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Walter, V., Göransson, L. (2022). Trade as a variation management strategy for wind and solar power integration. Energy, 238. http://dx.doi.org/10.1016/j.energy.2021.121465

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Energy 238 (2022) 121465

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Trade as a variation management strategy for wind and solar power integration

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ARTICLE INFO

Article history:
Received 24 March 2021
Received in revised form
29 June 2021
Accepted 8 July 2021
Available online 12 July 2021

Keywords:
Variable renewable energy
Flexibility
Grid integration
Macro energy systems
Energy system modelling
Transmission capacity

ABSTRACT

Trading electricity between regions can support the integration of variable renewable energy (VRE) through: (i) exploitation of temporal differences in wind power generation between regions (geographic smoothing); and (ii) connection between regions that have unequal VRE resources (resource transfer). This work investigates the impacts of these two different trade features in relation to other strategies for facilitating the integration of VRE. The impacts of transmission capacity on investments and the dispatch of generation and variation management capacity are investigated while minimising the cost of meeting the demand for electricity. The results show that when the cost of connecting regions is high, transmission capacity mainly facilitates wind power integration by reducing variability through geographic smoothing, whereas if the cost of connecting regions is low, transmission capacity results mostly in resource transfer. Geographic smoothing increases the share of the load which can be cost-efficiently supplied by wind power, at the expense of thermal generation. However, the provision of flexibility through geographic smoothing is limited in terms of both time and power capacity by differences in weather patterns. It is found that the extensive transmission capacity put in place for resource transfer can benefit the integration of both wind and solar power.

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1. Introduction

The global transition towards a carbon-neutral electricity system has begun but needs to be accelerated to reduce the risk of overshooting the 1.5 °C or even the 2 °C target [1]. During this transition, the share of the electricity demand supplied by wind and solar power is expected to increase significantly. As electricity generation from these renewable sources is unevenly distributed, both geographically and temporally, technologies and strategies that enable the matching of wind and solar power generation with the demand for electricity (temporally or spatially) would facilitate the integration of this variable renewable energy (VRE). The temporal matching of electricity demand and VRE generation is facilitated by variation management strategies (VMS) [2]. VMS can be divided into three categories: (i) complementing strategies and (ii) absorbing strategies to solve longer times with high and low (negative) net-loads, respectively, and (iii) shifting strategies to manage frequent variations. Absorbing and complementing strategies are important for increasing the value of wind power, whereas shifting strategies support the utilisation of solar power with diurnal peaks.

The output of wind power becomes more stable when connecting wind power from different sites (known as geographic smoothing), as explained by Molly [3] and visualised in energy systems modelling by Reichenberg and colleagues [4,5]. However, geographic smoothing is restricted by differences in net-load that result from shifting weather patterns. Olauson and Bergkvist [6] have shown correlations between wind power levels at different temporal scales across Europe. As a supplement to local VMS, connections between regions via transmission lines can support VRE integration by reducing variability through trade. Energy system studies that focus on electricity trade through transmission system optimisation have been performed with models that include local VMS, such as storage systems [7] and district heating systems [8]. Brown et al. [9] have conducted a study on electrification of the heat and transportation sectors, including storage and transmission systems with 30 nodes in Europe, in which transmission capacity and wind power are shown to compete with solar power and energy storage systems. These previous studies show that connecting regions with transmission lines increases the value

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https://doi.org/10.1016/j.energy.2021.121465
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of wind power, while reducing the need for other technologies [7–9]. Schlachtberger et al. [10] have highlighted how the main share of the cost-optimal transmission expansion can be reduced without significant impacts on the total system cost, which means that the initially high value of the transmission capacity levels off as it is used for purposes for which other solutions with similar cost are available. An alternative view on trade has been provided by Giebel et al. [11], who have suggested that transferring wind resources from low-population areas to centres of high demand could generate income for economically poor regions. Also Tröndle et al. [12] show how regions in the outskirts of Europe can supply central regions with electricity and that regions can reach higher self-sufficiency (for supply and flexibility) at a high cost penalty. Both Tröndle et al. [12] and Neumann [13] show that the main value of trade comes from the balancing of temporal differences. A large savings potential from transmission in the US is shown by Brown and Botterud [14].

Previous studies investigating the impact of trade on the integration of wind and solar power have included geographic smoothing and resource transfer but have focused on one or the other without distinguishing between their partial values. The aims of the present work are to define the impacts of geographic smoothing and resource transfer on the integration of VRE, and to relate these different features of trade to the VMS framework, thereby elucidating both the contribution of trade within different electricity system contexts and the interactions of geographic smoothing and resource transfer with other strategies to manage variations in the electricity system. The paper by Hansen et al. [15] highlights the need for connections of energy system models at different geographical scales. This work is intended to support the choice of method for connecting such models through further understanding of the value of electricity trade.

2. Trade features

This work divides the benefit of electricity trade for VRE integration into two main features: geographic smoothing and resource transfer. The benefits of trade that accrue from intra-annual trade from balancing the electricity system on hourly to seasonal time scale is considered. Additional values from inter-annual [16] and intra-hourly [17] balancing are not considered in this work.

2.1. Geographic smoothing

The movement of weather systems over land and sea results in momentaneous differences in the wind power generation patterns at different geographic locations. The strength of the correlation between wind power generation levels at two different locations decreases as the distance between the locations is increased [6]. Utilising the differences in generation or load profiles across a geographic area to reduce variability is called *Geographic smoothing*. Connected regions can, thereby, supply each other with excess capacity, so that the technologies that are earliest in the merit order can be utilised first in the joint electricity market. This cooperation can make use of otherwise curtailed electricity and reduce fuel-based generation in the trading regions. Owing to differences in the net-load profiles between the different geographic locations, geographic smoothing can reduce the total amount of thermal capacity required to meet positive net-load events. In this work, bidirectional trade on short timescales (hours to days), so as to exploit the differences in wind profiles, is considered to reflect the geographic smoothing feature of trade. Solar power can also have geographic smoothing effects, regarding differences in cloudiness, time-zones, and inflow angle. However, as this does not show major effects on the spatial resolution in this work, it is not assessed here.

2.2. Resource transfer

The uneven distribution of wind and solar resources, both spatially and as a consequence of differences in acceptance and competing interests for land-use, between different regions results in a geographically diverse potential for VRE expansion. Bridging these differences with transmission lines is in this work referred to as *resource transfer*. Resource transfer can be simply described as expanding wind or solar power generation in one region with the main purpose of exporting it to some other region with a lower potential for VRE expansion. Typically, in the case of wind power, the exporting region has a high potential for wind power but further expansion of wind power to supply local demand is uneconomic due to system saturation, such that increasing capacity would result in extensive curtailment. Resource transfer can increase the VRE share of the two trading regions if VRE in the exporting region replaces thermal generation in the importing region. However, VRE in the exporting region can also replace VRE in importing regions at locations with worse conditions for VRE generation compared to what is offered by import. In this case, resource transfer does not increase the total VRE shares of the trading regions but instead increases the cost and material efficiency. Wind and solar power at sites with good conditions also typically have more stable production profiles, so resource transfer can be considered to contribute with a reduced need for VMS. In this work, seasonal or yearly imbalanced trade are taken as signs of resource transfer. In northern/central Europe, imbalanced trade over seasons but balanced trade over the year is a sign of resource transfer of wind power in winter and resource transfer of solar power in summer. In contrast, imbalanced trade over the year is a sign of imbalanced VRE resource potentials in relation to the demand, with the result that regions become net importers/exporters.

3. Method

A cost-minimising electricity system investment model is applied to a case study designed to capture the differences between the trade features and to explain both qualitatively and quantitatively the impacts of the trade features on the electricity system.

3.1. Optimisation model and case description

The impacts of the two trade features on the electricity system are assessed from a techno-economic perspective, whereby we evaluate the ability of investment in transmission capacity to reduce the investment and operational costs of the electricity system while meeting a given demand for electricity. Net emissions of carbon dioxide from the electricity system considered are constrained to zero. A two-node version of the eNODE optimisation model is applied to pairs of regions subject to different costs for transmission capacity [18]. eNODE is a linear programming model that minimise the cost of investments in and the dispatch of the electricity system with a high temporal resolution (in this case 3-hourly). For an overview of the model, see Table 1. A technical lifetime of 40 years and interest rate of 5% was used to calculate the

Table 1
Simple model overview of the eNODE model. See Appendix A – Model and data, for full model description and input data.

Input
Costs - Investments, O&M, fuel.
Technical - Efficiency, lifetime.
Demand for electricity.
Potential for wind capacity.
Generation profiles from weather patterns.
CO_2 cap.
eNODE
Minimises the total cost of annualised investments and operation of the electricity system.
Meets electricity and hydrogen demand.
Balances batteries and hydrogen storage.
Meets Carbon emission limit.
Output
Total cost.
Capacity mix for generation technologies, transmission lines and storages.
Dispatch of generation and storages with 3 h resolution.
Marginal cost of electricity (electricity price).
Marginal cost of carbon emissions (CO_2 tax).

annuity factor for the transmission investments, and a small cost of 2 €/MWh for using the transmission network was included, to avoid import and export during instances of curtailment in both regions. The model is greenfield and does not consider exiting electricity generation or transmission capacity. The mathematical description of the model is presented in Appendix A – Model and data.

The role of trade is evaluated for 18 cases, corresponding to 18 different combinations of wind profiles and region pairs listed in Table 2. The regions are chosen to represent regions with different preconditions for wind and solar power and regions are grouped into pairs such that the impact of distance between regions is captured. The regions investigated have similar total demand for electricity, to reduce the number of parameters. In order to investigate the impact of geographic smoothing, the six region-pairs are subject to three different wind profile set-ups. The value of the trade features is captured by modelling the transmission capacity with four different investment costs listed in Table 2. The 18 cases investigated are further described below.

The model is run initially with normal wind profiles (*B – base profiles*), followed by two cases without the geographic smoothing effects (S/U - *stable/unstable synchronised profiles*), where the wind profiles in both regions are re-shaped into uniform profiles that are weighted according to the original full-load hours, so as to preserve the differences in the levelised cost of electricity (LCOE). The reason for running two cases with *synchronised profiles* is to capture differences due to a change in the stability of the wind profile. In this work, the wind profiles for the high wind region IE (*S – stable synchronised profiles*) and the low wind region HU (*U – unstable synchronised profiles*) are used for this re-shaping. The wind profiles are based on wind speed data derived by combining the MERRA [19] and ECMWF ERA-Interim [20] data for Year 2012, whereby the profiles from the former are re-scaled with the average wind speeds from the latter as presented in Ref. [21]. The high-level resolution of the wind profiles from the ERA-Interim data was processed into wind power generation profiles and combined into up to 12 wind classes for each region. The wind profiles applied in the stable and unstable cases correspond to the profiles of the main wind classes in terms of available area, with reasonable capacity factors in IE and HU, respectively. See Fig. A.2 in Appendix A for duration diagrams of the two profiles.

Table 2
The 18 cases are based on three wind profile set-ups and six region pairs, over which the transmission cost is varied according to four values given in this table. For example, the "stable" synchronised profile for the region pair HU-PO1 at a transmission cost of 3 M€/MW is designated as S-L1-3. The regions are IE – Ireland, HU – Hungary, RO – Romania, FR4 – eastern France, DE2 – western Germany and PO1 – southern Poland.

Wind profiles	Region pairs	Transmission costs [M€/MW]
B (base)	H1 (IE-HU)	10 (isolated)
S (stable - IE-profile)	H2 (IE-RO)	3
U (unstable - HU-profile)	H3 (IE-FR4)	1
	H4 (IE-DE2)	0 (copperplate)
	L1 (HU-PO1)	
	L2 (HU-DE2)	

The six region pairs were chosen to capture effects due to distance and different integration levels of wind and solar power. Ireland (IE, in high wind cases H1–H4) and Hungary (HU, in low wind cases L1-L2) are set as base regions (see map in Fig. A.1 in Appendix A). These regions are paired with other regions with similar annual electricity demands and medium wind conditions at different geographic locations within Europe. IE has a good wind power potential, whereas HU lacks the windiness of a coastal region but has a better solar potential, albeit not as good as that of a Mediterranean country. IE is paired with two regions in the eastern part of Europe (cases H1–H2) and two regions in western/central Europe (cases H3–H4). HU is connected to two regions in central Europe (cases L1-L2), as well as to IE (case H1). The distances between the regions span 400–2800 km, which is long for transmission but still intra-continental, with the limited differences in weather patterns and time zones that this distance covers.

The cost of transmission is modelled at 0, 1, 3 and 10 M€/MW independent on distance, to examine the value of the trade features. The levels 10 and 0 M€/MW are chosen to represent the region pair modelled in isolation and as a fully connected copperplate. Here, 1 M€/MW and 3 M€/MW correspond to low-cost transmission (shows low-value transmission) and high-cost transmission (only gives high-value transmission), respectively. The low and high costs respectively correspond to the costs for about 2100 km and 7100 km of over-head line or about 700 km and 2300 km of underground cable, including pairs of DC substations, with similar lengths to the cross-European lines being modelled [22]. The cost of transmission varies extensively between transmission projects and often involves different degrees of reinforcement of the existing transmission system at both ends of a new line or cable. The exact cost of transmission is, however, not paramount in this work, which instead focuses on the impacts of trade features on the electricity system.

4. Results

The results section describes the impacts of geographic smoothing and resource transfer on the cost and composition of the electricity system. The results are driven by the cost minimisation and constrained mainly by the requirement of meeting the demand for electricity every hour, limitations on carbon dioxide emissions and potential for wind and solar power. The results are thereafter related to the VMS framework to understand the interactions between these features of transmission and other strategies designed to facilitate the integration of wind and solar power. In general, the results of the modelling reveal a wide range of system costs and compositions. The average annual electricity cost is in the range of 40–55 €/MWh, with copperplate systems being 3%–17% cheaper than isolated systems (Fig. 1). The modelled systems are mainly composed of wind (35%–67%) and solar (25%–55%) power complemented by thermal power (6%–16%) and large battery storages (35–85 GWh storage capacity, enough to cover about 8 h of average load in the regions investigated). Thermal power includes a few percentage points of base-load power, here in the form of nuclear power, in some of the isolated systems.

Fig. 1 shows the relative system cost savings for different costs of transmission. The savings are largest for the base cases in which trade enables both resource transfer and geographic smoothing for high wind regions, as in cases B-(H1–H4), here illustrated by the grey, black, pink and red solid lines. For these cases, resource transfer and geographic smoothing reduce the cost by 5%–7% with access to transmission at 3 M€/MW and with 9%–12% of the transmission at a cost of 1 M€/MW; the higher savings pertains to the cases connecting regions located further apart (black and grey lines versus red and pink lines in Fig. 1). By removing the differences in wind profile (dashed and dotted lines), the system benefit of resource transfer alone is 0.2%–2.0% of the total system cost at a transmission cost of 3 M€/MW. This indicates that geographic smoothing is needed to achieve the main savings at this transmission cost. However, at a transmission cost of 1 M€/MW, resource transfer alone can reduce the total system cost by 2%–8%. Thus, resource transfer has a significant impact on the total system cost at a low cost of transmission. Fig. 1 shows that in the absence of geographic smoothing, a lower cost of transmission is required to attain the same relative savings as the base case, indicating a higher value of transmission if geographic smoothing is available. The difference in transmission costs between the cases with or without geographic smoothing at which the first savings appear (i.e., the horizontal distance between the solid and dotted/dashed lines in Fig. 1 at the point where the lines intersect the horizontal axis) is approximately 3–4 M€/MW. This value decreases to about 2 M€/MW and 1.0–1.5 M€/MW after 5% and 10% savings, respectively, are achieved. Thus, the isolated value of geographic smoothing declines but remains relevant as the relative savings, and total installed transmission capacity, increase.

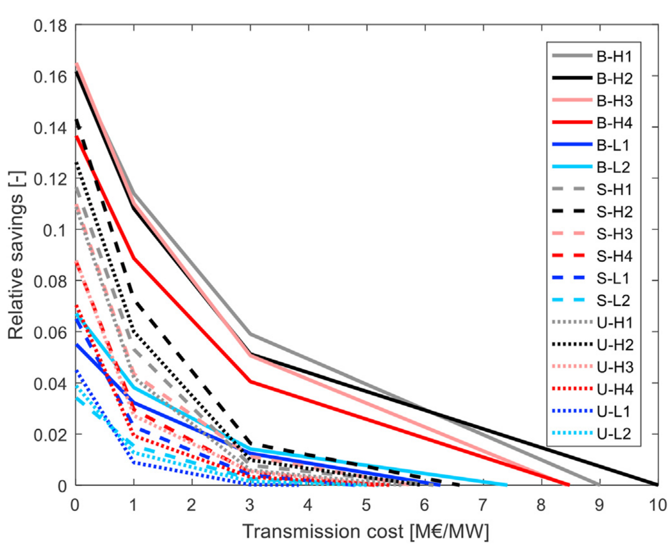

Fig. 1. System cost savings relative to the cost without trade. The solid, dashed and dotted/dashed lines represent the base, stable and unstable cases, respectively. The transmission cost (or marginal value) of the initial savings originates from the marginal value of transmission investments in the 10 M€/MW cases, in which no investments are made due to the high cost.

For region pairs with poor wind resources (teal and blue lines in Fig. 1), where wind power has a smaller potential to increase its share of the annual electricity demand, the trade features have about one-third of the savings potential compared to the region pairs that include a region with high wind potential. When the trading regions have synchronised wind profiles, sharing the more stable profile from the region with good wind conditions (S-cases) gives a 5%–9% lower total system cost compared to using the unstable profile from the low wind region (U-cases). This shows the difference in value between the smoother wind profile as a consequence of good wind conditions and the more varying wind profile coupled to worse wind conditions and indicates that there is a smoothing element also to resource transfer. The smoother wind profile reduces the need for VMS to manage high and low net-load events with medium-to-long duration (absorbing and complementing strategies).

4.1. VRE integration

The reduction in total system cost from trade between region pairs that include a region with good conditions for wind power in the cases that involve both resource transfer and geographic smoothing [B-(H1–H4)] is associated with an increase in the share of annual demand supplied by wind power. With transmission capacity offered at a cost of 1 M€/MW, the wind share is about 10% points higher than it is for the isolated cases, as shown in Fig. 2. If

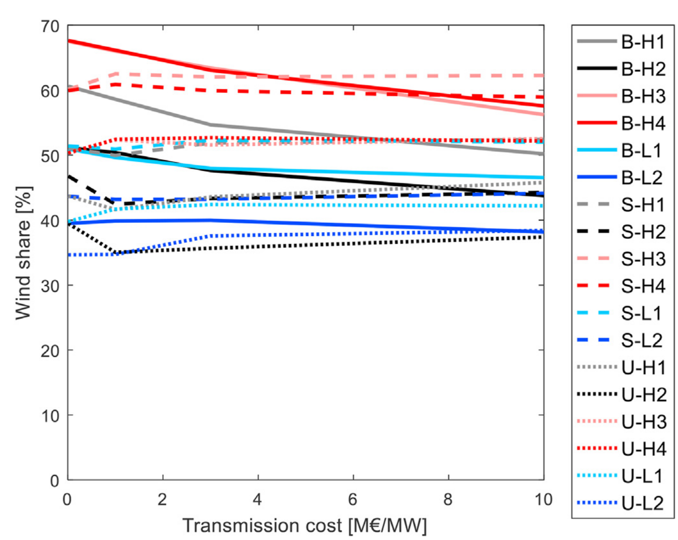

Fig. 2. The total combined wind shares of electricity generation in the region pairs.

only resource transfer is possible (dashed and dotted lines) the wind share is not impacted as strongly by trade, and without geographic smoothing a low cost of transmission can result in both an increase and a decrease in wind share compared to the isolated case, albeit with increased average capacity factor for wind power as investments move from the low wind region to the high wind region. In geographic isolation, the cases with synchronised stable wind profiles (S-cases) have a higher wind share than the base cases (B-cases, in which regions have their original wind profiles), and the cases with synchronised unstable wind profiles (U-cases) have a lower wind share than the base case. However, for the base cases, in which regions have their original wind profiles, the wind share increases as the cost of transmission is reduced and at a cost of transmission capacity of 3 M€/MW or lower, all the high wind base cases surpass the wind shares of the synchronised stable wind profile cases. Therefore, geographic smoothing is the main trade feature stimulating an increased wind power share.

The total VRE share increases (from already high levels in the isolated cases) as the cost of transmission capacity is reduced. In the base cases (B-cases), the increase in VRE share that occurs as the cost of transmission capacity is reduced is smaller than the increase in wind share due to a decrease in solar generation (i.e., wind power in combination with geographic smoothing outcompetes solar power). In the cases without geographic smoothing (S- and U-cases), the VRE share increases with reduced cost of transmission capacity, mainly due to increased solar generation. The increase in VRE share that results from the transmission cost reduction is largest in the cases with high wind potential (H1—H4-cases), and this is accompanied by a substantial increase in curtailment from moving wind installations to the region in which more wind can be curtailed while still remaining cost-competitive. In the base case, moving from a cost of transmission capacity of 10 M€/MW to 3 M€/MW, the relative curtailment stays constant despite an increase in the VRE share. Due to geographic smoothening, the VRE share can thus be increase without increasing curtailment.

4.2. Effects on dispatch

Fig. 3 shows the accumulated export from HU to IE (B—H1, S—H1 and U—H1 cases) for a cost of transmission at 1 M€/MW and 3 M€/MW. Most of the export occurs during the middle part of the year

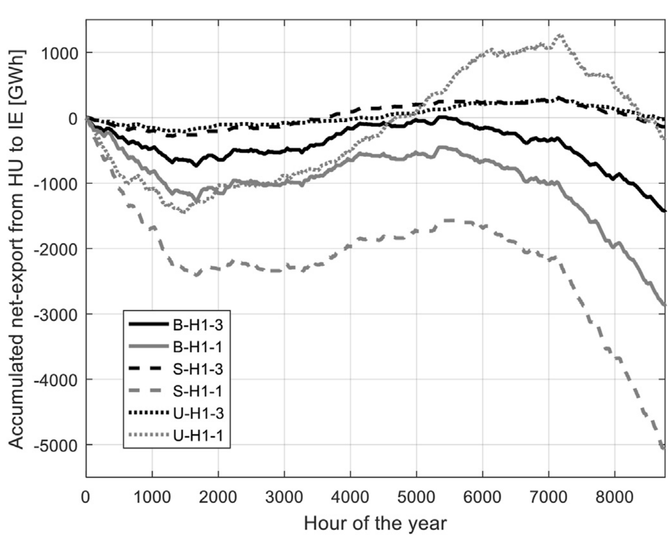

Fig. 3. Accumulated trade from the net-importing region HU to the net-exporting region IE (region pair H1). A negative end-value means that IE has exported more to HU than it has imported from HU.

(summer), while importing occurs during the first and last part of the year (winter), with periods of more balanced trade in between these seasons. The figure illustrates the behaviour of trade as a VMS that does not require storage capacity, for which import and export need to be balanced. All of the cases result in one overarching cycle, which for some cases ends with a large negative surplus (IE is a net-exporting region). These overarching cycles in Fig. 3 resemble the state-of-charge of seasonal storage systems that move electricity between summer and winter (but without the net-zero sum). In all the isolated base cases (B-cases), 70%—80% of the thermal generation occurs during winter and autumn, with simultaneous peak generation net-loads in all of the region pairs on an hourly time-scale. Transmission during winter promotes higher utilisation times of thermal generation technologies, which are primarily operated during this time of the year. With the support of batteries, the total need for generation capacity can be reduced by transmission investments despite the simultaneous peaks in net-load. During summer, transmission mainly reduces the battery storage capacity and reallocates investments in solar power to the most favourable locations (i.e., solar power investments are moved to the importing region HU). The reallocation of solar power is the main reason for the export from HU in the second part of the year. The trade in solar power increases the utilisation of the transmission lines and reduces the amount of storage needed for solar power integration. For the cases with synchronised wind profiles and a cost for transmission capacity of 3 M€/MW, the small amount of transmission that is built is used in both directions. If the wind profile is highly varying (as a consequences of poor wind conditions, U-cases), transmission capacity is used in both directions down to a transmission cost of 1 M€/MW. However, if the wind profile is smooth (as a consequence of good wind conditions, S-cases) the trade becomes more unidirectional at a low cost of transmission capacity. The case U—H1-1 (U-1 in Fig. 3) shows an example in which there is an even exchange of wind and solar resources, whereas B—H1-1 (B-1 in Fig. 3) is an example of more wind resources being exported, and in B-L2-1 (B-1 in Fig. B.1 in Appendix B) solar power is the main resource that is traded.

The dispatch of the 3-week period for the B—H2-3 case, visualised in Fig. 4, shows the trade between regions IE and RO together with the electricity generation in both regions. In Fig. 4a for region IE, four export periods of high wind power generation are seen, with import periods in between. In Fig. 4b for region RO, both import and export occur in the time between the two main solar generation periods (time-steps h0787 to h0862, 3 days in February). All export from RO during these weeks is accompanied by thermal generation in RO, which hosts intermediate load units with lower running costs than the thermal peak load units used in IE. In general, for the case of IE, the discharging of batteries and thermal generation and import events coincide (also the case for the reverse, i.e., export, battery charging and not running the thermal units). However, there are temporary exceptions when, for example, batteries in IE are charged during import events (around hour h0680 in Fig. 4a) or while running thermal units in IE (between hours h0820-h0830 in Fig. 4a). These exceptions, in which trade, thermal units and batteries work together, are cost-efficient, as the units are operated to minimise costs, reducing the usage of expensive fuels in units with low efficiency and through avoiding excess investments. Trade between the regions is not associated with a cost for storage, allowing it to balance variations on longer timescales than batteries. The variation management provided by transmission is in this respect similar to that offered by thermal units (for which the storage of fuels is so cheap as to be neglected in this work). In Fig. 4, these differences between fluctuating batteries (grey lines), as compared to more stable operations of transmission (black lines) and thermal generation (brown lines), are evident over

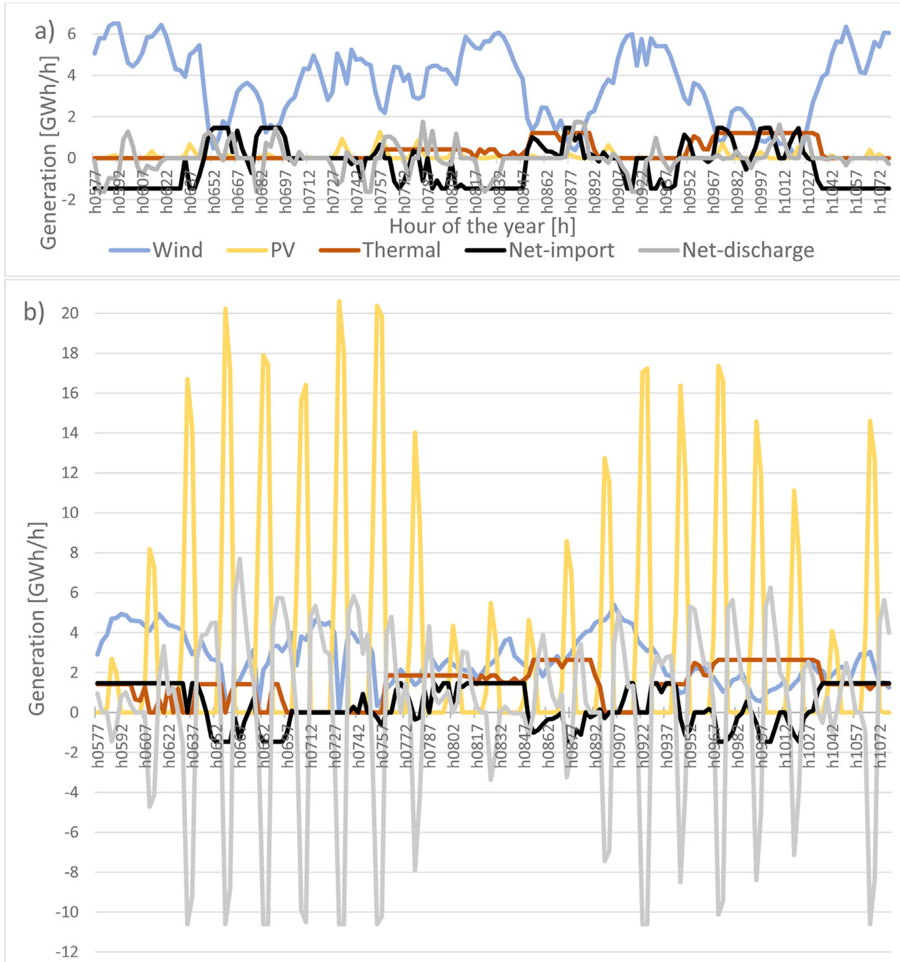

Fig. 4. Three weeks of dispatch (24th of January to 13th of February) in case B–H2-3, showing (a) region IE and (b) region RO.

the entire 3-week period.

5. Discussion

Although real electricity trade can never be divided into its component features, the present work suggests features that can improve our understanding of how transmission can be beneficial in several distinct ways. Geographic smoothing and resource transfer represent different ways of trading. Geographic smoothing and resource transfer with yearly balanced trade results in interdependency, whereby both regions benefit in similar ways, whereas in resource transfer with yearly imbalance, one region will sell electricity to the other in a more unidirectional fashion (energy moving one-way in return for payment), which reduces the regional security of supply of the importing region.

This work shows that the effects of geographic smoothing level off as the transmission capacity is increased. This indicates that the large transmission expansion seen in some models is a sign of resource transfer. Schlachtberger et al. [10] have shown that the optimal transmission expansion in Europe can be reduced to a large extent before it has a substantial effect on the total system cost. This suggests that a large fraction of the resource transfer could be cost-optimal from the techno-economic perspective but could be reduced without having a strong effect on the system cost. This would also reduce the acceptance issue, in relation to building both transmission networks and wind turbines (mainly) for someone else's benefit (solar power is not expected to encounter acceptance problems to a similar degree). However, a better wind resource utilised together with transmission means that there is lower wind capacity per unit of energy. This remains true despite the fact that this work shows that resource transfer could lead to higher levels of curtailment. Thus, resource transfer improves the material efficiency for wind turbines and reduce the overall area used for wind farms.

In energy systems modelling, the spatial or temporal scope is often reduced so as to reduce the model complexity and solution time. In these instances, the representation of either trade or other, local, VMS is often lacking. By investigating the interactions between trade and local VMS, the present work improves understanding of how the assumptions made regarding transmission can affect the modelling results. All four stages of the investment cost for transmission capacity investigated in this work could be interesting from a modeller's perspective. The isolated case is used in many models that examine an isolated region. For example, it is useful to reduce the complexity to elucidate the roles of different VMS, albeit with the risk of general overestimation of the need for flexibility. The copperplate case should be valuable for models that have a very large geographic scope, which tend to overestimate the ability to utilise geographic smoothing and the best weather resources, thus underestimating the need for flexibility. The cost level of 1 M€/MW is similar to the cost of transmission between neighbouring countries or even for transmission between regions that are farther apart. Thus, this represents the cost-optimal solution in the sense that the cost-efficient components of both geographic smoothing and resource transfer are implemented. The cost level of 3 M€/MW for transmission could be the cost of reaching over half the continent of Europe, as it is modelled for a few region pairs here. However, it could also represent a case in which the level of transmission expansion is limited due to other reasons. This cost level shows how transmission could be implemented if only applied to the most important/valuable issues. However, connecting only two regions (despite changing the distance and cost) does not fully address all the questions related to transmission modelling, and further work in this field is encouraged. Kan et al. [23] highlight the difficulty of evaluating the impact of regional policies on a specific region when assessing interconnected regions. This would also be true for other regional differences, modelling more regions would increase the overall impact of trade on VRE integration, while making results from a study like the present increasingly complex.

6. Conclusions

In this work, the possibility to use transmission to manage net-load variations is assessed for different costs and system contexts. It is found that in managing variations, transmission benefits from not requiring any storage capacity. Moreover, the level of charging needs not to equal the level of discharging over time (in the case of transmission, the total import does not need to equal the total export for a region). At the same time, electricity trading is not associated with start-up costs or start-up times. Transmission between regions can thus be used for absorbing and complementing electricity generation on both long and short timescales.

This work separates between two different features of transmission, geographic smoothing and resource transfer, to achieve a better understanding of its role in the electricity system integration of wind and solar power. It is found that at low transmission capacity (constrained by high cost or low level of acceptance) transmission primarily contribute with variation management through geographic smoothing. At a low-cost of transmission capacity, resource transfer has large economic benefits.

Extensive transmission capacity is useful for achieving high levels of renewables, as some regions lack adequate resources for wind or solar power or both and, therefore, benefit from an unbalanced trade on a seasonal to yearly basis. Resource transfer can also result in support for wind integration from the value of a more stable wind profile. These effects on wind and solar integration reduce the need for VMS to manage high and low net-load events with medium-to-long duration (absorbing and complementing strategies).

Geographic smoothing from transmission integrates additional wind power in exchange for thermal generation capacity without increasing wind curtailment. Geographical smoothing reduce variability of medium to long duration. The high cost of extensive transmission capacity as well as the infrequent differences in net-load variations between trading regions restricts the possibilities of using transmission to reduce net-load variations of high amplitude and high recurrence.

Geographic smoothing and batteries can, when applied concomitantly, manage a wide range of variations. Batteries are suitable for tackling high or low net-load events of high amplitude, even if these occur simultaneously in both trading regions. In contrast, geographic smoothing manages longer events of different net-loads in the trading regions. The synergies between the two strategies indicate that they belong to different categories in the VMS framework.

The two roles of transmission described in this work promote different forms of resource efficiency. Geographic smoothing uses the transmission infrastructure to improve the utilisation of the built capacities and to reduce the need for limited resources in the form of complementing electricity generation and, indirectly, the need for batteries. Resource transfer makes use of the best locations and increases the utilisation of the best winds, thereby providing more electricity per built wind turbine. This increasing resource utilisation potentially enables higher wind shares when acceptance limits are reached in regions with high electricity demand. This in turn reduces the need for other sources of electricity generation, although it requires acceptance both for wind power expansion in the exporting region and for expansion of the transmission network.

Author contributions

VW is the main author, responsible for conceptualization, method, analysis and the main writing. LG contributed with discussion and editing of the work.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

We would like to thank Professor Filip Johnsson for valuable feedback.

Appendix A. Model and data

The model

The model applied in this work is a cost-minimising regional investment model, which was first presented by Göransson et al. (2017). In the present work, it has been run with a 3-hourly resolution for a full year. This specific version is a two-node version with the possibility to invest in transmission lines between the two nodes. All variables that are not connected to costs or emissions have non-negativity constraints. The sets (upper-case letters), parameters (italic upper-case letters) and variables (italic lower-case letters) for the equations are listed below.

T the set of all timesteps
P the set of all technologies
Subsets of P:
P^{el} – include all electricity generation technologies
P^{VRE} – include 12 onshore wind power classes, offshore wind power and solar PV
K the set encompassing the timesteps k in the start-up interval
R the set of the two regions
c^{tot} the total system cost
C_p^{inv} the annualised investment cost of technology p
$C_p^{O\&M,fix}$ the fixed operations and maintenance costs of technology p
C^{CO_2} the charge for fossil CO_2 emissions (captured and stored biogenic emissions are counted as negative fossil emissions).
$i_{p,r}$ the capacity investments in technology p in region r
$C_{p,t}^{run}$ the running cost, including both the operational and maintenance (O&M) and fuel costs, of technology p in time-step t
$g_{p,t,r}$ the generation from technology p in timestep t and region r
$c_{p,t,r}^{cycl}$ the cycling cost (summed start-up cost and part load costs) of technology p in timestep t in region r
$e_{p,t,r}$ emissions from technology p in timestep t in region r
y is the capacity investment in transmission between the regions pair
$D_{t,r}$ demand for electricity at timestep t in region r
$R_{p,r}$ capacity limit for investments in wind and solar resources in region r
$W_{p,t,r}$ the profile limiting the weather-dependent generation of technology p in timestep t in region r
$g_{p,t,r}^{active}$ the active capacity of technology p, which is spinning and, thus, can generate electricity in timestep t in region r
L_p^{min} the minimum load of technology p
$g_{p,t,r}^{on}$ the capacity of technology p which is started in timestep t in region r
C_p^{on} the start-up cost of technology p
C_p^{part} the part-load cost of technology p
E_p emission factor for technology p
E_p^{part} part-load emissions factor for technology p
E_p^{on} start-up emissions factor for technology p
$s_{p,t,r}$ state of charge of (storage) technology p at timestep t in region r
$b_{bat,t,r}^{ch}$ charging of batteries at timestep t in region r
$b_{bat,t,r}^{dis}$ discharging of batteries at timestep t in region r
η_p efficiency of technology p
$I_{t,r}$ inflow of energy to hydropower reservoirs at timestep t in region r
$p_{electrolyser,t,r}$ electricity consumption in electrolysers at timestep t in region r
V_p share of emissions that can be captured with CCS for technology p
$z_{t,r,r2}$ the electricity exported from region r to region $r2$

The objective function of the model can be expressed as follows:

$$\min c^{tot} = \sum_{r\in R}\Bigg(\sum_{p\in P}\left(C_p^{inv} + C_p^{O\&M,fix}\right)i_{p,r} + \sum_{p\in P}\sum_{t\in T}\left(C_{p,t}^{run}g_{p,t,r} + c_{p,t,r}^{cycl} + C^{CO_2}e_{p,t,r}\right) + \sum_{p\in P}\sum_{t\in T}e_{p,t,r}^{CCS}\left(C^{tr} + C^{st}\right)\Bigg) + yC_{transmission}^{inv}, \quad (A1)$$

where C^{st} and C^{tr} are, respectively, the costs of storage and transport of CO_2 for CCS, and $C_{transmission}^{inv}$ is the annualised investment cost in transmission lines, including fixed operational and maintenance (O&M) costs.

The demand for electricity has to be met at all timesteps:

$$\sum_{p\in P^{el}} g_{p,t,r} + b_{bat,t,r}^{dis} \geq D_{t,r} + b_{bat,t,r}^{ch} + p_{electrolyser,t,r} + z_{t,r,r2}, \ \forall t\in \mathrm{T}, r\in \mathrm{R}, \{\mathrm{r2} = \mathrm{R}/\mathrm{r}\} \quad (A2)$$

The level of generation has to remain below the installed capacity, weighted by profile, $W_{p,t,r}$, which is weather-dependent for wind and solar power (but constantly equal to 1 for thermal technologies):

$$g_{p,t,r} \leq i_{p,r}W_{p,t,r}, \ \forall t\in T, p \in \mathrm{P}^{el}, r\in R. \quad (A3)$$

Investments in wind and solar power cannot exceed the regional resources capacity:

$$i_{p,r} \leq R_{p,r}, \ \forall p\in \mathrm{P}^{VRE}, r\in R. \quad (A4)$$

Thermal cycling is accounted for by equation (A5)–(A9) as follows:

$$g_{p,t,r} \leq g_{p,t,r}^{active}, \ \forall t\in \mathrm{T}, p\in \mathrm{P}, r\in R. \quad (A5)$$

$$L_p^{min} g_{p,t,r}^{active} \leq g_{p,t,r}, \ \forall t\in \mathrm{T}, p\in \mathrm{P}, r\in R. \quad (A6)$$

$$g_{p,t,r}^{on} \geq g_{p,t,r}^{active} - g_{p,t-1,r}^{active}, \ \forall t\in \mathrm{T}, p\in \mathrm{P}, r\in R. \quad (A7)$$

$$g_{p,t,r}^{on} \leq i_{p,r} - g_{p,t-k,r}^{active}, \ \forall k\in \mathrm{K}, p\in \mathrm{P}, r\in R. \quad (A8)$$

$$c_{p,t,r}^{cycl} = g_{p,t,r}^{on}C_p^{on} + \left(g_{p,t,r}^{active} - g_{p,t,r}\right)C_p^{part}, \ \forall t \in \mathrm{T}, p \in \mathrm{P}, r\in R. \quad (A9)$$

Equations A5 and A6 limit the generation of a technology so that it lies between the hot capacity and the minimum load. Equation

(A7) controls the amount of capacity that is started, while A8 controls that capacity deactivated for at least the minimum start-up time. Equation (A9) gives the hourly cycling cost for each technology.

The carbon dioxide emissions are calculated as:

$$e_{p,t,r} = E_p\, g_{p,t,r} + g^{on}_{p,t,r} E^{on}_p + \left(g^{active}_{p,t,r} - g_{p,t,r}\right) E^{part}_p - e^{CCS}_{p,t,r},\ \forall t \in \mathrm{T}, p \in \mathrm{P}, r \in R. \tag{A10}$$

where biogenic emissions are calculated as carbon-neutral and the reduction of emissions from CCS is calculated according to:

$$e^{CCS}_{p,t,r} \le g_{p,t,r} E_p V_{p..},\ \forall t \in \mathrm{T}, p \in \mathrm{P}, r \in R. \tag{A11}$$

Batteries are implemented in the model with the following energy balance constraint for the batteries:

$$s_{bat,t+1,r} \le s_{bat,t,r} + \eta^{ch}_{bat} b^{ch}_{p,t,r} - b^{dis}_{bat,t,r} \Big/ \eta^{dis}_{bat},\ \forall t \in \mathrm{T}, r \in R, \tag{A12}$$

All the balance equations (A12, A16, A17) are treated as cyclic, such that the first and the last timesteps of the year are connected.

The charge and discharge volumes are limited by the installed battery capacity.

$$b^{ch}_{bat,t,r} \le i_{bat\_cap,r},\ \forall t \in \mathrm{T}, r \in R. \tag{A13}$$

$$b^{dis}_{bat,t,r} \le i_{bat\_cap,r},\ \forall t \in \mathrm{T}, r \in R. \tag{A14}$$

The battery storage volume is limited by the battery storage size:

$$s_{bat,t,r} \le i_{bat\_store,r},\ \forall t \in \mathrm{T}, r \in R. \tag{A15}$$

Similar to A12, hydropower storage and hydrogen storage are modelled as described by A16 and A17, respectively.

$$s_{hydropower,t+1,r} \le s_{hydropower,t,r} + I_t - g_{hydropower,t,r},\ \forall t \in \mathrm{T}, r \in R, \tag{A16}$$

where $s_{hydropower,t,r}$ is limited by the current reservoirs.

$$s_{H_2,t+1,r} \le s_{H_2,t,r} + \eta_{electrolyser}\, p_{electrolyser,t,r} - \frac{g_{FC,t,r}}{\eta_{FC}},\ \forall t \in \mathrm{T}, r \in R, \tag{A17}$$

where $s_{H_2,t}$ is limited by the investment made in hydrogen storage, $p_{electrolyser,t}$ is the hourly electricity consumption in electrolysers, which is limited by the electrolyser investments, and $g_{FC,t}$ is the electricity consumption in fuel cells.

The export from region r is equal to the negative export from the other region:

$$z_{t,r,r2} = -z_{t,r2,r},\ \forall t \in \mathrm{T},\ r \in \mathrm{R}, \{\mathrm{r2} = \mathrm{R} / \mathrm{r}\} \tag{A18}$$

The transmission is limited by the installed transmission capacity:

$$z_{t,r,r2} \le y,\ \forall t \in \mathrm{T}, r \in \mathrm{R}, \{\mathrm{r2} = \mathrm{R} / \mathrm{r}\}, \tag{A19}$$

Data

Table A.1 gives the investment and variable costs for the electricity generation technologies considered in the model. The investment costs and fixed O&M costs are based on those given in the IEA World Energy Outlook 2016 [24], with the exception of the costs for solar PV which are from the Danish Energy Agency [25]. In the model, annualised investment costs are applied assuming an interest rate of 5%. The variable costs listed in Table A.1 exclude the cost of cycling thermal generation. Instead, the start-up costs and part-load costs are included explicitly in the optimisation. The start-up costs, part-load costs, and minimum load level applied here are based on those described in the report of Jordan and Venkataraman [26], in which all the technologies that employ solid fuels use the cycling costs given for large sub-critical coal-fired power plants. However, in the present work, the start-up fuel is biomethane rather than oil. The cycling properties of nuclear power are modelled with a start-up cost equal to running the plant for 72 h and a minimum load level of 90%.

Table A.1
Costs and technical data for the electricity and biomethane generation technologies, as well as for technologies that provide variation management. The variable costs for the bio-based technologies include a biomass price of 30 €/MWh_{th}.

Technology	Investment cost [M€/MW(h)]	Variable O&M costs [€/MWh]	Fixed O&M costs [k€/MW,yr]	Life-time [yr]	Minimum load level [share of rated power]	Start-up-time [h]	Start-up cost [€/MW]	Efficiency [%]
Biomass ST	2.05	2.1	55	40	0.35	12	57	35
CCGT[a]	0.93	0.8	17	30	0.2	6	45	61
GT[a]	0.47	0.4	16	30	0.5	0	36	42
CCGT CCS[a]	1.63	0.8	50	30	0.35	12	57	54
Nuclear	4.12	0	154	60	0.9	24	2750	33
Solar PV	0.42	1.1	6	40	–	–	–	100
Onshore wind	1.29	1.1	13	30	–	–	–	100

[a] Both for NG and biomethane (for the CCS case only: a mix of biofuels and fossil fuels that would make it have net-zero emissions is included).

The wind power generation profiles are calculated for wind turbines of low specific power (200 W/m^2), with the power curve and losses proposed by Johansson et al. [27]. The wind speed input data are a combination of the MERRA and ECMWF ERA-Interim data for Year 2012, whereby the profiles from the former are rescaled with the average wind speeds collated from the latter [19,20,28]. The high resolution of the wind profiles derived from the ERA-Interim data was processed into wind power generation profiles and combined into 12 wind classes for each region. The full-load hours (FLH) and the maximum capacities (Cap) for all classes, as well as the offshore wind and solar PV are shown in Table A.2. The wind farm density is set at 3.2 MW/km^2 and is assumed to be limited to 10% of the available land area. After removing protected areas, lakes, water streams, roads, and cities, about 6%–7% of the total land area is available for wind farms in the model [29].

Table A.2
Full-load hours (FLH) and maximum capacity (Cap) limits for onshore wind classes 1–12, offshore wind, and solar PV for the two base regions.

Wind class and technology	Hungary		Ireland	
	FLH [h]	Cap [GW]	FLH [h]	Cap [GW]
1	1190	0.0	–	–
2	1670	1.3	–	–
3	2100	5.5	–	–
4	2370	7.8	–	–
5	2570	2.4	–	–
6	2750	1.3	–	–
7	3070	2.4	–	–
8	3350	0.2	–	–
9	–	–	–	–
10	–	–	4240	0.3
11	–	–	4640	13.8
12	–	–	5360	2.1
Offshore	–	–	5360	…
Solar PV	1360	…	1000	…

Solar PV is modelled as mono-crystalline silicon cells installed so as to have optimal tilt with one generation profile for each region. Solar radiation data from MERRA are used to calculate the levels of generation with the model presented by Norwood et al. [30], including thermal efficiency losses. The full-load hours of solar PV in each region are shown in Table A.2.

The cost and technical data for batteries and hydrogen technologies are shown in Table A.3 [25]. The fuel properties are listed in Table A.4, and the costs for transport and storage of CO_2 are set at 20 €/t and 5.4 €/t, respectively.

Table A.3
Costs and technical data for the variation management technologies. The costs for electrolysers are given per MW and the costs of the batteries and hydrogen storage are given per MWh.

	Investment cost [M€/MW(h)]	Efficiency (charge/discharge) [%]	Fixed O&M costs [k€/MW(h),yr]	Life-time [yr]
Battery, Li-ion (storage)	0.08	95/95	–	25
Battery, Li-ion (capacity)	0.07	95/95	0.54	25
Electrolyser	0.39	79	18	15
Fuel cell	0.84	50	55	10
H_2 storage	0.011	100	–	30

Table A.4
Costs and carbon intensities of the fuels used in this study.

	Fuel cost [€/MWh$_{th}$]	Carbon intensity [tonne/MWh$_{th}$]
Biomass	30	0.40*
Coal (hard coal)	9.8	0.34
Natural gas	34.3	0.21
Uranium	8.1	0

* Biogenic emissions are not accounted for if emitted and are counted as negative if captured.

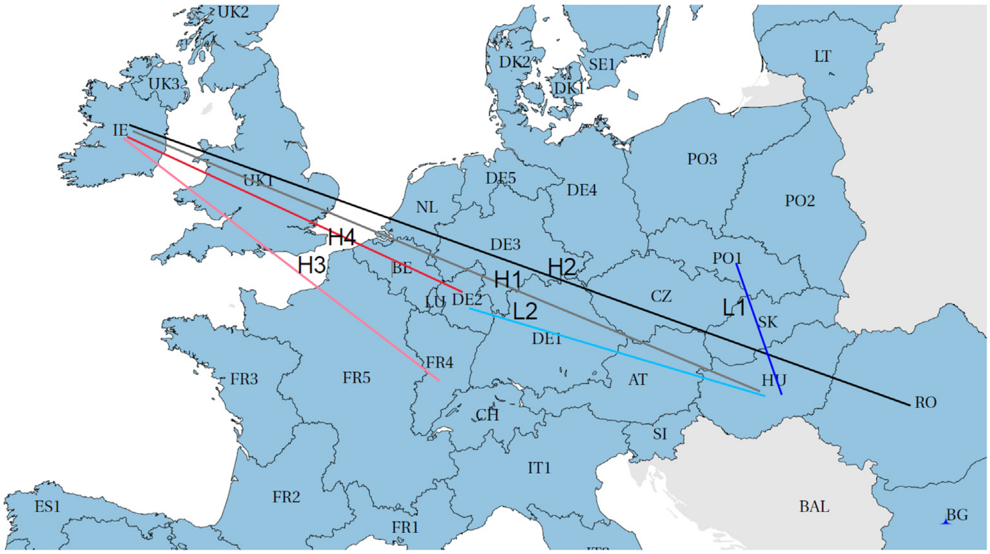

Fig. A.1. Map showing the regional pairings.

The load durations of the stable and unstable wind profiles are shown in Fig. A.2.

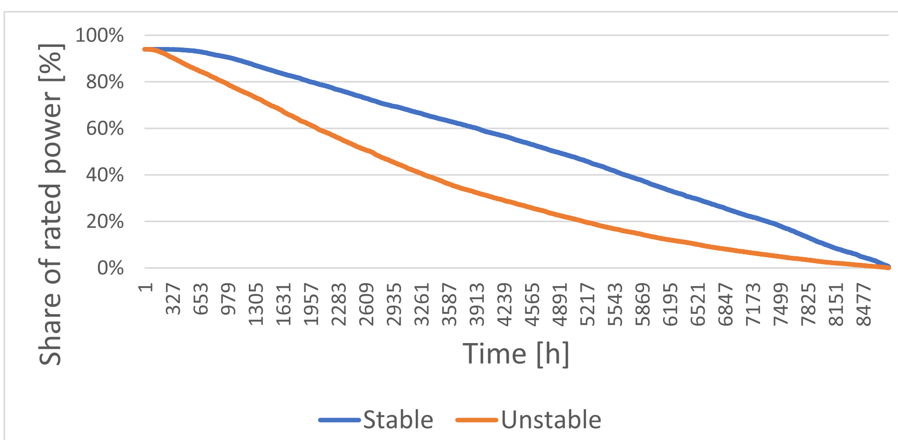

Fig. A.2. Load duration profiles of the stable and unstable wind power profiles.

Appendix B. Results

Additional results regarding accumulated trade flows between Germany and Hungary (Fig. B.1) as well as between France and Ireland (Fig. B.2) are presented in this section of the appendix.

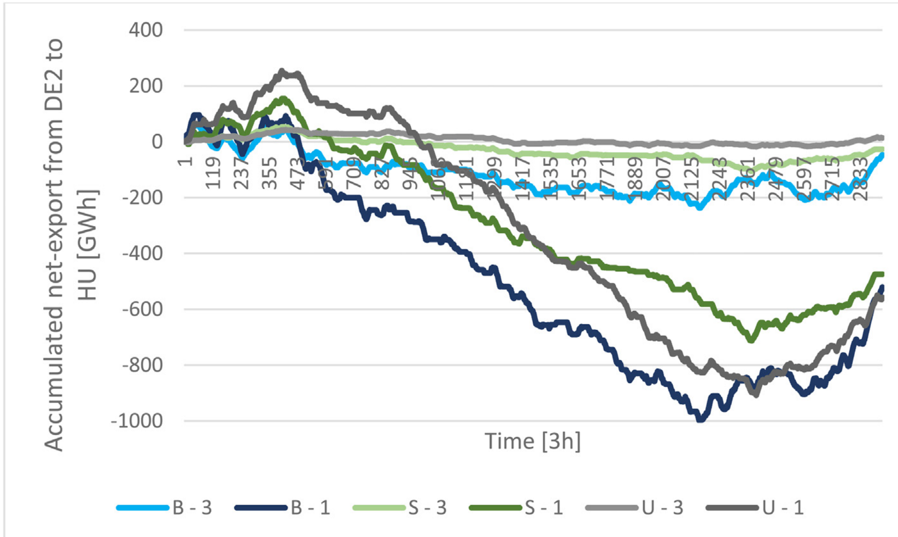

Fig. B.1. Accumulated trade from the net-importing region DE2 to the net-exporting region HU (region pair L2). A negative end-value means that HU has exported more to DE2 than it imported from DE2. The x-axis indicates the time of the year, with each time-stamp representing one 3-h period.

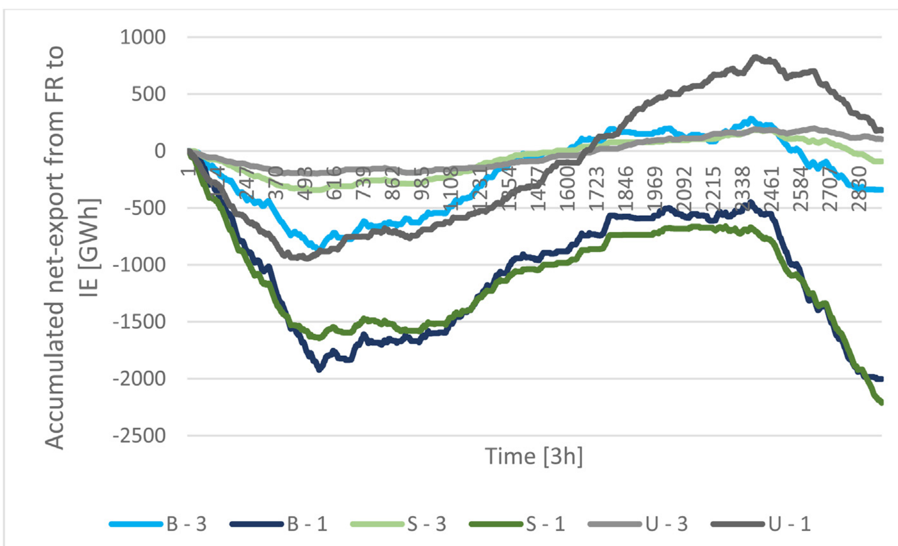

Fig. B.2. Accumulated trade from the net-importing region FR to the net-exporting region IE (region pair H3). A negative end-value means that IE has exported more to FR than it has imported from FR. The x-axis indicates the time of the year, with each time-stamp representing one 3-h period.

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