Impact of wind energy on the European interconnections: Congestions, loop-flows and zonal pricing

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Abstract

This paper investigates the implications of the substantial expansion of renewable energy sources, particularly wind power, on cross-border electricity trade in Europe. Employing Germany – a market with a high penetration of renewables – as a case study, the analysis demonstrates that during periods of high wind generation, Germany functions as a net exporter to all neighboring jurisdictions. Conversely, during periods of negligible wind injection, Germany reverts to a net importer position. This volatility is attributable, in part, to internal congestion within the German transmission system. In the absence of adequate infrastructure, this bottleneck results in the emergence of loop flows, which compromise network management in adjacent countries. Consequently, it is imperative to invest in domestic grid infrastructure within countries generating these loop flows, while simultaneously incentivizing renewable energy storage. This may be achieved through the reform of transmission and distribution network access tariffs. An alternative market design involves the implementation of zonal pricing (market splitting), as observed in the Nord Pool (e.g., Norway and Sweden), which would internalize congestion constraints. While the implementation of locational marginal pricing is often politically resisted in favor of uniform national pricing to ensure regional equity, the consequent socialization of congestion costs may induce spatial distortions and market inefficiencies.

Keywords: electricity, energy markets, energy policy.

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Highlights

The substantial integration of intermittent renewable electricity sources significantly exacerbates price volatility within wholesale electricity markets.

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This heightened volatility can induce negative externalities on the transmission networks of interconnected, neighboring countries (e.g., the observed impact of German wind power on adjacent grids).

Furthermore, congestion on specific national electricity transmission networks often triggers the phenomenon of "loop flows" across the transmission infrastructure of adjacent nations.

Two primary policy and investment solutions exist to mitigate these issues:

1. Strategic investment in the transmission network of the originating country (where the loop flows primarily emerge).
2. The implementation of a zonal wholesale electricity price system, segmenting the market into distinct price zones.

1. Introduction

The interconnection of electricity networks is a key component in the development of a single electricity market in Europe (CRE, 2024). By 2030, all EU Member States are expected to establish cross-border interconnection capacities equivalent to 15% of their national electricity generation capacity. Additionally, by 2026, 70% of these interconnection capacities must be allocated to cross-border commercial exchanges, in accordance with Regulation (EU) 2019/943. The liberalization of the electricity industry in Europe aims to foster convergence in wholesale electricity prices across EU Member States and, ultimately, to establish a single electricity market in which wholesale prices are broadly harmonized. This objective is pursued despite the existence of heterogeneous generation mixes with differing production costs. The primary instrument to achieve this integration is the development of cross-border interconnection infrastructure.

Electricity interconnections facilitate commercial exchanges of electricity between European Union member states and provide mutual support in the event of grid failures. However, these interconnections can also create challenges when the policy decisions of one country constrain the energy strategies of its neighbors. Germany exemplifies this dynamic, having prioritized the large-scale deployment of intermittent renewable energy – particularly wind power which reaches 28% of electricity production in 2024. At times, Germany exports surplus electricity to neighboring grids, while at other times it is compelled to import significant volumes of hydroelectric or nuclear power from these countries to balance its own system.

Furthermore, transmission constraints within Germany – especially between the north and the south – result in loop flows, whereby wind-generated electricity from northern Germany is routed through the grids of neighboring countries to reach consumers in the south. We take Germany as a significant example because the share of renewables, particularly wind power, is higher than the European average. In addition, Germany has many neighboring countries to which it can export its surplus electricity and from which it can import electricity when there is no wind. The approach begins by outlining the methodology employed to track hourly physical electricity flows among key European countries during 2024. It subsequently examines the findings, which demonstrate the significant influence of German wind power generation on neighboring countries' grid systems.

2. Methodology

It is necessary to separate commercial flows from physical electricity flows because the paths are not the same. Physical flows are subject to Kirchhoff's laws and must be taken into account when analyzing congestion on the grid. In the following, the term *physical flow* (PF) refers to the hourly flows defined by the ENTSO-E Transparency Platform (Entso-e, 2024) and available on the ENTSO-E website. The time series consist of 8,784 data points for the year 2024. To distinguish physical flows between different European bidding zones, the resulting physical flow between zone A and zone B is denoted as PF_A^B. If $PF_A^B > 0$, the electrical flow moves from zone A to zone B (A exports to B); if $PF_A^B < 0$, the electrical flow moves from zone B to zone A (A imports from B). The physical flow from zone A to zone B at a given time *t* is denoted as$PF_A^B(t)$.

The *physical balance* from zone A to zone B is defined as the sum of the physical flows from zone A to zone B:

$$\boldsymbol{PB_A^B} = \textstyle\sum_{\boldsymbol{Year}} \boldsymbol{PF_A^B(t)} \qquad \text{Equation 1}$$

The ENTSO-E website also allows downloading data related to electricity generation. We have downloaded the hourly data for Germany and summed the onshore and offshore wind power generation data. The time series representing the wind power component of German electricity generation is denoted as $P_{Germany}^{Wind}(t)$.

The time series $PF_A^B(t)$ can be decomposed into two components:

1. Projection onto a reference series $P_{Germany}^{Wind}(t)$: This component represents the part of $PF_A^B(t)$ that is aligned with $P_{Germany}^{Wind}(t)$. It is obtained by computing the orthogonal projection of $PF_A^B(t)$ onto $P_{Germany}^{Wind}(t)$: ${}_{Germany}^{\parallel Wind}PF_A^B(t)$.

$${}_{\boldsymbol{Germany}}^{\parallel \boldsymbol{Wind}}\boldsymbol{PF_A^B(t)} = \frac{\boldsymbol{Cov\left(P_{Germany}^{Wind}, PF_A^B\right)}}{\boldsymbol{Var(PF_A^B)}} \boldsymbol{P_{Germany}^{Wind}(t)} \qquad \text{Equation 2}$$

where Cov denotes the covariance and Var the variance.

2. Orthogonal component ${}_{Germany}^{\perp Wind}PF_A^B(t)$:

$${}_{\boldsymbol{Germany}}^{\perp \boldsymbol{Wind}}\boldsymbol{PF_A^B(t)} = \boldsymbol{PF_A^B(t)} - {}_{\boldsymbol{Germany}}^{\parallel \boldsymbol{Wind}}\boldsymbol{PF_A^B(t)} \qquad \text{Equation 3}$$

From Equation 2 and 3, it is easy to verify that ${}_{\mathrm{German}}^{\parallel \mathrm{Wind}}\mathrm{PF}_{\mathrm{A}}^{\mathrm{B}}(t)$ and ${}_{\mathrm{German}}^{\perp \mathrm{Wind}}\mathrm{PF}_{\mathrm{A}}^{\mathrm{B}}(t)$ are orthogonal since their covariance is null.

This decomposition (Equations 2 and 3), which separates the total physical flow into two orthogonal components, carries essential economic and physical meaning. The component parallel to German wind generation ${}_{Germany}^{\parallel Wind}PF_A^B(t)$ represents the portion of the electricity flow directly proportional to fluctuations in German wind output. It reflects the direct export of wind surpluses or import when wind power is low. Conversely, the orthogonal component ${}^{\perp Wind}_{Germany}PF_A^B(t)$ captures flows that are statistically independent of German wind variations, reflecting structural trade or imbalances stemming from other energy sources. Economically, the presence of strong orthogonal flows implies the need for complementary generation and storage capacity outside wind-intensive regions, while parallel flows indicate direct export of wind surpluses. These dynamics have implications for infrastructure planning, grid reinforcement, and market integration efforts within the EU and with its key non-member partners.

The parallel and perpendicular components of the *physical flows* between zone A and B may be integrated over a year to obtain the parallel and perpendicular *physical balance*:

$$\boldsymbol{{}^{\parallel Wind}_{Germany}PB_A^B = \sum\nolimits_{Year} {}^{\parallel Wind}_{Germany}PF_A^B(t)} \qquad \text{Equation 4}$$

$${}^{\perp Wind}_{Germany}PB_A^B = \sum\nolimits_{Year} {}^{\perp Wind}_{Germany}PF_A^B(t) \qquad \text{Equation 5}$$

For each EU27 member plus Norway, Switzerland, and the United Kingdom, one can calculate the *country balance* of a country A: CB_A . If the country is a single bidding zone then:

$$\boldsymbol{\begin{cases} CB_A = \sum_B PF_A^B \\ {}^{\parallel Wind}_{Germany}CB_A = \sum_B {}^{\parallel Wind}_{Germany}PF_A^B \\ {}^{\perp Wind}_{Germany}CB_A = \sum_B {}^{\perp Wind}_{Germany}PF_A^B \end{cases}} \qquad \text{Equation 6}$$

If the country A is decomposed in multiple bidding zones A_i, then:

$$\boldsymbol{\begin{cases} CB_A = \sum_{A_i}\left(\sum_{B\notin\{A_i\}} PF_{A_i}^B\right) \\ {}^{\parallel Wind}_{Germany}CB_A = \sum_{A_i}\left(\sum_{B\notin\{A_i\}} {}^{\parallel Wind}_{Germany}PF_{A_i}^B\right) \\ {}^{\perp Wind}_{Germany}CB_A = \left(\sum_{B\notin\{A_i\}} {}^{\perp Wind}_{Germany}PF_{A_i}^B\right) \end{cases}} \qquad \text{Equation 7}$$

The data have been analyzed and the figures have been realized with the help of the r language (R Core Team, 2021; Wickham, 2016). The base maps were obtained via the *rnaturalearth* library (Massicotte and South, 2025).

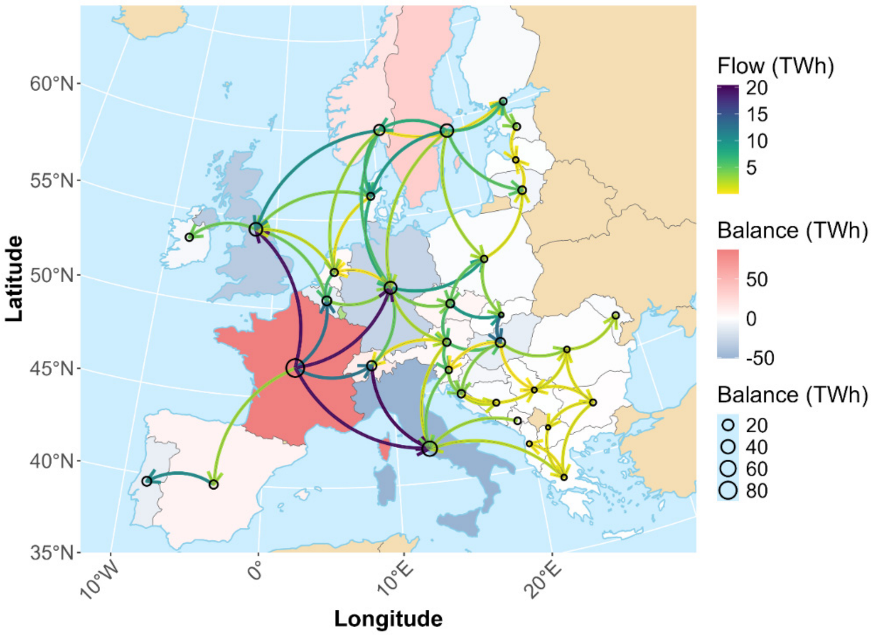
3. Results

3.1. Physical balance in 2024

In this analysis, we consider all physical electricity exchange flows between European countries for the year 2024, regardless of their origin. These figures represent net physical flows rather than commercial transactions. France appears as a net exporter to all of its neighboring countries. Export flows are particularly significant with Italy, the United Kingdom, and Germany. They are somewhat lower with Switzerland, Belgium, and also Spain. Given the substantial volume of Swiss electricity exports to Italy, it can be assumed that part of France's electricity exports transit through Switzerland. It should also be noted that Italy imports electricity from Austria. Italy is by far the largest net importer of electricity in Europe (net imports of 50.68 TWh), followed by the United Kingdom (35.02 TWh), Germany (28.84 TWh), Belgium (10.78 TWh), and Portugal (10.49 TWh) (see Figure 1 and Table 1).

France's status as a net electricity exporter is primarily attributable to its extensive nuclear generation capacity, which is characterized by very low marginal costs and facilitates substantial contractual exports, notably to Italy and Germany. Consequently, France serves as a stabilizing supplier for its interconnected neighbors. However, it is crucial to recognize that during periods of significant nuclear fleet unavailability, France's position can rapidly shift, transforming the country into a strong net importer. This volatility is exacerbated because its generation mix contains insufficient flexible conventional capacity to effectively compensate for peak demand or system outages.

Figure 1 – Physical Flows in Europe in 2024. The color of the arrow represents the total observed flow for the year 2024, while its direction indicates the flow direction. The color of the countries varies as follows: blue for net electricity-importing countries, red for net electricity-exporting countries, and light green for countries not considered for their exchanges with the EU27 zone. Only three non-EU countries – Norway, Switzerland, and the United Kingdom – are fully taken into account, while for other non-EU27 countries, only their electricity exchanges with an EU27 member state are considered



Data: ENTSO-E(2024)

Germany occupies a central position in European electricity exchanges, both along the north-south and east-west axes, due to its geographical location. It is a net exporter to the Czech Republic and Poland, but a net importer from France and the Nordic countries – namely Norway, Sweden, and Denmark. Overall, Germany is a substantial net importer of electricity.

Sweden is a net exporter to Denmark, Germany, Poland, Finland, Norway, and the Baltic States. Norway is a net exporter to Germany, the United Kingdom, and the Netherlands. Both Sweden and Norway possess significant hydroelectric generation capacity, which also enables them to serve as inter-seasonal storage hubs for part of the European electricity grid ("copperplate"). In addition, Sweden has a substantial nuclear power fleet.

To further deepen the data analysis, we chose to decompose commercial electricity exchanges into two orthogonal (uncorrelated) time series: one parallel (i.e., proportional) to German wind power generation, and one perpendicular to it (see methodology section). The decision to focus on German wind generation stems from the fact that Germany has the largest wind power capacity in the European Union and occupies a central geographical position within the continental grid. Furthermore, previous studies have shown that wind regimes in the United Kingdom, France, and Germany – more broadly, across the northern part of the European grid – are highly correlated (Percebois and Pommeret, 2018).

3.2. Impact of German wind power on cross-border physical flows

Table 1, Figures 2 and 3 present a detailed breakdown of cross-border (CB) electricity balances for European countries in 2024, distinguishing between total net physical electricity flows and their components aligned (∥) and orthogonal (⊥) to wind power generation in Germany. The data are expressed in terawatt-hours (TWh), with positive values indicating net exports and negative values net imports.

From an economic perspective, this decomposition provides insight into the spatial and temporal dynamics of electricity trade in relation to Germany's wind generation patterns – a key factor in Europe's renewable energy transition. As Germany is a major hub for wind energy, fluctuations in its wind output influence the cross-border flow structure across the continent.

Germany itself is a significant net importer in aggregate (−28.84 TWh), yet it exhibits a strong surplus (56.61 TWh) in flows aligned with its wind production and a large deficit (−85.45 TWh) in the orthogonal component. This suggests that during periods of high wind generation, Germany exports a substantial share of this surplus to its neighbors, while in low-wind or demand-peaking periods, it relies heavily on imports as showed in Table 1.

Table 1 – Electrical data for 2024[1] *(positive: net exporting country; negative: net importing country).* $CB_{Country}$ *is the balance for the physical flow,* ${}^{\parallel Wind}_{Germany}CB_{Country}$ *is the balance for the physical flow parallel to the wind production in Germany and* ${}^{\perp Wind}_{Germany}CB_{Country}$ *is the balance for the physical flow perpendicular to the wind production in Germany. Only three non-EU countries – Norway, Switzerland, and the United Kingdom – are fully taken into account, while for other non-EU27 countries, only their electricity exchanges with an EU27 member state are considered*

Country	$CB_{Country}$ **(TWh)**	${}^{\parallel Wind}_{Germany}CB_{Country}$ **(TWh)**	${}^{\perp Wind}_{Germany}CB_{Country}$ **(TWh)**
Austria	4,75	-5,25	10,00
Belgium	-10,78	1,67	-12,44
Bulgaria	1,49	-2,04	3,52
Croatia	-5,06	0,79	-5,85
Czech Republic	6,39	-3,73	10,12
Denmark	-3,80	7,92	-11,72
Estonia	-3,17	-1,05	-2,12
Finland	-3,18	-1,91	-1,28
France	87,29	-8,39	95,68
Germany	-28,84	56,61	-85,45
Greece	0,66	-2,12	2,78
Hungary	-11,56	-2,21	-9,34
Ireland	-4,42	0,00	0,00
Italy	-50,68	-8,77	-41,91
Latvia	-0,92	0,38	-1,30
Lithuania	-5,73	0,15	-5,87
Netherlands	4,18	-2,52	6,70
Norway	17,89	-16,48	34,37
Poland	-2,30	1,72	-4,02
Portugal	-10,49	2,70	-13,19
Romania	-1,03	2,62	-3,65
Slovakia	0,12	-0,09	0,20
Slovenia	2,42	-1,25	3,66
Spain	7,54	-3,56	11,10
Sweeden	33,54	-0,92	34,46
Switzerland	12,46	-14,44	26,90
United Kingdom	-35,02	-1,33	-33,69

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[1] Malta and Cyprus are not taken into account in the present study. Luxemburg is in the bidding zone (Germany-Luxemburg).

Several countries exhibit contrasting behavior in the parallel and orthogonal flow components. France, for example, stands out as a major net exporter (87.29 TWh) overall. Its orthogonal surplus (95.68 TWh) far exceeds its parallel deficit (−8.39 TWh), indicating that its exports primarily support neighboring countries when Germany's wind production is low. This positioning reinforces France's role as a stabilizing supplier, likely driven by its large nuclear fleet.

The Nordic region shows a mixed picture. Sweden and Norway are notable net exporters (33.54 TWh and 17.89 TWh, respectively), with Sweden's orthogonal component (34.46 TWh) closely matching its total, indicating steady exports regardless of German wind patterns. Norway, however, shows a large orthogonal surplus (34.37 TWh) and a negative parallel balance (−16.48 TWh), suggesting its flexible hydro capacity is deployed counter-cyclically to Germany's wind output.

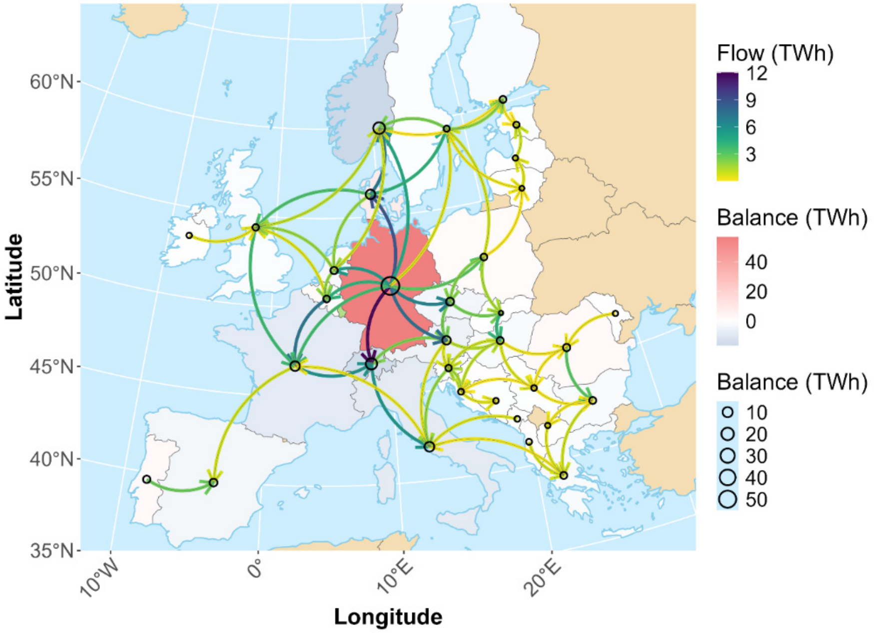
In contrast, southern countries such as Italy (−50.68 TWh) and the United Kingdom (−35.02 TWh) remain structurally dependent on imports, particularly in the orthogonal dimension, suggesting limited responsiveness to German wind generation and perhaps constrained domestic flexibility or interconnection.

Some Central and Eastern European countries (e.g., Czech Republic, Austria) demonstrate a pattern of counterbalancing Germany's wind output – Austria has a strong orthogonal surplus (10.00 TWh) and a negative parallel balance (−5.25 TWh), indicating adaptive export behavior when German wind is low. The Czech Republic displays complementary dynamics, potentially playing a buffer role in regional balancing.

Overall, this decomposition sheds light on how cross-border electricity trade responds not just to net imbalances but to intra-annual variability in renewable generation. Economically, the presence of strong orthogonal flows implies the need for complementary generation and storage capacity outside wind-intensive regions, while parallel flows indicate direct export of wind surpluses. These dynamics have implications for infrastructure planning, grid reinforcement, and market integration efforts within the EU and with its key non-member partners.

Since the data represent net physical flows, it is difficult to determine whether some of the wind electricity produced in northern Germany – where offshore wind farms are located in the Baltic Sea – is subsequently redirected to southern Germany (e.g., Bavaria). If that is the case, it would suggest the presence of loop flows caused by congestion in the north-south transmission corridors within the German grid.

Figure 2 – German wind parallel component of the Physical Flows in Europe in 2024. The color of the arrow represents the total observed flow for the year 2024, while its direction indicates the flow direction. The color of the countries varies as follows: blue for net electricity-importing countries, red for net electricity-exporting countries, and light green for countries not considered for their exchanges with the EU27 zone. Only three non-EU countries – Norway, Switzerland, and the United Kingdom – are fully taken into account, while for other non-EU27 countries, only their electricity exchanges with an EU27 member state are considered

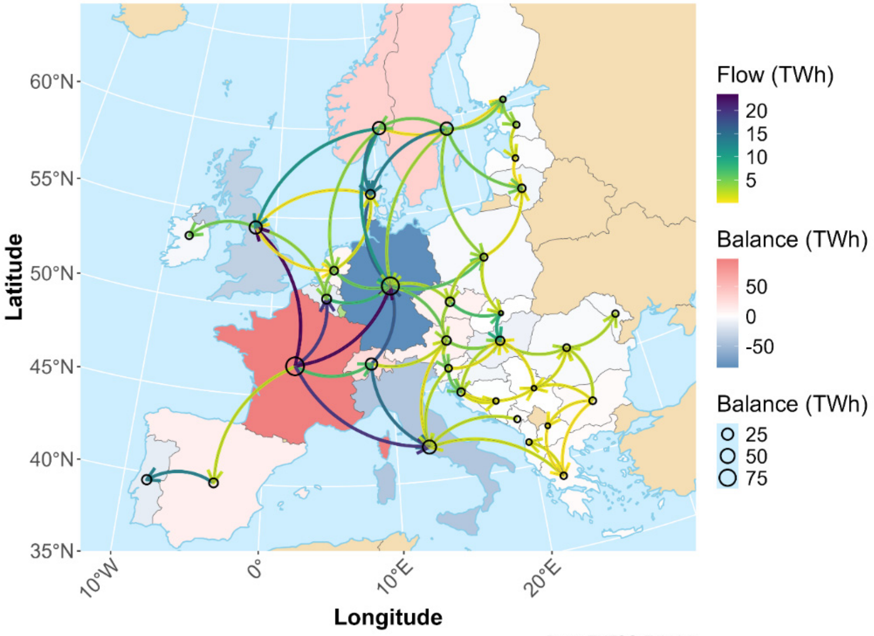


Data: ENTSO-E(2024)

Table 2 – Physical balance of Germany with the neighboring countries (positive: export; negative: import)

Country	$PB_{Germany}^{Country}$ (TWh)	${}_{Germany}^{\|Wind}PB_{Germany}^{Country}$ (TWh)	${}_{Germany}^{\perp Wind}PB_{Germany}^{Country}$ (TWh)
Austria	2.41	7.68	-5.27
Belgium	-3.51	4.22	-7.73
Czech republic	3.88	6.55	-2.68
Denmark	-7.41	8.88	-16.29
France	-19.77	3.63	-23.40
Netherlands	0.03	5.34	-5.31
Norway	-5.78	4.73	-10.51
Poland	8.81	2.97	5.84
Sweeden	-5.78	4.73	-10.51
Switzerland	-4.88	12.03	-16.91

Figure 3 – German wind perpendicular components of the Physical Flows in Europe in 2024. The color of the arrow represents the total observed flow for the year 2024, while its direction indicates the flow direction. The color of the countries varies as follows: blue for net electricity-importing countries, red for net electricity-exporting countries, and light green for countries not considered for their exchanges with the EU27 zone. Only three non-EU countries – Norway, Switzerland, and the United Kingdom – are fully taken into account, while for other non-EU27 countries, only their electricity exchanges with an EU27 member state are considered



Data: ENTSO-E(2024)

Overall, the data illustrate how variable renewable energy generation in a major hub like Germany generates significant cross-border spillovers, with wind output not only affecting German net exports but also reshaping flows between third countries. The Tables 1 and 2 and the Figures 2 to 3 provide strong evidence of the growing interdependence among European electricity systems and underscore the importance of coordinated grid operation and market design that can accommodate such variability – potentially through flexible infrastructure investments, dynamic pricing zones, or capacity-sharing mechanisms.

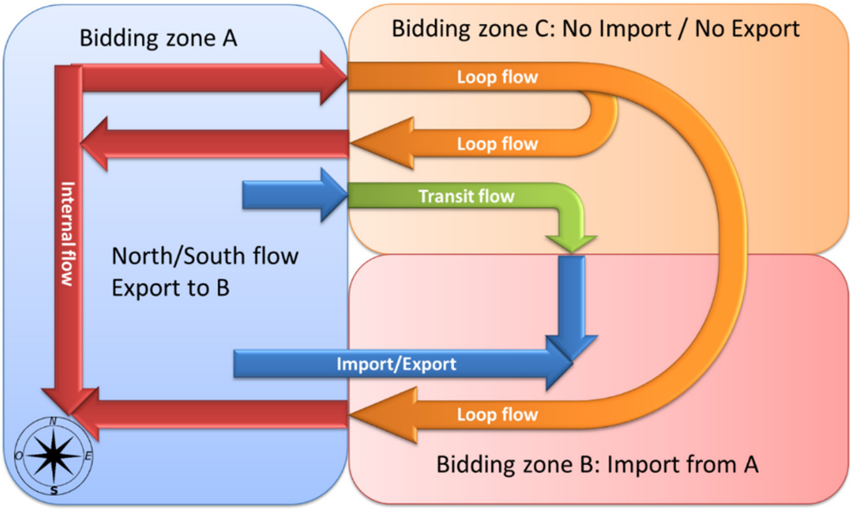
4. Loop-flows

Three types of cross-border electricity flows can be distinguished and are illustrated in Figure 4 (Entso-e, 2018; Lauer, 2021; Riou, 2024):

1. **Scheduled Commercial Flows:** These refer to the market-based exchange where a producer in Zone A sells electricity to a consumer in Zone B. This transaction results in a nominated commercial schedule representing the contractual obligation to transfer energy across the border from A to B.
2. **Unscheduled Physical Transit Flows:** Due to Kirchhoff's laws regarding voltage and impedance, the actual physical path of electricity does not strictly follow commercial paths. Consequently, a portion of the energy traded between A and B may physically flow through the grid of a third country (Zone C), which is not a party to the transaction. These are technically classified as transit flows.
3. **Loop Flows:** These represent unscheduled physical power flows driven by network impedance differences rather than commercial contracts. The figure illustrates two distinct manifestations of this phenomenon:
   a. **Intrazonal Loop Flows** ($A \rightarrow C \rightarrow A$): Electricity generated in Zone A exits to Zone C due to internal congestion (e.g., a North-South bottleneck in A) and subsequently returns to Zone A. The flow merely uses the neighbor's grid as a bypass for domestic transport.
   b. **Interzonal Loop Flows** ($A \rightarrow C \rightarrow B \rightarrow ...$): These are complex unscheduled flows where electricity – intended for domestic use in A – traverses multiple neighboring zones (C, B, etc.) in a circular or parallel manner before reaching its final sink. Crucially, like the intrazonal variant, this flow is primarily attributed to structural congestion and the inability of the direct interconnections to absorb the entirety of the nominated physical flow.

In all cases, these unscheduled physical flows create a negative externality by consuming cross-zonal transmission capacity in transit zones (C) and importing zones (B) without a corresponding market-based payment, thereby degrading the overall efficiency and security of the interconnected system.

Figure 4 – Diagram illustrating the distinction between loop flows, transit flows, import/export flows, and internal flows in an electricity network



Electricity interconnections facilitate commercial exchanges of electricity between European Union member states and provide mutual support in the event of grid failures. However, these interconnections can also create challenges when the policy decisions of one country constrain the energy strategies of its neighbors. Germany exemplifies this dynamic, having prioritized the large-scale deployment of intermittent renewable energy – particularly wind power. At times, Germany exports surplus electricity to neighboring grids, while at other times it is compelled to import significant volumes of hydroelectric or nuclear power from these countries to balance its own system.

Furthermore, transmission constraints within Germany – especially between the north and the south – probably result in loop flows, whereby wind-generated electricity from northern Germany is routed through the grids of neighboring countries to reach consumers in the south. These negative externalities have prompted some stakeholders to propose reforms to the current European grid design, including the introduction of multiple wholesale price zones within countries. Such measures could partially alleviate internal congestion and better align market signals with physical grid constraints.

It is crucial to note that, within the scope of this analysis, physical power flows are aggregated exclusively at the bidding zone level. Consequently, the 'loop flows' referenced here are conventional numerical representations that capture the macroscopic phenomenon of unscheduled power transfers resulting from internal grid congestion, rather than the precise physical flows calculable via a detailed nodal network simulation. While this aggregation simplification is a conventional methodology employed by organizations such as ENTSO-E for cross-border analysis, it remains relevant for illustrating the external systemic impact of internal constraints -such as those observed within the German transmission system- on adjacent synchronous grids.

The issue of loop flows has been addressed in the literature in connection with problems encountered on interconnected networks, mainly in Central Europe. Here again, Germany appears to have played a role in the impact that these loop flows have had on its neighboring countries (Singh et al., 2016).

It is known that in the event of a massive injection of wind-generated electricity, wholesale electricity prices on the German market are low, or even zero or negative. This phenomenon impacts the wholesale prices of neighboring countries, which often complain about it, such as Sweden. Conversely, in the absence of wind, German wholesale prices surge, forcing Germany to import large quantities of electricity from its neighboring countries. This is explained by the significant share of wind power in Germany's energy mix. The volatility of wholesale prices in Germany's neighboring countries is partly due to the variability of German wind power production, raising concerns about the unintended consequences of cross-border interconnections. Electricity companies in Sweden and Norway have reduced investment activity in response to persistently low electricity prices, a phenomenon largely attributable to significant imports of wind-generated electricity from Germany.

This dynamic can constrain future system flexibility, particularly when wholesale prices experience upward shocks. Conversely, when wind generation in Germany is insufficient, exports of low-cost hydroelectricity from Sweden or Norway to Germany can exert upward pressure on wholesale prices within the Nordic region, a development frequently criticized by local industrial consumers. Nevertheless, it should be emphasized that such cross-border electricity flows displace more expensive and carbon-intensive fossil-based generation in Germany, thereby exerting a downward influence on European wholesale prices and contributing to CO_2 emissions reductions (Percebois and Pommeret, 2021). As a result, the intermittency inherent to renewable energy sources is emerging as a shared operational and economic constraint across Northern Europe, intensifying the interdependence of regional electricity markets.

5. Discussion and solutions

Although this analysis does not directly quantify the magnitude of physical loop flows, the data presented in Table 2 and Figure 2 offer indirect evidence of the negative externality generated by German internal grid congestion. Germany's substantial parallel balance (closely correlated with wind generation), projected at 56.61 TWh for 2024, indicates a massive export of its wind surplus. Given the existing north-south transmission constraints within Germany's internal transmission system, a significant portion of this northern wind power surplus is highly likely rerouted through the transmission networks of adjacent countries to serve southern German demand. This physical displacement effectively reduces the available transmission capacity (ATC) of these third countries for mutually beneficial commercial power exchange.

The European Commission actively advocates for increased investment in cross-border electricity interconnections to optimize the allocation and flow of electricity across member states. However, these enhanced interconnections can generate unintended systemic effects: when a country faces either surplus or deficit in intermittent renewable generation, it can destabilize the electricity balance in adjacent grids. Neighboring systems are then compelled to either absorb excess electricity or compensate for deficits, and, in some instances, facilitate the transit of surplus power due to congestion within the originating country's transmission network (Amundsen and Bergman, 2006).

With the growing frequency of network congestion, the reliance on costly redispatch measures is increasing, as highlighted by Neuhoff (Neuhoff et al., 2025, 2013). If internal grid bottlenecks become too pronounced, the delineation of national wholesale price zones ceases to be efficient, undermining market signals and welfare optimization. This challenge is fundamentally rooted in the non-storable nature of electricity, which necessitates real-time balancing between supply and demand.

Several policy and technical measures can mitigate the unintended externalities of cross-border electricity flows:

- First, countries generating surplus intermittent power could be mandated to curtail wind generation during oversupply periods and prioritize grid expansion to internalize congestion costs, notwithstanding high capital expenditures and potential community opposition to infrastructure projects. Moreover, the inability to feed part of the renewable electricity into the grid due to congestion or at the request of the grid operator can be collectively costly if the producer receives public support.
- Second, physical flow control mechanisms – such as Poland's deployment of phase-shifting transformers at interconnection points – can selectively block uncontrolled transit, though these risks contravening EU market integration principles.
- Third, adjusting transmission tariff structures to reflect marginal congestion costs could economically incentivize optimal flow patterns and reduce loop flows.

- Fourth, the Agency for the Cooperation of Energy Regulators (ACER) proposes subdividing national wholesale price zones in countries with pronounced internal congestion, thereby aligning market prices more closely with localized grid conditions and mitigating overflow externalities (ACER, 2022).

These measures collectively aim to address the spatial and temporal mismatches inherent in renewable energy systems while balancing economic efficiency, grid stability, and regulatory coherence.

A fundamental principle in European electricity market design is that, in the absence of internal congestion, a single wholesale price should be maintained within each country, reflecting uniform market conditions. In the event of congestion, and when grid expansion is not a viable option, the market adopts a zonal pricing system, segmenting into multiple price zones that correspond to the physical limitations of the grid. In cases of persistent internal bottlenecks, regulatory guidelines recommend redrawing zones to align market boundaries with actual physical limitations, thereby improving price signal accuracy and congestion management (Glachant and Pignon, 2005).

European electricity markets currently rely predominantly on zonal pricing, a model in which each bidding zone is assigned a single wholesale price. While this framework effectively supports cross-border market integration and liquidity, it increasingly fails to accurately reflect physical grid realities as the penetration of intermittent renewable generation expands and internal transmission congestion intensifies. Consequently, policymakers across the European Union are actively debating reforms to existing bidding zone configurations and considering the potential long-term transition towards more granular locational pricing schemes.

Wholesale prices vary across zones: they tend to be lower where electricity production exceeds demand and higher where demand surpasses supply. This price divergence incentivizes industrial consumers to relocate to lower-cost zones and encourages electricity producers to invest in higher-price zones, although the magnitude of price differentials may sometimes be insufficient to motivate significant relocation. It is important to recognize that industry location decisions are influenced by multiple factors beyond energy costs, such as infrastructure quality and labor availability.

Zonal pricing structures already exist in several European electricity markets, including five zones in Norway, four in Sweden, two in Denmark, and as many as seven in Italy (Amundsen and Bergman, 2007). In these systems, each zone establishes its own spot price when inter-zonal transmission constraints emerge, thereby reflecting the local supply-demand equilibrium and the available transfer capacity. The delineation of zones is based on actual physical congestion points in the transmission network, rather than on administrative or national boundaries. The Agency for the Cooperation of Energy Regulators (ACER) and the European Commission are currently evaluating the potential for a broader implementation of zonal pricing across the EU, including in France – where the transmission grid is highly meshed and internal congestion remains limited. ACER's objective is to move away from a price zone configuration that largely mirrors national borders and instead adopt one grounded in economic and physical grid realities (Montel, 2025).

The adoption of a multi-zonal wholesale pricing mechanism can yield efficiency gains by reducing network management costs, mitigating congestion, and providing locational price signals that guide investment and operational decisions. Nonetheless, such a system introduces significant complexity, particularly with respect to the accurate definition of zone boundaries and the potential for reduced market liquidity, which may exacerbate price volatility in less interconnected zones (Glachant and Pignon, 2005).

An alternative market design approach involves the establishment of transnational wholesale electricity price zones. For instance, low-price areas in northern Norway and Sweden could be aggregated into a single combined zone, while their respective high-price southern regions could constitute a separate zone. This strategy aims to align bidding zone configurations with the physical characteristics of the transmission network rather than being constrained by national political boundaries. Expanding the geographical size of zones generally enhances market liquidity and contributes to dampening price volatility by enabling more robust trading volumes and improved price discovery mechanisms within each enlarged zone. However, the efficacy of zonal splits is subject to intense policy debate. For example, the Swedish subsidiary of the German utility E.ON advocated in 2025 for the reunification of the country's electricity market into a single bidding zone in order to mitigate domestic price volatility. The Swedish market had been deliberately segmented into four auction zones in 2011 with the express goal of providing better locational investment signals for both new generation and consumption capacity. As this measure is largely assessed to have failed to attract the anticipated investment, the utility argued for its repeal. Conversely, in the Norwegian context, while the current five price zones are generally performing effectively, the potential subdivision of zone NO4 (Northern Norway) is under consideration. This proposed split is motivated by the aim to:

- facilitate a more optimal utilization of hydro-electric resources,
- reduce transmission congestion,
- narrow internal price discrepancies within the region.

The primary factor driving this consideration, as explained by Statnett (the Transmission System Operator), is the anticipated increase in industrial consumption within Northern Norway. The operational parameters of the Norwegian electricity transmission network are fundamentally constrained by geography (a highly mountainous topography). Furthermore, nearly all electricity generation is hydro-electric, with reservoirs and power stations dispersed widely across the country. Consequently, the existing auction zones are instrumental in allowing the Norwegian hydro-electric system to preserve the economic value of water by accurately reflecting the actual geographical and network constraints inherent to the system.

Most empirical and theoretical analyses converge on the conclusion that "multi-regional zonal pricing improves static market efficiency relative to uniform national pricing, albeit without reaching the allocative precision of full nodal pricing" (Neuhoff et al., 2013). While nodal pricing remains the theoretically first-best solution for achieving static economic efficiency, its significant implementation complexity, demanding data requirements, and critical institutional and political hurdles have rendered zonal pricing the most practical and preferred intermediate step in European market integration efforts (Borowski, 2020; Knörr et al., 2025). Internalizing transmission congestion within electricity prices (even through multinational zonal configurations) is the fundamental mechanism required to provide locational investment signals and enable market forces to rebalance the system through both generation and consumption investment. This approach is crucial because it minimizes network upgrade costs and incentivizes large electricity consumers to locate their activities in areas where system prices are lowest. However, it is pertinent to note that the cost of electricity is typically not the sole determinant in this locational decision-making process. Other critical factors, particularly political considerations such as tax incentives, subsidies, and labor costs, significantly influence the ultimate choice of industrial siting.

The reform of electricity bidding zone configurations is inextricably linked to the broader context of the energy transition toward renewable sources. Optimally configured zones have the potential to better monetize local renewable generation and enhance overall system flexibility. However, the frequency of such zonal configuration changes is a critical consideration. Excessive reconfiguration frequency introduces regulatory uncertainty for capital investment (Lété et al., 2022; Sarfati and Holmberg, 2020). Furthermore, reconfiguring zones entails tangible operational costs and may lead to potentially negative short-term market effects. A key concern raised by several market operators is that the shift to smaller zones could compromise market liquidity and increase local price volatility.

The massive development of storage facilities, particularly batteries, should also prevent these congestions and loop flows. One way to encourage producers to use storage as a flexibility solution is to introduce incentive pricing for access to electricity transmission and distribution networks. France has such a project. In France, for example, the regulatory commission in charge of access tariff will introduce a new tariff option, the injection-withdrawal tariff, reserved for standalone storage, which will come into effect on August 1, 2026 (CRE, 2025). The principle takes into account congestion zones linked to renewables.

Approximately 13% of the network's areas are constrained in terms of "photovoltaic and wind injection" – that is, in these areas, the network tends to be saturated on the production side during peak solar hours (summer, 12 p.m. to 4 p.m., ~125 consecutive days). In these areas, the injection-withdrawal tariff remunerates storage for withdrawing during these peaks. Approximately 50% of the grid's zones are subject to withdrawal constraints – the grid tends to be saturated on the consumption side during peak hours (winter tariffs). In these zones, the feed-in/withdrawal tariff remunerates storage for injecting during peaks. Thus, the toll can be negative: this tariff remunerates storage for its countercyclical activity.

Unlike the price zones proposed by the European regulator (ACER), which would create several wholesale price zones, the tariff zones planned by the French regulator are zones of differentiation in network access tariffs, with the aim of promoting on-site storage of renewables and thus limiting wholesale price volatility. The aim is to encourage storage facilities to adopt behavior that reduces local network peaks, whether these are local injection or withdrawal peaks. This tariff component therefore distinguishes between two types of network pockets based on their size: 1) in pockets sized for withdrawal, the tariff signal encourages a reduction in the withdrawal peak, i.e., injection during periods when withdrawal peaks are significant. To this end, the tariff component selected introduces an additional cost if the user withdraws during a local withdrawal peak, and a cost reduction if the user injects during a local withdrawal peak; 2) in so-called injection zones, the tariff signal selected encourages storage facilities to reduce injection peaks, i.e. to withdraw during injection peaks. To achieve this, the tariff component selected imposes an additional cost if the user injects during a local injection peak, and a cost reduction if the user withdraws during a local injection peak.

6. Conclusion

National energy policy decisions can impose externalities on neighboring electricity systems, either by exporting surplus electricity during periods of oversupply or by drawing heavily on cross-border imports during domestic shortages. Additionally, internal transmission bottlenecks within one country can induce unintended power flows – so-called loop flows – across the networks of neighboring countries, thereby compromising their operational stability and increasing congestion costs at the regional level.

This analysis highlights the necessity of reinforcing internal transmission infrastructure, or, where such investments are insufficient or delayed, the alternative of establishing zonal markets. Introducing transnational price zones is another potential measure to reduce redispatching and congestion management costs. Ultimately, a trade-off arises between expanding physical transmission capacity and implementing market-based spatial segmentation – a choice that has significant implications for the goal of achieving wholesale price convergence across the European interconnected grid.

Furthermore, the implementation of zonal or transnational locational pricing mechanisms introduces a significant policy trade-off. On one hand, these mechanisms provide the necessary locational signals for long-term generation and consumption investments, thereby restoring economic efficiency over time. On the other hand, the design of these mechanisms must be carefully balanced against national policy objectives. These objectives include the territorial harmonization of retail electricity tariffs and industrial strategies designed to steer the regional siting of energy-intensive sectors. Moreover, the existence of different zonal pricing structures raises fundamental concerns regarding the European Union's long-term goal of establishing a fully integrated wholesale electricity market primarily facilitated through cross-border interconnectors.

The growing development of renewable energies will increasingly require the storage and release of intermittent renewable electricity, which will necessitate the development of battery installations. Appropriate pricing for access to transmission and distribution networks can encourage the development of such storage facilities.

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