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RESEARCH ARTICLE

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A comparison of variation management strategies for wind power integration in different electricity system contexts

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Abstract

Variation management strategies improve the capability of the electricity system to meet variations both in the electricity demand and in the generation that relies on variable energy sources. In this work, we introduce a new, functionality-based, categorization of variation management strategies: shifting (eg, batteries), absorbing (eg, power-to-gas), and complementing (dispatchable generation, including reservoir hydropower) strategies. A dispatch model with European coverage (EU-27 plus Norway and Switzerland) is applied to compare the benefits of shifting and absorbing strategies on wind integration in regions with different amounts of complementing strategies in place. The benefits are measured in terms of the wind value factor, wind owner revenue, and average short-term generation cost.

The results of the modeling show that the reduction in average short-term generation cost and the increase in revenue earned by the wind owner from shifting strategies, such as the use of batteries, are more substantial at low wind shares than at high wind shares. The opposite situation is found for absorbing strategies, such as power-to-gas, which are found to be more efficient at reducing the average generation cost and increasing profit for the wind owner as the wind share increases. In regions that have access to complementing strategies in the form of reservoir hydropower, variation management has a weak ability to reduce the average short-term generation cost, although it can increase significantly the revenue accrued by the wind power owner.

KEYWORDS

electricity system, flexibility measures, variation management, wind power

1 | INTRODUCTION

Renewable energy has the potential to increase the security of supply and to meet carbon emissions reduction targets. Most investments made in renewable energy are in the form of wind and solar electricity generation. As wind and solar energy provide variable renewable electricity (vRE), a high penetration rate of such generation will greatly affect the electricity system and markets. Solar power is often implemented in combination with the usage of batteries, which have a cost structure that is appropriate to the regular diurnal variations of solar generation. As batteries also share the modular properties of solar power, they are particularly suitable for households and island systems. Here, the focus is on wind power and the possibilities to maintain a high value for wind power, from the wind owner and system cost perspectives. Electricity systems with high vRE share are subject to variability and uncertainty on second to interannual timescales. The focus of this work is to analyse measures that can tackle the variability on timescales of hours up to 1 year (ie, seasonal). We here define such measures as variation management strategies. To what extent the technologies applied in the different strategies can provide frequency control and maintain reactive power is not investigated in this work.

The discourse on variation management is typically dominated by energy storage with an emphasis on batteries. A literature search on articles dealing with wind power and the different variation management strategies considered in this work (Figure 1) shows that the use of batteries for wind variation management also dominates the research field.

Furthermore, Figure 1 reflects the many research papers published to date in the field of wind variation management. However, most of the papers that deal with modeling the system impact of variation management have limited themselves to investigating one variation management strategy. Only a few papers have compared the impacts of a broader range of variation management strategies and their implications for the overall electricity system. Kiviluoma et al[1] have investigated investments in energy systems in a context in which flexibility through interactions with the transportation and heat sectors are available via battery electric vehicles and electric boilers, respectively. They have shown that the establishment of connections with the heat sector may offer cost-efficient flexibility. Salpakari et al[2] have investigated the potential flexibility provided by power-to-heat and demand-side management through the shifting of electric heat loads for the Helsinki energy system and have reported that these measures absorb a large share of the surplus electricity, thereby reducing the need for other types of heat generation. Østergaard[3] has compared the impacts of electricity storage (batteries), biogas storage, and district-heating storage systems on a 100% renewable energy system for the city of Aalborg (Denmark) and discovered that batteries are the most favorable option for increasing the ability of the system to accommodate wind power, although batteries are much more expensive than the two other options. Mathiesen et al[4] have compared the impacts of 7 different strategies for managing variations applied to the Danish energy system, including electrification of the heat and transportation sectors through the use of electric boilers, battery electric vehicles, and hydrogen fuel cell vehicles. They have stated that large-scale electric boilers are particularly promising due to their ability to absorb "excess" electricity. Kiviluoma et al[5] investigate a range of what they denote flexibility options (which is a broader term than variation management strategies and address uncertainty as well as variability) in a north European context and further strengthen the conclusion that application of power-to-heat can enhance the value of wind power and add that similar benefits can be achieved through transmission capacity expansion.

The above-described studies, which apply models to evaluate various variation management strategies, have provided important insights into the effects of the different strategies on the investigated systems. The work presented in this paper adds to the previous results by investigating various variation management strategies in many different system contexts, including regions with access to hydropower and regions with weak ability to trade.

Some research papers have reviewed technologies that could provide variation management. Ould Amrouche et al[6] have compared a number of energy storage technologies, including batteries, hydrogen storage, and thermal energy storage, with respect to properties such as timescale and efficiency. They conclude that more research in the energy storage field is needed to reduce the cost of storage, so as to achieve greater integration of renewable electricity generation. Lund et al[7] have provided a comprehensive overview of strategies to manage variations, illustrating the broad range of technologies and concepts that could enhance the flexibility of electricity systems. Their work covers demand-side management, ancillary services, energy storage, supply-side flexibility, infrastructure, advanced technologies, and electricity markets, all of which can contribute to increasing the flexibility of the electricity system. They emphasize the capability of the present system to provide flexibility simply by stimulating a more holistic view of energy systems planning and operation, for example, by considering the power and heat sectors together rather than separately. A review article by Tuohy et al[8] concludes, based on a number of research papers on energy storage and demand response, that the value of variation management strategies depends on a number of factors, including the penetration level of wind, the capacity of the transmission system, and the flexibility of power plants other than wind power plants.

Some review papers have categorized strategies to manage variations. Lund et al[7] have compared different storage technologies in terms of power and discharge time. Similar comparisons have been made by Ehnberg et al[9] and Nourai.[10] Hedegaard et al[11] have analyzed the wind power data series for western Denmark to identify the need for variation management and followed this with a review of strategies to manage variations categorized according to their timescale properties (ie, whether the strategies are suited to meet intrahourly, intraday, or seasonal variations). In the

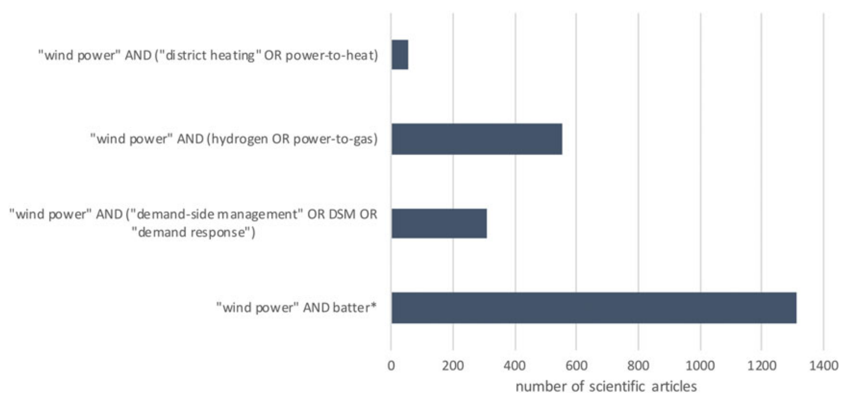

FIGURE 1 Scientific articles matching the given search phrases (in title, abstract, or keywords), as listed in Scopus as of January 2017. For the last bar, the asterisk indicates that any possible ending to the term was accepted, ie, included both "battery" and "batteries" terms [Colour figure can be viewed at wileyonlinelibrary.com]

present work, we instead propose a categorization of variation management strategies that reflects the ways in which these strategies can contribute to modulating varying generation to meet a varying demand.

2 | CATEGORIZATION OF VARIATION MANAGEMENT STRATEGIES

The main ways in which the ability of varying electricity generation to meet a varying electricity demand can be improved are as follows: (1) to store excess or low-cost electricity from varying and inflexible generation for later use and to *shift* the demand for electricity in time to fit more closely the production profile; (2) to *absorb* excess generation and convert it to another energy carrier, such as a fuel; and (3) to *complement* variable generation by generation that can be dispatched in time, ie, load-following generation, including reservoir hydropower. With this in mind, we propose the following variation management strategies:

- Shifting: to shape the net load curve by shifting electricity in time,
- Absorbing: to use another sector to absorb the excess electricity, and
- Complementing: to use complementary generation to produce additional electricity when required.

Table 1 presents the 3 categories of variation management strategies, together with their general impacts on the electricity system, and gives examples of technologies that can be used to implement the strategies.

3 | METHOD AND MODEL

The effects of shifting strategies using batteries and of load shifting and absorbing strategies using power-to-heat and power-to-gas are evaluated in terms of the wind value factor, wind owner revenue, and short-term generation costs. Variation management is added exogenously to the system, and the impacts of the strategies are investigated in 152 different regional electricity systems, including regions with or without access to complementing strategies in the form of reservoir hydropower. A dispatch model with 3-hour time resolution is applied to evaluate the impacts of the variation management strategies on the electricity system over a 1-year period.

3.1 | System contexts

The 152 different system contexts are represented by 38 distinct regions of Europe (EU-27 countries plus Norway and Switzerland) at 4 different points in time, years 2032, 2037, 2042, and 2047, with the electricity mix obtained from the ELIN investment model.[12] ELIN is a linear model that minimizes the costs associated with transmission capacity investments, power plant investment, and operation so as to meet the demand for electricity in Europe, every year from now until year 2050. Each year is represented by 16 time slices. ELIN relies on a detailed description of the existing power plant capacity, including age structure, which is taken from the Chalmers power plant database,[13] which is continuously updated (year 2016 version used here). The technology options and their associated costs applied in ELIN are included in Appendix A.1. The Regional Policy scenario[14] is applied to define the overall system boundary. The Regional Policy scenario includes a cap on CO_2 emissions, national targets on renewables, and a leveling out of the total European electricity demand due to the application of efficiency measures. The developement of the European electricity system as given by ELIN is illustrated in Appendix A.2.

In the ELIN model, Europe is subdivided into 50 regions (see Appendix A.3 for the location of the regions and the notation used for these) based on the potential risk for congestion. Between regions, trade is subject to constraints on transmission capacity, taking its departure from the existing transmission capacity with possibilities for the model to invest in new transmission capacity, if required, to lower system costs. For the case investigated here and for the 4 different years taken from the ELIN model results, there are several regions between which there is little or no congestion. These regions are aggregated in the analysis, resulting in 38 regions, which can be subdivided into the following categories:

1. Regions with access to reservoir hydropower;
2. Isolated regions; and
3. Regions "typical" for continental Europe.

TABLE 1 The 3 variation management strategies proposed in this work

Shifting	Absorbing	Complementing
Electricity ⇒ Electricity • Reduce curtailment and peak power • More even cost on diurnal basis	Electricity ⇒ Fuel • Reduce curtailment • Fewer low cost events	Fuel ⇒ Electricity • Reduce peak power • More even costs on yearly basis
Batteries[a]	Power-to-heat[a]	Flexible thermal generation
Load shifting[a]	Electrofuels	Hydropower[a]
Pumped hydro	Power-to-gas (hydrogen[a])	

[a]The technologies used in the analysis.

Regions that have access to reservoir hydropower have a hydropower capacity within the region that corresponds to at least 35% of the peak load. Examples of such regions are found in Sweden, Norway, and the Alps. Isolated regions are defined as having a total transmission capacity to neighboring regions of ≤10% of the peak load, including investments in transmission capacity from the investment model (investments in transmission by year 2042 are used to evaluate this criterion). Examples of such regions are, using the notation in this work, UK1 (England and Wales) and IEUK3 (the Republic of Ireland and Northern Ireland). Regions that are typical for continental Europe do not fall into the hydropower category or the isolated category. The 38 regions considered and the regional category to which they belong are given in Appendix A.4.

3.2 | The EPOD dispatch model

For each of the 4 years given above, the EPOD dispatch model takes the power plant and transmission capacities provided by ELIN and minimizes the cost to operate these plants so as meet the demand for electricity. The EPOD dispatch model is a linear optimization model that is applied in the present study with a 3-hour time resolution. The model includes the minimum load level, start-up time, and start-up and part-load costs for thermal generation, as first suggested by Weber[15] and later evaluated in a study conducted by Göransson[16] (in which this approach is referred to as "the two-variable approach").

While the EPOD model has the same regional resolution as the ELIN model, in EPOD trade between regions must comply not only with capacity constraints but also with flow constraints implemented applying the dc load flow approach described, for example, by Wood et al[17] within synchronous systems (ie, the Nordic system, the UK, and continental Europe).

Hydropower in continental Europe is subdivided into run-of-river and reservoir hydropower. Run-of-river hydropower generates electricity according to an inflow profile, whereas reservoir hydropower can be freely allocated as long as it complies with annual energy and capacity constraints. Nordic hydropower is subject to reservoir constraints, across which the inflow and production are balanced.[16] Hydropower in Sweden, which is mainly located in long cascading systems, is in addition subject to ramp limitations that reflect the time it takes for the water to move along a river.

$$gen_{hydro,t+1,reg} - gen_{hydro,t,reg} \leq M_{reg}^{up} + K_{reg}^{up} gen_{hydro,t,reg}$$

$$gen_{hydro,t,reg} - gen_{hydro,t+1,reg} \leq M_{reg}^{low} + K_{reg}^{low} gen_{hydro,t,reg}$$

where $gen_{hydro,\ t,\ reg}$ is the electricity generation in hydropower plants in time-step t and region reg, and K and M are defined based on Swedish hydropower production statistics.[18]

3.3 | Evaluation of variation management strategies

The benefit of variation management is evaluated by adding variation management to the regions in EPOD and comparing the results to the case without variation management (with respect to the selected measures presented in the next paragraph). The capacities of the variation management technologies added to each region, as well as the annualized investment cost of implementing these, are given in Appendix A.5. However, the levels of cost-effectiveness of the different strategies are not directly comparable since (1) the investment costs of the different technologies to achieve the different strategies are not included and (2) these costs differ depending on the strategy. Instead, the variation management strategies as implemented here represent a large-scale implementation in which, for example, all households and apartments have batteries in place or all steel plants in Europe use hydrogen as the reducing agent. This is in line with the assumption that variation management is just one of many drivers for these investments and that willingness to pay will vary substantially depending on the sector (eg, steel industry vs residential home).

Load shifting, which is implemented according to the method suggested by Göransson et al[19] and complemented by Zerrahn et al,[20] implies that a certain share of the electricity demand, here assumed to be 20%, can be delayed for a period up to an upper limit, here set at 12 hours. The implementation includes an energy balance equation of delayed demand and a time-dependent upper limit of the aggregated delayed demand. The time constraint of 12 hours relates to the obvious nature of most household loads, which can be scheduled anytime during the night or the workday but not over longer intervals and should be seen as an upper limit for illustration purposes only. In practice, the delay time will vary depending on the type of household load (eg, heat load and appliances).

Batteries are assumed to have storage volumes that correspond to 20% of the load during 12 hours of an average day. The battery capacities per region are listed in Appendix A.5. This obviously implies a highly optimistic scenario for battery usage in which the energy storage capacity is the same as that for load shifting but in which the energy can be stored indefinitely in time in the case of batteries. In addition, it is assumed that batteries have a C-factor (the discharge capacity relative storage capacity) of 1, which means that batteries have a greater ability to provide capacity than load shifting (as implemented here).

Absorbing strategies convert power to some other energy carrier, such as heat or fuel. Among the absorbing strategies, it is important to distinguish between opportunistic loads for heat and fuel generation, which consume electricity if the price is competitive compared to other options to serve the demand for heat or fuel, and annually fixed loads for which the consumption of electricity is not optional. Since heat and fuels are cheaper to store than electricity, all absorbing strategies can uncouple the demand for heat and fuel from the demand for electricity. However, if the consumption of electricity to produce the end product is not optional and if the fuel storage is small (ie, corresponding to a relatively small amount of energy), the strategy becomes shifting rather than absorbing.

Power-to-gas is exemplified by the usage of hydrogen in the steel industry, ie, using hydrogen to reduce the iron ore rather than coal or coke (although this will require significant work to develop new iron-ore reduction technologies). Carbon-free hydrogen can be produced from electricity derived from renewables using electrolysis. If one assumes a future in which there is a transition to hydrogen, the demand for hydrogen from the steel industry should be fairly inelastic in the short-term perspective (ie, from 1 wk to another). This work assumes a complete shift from coal to hydrogen as the reducing agent in all of the 21 integrated steel plants in Europe (ie, in plants that use iron ore as the raw material in their production), where plant capacities and locations are based on the data of Rootzén et al.[21,22] This requires around 4 GWh of electricity per ktonne of produced steel (it is assumed that hydrogen consumption is evenly distributed over the year). Table 2 lists the levels of demand for electricity for hydrogen production in the 17 European regions within which the 21 integrated steel plants are located. A case with hydrogen demand but without hydrogen storage (ie, where the demand for electricity for the electrolysis process has to be met instantaneously) is compared to a case in which there is hydrogen storage corresponding to 7 days of hydrogen consumption, with the hydrogen production capacity being twice the hourly hydrogen demand. For the cases with hydrogen production, demand for electricity is rescaled so that the total annual electricity demand, including electricity for hydrogen production, remains the same as in the cases without hydrogen production.

Power-to-heat is investigated by simulating electric boilers in distric heatig systems in regions with district heating systems in place. Such boilers can represent an opportunistic load if they are installed in addition to other heat generation units in district heating systems. Thus, as implemented here, heat will only be generated in electric boilers if the value of the heat is greater than the cost of the electricity produced. If heat is to be generated from electricity, heat pumps are a better choice than electric boilers from a resource perspective. However, opportunistic heat generation, requiring investments in addition to the heating system in place, is more likely to be performed by electric boilers with lower investment cost than heat pumps. In line with the assumption of a large-scale implementation of electric boilers, the willingness to pay for heat from electric boilers is assumed to be the same as the willingness to pay for heat from CHP plants, ie, the share of the fuel and Operation and Maintenance (O&M) costs from CHP plants that can be allocated to the heat sector, in the EPOD model. Thus, the willingness to pay depends on the relationship between the total efficiency and electrical efficiency of the CHP plants in the region, as well as the outdoor temperature and desired indoor temperature. Figure 2 shows the willingness to pay for heat in the European regions. It is assumed that the capacity of electric boilers in the system is 20% of the annual peak electricity load, based on an assumption of 3-GW electric boilers in south Sweden, whereby these would make up 20% of the installed heat generation capacity in district heating systems.

4 | MEASURES

Three measures are selected to evaluate the wind owner and system benefit of variation management strategies in the different regions. Thus, the following parameters are calculated from the EPOD modeling results:

- The *average wind owner revenue* (EUR/MWh), which is here calculated as the annual production-weighted marginal cost of electricity for wind power divided by the annual wind power production. Thus, the revenue considered here is pure market revenue without subsides.

TABLE 2 Hourly electricity demand for hydrogen production to serve the steel industry

Region	Electricity Demand for H_2, MWh/h
BE	1826
CZ	2511
DE3	14201
DE4	1005
DE5	1973
ES1	1507
FI	1370
FR1	2146
FR4	1598
FR5	2831
HU	594
IT3	4201
NL	3196
PO2	2283
SE2	868
SE4	1370
SK	2055
UK1	4064

Region specifications are given in Appendix A.3.

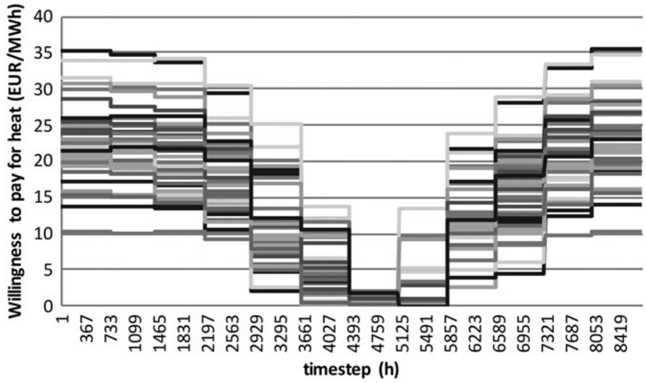

FIGURE 2 Levels of willingness to pay for heat in the European regions over the year, corresponding to the alternative cost of supplying this heat from CHP plants in the regions, as obtained from EPOD. The profiles are segmented into months, as monthly temperature data are used as the input to the EPOD model

- The *wind value factor*, which is the average wind owner revenue (as defined above) relative to the average annual marginal cost of electricity. This measure was first suggested by Stephenson[23] and applied as in this work by Fripp et al[24] and Hirth.[25] The wind value factor is given by

$$\textit{value factor}_{wind} = \frac{\sum_t 1}{\sum_t 1 \cdot mc_t} \cdot \frac{\sum_t mc_t gen_{wind,t}}{\sum_t gen_{wind,t}},$$

where $gen_{wind,\ t}$ is the wind power generated at time t and mc_t is the marginal cost of electricity at time t.

- The *average short-term generation cost* (EUR/MWh), which is calculated as the sum of the annual fuel costs, operational and maintenance costs, and cycling costs divided by the annual level of electricity generation for each region.

In Section 5, these measures are provided relative to the wind share of the annual electricity demand, ie, the annual wind power generation before curtailment divided by the annual electricity demand. Since electricity can be curtailed and traded between regions, regions with good conditions for wind power generation may have an annual wind share exceeding 1.

4.1 | Data

Investment costs for new generation capacity in the ELIN model are taken from the World Energy Outlook.[26] For wind and solar power, we apply a gradually reducing investment cost based on the costs stated in the World Energy Outlook for years 2020, 2030, and 2040. The wind speed data applied in both the ELIN and EPOD models for onshore wind power are reanalysis data from ERA Interim,[27] which provide a high geographical resolution in combination with the MERRA reanalysis data,[28] which give a 1-hour time resolution (every third hour is modeled in this work). Onshore wind power production is calculated by applying the ERA Interim wind speed data to a wind farm power curve derived from the work of Johansson et al,[29] corresponding to a wind turbine design with a specific power of 200 W/m^2. In the ELIN model, there are 12 wind power investment classes per region for onshore wind power, with different profiles representing different wind conditions, whereby each class has an upper limit as the amount of wind power capacity that it can accommodate. The capacity density for onshore wind power is assumed to be 390 kW/km^2, which is lower than the capacity density of a single farm (typically around 2000 kW/km^2) but in the same range as the capacity densities over larger regions currently achieved in northern Germany and in Denmark (capacity densities in Schleswig-Holstein, Brandenburg, Niedersachsen, and Jutland are in the range of 100-200 kW/km^2).

In addition to onshore wind power, the models consider offshore wind power and 4 different types of photovoltaic (PV) generation. For these technologies, there is one investment class per NUTS2 area[30] with conditions for power generation corresponding to the average for those sites enclosed by the NUTS2 area in the ERA Interim dataset.[27] The power curves for offshore wind and solar PV generation are based on the data of McLean[31] and Huld et al,[32] respectively.

The annual electricity demand data are based on the Energy Roadmap scenario "High Energy Efficiency."[33] These data are allocated to regions within a country based on regional share of the national GDP, whereby each region is made up of a number of NUTS2 areas for which GDP data are collected from Eurostat.[34] All the regions are assumed to have the same electricity demand profile, and the national demand profiles used in the EPOD modeling are retrieved from ENTSO-E.[35]

The cycling costs and operational and maintenance costs of thermal generation are based on the report of Jordan et al,[36] which lists these costs for gas and coal power plants. Biomass-fired plants and units with CCS are assumed to have the cycling properties of coal power plants. Oil is assumed to be used as the start-up fuel for all the solid fuel-fired plants. Nuclear power plants are assumed to have a start-up time of 24 hours and a minimum load level of 75% based on Persson et al.[37] Nuclear power plants may indeed be cycled down to 50% load level, but such cycles can only be undertaken a limited number of times during the lifetime of the plant, and therefore, frequent ramping down to these levels would imply drastic reductions in lifetime of the plant.[38] The start-up costs for nuclear power are assumed to correspond to the cost of operating at minimum load level during the start-up period.

5 | RESULTS

5.1 | The wind value factor

Figure 3 gives the wind value factors for the different system contexts (Figure 3A) and shows how these factors are increased through the use of load shifting (Figure 3B), hydrogen storage (Figure 3C), and electric boilers (Figure 3D). In the case of shifting strategies, we report results for both load shifting and the battery case, although only load shifting is included in the plots as both these shifting strategies give similar results. In panels C and D, only regions with integrated steel plants and combined heat and power plants, respectively, are represented.

The relationship between the wind share and the wind value factor was first investigated by Fripp et al[24] and Hirth.[25] They found that the wind value factor decreases with increased wind share, which is in agreement with the results from this work, as shown in Figure 3A. As can be seen from Figure 3A, the value factor decreases with increased wind share in all the regions, although the range of value factors expands with increased wind share, with the value depending on region. Thus, in addition to the work by Fripp et al and Hirth, this work shows the difference in span due to the differences in system contexts, whereby regions with access to hydropower are typically positioned at the upper end of the range (squares in Figure 3A). This positioning is particularly evident at wind shares around 0.1 to 0.4. At higher wind shares, the wind value factors for regions with access to hydropower are similar to those for regions typical for continental Europe. This is the case because the value factors at high penetration levels are to a large extent reflecting wind power generation during zero-price hours, which is not influenced by hydropower. While limited possibilities for trade have a weak impact on the wind value factor initially (triangles in Figure 3A), at high wind penetration levels, isolated regions have

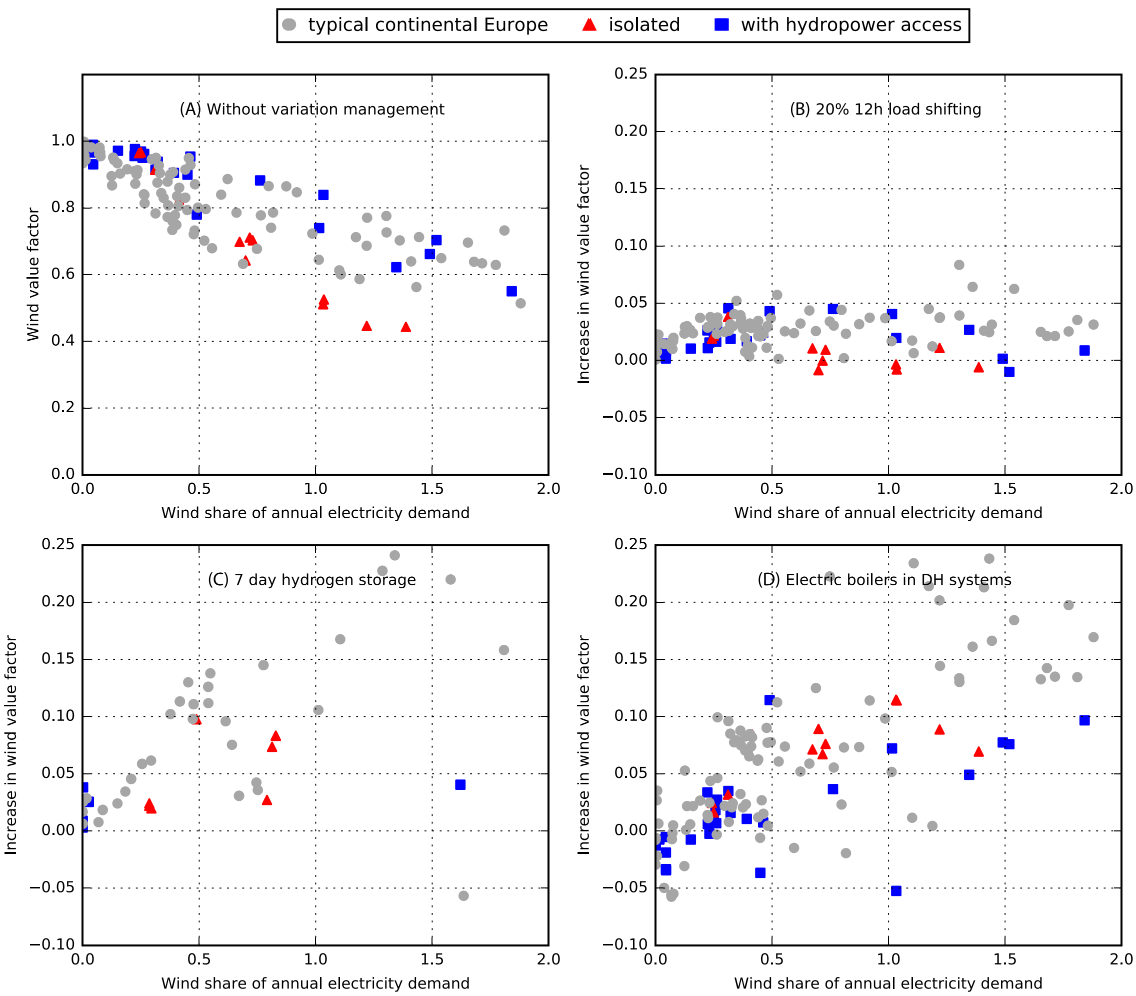

FIGURE 3 A, Wind value factors for the 152 different system contexts and the increase of the wind value factor applying B, load shifting; C, hydrogen storage; and D, electric boilers. In panels C and D, only regions with integrated steel plants and combined heat and power plants, respectively, are represented [Colour figure can be viewed at wileyonlinelibrary.com]

substantially lower wind value factors than regions typical for continental Europe (circles in Figure 3A); this is due to an inability to access flexibility in other regions and to accrue benefits from geographical smoothening phenomena.

Figure 3B shows how the wind value factor increases as load shifting is introduced to the regions. The wind value factor increases in the range of 0 to 0.05, and the increase is at least as high for low-to-medium wind shares as for high wind shares. The exceptions to this, showing a 0.08 increase in wind value factor for a wind share of 1.35, is northern Poland. This is because load shifting is able to reduce load-related congestion in the regions neighboring Poland that have relatively low wind shares, such that load shifting facilitates wind power exports from northern Poland to neighboring regions. This is in agreement with the previous work of Göransson et al,[39] who showed that load shifting could reduce load-related congestion. Isolated regions experience a less-pronounced increase in wind value factor from load shifting than regions that are typical for continental Europe, since trade flows are capacity limited even if load-related congestion is reduced.

Figure 3C shows the increases in wind value factor from power-to-hydrogen for 7 days of hydrogen storage with the demand corresponding to that of the 21 European integrated steel plants. It is evident that this absorbing strategy yields a steep increase in wind value factor with an increase in wind share, and already a wind share of 0.5 yields an increase that exceeds that obtained through load shifting. At low-to-medium wind shares, the increase in value factor is in the range of 0.02 to 0.14, whereas an increase of above 0.2 is attained in some regions at high wind share. There are no clear differences in the magnitude of the increase in wind value factor between the 3 types of regions. This is as expected, since with 7-day storage, the surplus electricity can almost always be used for hydrogen production.

Figure 3D shows how the wind value factor increases as electric boilers are introduced to the district heating systems in the regions. The total European heat generation by electric boilers in model year 2042 is 90 TWh, or 20% of the current 430 TWh of heat demand served by district heating in Europe.[39] As in the case of hydrogen storage, electric boilers cause a greater increase in wind value factor at high wind shares. The increase in value factor is also in the same range as for the hydrogen storage case for medium-to-high wind shares. At low wind shares, electric boilers may result in a reduced wind value factor, as the demand for heat can motivate more baseload operation. For a few regions, there is a reduction in wind value factor at high wind shares both in the hydrogen storage case and the electric boiler case. This is due to that the regions trade with each other and the introduction of variation management strategies may reduce congestion and change trade patterns. Thus, for some regions, in the case of the electric boilers and hydrogen storage, there is an increased import of low cost generation, which results in reduced wind value factor in the importing regions, while the wind value factor in the exporting regions is increased.

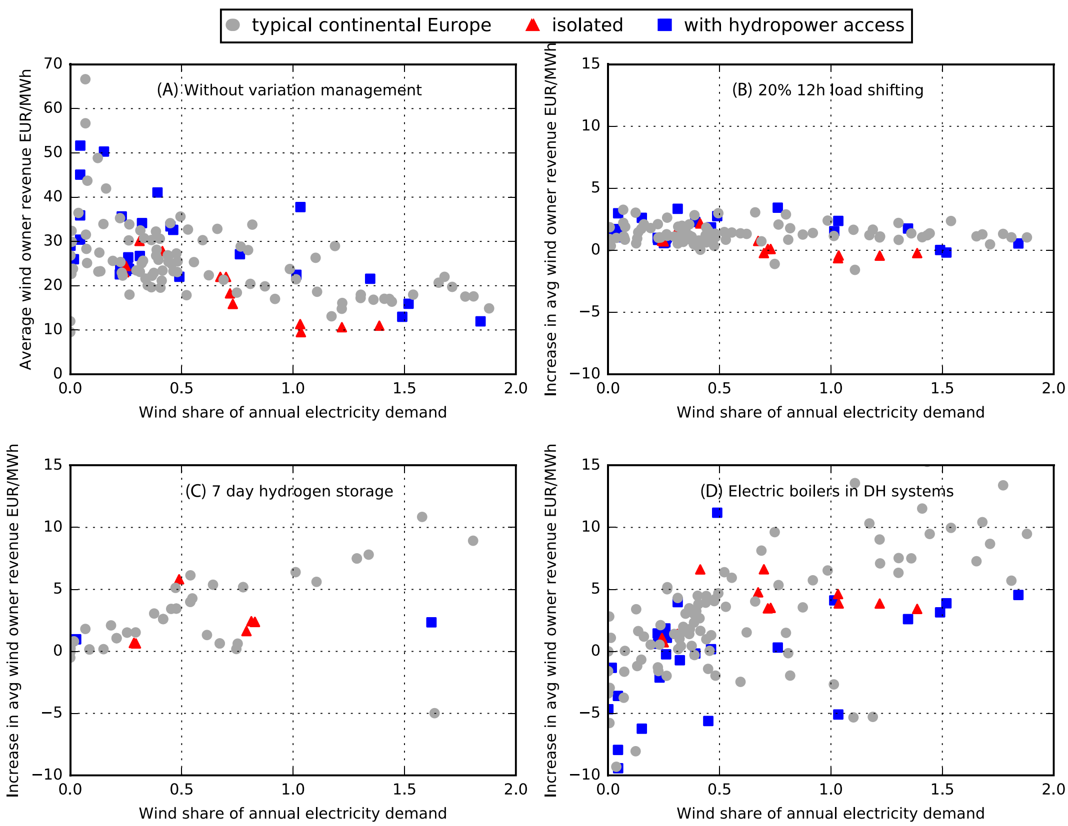

FIGURE 4 A, Average wind owner revenues in different system contexts and the increases in these revenues brought about by B, load shifting; C, hydrogen storage; and D, electric boilers. In panels C and D, only regions with integrated steel plants and combined heat and power plants, respectively, are represented [Colour figure can be viewed at wileyonlinelibrary.com]

5.2 | The average wind owner revenue

Figure 4 presents the wind owner revenues (Figure 4A) and the increases in revenue obtained for the three different variation management strategies investigated (Figure 4B-D) for the different wind shares. Since the wind owner revenue is the annual production-weighted marginal cost of electricity divided by the annual production, it is of relevance to examine also the pattern of the average annual marginal cost of electricity (Figure 5). It is clear that the marginal cost is only slightly reduced with wind share, whereas the average wind owner revenue (Figure 5A) is drastically reduced with wind share. Thus, as the marginal cost during high-wind events is reduced (resulting in reduced wind owner revenue), the marginal costs during other hours increase as the baseload with low running costs is replaced by thermal units with higher running costs. There are two reasons for this: (1) Cycling properties prevent baseload from generating to the same extent when net load variations increase, and (2) high wind shares are more common for years that lie further in the future (ie, years 2042 and 2047) when some baseload has been retired but no investment has been made in new baseload. An increase in the difference in marginal costs between low-cost and high-cost events would be expected to lead to increased benefits from load shifting. However, the trend apparent in Figure 4B indicates the opposite. The increase in wind owner revenue from the addition of batteries is close to identical to the load shifting case in Figure 4B (and therefore not shown in the graph). Thus, despite a greater capacity of batteries to charge and discharge compared to load shifting, the wind owner revenue is reduced as the wind share increases. This is because, as the wind share increases, the wind power variations, rather than the load variations, determine the duration of low–net load events. High-wind (low-cost) periods are of longer duration than low-load periods, and the limited energy levels that can be shifted in time with the batteries and load shifting strategies investigated make these shifting strategies less efficient as a means to increase the value of electricity during low–net load events, which typically coincide with high wind production at medium-to-high wind shares. In general, the impacts of variation management on wind owner revenue (Figure 4B-D) show strong similarities to the trends in wind value factor.

5.3 | Average short-term generation costs

Figure 6 presents the average short-term generation costs (Figure 6A) together with the reductions in this cost obtained through the 3 variation management strategies investigated (Figure 6B-D). Since wind power entails low running costs, the average generation costs are reduced as the wind share increases (Figure 6A). As expected, regions with hydropower have lower average generation costs than other regions with the same wind share.

Figure 6B reveals the reductions in average generation costs from load shifting up to 12 hours for all regions and for the 4 years investigated. Load shifting reduces the average generation costs by up to 3 EUR/MWh, as achieved in Hungary in year 2047 with a 0.16 wind power share of annual demand, and this is attributed to increased imports from northern Poland as load-related congestion is reduced. It is clear that the reductions achieved through load shifting are reduced with increased wind share. If batteries, instead of load shifting, are applied as the shifting strategy, the reductions in average short-term generation costs (not shown in Figure 6) are very similar to those in Figure 6B.

Figure 6C shows that the reductions in average generation cost for the European regions that produce hydrogen from electricity are most substantial at medium-to-high wind shares, similar to the above-presented results for wind owner revenue. At high hydrogen-load shares, a large share of the load is flexible in time and a good match to wind generation can be achieved even at high wind shares. In similarity to load shifting (ie, shifting strategies), there is weak reduction in the average generation costs for regions that have access to hydropower. For some regions, there is a

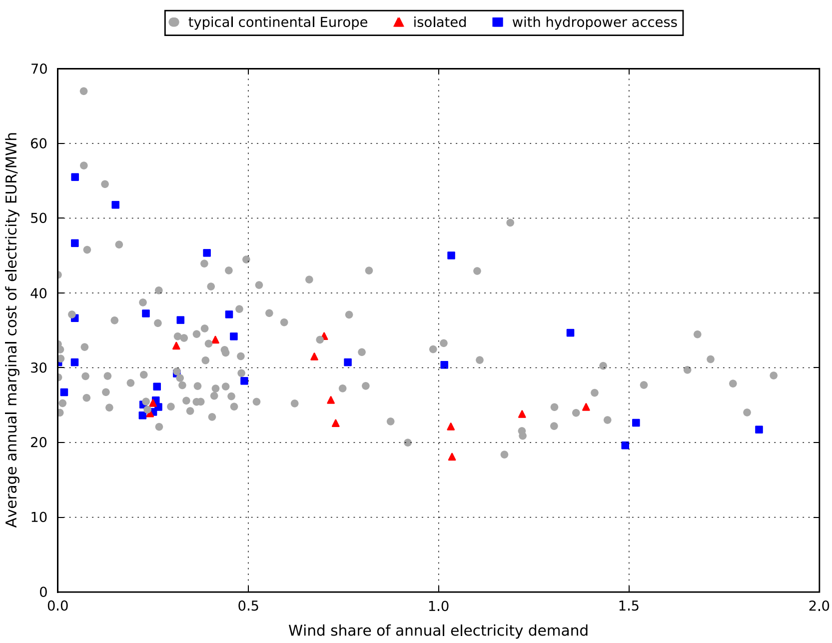

FIGURE 5 Annual average marginal costs of electricity in the 152 different system contexts, as obtained from the modeling [Colour figure can be viewed at wileyonlinelibrary.com]

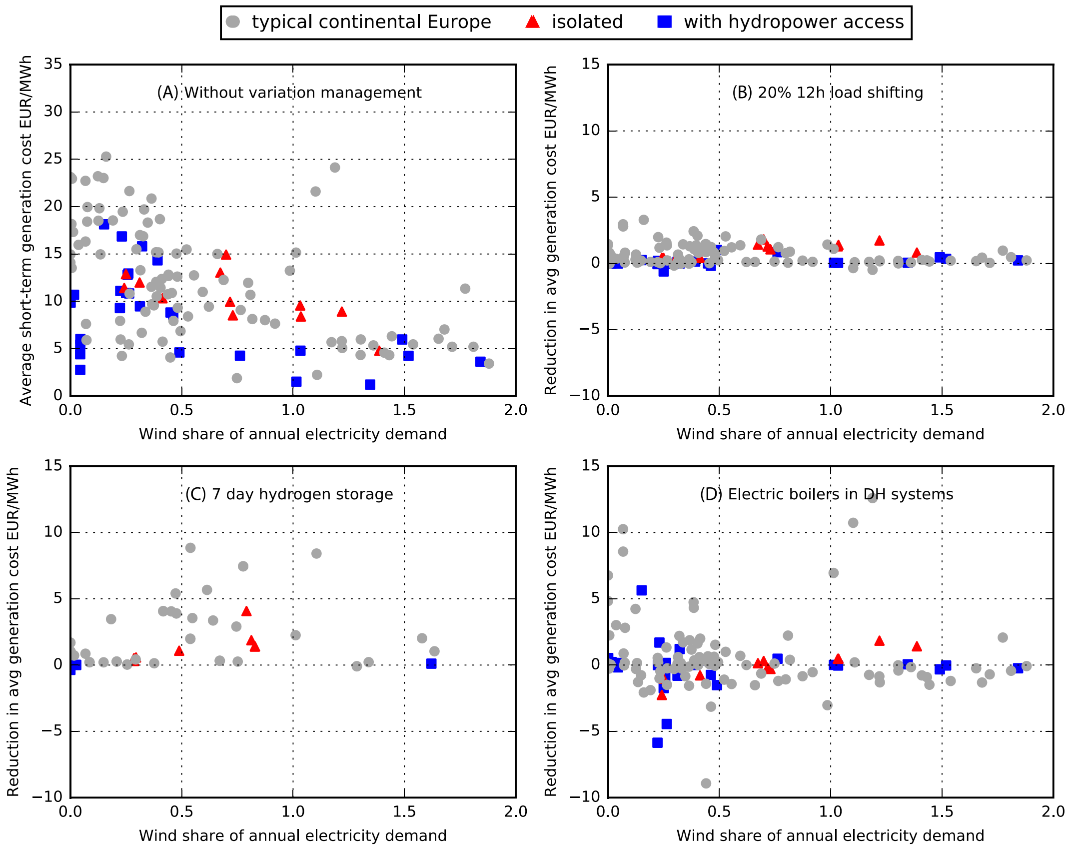

FIGURE 6 A, Average short-term generation costs in different system contexts and the reductions in these same costs caused by B, load shifting; C, hydrogen storage; and D, electric boilers. In panels C and D, only regions with integrated steel plants and combined heat and power plants, respectively, are represented [Colour figure can be viewed at wileyonlinelibrary.com]

negative reduction, ie, an increase in the average short-term generation costs as load shifting or hydrogen storage is introduced in the region. These regions have low generation costs relative to the other European regions, and therefore, they increase their exports as variation management reduces congestion.

Figure 6D presents the reductions in average generation costs for all regions and years investigated when electric boilers are introduced. The reductions in average generation costs are typically less than 3 EUR/MWh, although the reductions can be substantially higher at low wind shares. As shown in Figure 6D, there are also conditions under which there is an increase in the average generation costs (ie, the negative values). When electricity is used to generate heat, the total generation is increased while the installed capacity, for the cases investigated, remains unchanged. An increased load typically implies higher average generation costs, as more expensive units are brought into operation. An increase in generation cost is a typical outcome when the willingness to pay for heat is very high. However, when there is a moderate willingness to pay the heat load, this load is usually activated only if it can be met by low-cost generation, such as excess wind power or baseload, and can thus reduce the average generation cost. Reductions are more easily achieved at low wind shares when the average running costs are higher.

5.4 | Complementing strategies—with or without access to reservoir hydropower

In several of the regions investigated, complementing strategies are available in the form of flexible thermal generation and/or reservoir hydropower. As illustrated in Figures 3 and 6 (cf "with hydropower access"), regions with reservoir hydropower differ from other regions in 2 important aspects: (1) The value of wind is higher for low-to-medium wind shares (Figure 3A), and (2) the average short-term generation costs are lower compared to other regions with the same wind share (Figure 6A). Thus, the system impact of wind power is different in regions with hydropower than in other regions. Furthermore, the results presented in the previous sections reveal a different response to load shifting in regions that have access to reservoir hydropower, as compared to typical or isolated regions. Figure 3B shows that load shifting has the ability to increase wind owner revenue in regions with access to hydropower, at least to the same extent as in regions that are typical for continental Europe, whereas Figure 5B shows that load shifting is less capable of reducing the average short-term generation costs in hydropower regions compared to other regions. This section explores the reason for this difference.

Figure 7 shows the impact of variation management on the marginal costs of electricity for a relatively isolated wind-thermal system without access to hydropower (England and Wales) and a system that has reservoir hydropower (south Sweden). There are significant differences in the

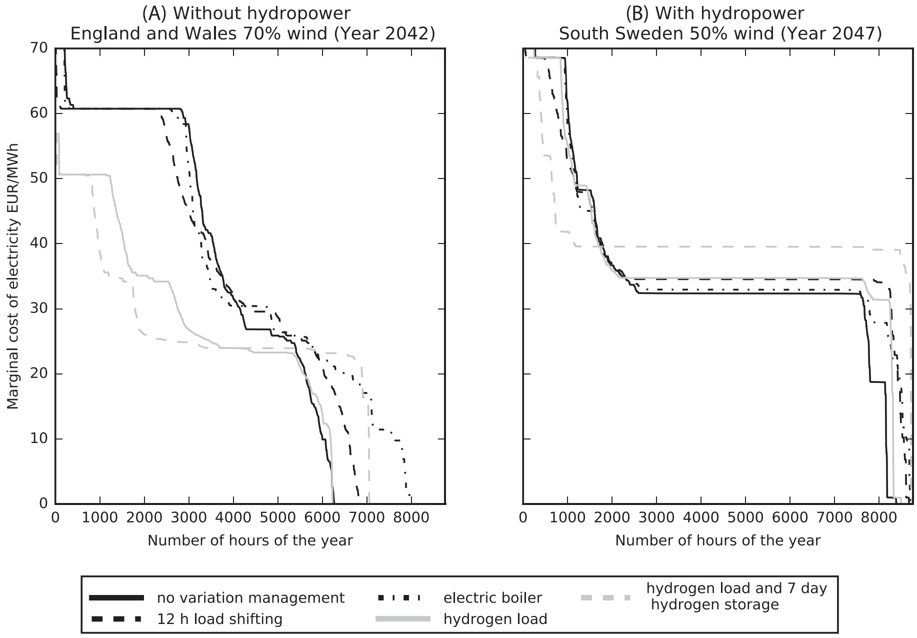

FIGURE 7 Marginal costs of electricity with and without variation management for a region: A, without access to hydropower (England and Wales with 70% wind share) and B, with reservoir hydropower (south Sweden at 50% wind share)

effects of the variation management strategies between the 2 regions. In addition, each region exhibits, as expected, differences between the shifting and absorbing strategies.

Without access to reservoir hydropower (Figure 7A), load shifting reduces the marginal cost variations between hours that are close in time, resulting in a reduced inclination between high- and low-cost hours and a reduction in high- and low-cost hours of about 20%. By shifting load up to 12 hours in time, load shifting provides peak shaving and valley filling as long as peaks and valleys are of short duration. In the region with access to extensive hydropower with reservoir (Figure 7B), the marginal cost of electricity is closely associated with the value of the water. If the demand for electricity is increased by one unit at some point in time, it can be met by increased hydropower production, although due to the limited hydropower resource, some other generation unit has to increase its output at some other point in time. The value of the water (and the marginal cost of electricity when hydropower is price setting) in a hydropower region is therefore typically related to the marginal cost of electricity during low-load hours in the region or in one of its neighboring regions. Variation management strategies increase the marginal cost of electricity during low-cost events, and, thus, the marginal cost of electricity during hours when hydropower is price setting, ie, the value of the water, is also increased. Due to the increased value of the water, the wind owner revenue is increased substantially as load shifting is added to the system. Nevertheless, the short-term generation costs of the system are affected to a negligible extent, and despite a reduction in high-cost events, the revenue of the owner of the hydropower is only slightly reduced.

In the system without reservoir hydropower, the marginal cost of electricity of the system with hydrogen production is subject to a number of gradually reducing plateaus (cf Figure 7A). With 7-day hydrogen storage, the marginal cost of electricity is shifted downwards to the next marginal cost plateau, reflecting the large amounts of energy that can be moved in time with hydrogen storage in place. In the system with reservoir hydropower (Figure 7B), 7-day hydrogen storage increases the value of the water, relative to the case with hydrogen production but no storage, in a manner similar to that achieved by load shifting. However, the effect of the 7-day hydrogen storage on the marginal cost plateau defined by the value of the water is greater both in terms of magnitude and duration, as compared to the load shifting case. A 7-day hydrogen storage system increases the revenue of the owner of the hydropower, as well as that of the wind power owner.

Electric boilers are particularly efficient at reducing low-cost hours, whereas high-cost hours are weakly affected. In the system with access to hydropower, also load shifting is able to reduce low-cost hours due to the interplay with hydropower, as described in the previous paragraph. However, in the system without access to hydropower, electric boilers are much more efficient than load shifting in reducing low-cost hours.

6 | DISCUSSION

To date, the discourse and discussion on wind variation management have tended to be restricted to a few energy storage alternatives with sizing of the storage based on wind share only and often focused on batteries (cf Figure 1). In contrast, the results presented here show that the benefits derived from the different variation management strategies depend not only on wind share but also on regional energy system composition, including possibilities to trade electricity between regions. Therefore, the system context should be considered when a decision to invest in or support a certain variation management technology is taken.

The results of this work reveal that while wind power can initially benefit from shifting strategies, absorbing strategies are more beneficial at high wind shares. In other words, even though a shifting strategy using batteries is important, unless prices for batteries (or possibly other storage of electricity) is drastically reduced, such strategy cannot be expected to manage future wind variations, for which absorbing, as well as complementing strategies are needed. Absorbing strategies convert electricity to some other energy carrier, ie, transfer electricity from the electricity sector to other sectors (eg, the transportation and industry sectors). Time-resolved analysis of sectorial linkages are thus of great relevance for wind power variation management in cases with high wind shares.

Future RES policies must ensure that the benefits of variation management can be reaped. Barriers between sectors in the energy system need to be identified and removed. Variation management can reduce the need for policy intervention to achieve high shares of wind power. However, whether variation management itself requires support schemes to realize its full potential to benefit the system remains to be investigated.

In this work, variation management is added exogenously to the regions, ie, this work does not provide any optimization of the amount and distribution of the different variation management technologies. Instead, the exogenously given amount of variation management in each case is selected to correspond to a large-scale implementation. This approach is motivated by the uncertainty in future costs of several of the technologies applied for variation management, the presence of other factors that could motivate the investments in variation management (eg, security of supply), and a need to keep the modeling solvable. Annualized regional investment costs for implementing the cases investigated are provided in Appendix A.5. Although the electric boiler case is associated with the lowest investment costs, the benefits of this technology vary greatly between regions depending on alternative costs for supplying heat, as can be seen in Figures 3, 4, and 6. Also, as an opportunistic absorbing strategy, electric boilers do not offer any reduction in investments in heat generation capacity. The cost of implementing the hydrogen storage is, obviously, highly dependent on the volume of the regional steel production but is for many regions in the same range as the battery case. An important follow-up work is to model and analyse cost-optimal combinations of variation management strategies. This will require substantial model development combined with a thorough assessment of the costs of the different technologies for variation management, but which are outside the scope of the work presented in this paper. Yet, based on the findings of this work, we can conclude that such cost-optimal combinations are likely to depend on the system context.

The isolated regions (defined as a those for which the total transmission capacity to neighboring regions of ≤10% of the peak load) are used to illustrate how the absence of trade influences the value of wind power and variation management. Indeed, one may chose to define trade as a variation management strategy within the framework suggested in this work. To do this will require an extended analysis since the impact of transmission on the value of wind power is likely to depend on the properties of the region on the other side of the line.

7 | CONCLUSIONS

A new, functionality-based categorization of vRE variation management into shifting, absorbing, and complementing strategies is introduced. Benefits from a wind integration perspective of two shifting strategies, batteries and load shifting, and two absorbing strategies, electric boilers in the district heating system and hydrogen production with storage, are investigated using electricity systems modeling, covering the EU-27 countries plus Norway and Switzerland. The impacts of the two shifting strategies and the two absorbing strategies are evaluated in 152 different electricity system contexts, including systems with and without reservoir hydropower as a complementing strategy.

We show that the *benefits derived from the different variation management strategies depend on wind share*. The abilities of the shifting strategies to increase wind owner revenue and to reduce short-term generation costs are reduced as wind share is increased, while the converse is true for the absorbing strategies. Our results indicate that absorbing strategies are of particular relevance for systems that expect medium-to-high wind shares due to the relatively low cost of storing large energy volumes in the form of heat or fuel.

It is furthermore shown that *the benefit of variation management depends on the composition of the regional electricity system and possibilities to trade*. In regions that have access to hydropower, shifting strategies increase the wind owner revenue to the same extent as in regions that are typical for continental Europe, although they have a low impact on the short-term average generation costs. The converse is true for isolated regions, in that shifting strategies have a low impact on wind owner revenue but their ability to reduce the short-term generation costs in isolated regions is equivalent to the corresponding reductions achieved in regions that are typical for continental Europe.

On the basis of the results presented here, we suggest that investments in variation management strategies, as well as support schemes designed to stimulate such investments, should be made while considering both the present and future system contexts.

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APPENDIX A

A.1 | The technology options and their associated costs applied in ELIN

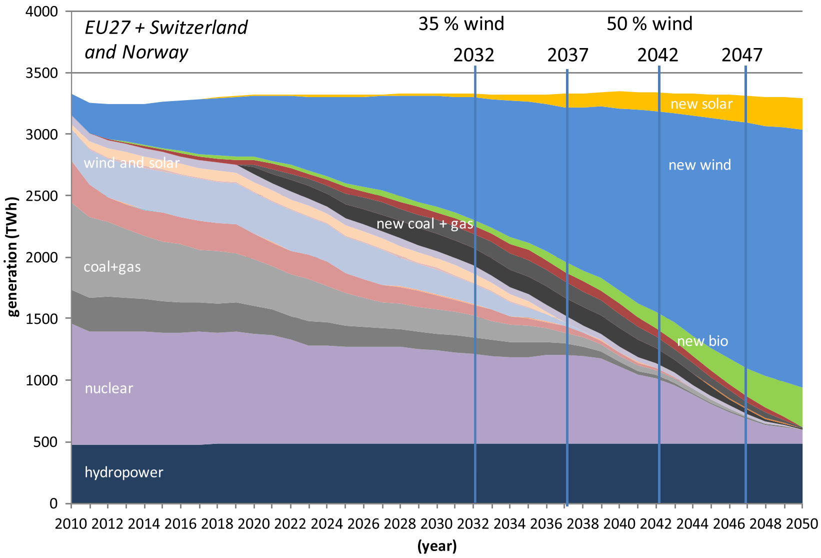
Technology	Lifetime, y	Investment costs 2030, €/kW	Investment costs 2050, €/kW	Fix O&M, €/kW,y	Var O&M, €/MWh
Hard coal					
Steam	40	1550	1550	27.4	
CHP/BP	40	1550	1550	27.4	
CCS	40	2390	1970	47.9	1.55
CCS cofire	40	2790	2370	57.5	1.86
Lignite					
Steam	40	1250	1250	31.7	
CHP/BP	40	1250	1250	31.7	
CCS	40	2190	1770	44.9	1.36
CCS cofire	40	2590	2170	53.9	1.63
Natural gas					
GT	30	380	380	8	
CCGT	30	750	750	13	
CHP/BP	30	780	780	16.6	
CCS	30	1170	1020	41.2	2.8
Nuclear					
Steam	60	4200	4200	57.6	
Bio and waste					
Steam	40	2500	2500	50	
Waste	40	9060	9060	443	
CHP/BP	40	2900	2900	57.6	
VRE					
Onshore wind	25	1320	1190	27.4	
Offshore wind	25	2190	1880	72.7	
Solar PV	25	1280	660	27.4	

Source: Assumptions from the World Energy Outlook 2011 to 2014 editions, extrapolated after year 2035. Cost of CCS from the Zero Emission Platform (ZEP) 2011.

Fuel	Cost 2030, €/MWh	Cost 2050, €/MWh
Hard coal	9.8	9.8
Lignite	5.5	5.5
Natural gas	30.3	34.3
Uranium	6.7	8.1
Biomass[a]	28.8	28.8

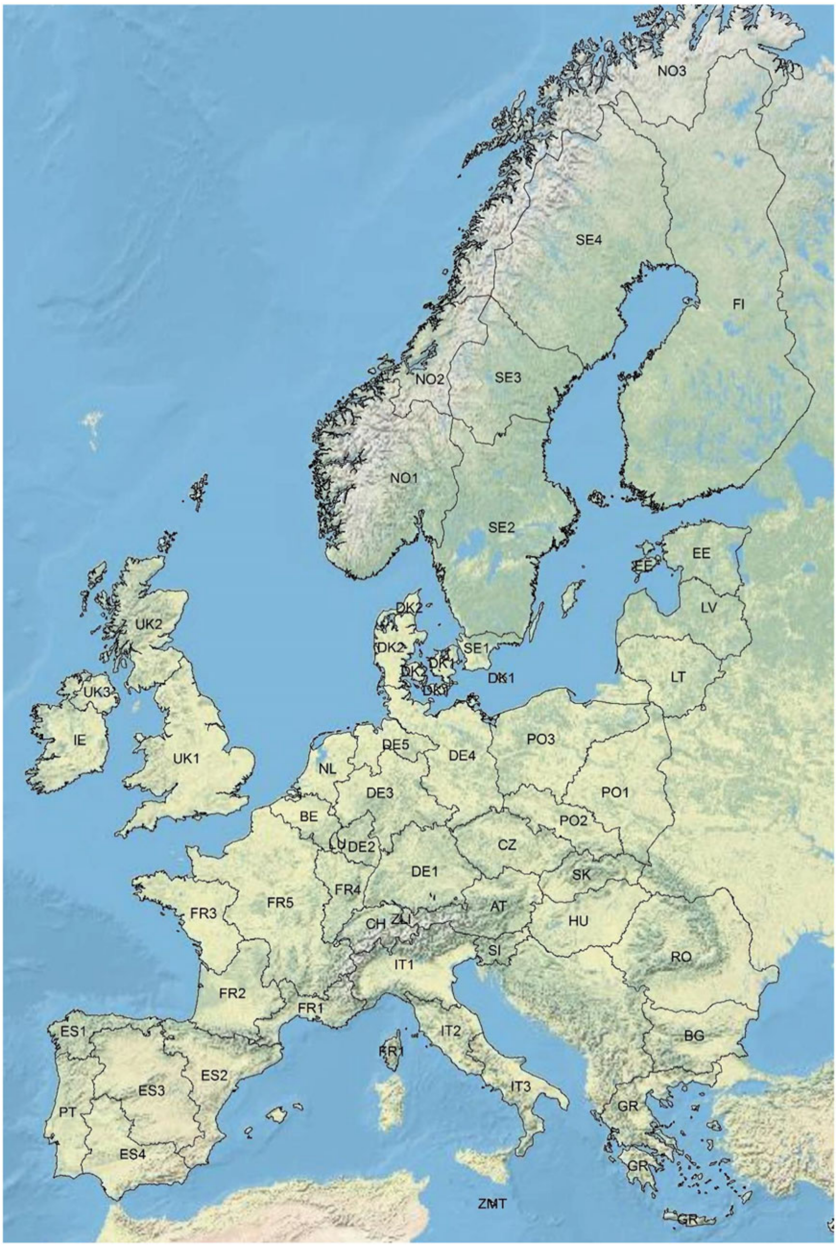
[a]Assumed biomass price on an international market. There are also national cost-supply curves for biomass in the ELIN model.

A.2 | European electricity generation mix as obtained from the ELIN model



Source: The development of the European electricity generation from year 2010 to year 2050 as given by the ELIN model, for the Regional Policy scenario[12] in which there is a strict cap on CO_2 emissions (which have to be reduced by at least 95% of the 1990 emissions by 2050), a flattening out of the total European demand for electricity (assuming successful efficiency measures) and continued national ambitions on electricity from renewables (extrapolation of the national renewable energy action plans after 2030). The years marked (2032, 2037, 2042, 2047) are used in the analysis of variation management strategies. Key inputs to the ELIN model include the technology options and costs in Appendix 1 and the Chalmers Power Plant Database[13].

A.3 | The locations of the regions modelled by ELIN and EPOD and the notation used for these



A.4 | The 38 regions considered in the ELIN/EPOD-modeling of this work and their wind shares, as given by ELIN, for the 4 years selected for the EPOD modeling in this work

Region	Region Type	Share Wind 2032	Share Wind 2037	Share Wind 2042	Share Wind 2047
AT	Typical	0,07	0,07	0,22	0,49
BE	Typical	0,34	0,37	0,39	0,38
CZ	Typical	0,14	0,19	0,36	0,66
DE1	Typical	0,01	0,04	0,08	0,12
DE2	Typical	0,38	0,48	0,59	0,82
DE3	Typical	0,27	0,36	0,48	0,56
DE4	Typical	1,17	1,22	1,41	1,43
DE5	Typical	1,22	1,81	1,65	1,68
FI	Isolated	0,24	0,25	0,31	0,41
FR1	Typical	0,32	0,41	0,75	1,11
FR2	Typical	0,01	0,00	0,31	0,48
FR3	Typical	0,46	0,62	1,30	1,71
FR4	Hydro	0,02	0,00	0,45	1,03
FR5	Typical	0,24	0,35	0,52	0,69
HU	Typical	0,08	0,13	0,15	0,16
IT3	Typical	0,81	1,01	1,10	1,19
LU	Typical	0,23	0,23	0,26	0,45
NL	Typical	0,40	0,41	0,40	0,40
NO1	Hydro	0,01	0,00	0,00	0,00
NO2	Hydro	0,01	0,00	0,00	0,00
NO3	Hydro	0,53	0,00	0,00	0,00
PO1	Typical	0,00	0,13	0,44	0,76
PO2	Typical	0,01	0,00	0,00	0,00
PO3	Typical	1,30	1,36	1,54	1,88
PT	Hydro	0,46	0,76	1,01	1,35
SE3	Hydro	0,16	0,14	0,00	0,00
SE4	Hydro	0,21	0,06	0,00	0,00
SI	Hydro	0,25	0,26	0,23	0,15
SK	Typical	0,30	0,33	0,33	0,26
CH	Hydro	0,04	0,04	0,04	0,04
UK1	Isolated	0,73	0,72	0,67	0,70
UK2	Hydro	1,49	1,52	1,84	2,69
SE1SE2	Hydro	0,22	0,26	0,31	0,49
BGROBAGR	Hydro	0,22	0,26	0,32	0,39
ES1ES2ES3ES4	Typical	0,31	0,39	0,44	0,53
EELTLV	Typical	0,46	0,44	0,80	0,99
IT1IT2	Typical	0,00	0,00	0,07	0,07
IEUK3	Isolated	1,04	1,03	1,22	1,39
DK1DK2	Typical	0,92	0,87	1,44	1,77

A.5 | Variation management capacity and annualized investment costs for implementing the strategies

Region	Battery Capacity, GWh	H_2 el Demand, MWh/h	7 day H_2 Storage, GWh	Electric Boiler Capacity, MW	Cost Batteries Case, M€/y	Cost H_2 Storage Case, M€/y	Cost Electric Boilers Case, M€/y
AT	18	0	0	2047	710	0	8
BE	23	1826	307	2594	907	766	10
CZ	17	2511	422	1924	671	1053	8
DE1	44	0	0	4855	1736	0	19

(Continued)

Region	Battery Capacity, GWh	H_2 el Demand, MWh/h	7 day H_2 Storage, GWh	Electric Boiler Capacity, MW	Cost Batteries Case, M€/y	Cost H_2 Storage Case, M€/y	Cost Electric Boilers Case, M€/y
DE2	7	0	0	824	276	0	3
DE3	50	14201	2386	5568	1973	5953	22
DE4	26	1005	169	2930	1026	421	12
DE5	7	1973	331	785	276	827	3
FI	22	1370	230	2603	868	574	10
FR1	16	2146	361	2107	631	900	8
FR2	14	0	0	1840	552	0	7
FR3	17	0	0	2255	671	0	9
FR4	11	1598	268	1395	434	670	6
FR5	89	2831	476	11665	3511	1187	47
HU	12	594	100	1172	473	249	5
IT3	16	4201	706	1746	631	1761	7
LU	2	0	0	234	79	0	1
NL	31	3196	537	3354	1223	1340	13
NO1	27	0	0	3502	1065	0	14
NO2	2	0	0	314	79	0	1
NO3	3	0	0	330	118	0	1
PO1	17	0	0	1845	671	0	7
PO2	22	2283	384	2404	868	957	10
PO3	16	0	0	1699	631	0	7
PT	15	0	0	1863	592	0	7
SE3	5	0	0	633	197	0	3
SE4	2	1370	230	244	79	574	1
SI	4	0	0	431	158	0	2
SK	9	2055	345	931	355	862	4
CH	17		0	1835	671	0	7
UK1	85	4064	683	10114	3353	1704	41
UK2	8	0	0	1015	316	0	4
SE1SE2	29	868	146	3915	1144	364	16
BGROBAGR	44	0	0	5199	1736	0	21
ES1ES2ES3ES4	86	1507	253	10201	3393	632	41
EELTLV	8	0	0	1014	316	0	4
IT1IT2	77	0	0	8554	3038	0	34
IEUK3	11	0	0	1362	434	0	5
DK1DK2	8	0	0	1048	316	0	4

Costs for the variation management cases given here are based on costs for batteries, hydrogen storages, electrolyzer capacity, and electric boilers from Energistyrelsen (2012) and represent 2050 cost levels. Batteries are assumed at an investment cost of 0.15 M€/MWh with a fixed O&M cost of 25 k€/MWh,y and a lifetime of 25 years. Hydrogen storages are assumed at 0.011 M€/MWh and a lifetime of 30 years. Electrolyzers are assumed at 1 M€/MW with a fixed O&M cost of 20 k€/MW,y and a lifetime of 10 years. Electric boilers are assumed at 0.05 M€/MW and a lifetime of 20 years. A 5% interest rate has been applied in all calculations.

The net benefit of variation management, ie, the reduction in regional cost of electricity generation by means of batteries, hydrogen storage, or electric boilers is of obvious interest. Yet additional analysis is required to estimate the economic value of the different strategies. The value of the different management strategies will depend on sector and context. The economic benefit is unevenly distributed between regions since regions trade, and thus as one region takes a large investment cost, a neighbouring region may benefit. There may also be other benefits such as added reliability and security of supply for the end-user (eg, the industry consuming hydrogen or the household with batteries) which are not accounted for here.