. The highest peak imports were in the cases *P2H* (41%/91% higher than the reference, constant CHP/variable CHP) and *All, with P2G* (57%/-91%), whereas the lowest peak imports was in the cases Curtailment (5%/70%). As for peak export, in all the modelled cases without P2G, the peak export reached the transmission capacity limit 5460 MW, suggesting that the amount of wind integration was especially limited by the export capacity.

3.4. Costs and CO_2 emissions

Finally, we analysed the annual costs and CO_2 emissions of the scenario cases. The overall results are shown in Fig. 8, while the numerical values can be found in Table 3.

All cases had lower annual costs (-1-10%) and CO_2 emissions (-5-28%) than the reference case. The lowest cost was in the case *All, no P2G* (−10%/-10%, constant CHP/variable CHP), followed by *P2H* (−8%/-9%) and *Curtailment* (−7%/-10%) respectively. The cases with constant CHP had on average 2% higher costs than variable CHP. On the other hand, cases *Smart charging*, *B2B*, *Heat storage* and *Elec storage* had exactly the same costs than the case with no P2X, further highlighting the apparent ineffectiveness of these particular technologies for cost-effective wind power integration as they were not able to decrease system costs. However, this may have partly been caused by the limited power export capacity discussed in Section 3.1.

As for the CO_2 emissions, the lowest emissions were found in the *P2H* case (−15%/28% from the reference), followed by *All, with P2G* (−15%/23%) and *All, no P2G* (−14%/20%). All the other cases had similar emissions than the *No P2X* case. The cases with constant CHP had on average 11% higher emissions than variable CHP explained by the higher fossil fuel demand of CHP.

In this study, the level of nuclear power remained constant. However, we also conducted a separate analysis to assess whether wind power would replace nuclear power in a cost-minimizing optimization. For this purpose, we modified the *All, no P2G* case (both with constant/variable CHP) by allowing unlimited nuclear power (*All, no P2G, variable NUC*). The share of wind power would then be 10/12% of the total electricity production, whereas the share of nuclear would be 60% (+92/95% to the nuclear production in the reference case). In addition, the electricity export increased significantly (22% of the total electricity production was exported). The annual costs would decrease by 18/20% and the CO_2 emissions by 14/20% from the reference case (constant CHP/variable CHP).

The reference investment cost of nuclear power used in this analysis (€4000 € kW^{-1}) may be quite low for present conditions, for which reason we repeated the analysis above with a more recent baseline cost estimate of $6,755 kW^{-1} [52], which corresponds to ca €5700 kW^{-1} (Dec 21, 2017, $1 = €0.84), which increases the investment cost of nuclear power by 43%. Surprisingly, the results were almost identical with the previous case with the lower nuclear cost: the share of wind power would then be 10/16% of the total electricity production (constant CHP/variable CHP), whereas the share of nuclear would be 59/60%. 19% of the total electricity production was exported. This means that with the higher nuclear cost, the optimized energy system has a nearly identical power generation portfolio than with the lower nuclear cost, composing of a 60% nuclear share and a ca 12% wind share. A possible reason for this similarity could be in the very high share of the energy-intensive industries of the overall power demand in Finland. Industry represents about half of the annual electricity consumption, and in our reference case the baseload represented 36% of the peak demand. Therefore, base-power-type nuclear power would better match the more constant baseload part of the load than variable wind power, which would need to interact more intensively with the Nordic electricity market to balance the supply and demand mismatch. This could lead to a more volatile revenue profile depending on the Nordic electricity market conditions and could possibly lead to poorer overall economics for wind power at a high wind share than in case of nuclear power, though the cost of power production (e.g. LCOE) were lower. With the higher nuclear cost, the annual costs would decrease by 14/15% and the CO_2 emissions by 17/28% from the reference case (constant CHP/variable CHP), indicating that increasing the nuclear costs by 43%, the annual costs would increase on average only 6%.

In these special nuclear cases, the main technical limitation for wind power addition seemed to be the manual curtailment limitation, which limited the share of wasted wind power in annual wind power production to 5% (see Section 2.3). Adding more wind power on top of the high nuclear baseload would have been cost-effective, but the manual curtailment limit prevented curtailing more than 5% of the annual wind power production. The main reason behind the wind power curtailment was systemic congestion: there is too much electricity in the system. The high nuclear baseload leaves little room for additional electricity input from wind power, even after all the heat- and EV-based flexibility mechanisms (power-to-heat and V2G) are utilized. The outcome also indicates that wind power combined with congestion-alleviating P2G or electricity storage would still be more expensive than nuclear power, also with higher nuclear cost. Exploring the detailed effect of the manual curtailment limitation used here may also have some effect, but was outside the scope of this paper. However, this compromise between high shares of nuclear and wind power is also in line with previous literature [33]. Overall, these results indicate that with both nuclear costs used in this special analysis, wind power would not replace nuclear power, and adding nuclear power might be cost-effective, as the annual costs were lower than in any other case. However, this amount of additional nuclear power would require major energy system changes and legislative considerations. Furthermore, this analysis suggests that a political lock-in in nuclear power may limit wind power integration, as a high nuclear baseload may lead to systemic congestion when the amount of wind power increases, and the cost-effective heat-

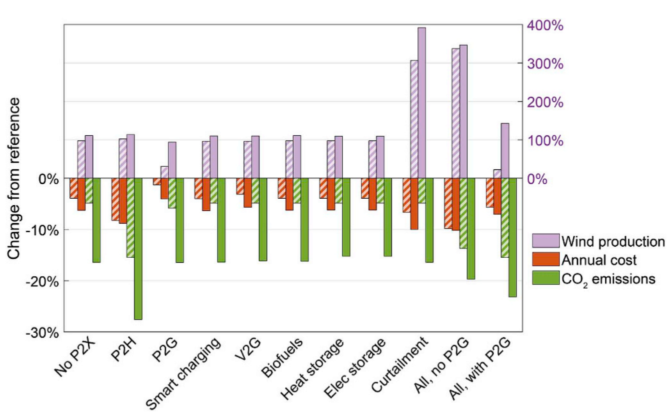

Fig. 8. Effect of the different flexibility measures as change from the reference case (Finland 2030). Power-to-heat (P2H) and curtailment are the most cost-effective options, though the cost differences are quite small, max. 10% from the reference case. The columns on the left (striped) refer to constant CHP, and on the right (solid) to variable CHP.

based flexibility mechanisms are not enough to compensate for this.

As the final note, we also tested how much wind power could be integrated to the energy system at maximum, without any cost optimization. With all the available technologies (similar to *All, with P2G*), wind power production could be increased up to 70% of electricity production, which would decrease the CO_2 emissions by 50–81% from the reference case, but this would result in 46–58% higher costs. The total electricity production in this case would be almost three times as high as in the reference case, but 45–57% of the total electricity production was directed to power-to-gas, meaning that the excess wind power was directed to P2G to ease the systemic congestion discussed in the nuclear case. Without P2G (similar to *All, no P2G*), the corresponding numbers would be up to 50% wind power, 18–35% higher costs, and 16–19% lower emissions. These results illustrate that allowing up to 35% higher costs compared to the reference case, the amount of wind power could be increased up to one half of all power production, compared to the 9% wind share in the reference case. To enable this high share of wind power, heat- and fuel-based flexibility measures were utilized to the maximum extent. Heat production from CHP and separate boilers was replaced with electric boilers, and excess electricity was directed to P2G both to ease the systemic congestion, and to replace fossil fuels with P2G-based synthetic gas. However, this result may be sensitive to the cost assumptions used in the analysis, but the technical limitations of wind power integration are insensitive to cost uncertainties.

Overall, adding wind power to the Finnish power system seems to decrease the annual costs and CO_2 emissions of the power system, also illustrated in Fig. 9. Overall system cost exhibits a clear downward trend with increasing wind power in the original scenarios. However, the wind-maximizing scenarios with wind shares of over 40% have significantly higher annual costs than the original scenarios. Based on this observation, it seems that wind power could be cost-effective up to a certain limit, but after this limit increasing wind power would increase the costs. The reason for this is that unusable excess wind power may be more expensive to integrate to the energy system, for example using P2G or electrical storage, than the cost benefit of fossil fuel replacement. Furthermore, large-scale wind power integration may imply major energy system changes, such as extension of infrastructures, the analysis of which were beyond the scope of this study.

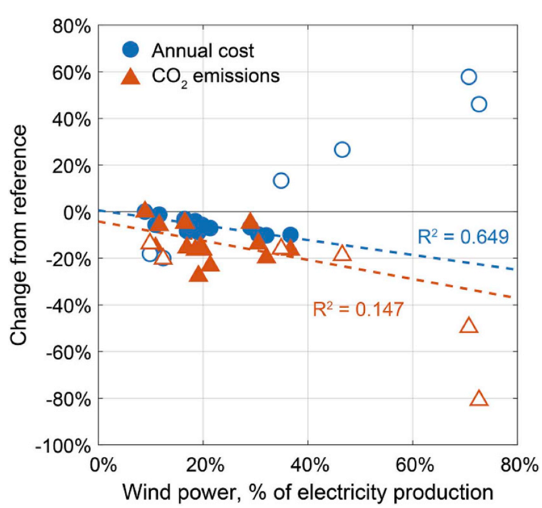

Fig. 9. Relative annual cost and CO_2 emissions against the share of wind power in all cases. The linear trend lines consider only the original scenarios (filled points), whereas the unfilled points represent the special scenarios with variable nuclear power (original nuclear cost) and wind maximization. Annual cost presents a clear downward trend with increasing wind power in the original scenarios.

4. Conclusions

The purpose of this paper was to assess the effects of different flexibility options for large-scale integration of wind power into the national energy system using Finland as a case. The main flexibility options considered were sector-coupling such as power-to-heat and power-to-gas, energy storage in the form of thermal and electric storage, electric vehicles, biomass-to-biofuel, and curtailment. As the reference case we used Finland's energy strategy for year 2030, which heavily relies on forestry (wood) biomass and nuclear power as low-carbon energy sources with less focus on wind or solar power. We investigated here to what extent flexibility could cost-effectively be used to integrate wind power in large scale.

The results show that wind production could be increased up to one third of the total electricity production, while decreasing annual system costs (up to 10%) and carbon emissions (up to 28%) at the same time. The amount of wind power was mainly limited by the cross-border transmission capacity and the high amount of nuclear baseload. From the different flexibility options, power-to-heat (P2H), wind curtailment, and the combination case *All, no P2G* produced the most cost-effective scenarios with the lowest CO_2 emissions. On the other hand, the other simulated flexibility options (P2G, EV smart charging, vehicle-to-grid, biomass-to-biofuel, and heat and electricity storages) appeared to be quite similar to the situation without additional flexibility measures. Furthermore, power-to-gas (P2G) was the most expensive option for wind power integration, and stationary electricity storage was not added in any of the cases also implying low cost-effectiveness.

We also found that combined heat and power (CHP) may limit cost-effective wind power integration, as separate heat production and heat pumps are preferred to CHP in the cost-minimizing simulations. The cases with less CHP had higher amounts of wind power (avg. 20%) as well as lower annual costs (avg. 2%) and lower emissions (avg. 11%) than the cases with a reference level of CHP. The replacement of CHP by heat pumps is in line with several previous studies [13,33]. Furthermore, we briefly analysed the co-optimized amounts of nuclear and wind power, and we found that adding nuclear and wind power together might be even more cost-effective than adding only wind power, but major nuclear power addition would require power system changes and legislative considerations. Nuclear lock-in may also limit wind power integration, as high nuclear baseload also led to systemic congestion due to excess electricity. The cost-effective heat-based flexibility mechanisms were not enough to ease this congestion, and wind power coupled with P2G and electricity storage was too expensive compared to nuclear power.

Overall, the results suggest that wind power integration with sector coupling could be done cost-effectively up to a certain limit, which was 37% of the electricity production in the Finnish case. The amount of wind power could technically be increased even to a higher level, up to 70% of the electricity production, but this would result in a 60% higher system cost than the reference due to the high costs of excess wind power integration via P2G or electrical storage. Importantly, the results indicate that viewing the energy system as a whole rather than each sector separately provides valuable insight and options for wind power integration. However, the results and conclusions may be sensitive to the cost assumptions used in this analysis, and our future studies will further explore the effect of cost and other uncertainties not included here.

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Appendix A

Input data for the cases

Table A.1
Fuel costs (excluding taxes) and carbon contents. The costs are based on [53] if not mentioned otherwise. The CO_2 emission factors are based on [41]. Fuels not listed are assumed to have zero cost and emissions. Emissions from biomass are written in brackets, but here they are considered carbon neutral in the optimization.

Fuel type	Cost (€/GJ)	CO_2 emission factor ($kgCO_2$/GJ)	Notes on costs
Oil	9.1	73.0	
Coal	2.3	93.3	
Natural gas	7.6	55.0	
Peat	3.8	105.9	
Nuclear	1.1	0	[54]
Industrial wood residue	0	(109.6)	Own assumption
Other wood	6.0	(109.6)	
Agro-biomass	3.0	(100.0)	Assumed half of the cost of energy wood
Waste	0	31.8	Own assumption
Biogas	7.6	(56.1)	Cost assumed same as natural gas

Table A.2
Costs of different technologies used in the study. The costs are based on [30,54–56], if not mentioned otherwise.

Technology	Invest. cost (€/kW)	Fixed O&M (€/kW)	Variable O&M (€/MWh)	Lifetime (years)	Notes
Hydropower	1500	8	0	50	
Wind power	1200	37	11.0	25	
Nuclear power	4000	40	0	50	
Solar PV	800	17	8.2	25	
CHP-DH	1300	25	2.7	30	
CHP-industrial	1300	25	2.7	30	
Condensing power	1300	52	0	35	
Heat-only boiler	150	9	1.5	35	
Residential boiler	200	2	0	20	
Electric boiler	40	1	0	40	
Heat pumps	900	2	0	40	
P2G	800	32	–	30	[36]
G2L	300	12	–	20	[36]
Biofuel conversion (unit €/PJ_{out})	17.5	1.9	–	20	[57]
	Invest. cost (€/MWh)	**Fixed O&M (% of invest.)**		**Lifetime (years)**	
Heat storage	900	1%		25	
Electricity storage	100 000	3%		15	
V2G	Cost of vehicle-to-grid calculated from the number of extra cycles to car batteries due to V2G activity, based on 1000 cycles during normal lifetime.				

Table A.3
Conversion efficiencies of advanced conversion (P2X). The efficiencies are based on own assumptions if not mentioned otherwise. The conversion efficiencies of conventional technologies, such as CHP, are assumed to be the same as in 2013 [43].

Technology	Conversion efficiency		Notes
P2H – Electric boiler	0.95		
P2H – Heat pump	3		
P2G	0.55		[58]
Gas-to-liquid (G2L)	0.8		[36]
Biofuel conversion	0.8		
	Charging efficiency	**Constant loss**	
Heat storage	1	0.06%/hour	[59]
Electricity storage	0.9	3%/month	[60]

Appendix B. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.esr.2019.100368.

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