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Review

Trend Analysis of Cross-Border Electricity Trading in Pan-European Network

Venizelos Venizelou and Andreas Poullikkas *

Cyprus Energy Regulatory Authority, P.O. Box 24936, Nicosia 2002, Cyprus
* Correspondence: andreas.poullikkas@eecei.cut.ac.cy

Abstract: The long-term global target of facilitating energy security and optimizing resource utilization while supporting the transition to sustainable energy systems has led the pathway towards regional cooperation in the context of energy infrastructures and trading. Recent trends highlight the development of transnational energy grids, pipelines, and renewable energy projects, facilitating efficient distribution of electricity, gas, and other energy forms. These advancements offer benefits such as increased reliability of energy supply, cost savings through shared resources, and strengthened relationships between countries. However, challenges persist, including regulatory differences, geopolitical tensions, alignment of market rules as well as substantial investment requirements in infrastructure and technology. Addressing these challenges necessitates harmonized policies, robust legal frameworks, and cooperative international governance, which are crucial for effective cross-border energy trading. The aim of the work is to present the current landscape as well as analyze the latest trends and developments in the dynamic field of electricity interconnectors, providing insights into its trajectory and implications for the European internal energy market.

Keywords: cross-border trading; electricity interconnection; energy infrastructure; energy transition; internal energy market

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1. Introduction

The European Union (EU) has placed decarbonization at the core of its energy policy, driven by commitments to combat climate change and transition towards a sustainable energy future. The EU's strategies for decarbonization are multifaceted, aiming to reduce greenhouse gas emissions, enhance energy efficiency, and promote Renewable Energy Sources (RES). The cornerstone of these strategies is the development and integration of a cohesive Internal Energy Market (IEM). Electrical interconnectors are a linchpin in the development of the European IEM through the physical integration of national electricity markets, thus allowing for cross-border electricity trade, enhancing the security of supply, supporting the integration of renewable energy, and contributing to price convergence.

The history of electricity interconnectors in Europe is rooted in the broader effort to create a more integrated, reliable, and sustainable energy market across the continent. The development of these interconnections emerged from the post-World War II period, evolving through political and economic changes, technological advancements, and environmental considerations. The EU's growing push for a single energy market was formalized with the First Energy Package in 1996 [1], which aimed to liberalize and integrate electricity markets across member states (MSs). This created a framework where cross-border electricity interconnectors played a vital role in enabling competition and energy trading. At the Barcelona European Council in 2002, the EU set a target for each member state to have at least 10% of its installed electricity generation capacity connected via interconnectors to other countries [2]. This was intended to ensure that no country would be isolated from the broader European electricity market. The rise of renewable energy as a European priority further accelerated the development of interconnectors. The

increasing share of intermittent renewable sources like wind and solar required a more flexible and interconnected grid to maintain supply and demand balance across borders [3]. The European Commission's (EC's) Third Energy Package in 2009 (Directive 2009/72/EC [4], Directive 2009/73/EC [5] and Regulation (EC) 714/2009 [6]) introduced several reforms to enhance market integration and electricity grid coordination, while also established bodies like the Agency for the Cooperation of Energy Regulators (ACER) [7] and the European Network of Transmission System Operators for Electricity (ENTSO-E) [8] to oversee and promote the development of interconnectors.

Nevertheless, the magnitude of these investments, along with their strategic nature, highlights the fact that we cannot solely depend on the market to provide all the required capital. The economic crisis had a significant impact on the private sector's ability to adequately finance infrastructure projects. Hence, the European Commission also had to formulate its own plan regarding the advancement of energy infrastructure in order to encourage appropriate investments in power transmission. Establishing an appropriate financial structure is an essential measure for constructing a unified energy market across Europe. In this regard, the EC is motivated to establish the most advantageous amounts of public and private funding while considering the relevant state aid regulations. Additionally, the EC aims to identify and designate strategic infrastructures that are crucial for the EU in terms of ensuring a reliable energy supply and facilitating access to RES. These projects are designated as "Projects of Common Interest (PCIs)" and "Projects of Mutual Interest (PMIs)" and are eligible for an enhanced permitting process and funding. The first initiative for PCIs was introduced in 2013 under the trans-European energy networks (TEN-E) Regulation 347/2013 [9], while the latter PMIs were added to the framework later with the revised TEN-E Regulation 2022/869 [10], which came into force in 2022 with the objective to extend the scope of infrastructure projects to those involving cooperation between EU member states and third countries (non-EU countries), enhancing energy security and decarbonization efforts beyond the EU's borders. Projects listed as PCIs or PMIs are eligible for financial support from the Connecting Europe Facility (CEF) [11], a major EU fund dedicated to infrastructure development. This financial assistance helps cover the high costs associated with the planning, development, and construction of large-scale cross-border energy projects, reducing financial barriers and attracting investment.

The growing importance of electricity interconnectors in cross-border trading has been driven by the need for a more integrated, reliable, and efficient European energy market. The critical role of these infrastructures and the significance of a unified electricity market are vastly discussed in various key studies and theoretical frameworks that explore the economic, technical, and policy aspects of electricity interconnectors and their influence on market dynamics.

The work conducted in [12] analyses the effectiveness and worth of separate and interconnected trading for the four direct current (DC) interconnectors to the United Kingdom (UK) across several timeframes ranging from one year in advance to intraday, as well as the societal costs and benefits that are not accounted for in the individual gains. Due to their intrinsic complexity, such undertakings often encounter multiple impediments. These factors can encompass regulatory ambiguity, fragmented regulations, multiple permitting processes, uncertainties related to construction and supply and demand levels, uneven prioritization on both sides of the border, complexities in coordinating funding sources, and other challenges in planning, preparing, and executing projects. Consequently, cross-border initiatives frequently experience delays in their initiation and face additional expenses. Notwithstanding their high expenses and intricate nature, cross-border infrastructure plays a crucial role in the EU's economy and the operation of its internal energy market, as well as in any regional market worldwide [12]. Investing in sound cross-border infrastructure projects is justified due to the substantial long-term economic and social advantages they provide by enhancing connectivity.

In [13], a thorough analysis of the various technological methods for implementing interconnectors is presented. It explores past patterns and evaluates the ownership models,

regulatory frameworks, and market structures that are crucial for making a compelling investment case for new electricity interconnectors. Utilizing both technical and market factors, the work examines the potential influence of electricity interconnectors on the energy market and stakeholders in connected markets. It then delves into the policy implications of introducing new electricity interconnection projects to the UK energy sector, highlighting the need to consider additional factors beyond consumer welfare in the decision-making process regarding interconnector investment. The research presented in [14] examines the power trade between the UK and neighboring nations in 2030. The economic power dispatch for 2030 was determined by solving a linear programming merit order dispatch model. Assumptions were made for five different price scenarios for the import-only interconnector and four different capacity scenarios for the UK–France electricity interconnector, which has a capacity of 2 GW. The projected configuration had two connecting links, IC1 and IC2, with a combined capacity of 17.7 GW. IC1 was designed for one-way import-only purposes, while IC2 facilitated two-way trade between Great Britain (GB) and France. The purpose of the IC2 link was to transfer electricity from a country with lower costs to a country with higher costs. The findings suggest that the proportion of generating technologies in 2030 is contingent upon the IC1 import price and the IC2 capacity. The capacity factor of the IC2 link decreases as the IC2 capacity increases while maintaining a constant IC1 import price. Furthermore, as the IC1 import price increases, the capacity factor of the IC2 link also increases while keeping the IC2 capacity constant. The results indicated the price effects in relation to the capacity factor, hindering the economic importance behind these infrastructures.

The authors of [15] present the setting, approach, and verification of developing a representative model of the European high-voltage grid, encompassing electricity infrastructures of voltages above 200 kV, utilizing publicly available data. Towards enhancing the worldwide significance of open and maintainable data for high-voltage interconnectors, the dataset and methodology are integrated with an open-source, sector-coupled optimization model of the European energy system.

The objective of [16] is to propose a multi-criteria decision analysis technique that can effectively evaluate and rank cross-border energy interconnection projects based on technical, economic, environmental, and social factors. In addition, this study examines the impact of electricity interconnections on the resilience of linked power networks. In order to confirm its applicability, the new Spain–France interconnection infrastructure projects are utilized. Based on the collected results, it is evident that the technical and environmental requirements are of utmost significance in cross-border energy interconnection projects. Results also highlight that the interconnector infrastructures improve market coupling, reduce congestion, enhance dependability, and minimize environmental impacts. In [17], a thorough examination of the existing literature about the idea of a worldwide interconnected power grid is presented. This work examines the advantages and difficulties related to a worldwide power grid, as well as intercontinental electricity interconnectors. Additionally, it evaluates current initiatives that support the notion, as well as an evaluation of the latest advancements in intercontinental interconnection projects. Also, in [18], the effectiveness of evaluating interconnection lines by quantifying their effects on the primary measures of reliability and vulnerability in linked power networks is evaluated. The reliability analysis is conducted using the sequential Monte Carlo simulation technique, while the vulnerability evaluation is accomplished through the implementation of a cascading failures methodology. In this scope, seven case studies are conducted using the IEEE RTS-96 test system. The findings indicate that infrastructures with strong connections exhibit both high dependability and limited robustness, implying that these techniques demonstrate distinct operational features of the power system. However, a suitable expansion in the quantity and capacity of the interconnections might enhance the security aspects of the power supply.

The global and regional initiatives in the perspective of achieving a sustainable future are examined in [17]. The work discusses the advantages and difficulties associated with

globally interconnected electricity grids and transcontinental interconnectors, proving that the problems and opportunities associated with the global grid idea are well-defined, but there is a lack of precise measurement and analysis of the costs, benefits, and environmental impacts. This gap in the existing literature is significant and indicates that research in this area is still in its early stages. The evolving regulatory framework for electricity interconnectors and cross-border trading is shaped by the need for greater market integration, the support of renewable energy, and the response to new geopolitical realities. However, recent studies show that there is now a significant lack of understanding and comprehension of the linkages and the concept of an integrated EU and the roadmap towards sustainability, while the public majority fails to identify any distinct benefits or drawbacks of energy interconnections or a fully integrated European energy market [19].

Despite a plethora of studies on the technological advancements and economic benefits of electricity interconnectors and cross-border trading, a significant gap remains in the literature pertaining to a better understanding of how these infrastructures align with the principles of energy market coupling, their evolution over time, and the recent trends shaping their development. Moreover, there is limited research that connects these aspects with the broader goals of market integration, leaving the academic and research community with an incomplete picture of their full impact on the European energy landscape. This work seeks to bridge that gap by enriching the currently limited knowledge thorough a comprehensive exploration that not only tracks the development of these infrastructures as well as recent trends in market coupling but also connects them to the core mechanisms of market integration and energy transition policies in an attempt to also support researchers in identifying areas where further investigation is mandated or interdisciplinary approaches are required. In overview, this work makes significant contributions to both research and industrial applications in the energy sector by:

- Providing an in-depth exploration of the recent trends influencing the evolution of cross-border electricity interconnections and trading.
- Identifying critical links between technological advancements, regulatory frameworks, and market dynamics with the overarching objectives of market integration and energy transition policies.
- Delivering key insights that support future research, inform policymaking and guide technological innovation within the field of electrical interconnectors and cross-border trading.

The remaining of this analysis is structured as follows: Section 2 overviews the current European state-of-play in electricity interconnectors as well as cross-border trading focusing on regulatory frameworks, such as the European Electricity Market Target Model, and initiatives like the PCIs and the main barriers preventing their large-scale deployment. Section 3 presents the recent trends associated with technological advancements. Section 4 overviews the TEN-E policy framework's goals and implementation steps to transform the European energy network into a sustainable, resilient, and integrated system, while Section 5 showcases the principles and characteristics of the energy market coupling as well as the latest development in the EU. Based on the foundations and concepts laid in these sections, Section 6 delves into the most recent trends and research topics surrounding electrical interconnectors and trading. Section 7 provides a discussion and concluding remarks, synthesizing the key takeaways from the recent trends, outlining the potential opportunities ahead as well as emphasizing the future role of interconnectors in enabling a low-carbon, secure, and economically efficient energy EU.

2. Evolution of the Pan-European Electricity Market and Infrastructure

Electricity generation began in the late 19th century with the establishment of local electricity grids in countries like Germany, France, and the UK. These grids were initially isolated and limited to urban areas. The concept of interconnecting regional grids started to take shape in the 1920s, aimed at improving reliability and load balancing. The first known cross-border interconnection was established between Switzerland and France in 1920,

laying the foundation for future European cooperation in electricity supply. Following World War II, Europe faced the urgent need to rebuild its infrastructure, including energy systems. The Marshall Plan facilitated this reconstruction and indirectly promoted energy cooperation across borders. In 1948, the Union for the Coordination of Production and Transmission of Electricity (UCPTE) was established to coordinate the transmission systems in Western Europe, marking a significant step towards a more integrated European grid [20]. The formation of the European Coal and Steel Community in 1951 further reinforced the idea of regional energy integration among its founding members.

During the Cold War, the development of electricity interconnections continued. By 1958, a synchronous interconnection between France, Germany, and Switzerland was established, creating a stable regional grid. The 1960s and 1970s saw further expansion, particularly in Northern Europe, with the creation of the Nordel system, which interconnected the Nordic countries and emphasized hydropower cooperation. By 1977, UCPTE had successfully synchronized most of Western Europe's power systems, creating a resilient network capable of managing cross-border electricity flows. The 1990s were a period of significant change as Europe moved towards liberalizing its energy markets. EU began to promote the creation of an internal electricity market, which necessitated further cross-border interconnections. The European Energy Charter Treaty, signed in 1995, was instrumental in this process, aiming to create a single energy market across Europe, while in 1996, the EU introduced the Electricity Directive [1], providing a legal framework to support market liberalization and the development of trans-European energy networks. Over time, the focus of the organization shifted more towards the transmission aspect as the electricity markets became more liberalized and generation increasingly involved diverse energy sources, including renewables. As a result, in 1999, the UCPTE was renamed the Union for the Coordination of Transmission of Electricity (UCTE), reflecting a more specific focus on the coordination of electricity transmission rather than production [21]. The UCTE grid was also expanded to include countries from Central and Eastern Europe following the end of the Cold War. In the 21st century, the focus has been on further integrating the European electricity grid and transitioning towards renewable energy. The founding of the ENTSO-E in 2002 marked a new era of coordinated grid development across the continent [22]. The EU's Third Energy Package, introduced in 2009, further emphasized infrastructure development and cross-border interconnections as part of the internal energy market [23]. The European Green Deal of 2020 set ambitious targets for reducing carbon emissions and increasing renewable energy use, highlighting the importance of a highly interconnected and resilient European electricity grid, while the energy crisis in 2022, triggered by geopolitical tensions, underscored the need for even greater interconnection to enhance energy security and reduce dependence on specific energy sources [24].

The history of electricity interconnection in Europe reflects over a century of technological advancements, geopolitical changes, and economic integration. The evolution from isolated national grids to a highly interconnected trans-European network is marked by several key milestones among which the European Electricity Market Target Model stands as the pioneering step towards developing a unified internal electricity market. The European Electricity Market Target Model is a regulatory framework designed to facilitate cross-border electricity trading, increase market competition, enhance energy security, and enable the efficient integration of renewable energy. This model is central to the EU's energy strategy, ensuring that electricity can flow freely across national borders and that consumers benefit from a competitive and secure energy supply. The Electricity Market Target Model introduced various market horizons that operate on sequential timeframes, including long-term markets (forward energy markets, forward transmission markets, and capacity mechanisms), wholesale or spot markets (day-ahead and intraday markets), balancing markets (balancing capacity and balancing energy markets) and transmission redispatch "markets" (reservation for redispatch and redispatching markets). In this domain, balancing service providers (BSPs) and balance responsible parties (BRPs) play crucial roles in ensuring the stability and efficiency of electricity markets, especially in real-time

balancing. Since they are major actors in maintaining system stability and avoiding outages, BSPs are entities that offer balance services to Transmission System Operators (TSOs) to help maintain the balance between electricity generation and consumption in real time by providing the necessary flexibility to adjust generation or consumption at short notice to correct any imbalances in the grid, while BRPs are market participants that are responsible for maintaining a balance between their electricity supply and demand portfolios over a specified time period. In other words, BRPs are financially responsible for any imbalances they cause between their contracted electricity volumes and actual consumption or generation. The BSPs and BRPs are complementary actors in the balancing process in the sense that when a BRP creates an imbalance, the TSO activates the necessary balancing services from BSPs to restore balance. The different market timeframes of the European Electricity Market Target Model are illustrated in Figure 1.

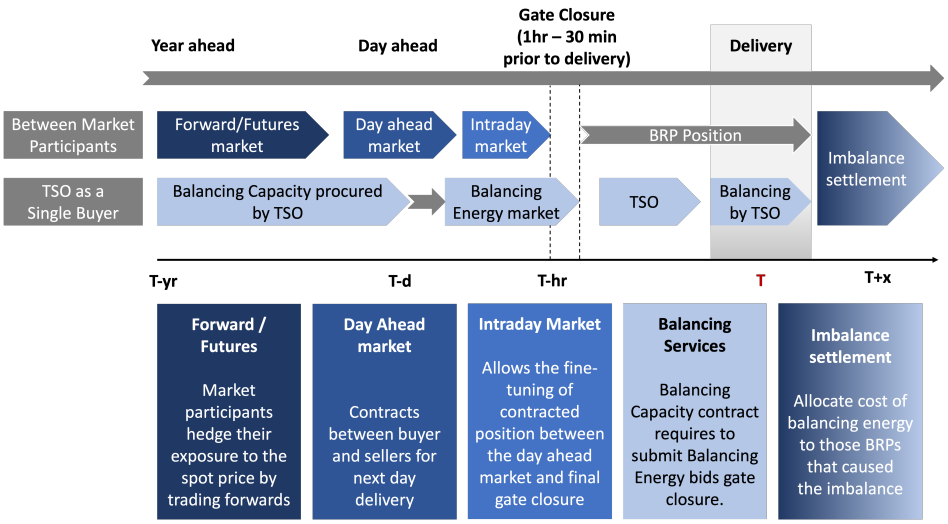


Figure 1. Electricity Market Target Model timeframes.

The focus on creating a long-term electricity market for contracts, including forward and futures markets, aims at allowing market participants to hedge against price fluctuations over longer time horizons, enhancing market stability and investment certainty. The integration of these long-term markets across borders helps market participants mitigate risks associated with price volatility and creates a more predictable market environment for investment in electricity generation and infrastructure, such as interconnectors. In relation to the forward market, which encompasses timeframes preceding the day-ahead phase (such as monthly, quarterly, yearly, and multi-yearly periods), the Electricity Market Target Model typically dictates that transmission capacity should be assigned through explicit auctions using Physical Transmission Rights (PTRs) that adhere to the "use-it-or-sell-it" principle, or through Financial Transmission Rights (FTRs). However, in cases when liquid financial markets enable effective hedging across various countries, products such as Contracts for Differences (CfDs) may be suitable.

The European Electricity Market Target Model also introduces a market-coupling mechanism, which integrates the Day-Ahead Markets (DAMs) of various EU countries and where electricity for the next day is traded. Under market coupling, electricity prices are determined not only by national supply and demand but also by the availability of cross-border transmission capacity. This ensures that electricity flows from areas with lower prices (surplus generation) to areas with higher prices (higher demand), optimizing the use of generation resources across Europe. By allowing electricity to flow where it is most needed, market coupling helps reduce price disparities between countries and improves overall market efficiency. The European power exchange (EPEX) and other national exchanges are linked through this mechanism, which is coordinated by TSOs

across the EU. The intraday market allows market participants to trade electricity closer to real time, adjusting for unexpected changes in generation or consumption.

The European Electricity Market Target Model extends the concept of market coupling to the intraday market, where electricity can be traded continuously across borders up to one hour before delivery. The integrated operation of the EU's day-ahead and intraday markets is assigned to the Nominated Electricity Market Operators (NEMOs), which are organizations mandated to act as market operators in national or regional markets to perform single-day-ahead and intraday coupling in cooperation with TSOs and other NEMOs. To ensure the security of supply under real-time conditions, an additional market horizon should be implemented. This is particularly important for integrating RES, which are variable and often require adjustments (e.g., generation fluctuations). The balancing market ensures that electricity supply and demand are balanced in real time, typically through the activation of reserve power. The Electricity Market Target Model seeks to harmonize the balancing markets across EU member states, creating a coordinated approach to real-time system balancing. This involves the exchange of balancing services across borders, where TSOs can call on electricity reserves in neighboring countries to stabilize the grid. For example, if a sudden increase in demand occurs in one country, another country's power reserves can be used to meet that demand, therefore enhancing the security of supply across Europe. The procurement of balancing capacity is made in parallel to other timeframes, while the procurement of balancing energy takes place during or after the intraday timeframe. The Electricity Balancing (EB) Regulation establishes and regulates the smooth exchange of balancing energy across the EU [25]. The balancing market process is depicted in Figure 2.

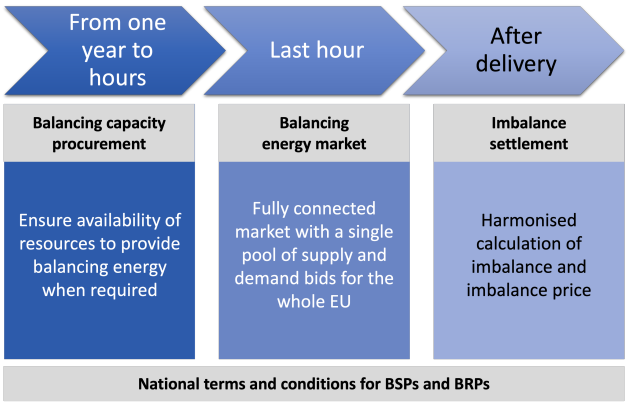


Figure 2. Timeframe for balancing procurement.

Efficient cross-border electricity flows depend on the availability of transmission capacity. The Electricity Market Target Model introduces a Capacity Allocation and Congestion Management (CACM) framework [26] to allocate cross-border transmission capacity fairly and efficiently. This framework ensures that electricity flows are optimized based on market prices, and it minimizes the costs associated with congestion (bottlenecks in transmission lines). Under this system, transmission capacity is allocated through market-based mechanisms, such as auctions, ensuring that it is used by those who value it most. This optimizes the use of existing transmission infrastructure and encourages investment in new cross-border interconnectors. CACM impacts anyone trading or wishing to trade interconnector capacity and cross-border energy in the day-ahead or intraday timeframes. The physical trades take place up to one day ahead or some minutes (e.g., 15 min) ahead of the physical delivery.

The process of capacity calculation is organized and managed by System Operators (SOs). The term "SO" refers to an entity that carries out the real-time operation of the power system, often known as dispatch. This entity can either be the owner or the concessionary of the power grid infrastructure, such as a TSO. The process entails consolidating the separate grid models created by each SO into a unified European grid model, referred to as the

common grid model. The most efficient way to allocate cross-zonal capacity is using the Union-wide market coupling, which collects all bids and offers from the bidding zones within the EU and maximizes the economic surplus. A bidding zone refers to the widest geographical area where market participants can trade energy without the need for cross-zonal capacity attribution. Within a bidding zone, cross-border congestion does not induce a market split, resulting in a uniform energy price throughout the entire zone. For capacity calculation, the Electricity Market Target Model foresees that European TSOs establish coordinated methodologies to calculate Available Transfer Capacity (ATC), which views the bidding zones as nodes within a certain network topology, connected by interconnectors (cross-border transmission lines) [27].

The transfer of power between two bidding zones is constrained by the ATC of the interconnector. The network code permits the utilization of either Flow-based (FB) or coordinated Net Transfer Capacity (NTC) methods for day-ahead and intraday periods. The NTC approach is widely recognized, has been utilized since the inception of market liberalization, and refers to the largest volume of energy that can be exchanged between two locations while adhering to the security regulations of both areas. The NTC technique operates on the premise of evaluating and establishing in advance a specific level of maximum commercial exchange capacities for each border between bidding zones. This is achieved by augmenting the power flow within the common grid model to a level where any more increase would lead to a breach of security constraints in either or both of the bidding zones being examined. The power flow determines the highest level of capacity allowed on the interconnections between the bidding zones. The development of the FB method has been driven by recent advancements in linked power networks. The FB approach produces a distinct margin on each crucial grid element and an influencing factor rather than a single combined margin, as in the NTC method. The FB method is capable of efficiently handling a wide range of phenomena over a short period of time and in complex grid structures. It outperforms the NTC method by considering the interdependence of all power flows in a meshed grid. This is achieved using power transfer distribution factors (PTDF), which estimate the impact of any transaction between different zones on a specific element of the grid. Nevertheless, the approach is limited to transactions within the specific capacity calculation region, indicating that the performance of the FB method improves as the size of the considered region increases. The applied capacity calculation methods, in relation to the market timeframes deployed, are presented in Figure 3.

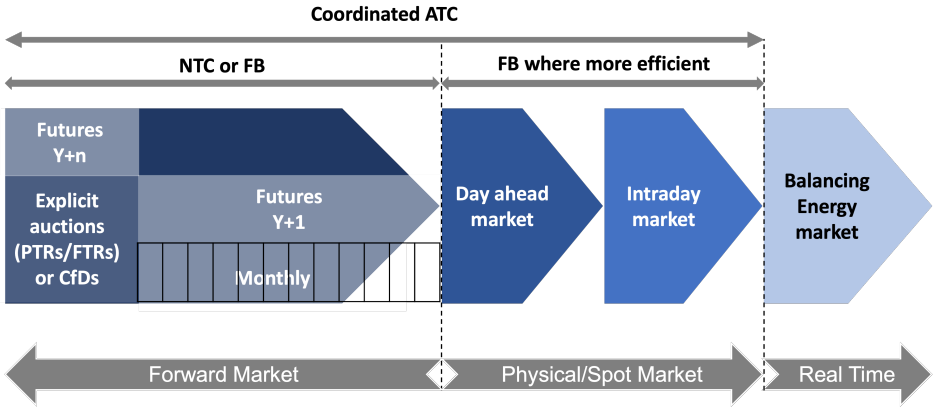


Figure 3. Capacity calculation methods.

At a higher level, bidding zones are separated into control areas, which refers to a specific section of the interconnected system that is managed by a single SO. This area includes any associated physical loads and/or generation units, if applicable. At the highest level, the European countries are divided into synchronous areas, which correspond to a large-scale three-phase electric power grid that works at a synchronized utility frequency and is electrically interconnected under normal system conditions. An asynchronous

area consists of one or more control areas that work together to ensure that the system's frequency remains at its designated value (which is 50 Hz in all European asynchronous regions). The Continental Europe synchronous area encompasses the control areas of 24 European countries. An overview of the regional separation of the European countries under the umbrella of market coupling is presented in Table 1.

Table 1. European regions for cross-border electricity trading.

Country	Synchronous Area	Control Areas (TSO)	Bidding Zones	NEMO
Iberian Peninsula–South-West Europe (SWE)				
Portugal	Continental Europe	REN	PT	OMIE
Spain		REE	ES	
Continental Western Europe (CWE)				
France	Continental Europe	APG	AT	EPEX
				Nord Pool
				EXAA
Belgium		Elia	BE	EPEX
				Nord Pool
France		RTE	FR	
Germany		TransnetBW		
		TenneT DE		
		Amprion		
		50Hertz		
Luxembourg		Creos		
Netherlands		TenneT NL	NL	
Switzerland		Swissgrid	CH	EPEX
Central Eastern Europe (CEE)				
Czech Republic	Continental Europe	ČEPS	CZ	OTE
Hungary		MAVIR ZRt	HU	HUPX
Poland		PSE	PL	TGE
				EPEX
				Nord Pool
Romania		Transelectrica	RO	OPCOM
Slovakia		SEPS	SK	OKTE
Slovenia		ELES	SI	BSP
South-Eastern Europe (SEE)				
Bulgaria	Continental Europe	ESO	BG	IBEX
Croatia		HOPS	HR	CROPEX
Greece		IPTO	GR	HEnEx
Serbia		EMS	RS	SEEPEX
Apennine Peninsula (Italy)				
Italy	Continental Europe	Terna	NORTH	GME
			SOUTH	
			CNTR–NOR	
			CNTR–SOU	
Northern Europe				
Denmark	Continental Europe	Energinet	DK1 & DK2	EPEX
	Nordic (East)			Nord Pool
Estonia	Baltic	Elering	EE	
Finland	Nordic	Fingrid	FI	Nasdaq Oslo
				Nord Pool
Latvia	Baltic	AST	LV	EPEX
				Nord Pool
Lithuania	Baltic	Litgrid	LT	
Norway	Nordic	Statnett	NO1 to NO5	
Sweden	Nordic	Svenska Kraftnät	SE1 to SE4	Nasdaq Oslo
				EPEX
				Nord Pool
British Isles				
Ireland	Ireland	EirGrid	IE–SEM	SEMO
UK	Great Britain	National Grid	UK	EPEX
				Nord Pool
	Ireland	SONI	IE–SEM	SEMO

By integrating national electricity markets, the Electricity Market Target Model promotes price convergence across Europe. As electricity flows freely between countries with the help of cross-border interconnectors, price discrepancies are reduced, leading to more stable and competitive prices for consumers. This also results in better utilization of generation resources, particularly renewables, and reduces the need for expensive backup power in individual countries. As of 2024, Europe has more than 400 electricity interconnectors linking various countries across the continent [28]. Out of those, around 149 projects received funding under the CEF for energy infrastructure development, while the latest PCI list (sixth in line) [29] features 85 electricity projects, including 12 related to storage, 5 smart grids projects, and 12 offshore infrastructure projects. For the first time, hydrogen and electrolyzer projects (65) are also included. The list also includes 14 CO_2 network projects in line with our goals to create a market for carbon capture and storage. It also includes ten PMIs, which include electricity interconnections with the United Kingdom, the Western Balkans, as well as North African countries [29]. The latest list is also the first compilation of PCIs and PMIs in accordance with the updated TEN-E Regulation [29]. The amended regulation ceases funding for fossil fuel infrastructure and shifts its attention towards the development of cross-border energy infrastructure that aligns with future needs. Since 2013, there have been five sets of PCIs adopted, with each set being updated every two years. A summary of the most prominent and significant European electricity interconnections is tabulated in Table 2.

Table 2. Most prominent European electricity interconnections.

Interconnector Name	Capacity (MW)	Construction (Year)	Operation (Year)	Connecting Countries	Developer
Konti–Skan	740	1963	1965 (upgraded 2006)	Denmark–Sweden	Energinet Svenska Kraftnät
SACOI	300	1964	1967–2025 (renovation)	Italy (Corsica–Sardinia)	Terna
Nea Santa	600	1965	1970s (upgraded)	Greece–Bulgaria	IPTO ESO
Greece–North Macedonia	400	1978	1980s	Greece–North Macedonia	IPTO MEPSO
IFA	2000	1982	1986	France–UK	RTE National Grid
Konti-Skan 2	300	1986	1988	Denmark–Sweden	Energinet Svenska Kraftnät
Liaison France–Andorre	60	1978	1982	France–Andorra	RTE
Greece–Albania	400	1982	1985	Greece–Albania	IPTO OST
NorNed	700	2004	2008	Norway–Netherlands	Statnett TenneT
Pfalzwerke–Hessenrück	200	1993	1995	Germany	Pfalzwerke
SwePol Link	600	1997	2000	Sweden–Poland	Svenska Kraftnät PSE
IPP	500	1997	2001	Greece–Italy	IPTO Terna

Table 2. *Cont.*

Interconnector Name	Capacity (MW)	Construction (Year)	Operation (Year)	Connecting Countries	Developer
Fenno–Skan 1	500	1987	1989	Finland–Sweden	Fingrid Svenska Kraftnät
Ballylumford–Scotland	500	1998	2002	UK (Northern Ireland–Scotland)	SONI National Grid
SAPEI	1000	2008	2011	Italy (Sardinia–mainland)	Terna
Estlink 1	350	2004	2007	Estonia–Finland	Elering Fingrid
BritNed	1000	2007	2011	UK–Netherlands	National Grid TenneT
Greece–Turkey	400	2005	2008	Greece–Turkey	IPTO TEİAŞ
Neptune	1000	2011	2014	Netherlands–UK	TenneT National Grid
Inelfe	2000	2011	2015	France–Spain	REE REE
Baixas–Santa Llogaia	2000	2011	2015	France–Spain	INELFE
Estlink 2	650	2010	2014	Estonia–Finland	Elering Fingrid
North Sea Link	1400	2018	2021	Norway–UK	Statnett Statnett
COBRAcable	700	2016	2019	Denmark–Netherlands	TenneT Energinet
Alegro	1000	2016	2020	Germany–Belgium	Amprion Elia
Cyclades	170	2015	2018 (Phase 1)	Greece (mainland–Cyclades islands)	IPTO
Crete–Peloponnese	150	2018	2021	Greece (Crete–mainland)	IPTO
Oslo2–Drammen2	200	2012	2014	Norway (internal project)	Statnett
Elettrodotto	600	2016	2019	Italy–Montenegro	Terna CGES
Greece–Turkey	400	2005	2008	Greece–Turkey	IPTO TEIAS
ElecLink	1000	2016	2022	France–UK	Eurotunnel Getlink
Hansa PowerBridge	700	2021	2026 (expected)	Sweden–Germany	Svenska Kraftnät 50Hertz
Ariadne	1000	2018	2023 (expected)	Greece (Crete–mainland)	IPTO IPTO

Table 2. *Cont.*

Interconnector Name	Capacity (MW)	Construction (Year)	Operation (Year)	Connecting Countries	Developer
GREGY	3000	2023 (planned)	2027 (expected)	Greece–Egypt	IPTO Egypt Electricity
GSI	2000	2025 (planned)	2030 (expected)	Greece–Cyprus	IPTO
Dodecanese–Mainland	200	2028 (planned)	2028 (planned)	Greece (Dodecanese islands–mainland)	IPTO
Viking Link	1400	2019	2023 (expected)	Denmark–UK	National Grid Energinet
Iceland–UK HVDC	1000	2023 (planned)	2027 (planned)	Iceland–UK	Landsvirkjun National Grid

Despite the strong promotion and deployment of electricity interconnectors across Europe and the clear benefits they bring, such as enhanced energy security, increased market efficiency, and greater integration of RES, several significant challenges remain that hinder the full realization of their potential in the European energy market. These challenges span technical, regulatory, environmental, and economic domains, and they are crucial factors that must be addressed to fully realize the potential of cross-border and long-distance electricity transmission. One of the most significant barriers to the deployment of electrical interconnections is the complex regulatory and political landscape. Electrical interconnectors often involve multiple countries, each with its own set of regulations, standards, and energy policies. Coordinating between different regulatory frameworks can be time-consuming and difficult, often leading to delays in project approvals.

Additionally, political considerations, such as national energy security concerns, can create resistance to cross-border projects. Some countries may be reluctant to depend on energy imports from neighboring nations, fearing a loss of energy sovereignty or potential vulnerabilities in the case of political conflicts. The high upfront costs associated with the construction of electricity interconnections can also be a major barrier [30]. These projects require significant investment in advanced technologies, such as converter stations, submarine cables, and specialized installation equipment. While the long-term benefits of such projects can be substantial, the initial capital expenditure can be prohibitive, particularly in regions with limited financial resources. Furthermore, the economic viability of these projects often depends on long-term energy price agreements and stable policy environments, both of which can be uncertain. Additionally, integrating large-scale interconnectors into existing grids poses challenges related to grid stability, synchronization, and the management of power flows, especially when dealing with multiple RES with variable outputs.

Integrating new interconnectors into existing electricity grids is not always straightforward [31]. The addition of large power flows from new interconnectors can pose challenges to grid stability, especially in regions where the grid infrastructure is already strained or outdated. Managing the intermittent nature of RES, such as wind and solar power, adds another layer of complexity. Grid operators must ensure that the grid remains stable and resilient, even as these new interconnectors bring in large amounts of variable power from distant sources. This requires sophisticated grid management tools and coordination across multiple regions, which can be difficult to achieve.

The deployment of electrical interconnections also faces uncertainties related to energy markets and demand forecasts. Fluctuations in energy demand, changes in energy policies, and the evolving landscape of renewable energy technologies can all impact the long-term viability of interconnector projects. For instance, if energy demand in a region

decreases or if local renewable energy production increases significantly, the need for and profitability of an interconnector could be diminished. This uncertainty makes it challenging to secure long-term investment and commitments from stakeholders. Shifting towards a digitalization era of power systems, and as electrical interconnectors increasingly rely on digital technologies and smart grids, these infrastructures become more vulnerable to cybersecurity risks. A successful cyberattack on an interconnector could disrupt power flows between countries, potentially leading to widespread outages or instability in the grid. Ensuring the cybersecurity of these critical infrastructures requires ongoing investment in security technologies and practices, as well as international cooperation to protect against cross-border threats. A mapping of the main barriers to the realization of cross-border infrastructure projects, along with their associated causes and consequences, is depicted in Figure 4.

Technological advancements, along with the attempts to establish an optimal European unified electricity market, are crucial in addressing many of the challenges associated with the deployment and effective operation of electricity interconnectors. Both of these factors contribute to enhancing the efficiency and scalability of interconnectors as well as the reliability and flexibility of the European energy system, and together, they provide comprehensive solutions to handle the growing demands of a modern, integrated electricity market, especially with increasing shares of renewable energy.

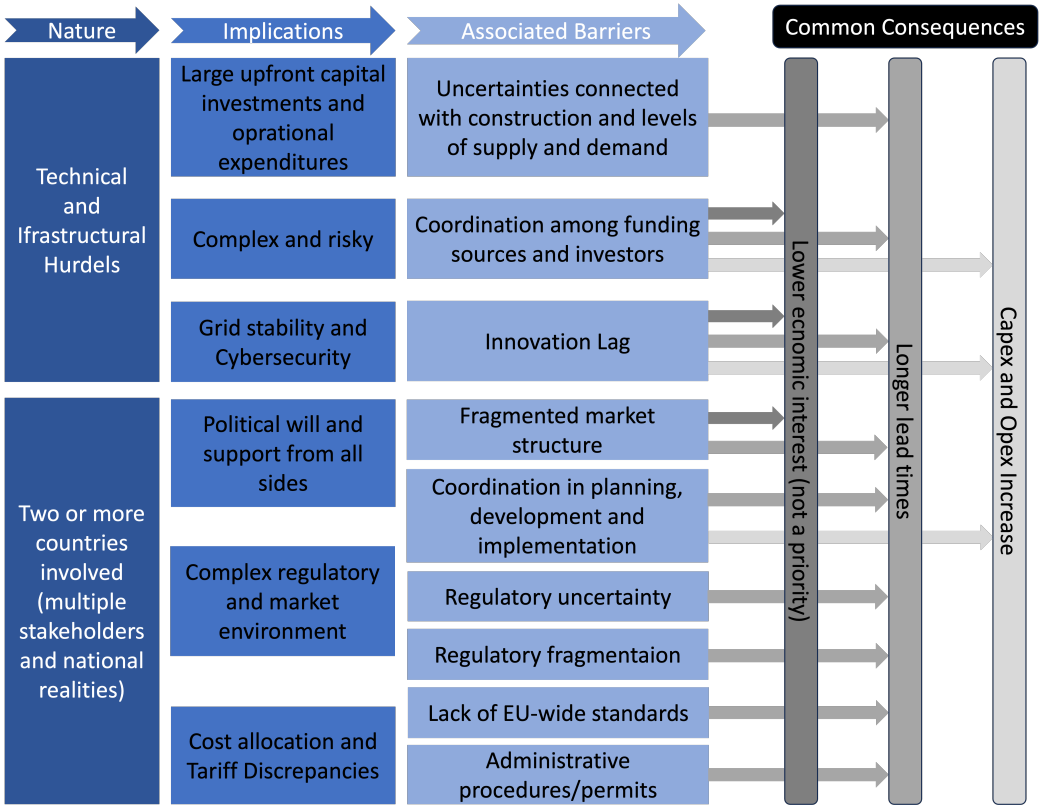


Figure 4. Main barriers to the realization of cross-border infrastructure projects.

3. Recent Technological Trends in Electricity Interconnector Infrastructures

The evolution of electricity interconnectors represents one of the most significant advancements in global energy infrastructure over the past few decades. As the demand for energy grows and the push for renewable energy integration intensifies, these interconnectors have become essential for ensuring a stable, efficient, and resilient power supply across vast distances and between nations. At the heart of this progress are the technological breakthroughs and innovations driven by leading European vendors. Historically, electricity grids operated largely within national boundaries, with alternating current (AC)

transmission being the dominant technology. However, as the need for long-distance, cross-border electricity transmission increased, especially across bodies of water, traditional AC systems faced limitations due to significant transmission losses over long distances.

This need led to the development and adoption of high-voltage direct current (HVDC) technology, which offered a more efficient solution for these long-haul connections. Over the years, HVDC technology has advanced significantly, with breakthroughs in submarine DC cables and converter stations playing a pivotal role in the expansion and reliability of electricity interconnectors. In synchronous interconnection, it is necessary for the operational frequencies of both interconnected electricity grids to be identical, either 50 Hz or 60 Hz [32]. In asynchronous interconnection, the operating frequencies of the interconnected electricity grids may be either identical or different. The current state of large power grid interconnection worldwide consists of various technologies, such as AC synchronous interconnection, HVDC asynchronous interconnection, such as Line-Commutated Converters (LCC)-HVDC, Voltage Source Converters (VSC)-HVDC light and modular Multi-Level Converter (MMC), as well as AC asynchronous interconnection based on Variable Frequency Transformer (VFT) [33–35].

An AC link is the most commonly used technology for connecting two AC power grids. An AC link refers to the interconnection of two separate AC power grids using a tie-line [36]. The working principle of this system is based on the regulation of power flow through a tie-line, using regional Automatic Generation Control (AGC) [37]. It is necessary to regulate the power-angle of generators on both sides of the tie-line in order to ensure the safe and stable operation of the interconnected system. Both the active power and the reactive power are transferred in an AC synchronous link. The regulation of power transmission over these transmission lines is accomplished using different power flow control devices, including Load Tap Changing transformers (LTC) [38], Phase Shifting Transformers (PST) [39], and Flexible Alternating Current Transmission System (FACTS) controllers [40]. While being a straightforward and economical approach to grid interconnections, it also introduces complexity to the operation of power networks. Furthermore, it diminishes the dependability and consistency of the electricity grid under severe fault situations. In the event of a problem, there will be an increase in the short circuit current on the unaffected side of the power network as well.

HVDC interconnection commonly refers to the linking of two separate power networks for transmitting power over long distances. Although the fixed costs of terminals at both ends of HVDC links are higher than those of AC, the cost per unit length of the HVDC line itself is lower. This means that assuming all other factors are the same, the longer the distance of the link, the lower the relative cost of the link per unit of energy. Within a specific range, known as the "break-even distance" (often around 600–800 km using present technologies), HVDC becomes the most economically advantageous choice [41,42]. Furthermore, there are no inherent technical constraints on the maximum length that a HVDC cable can achieve. The presence of significant cable capacitance in a lengthy AC cable transmission will restrict the maximum achievable transmission distance by causing reactive power flow. There are no limitations with HVDC. A graphical representation of the relative economic comparison between HVAC and HVDC for interconnecting power systems is exhibited in Figure 5.

This HVDC system can be either an LCC-HVDC system [43] or a VSC-HVDC system [44]. It can be used in either a back-to-back or point-to-point configuration, depending on the specific operating conditions [45]. The HVDC system can be classified as either monopolar or bipolar based on the operational requirements and the geographical placement of the converter stations. A monopolar system has two converters connected by a single-pole line, with the ground serving as the return path. This technique is commonly employed for transmitting power over the sea to minimize expenses. A bipolar system is a system consisting of two conductors, one with a positive polarity and the other with a negative polarity. This scheme possesses a superior advantage compared to the monopolar strategy. In the event of a fault in one of the conductors, the other pole continues to function

by serving as a monopolar connection with the ground. The HVDC interconnection offers both insulation between interconnected power system networks and the capacity to govern active power transfer. Besides the economic advantages, the shift from AC to HVDC for long-distance and cross-border electricity transmission is also driven by significant technical offerings. Lower transmission losses, the ability to interconnect unsynchronized grids, better control over power flows, and the feasibility of longer submarine and underground cables make HVDC the standard choice for modern interconnector projects. As the global energy landscape continues to evolve, with an increasing emphasis on renewable energy and cross-border electricity trade, HVDC technology is expected to play an even more critical role in ensuring efficient, reliable, and sustainable power transmission. The schematic illustration of an HVDC offshore electricity interconnector between two regions is presented in Figure 6.

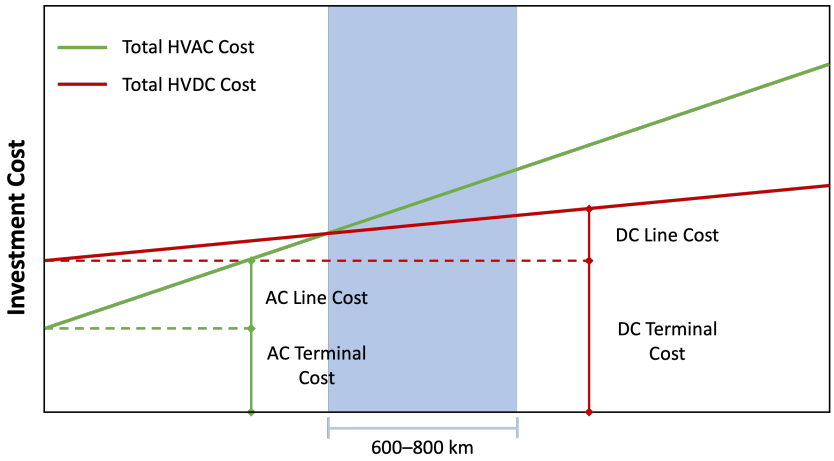


Figure 5. Relative economic comparison of HVAC and HVDC for interconnecting power systems.

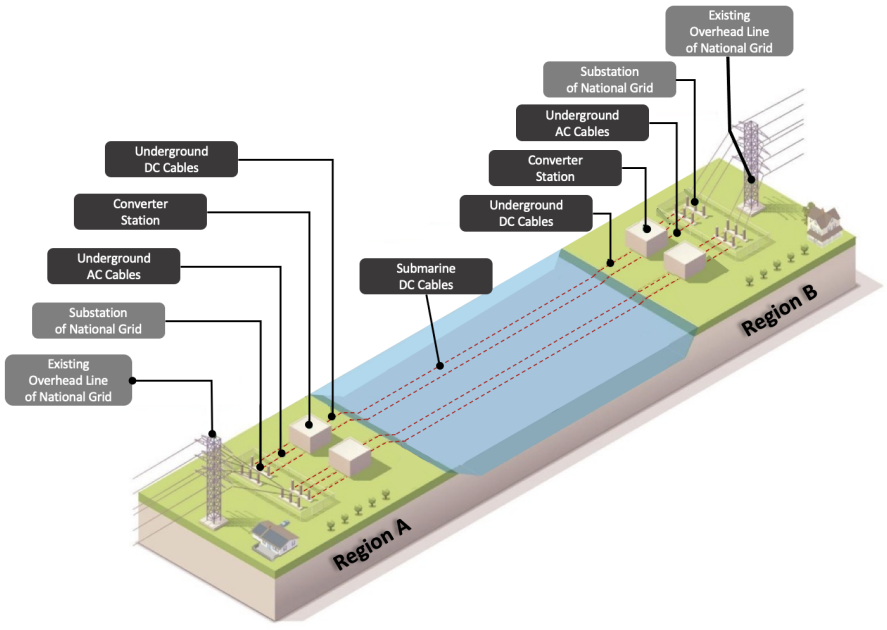


Figure 6. Schematic illustration of HVDC offshore electricity interconnection infrastructure.

Cables are critical components of electricity interconnector infrastructure, enabling the transmission of electricity across significant distances, whether across land or under the sea. They serve as the physical link between different grids, facilitating the exchange of electricity across borders, which is essential for grid stability, energy security, and the integration of RES. The primary function of these cables is to transmit large quantities of

electricity over long distances with minimal losses. High-voltage cables are designed to handle substantial power loads, ensuring that electricity can be efficiently delivered across borders to meet demand. The choice between submarine and underground cables depends on the specific requirements of the interconnector project.

Submarine cables, with their essential armoring, are critical for underwater interconnections, providing secure and reliable electricity transmission across seas. Underground cables, while more straightforward to install on land, require careful consideration of environmental and logistical factors to ensure they function effectively. Both types of cables are indispensable in ensuring the success of cross-border electricity trading and the stability of interconnected power grids.

Submarine DC cables are a cornerstone of modern electricity interconnectors, playing an indispensable role in the global energy infrastructure, particularly in regions separated by large bodies of water. These cables are not just technological marvels; they are vital components that enable the efficient and reliable transmission of electricity across vast distances, connecting countries and continents in ways that were previously unimaginable. The progression of submarine DC cables has been marked by several key advancements, which have made them the backbone of long-distance electricity transmission. Initially, AC cables were used for submarine applications, but their limitations in terms of distance and efficiency prompted the shift to HVDC technology [46]. This transition minimized transmission losses and allowed for stable voltage maintenance over long distances, making HVDC cables ideal for intercontinental connections. Furthermore, modern submarine DC cables have evolved to support higher voltages, now reaching up to 525 kV, and greater power capacities, often exceeding 2 GW per cable pair. A comparative illustration of the structural differences between submarine and underground power cables is provided in Figure 7.

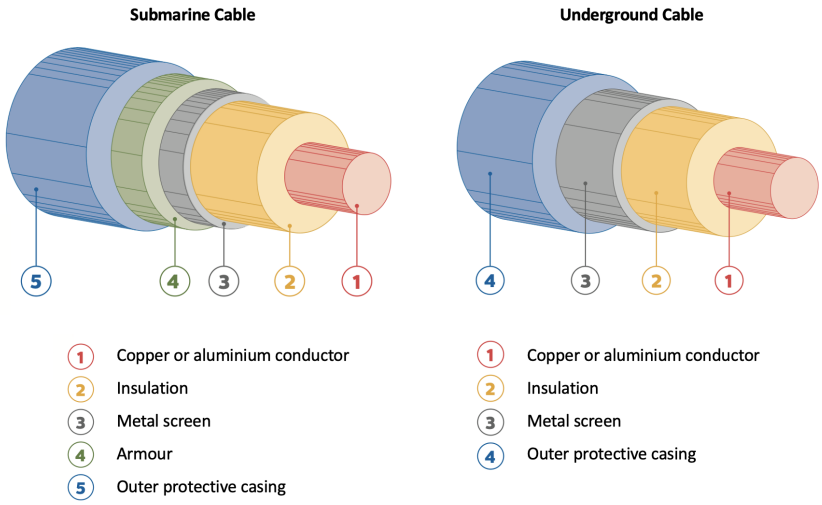


Figure 7. Structural comparison between submarine and underground power cables.

This increase in capacity is critical for supporting the growing energy demands and the integration of large-scale renewable energy projects [47–49]. Alongside these advancements, the development of new materials, such as cross-linked polyethylene (XLPE), has significantly improved the durability and performance of submarine cables, offering better insulation and longevity, which are crucial for the harsh underwater environments where these cables are deployed. Serving as the essential components that enable the conversion of electrical power between AC and DC forms, converters are indispensable components of HVDC interconnector infrastructures that facilitate the efficient, reliable, and flexible transmission of electricity across long distances and between different power grids. They enable the conversion between AC and DC power, control voltage and power flows, link unsynchronized grids, and support the integration of RES. At the sending end of an HVDC

interconnector, the converter station performs rectification, which is the process of converting AC power generated by the power plants or supplied by the grid into DC power. This conversion is necessary because DC transmission is more efficient over long distances due to lower losses, the absence of reactive power issues, and the ability to maintain voltage levels more effectively, while at the receiving end of the HVDC interconnector, the converter station performs inversion, converting the transmitted DC power back into AC power, which can then be fed into the local AC grid for distribution and consumption. This step is essential because most electrical appliances, industries, and infrastructure are designed to operate on AC power.

One of the significant advantages of HVDC systems, and by extension the converters, is their ability to precisely control the direction and magnitude of power flow between interconnected grids. Converters can adjust the amount of power transferred through the HVDC link in response to demand changes or grid conditions, which is crucial for managing energy distribution across large regions or between different countries. This flexibility helps in optimizing the use of available generation resources and in balancing supply and demand across interconnected grids. Converters also contribute to overall grid stability and reliability by providing dynamic support to the grid during disturbances or fluctuations [50]. They can quickly adjust power flows to stabilize the grid if there is a sudden drop or spike in electricity demand or supply. This ability to provide a fast-acting response helps in maintaining the continuous balance between electricity generation and consumption, which is critical for preventing blackouts and ensuring reliable power delivery, while promoting higher penetration levels of intermittent renewable energy.

Parallel to the advancements in submarine cables, converter stations have also seen significant technological evolution, which has been driven by the need for higher efficiency, smaller footprints, and better integration with modern grids. The advent of VSC marked a substantial leap forward in this regard. Unlike traditional LCCs, VSCs provide greater control over power flow, an essential feature for integrating intermittent RES like wind and solar power into the grid. This development was further enhanced by the introduction of MMC, which represents the latest evolution in converter station technology. MMCs offer improved efficiency, reduced harmonic distortion, and better scalability, making them ideal for both onshore and offshore applications. Additionally, MMCs allow for more compact converter stations, which is particularly advantageous in space-constrained environments like offshore platforms. Modern converter stations are also increasingly equipped with sophisticated control systems that allow them to interact seamlessly with smart grids. This capability is essential for maintaining grid stability, especially in regions with high levels of renewable energy penetration, where power supply can be more variable.

The major European HVDC interconnector projects, [51–53], that introduced significant technological innovations as well as profound breakthroughs are presented in Table 3.

Table 3. Innovation within the interconnector European landscape.

Project Name	Developer	Commission Date	Supplier	Innovation
IFA (France-UK)	CEGB/EDF	1986	GEC (Paris, France), Alcatel (Paris, France), BICC (Merseyside, England), Pirelli (Milan, Italy)	First large scale UK HVDC interconnector (2 GW)
Western Link (UK)	National Grid/SPT	2017	Siemens (Munich, Germany)/Prysmian (Milan, Italy)	First application of 600 kV and highest rated submarine cable at 2.21 GW
East/ West (Ireland/UK)	EirGrid	2012	ABB (Vasteras, Sweden)	First application of VSC at scale

Table 3. *Cont.*

Project Name	Developer	Commission Date	Supplier	Innovation
Skagerrak 4 (Norway/Denmark)	Statnett Energinet	2015	ABB/Prysmian/Nexans (Paris, France)	First European application of multi-terminal HVDC (Worlds first operational was in China)
NEMO Link (Belgium/UK)	National Grid/Elia	2018	Siemens/JPower (Tokyo, Japan)	First application of 400 kV XLPE and first award to non-European supplier
NSN (Norway/UK)	National Grid/Statnett	2021	ABB/Prysmian/ Nexans	Longest HVDC submarine cable project

4. Towards the Trans-European Energy Network

While the high capital expenditure associated with the deployment of electrical interconnections, particularly HVDC interconnectors, is considered to be the most significant barrier, it is crucial to recognize that this upfront investment can be justified, and even outweighed, by the substantial long-term benefits that these infrastructures provide. These benefits not only enhance the economic viability of such projects but also make a compelling case for their development despite the initial financial hurdles. Their crucial role in enhancing energy security by linking the power grids of different regions or countries facilitates the sharing of electricity across borders, which is particularly vital during supply shortages or emergencies, while the ability to import electricity from neighboring regions can prevent blackouts and ensure a stable energy supply. Furthermore, even though the initial costs of constructing interconnectors are substantial, they lead to considerable economic efficiencies and cost savings in the long run.

By enabling electricity trading between regions with varying generation costs, interconnectors allow for more efficient use of resources. For example, countries with abundant and cheaper renewable energy can export excess power to regions with higher electricity costs, resulting in lower overall electricity prices and a more balanced supply and demand across interconnected regions. In addition to economic benefits, interconnectors are instrumental in facilitating the integration of RES into the grid. Given that renewable energy, such as wind and solar, is often intermittent and geographically constrained, interconnectors make it possible to transfer surplus renewable energy from regions where it is abundant to areas where it is needed. This capability is essential for advancing climate goals and reducing reliance on fossil fuels, therefore supporting the transition to a cleaner and more sustainable energy system. Moreover, the development of interconnectors fosters market integration by connecting isolated or less integrated energy markets. This increased connectivity promotes competition among electricity producers, which can lead to lower prices and improved services for consumers. As markets become more interconnected, they also become more efficient, with electricity prices more accurately reflecting the true costs of production and distribution. This competitive and transparent market environment ultimately benefits consumers by reducing energy costs and enhancing service reliability. In addition to these economic and environmental benefits, interconnectors also add resilience and flexibility to the power grid. By linking diverse energy systems, they enable the sharing of reserves and backup power across regions, therefore making the grid more robust against disruptions. This flexibility is increasingly important as the energy supply becomes more variable due to the growing share of renewables.

The ability to quickly and efficiently transfer power across borders helps stabilize the grid and manage the variability of RES, ensuring a reliable electricity supply even during periods of peak demand or low renewable generation. Finally, from a strategic perspective, interconnectors offer significant geopolitical advantages. By fostering energy cooperation between countries, they reduce dependency on a single energy source or supplier, which in turn mitigates the risks associated with geopolitical tensions. Additionally, interconnectors

can strengthen diplomatic ties by creating mutual dependencies, where countries benefit from shared energy infrastructure, leading to more stable and collaborative international relations. These advantages indicate that the initial financial outlay is not merely a cost but rather an investment in a more sustainable, efficient, and resilient energy future, with returns that can far exceed the initial expenditures, underscoring the importance of developing such capex-intensive infrastructure.

These benefits are strongly tied to the EU's prevalent policy of developing well-connected and interoperable TEN-E that among other initiatives, introduced the PCIs and PMIs. The primary strategic framework for the coordinated development of energy infrastructure in the EU is known as the Ten-Year Network Development Plan (TYNDP) (Article 8(3) "Tasks of the ENTSO for Electricity" of Regulation (EC) 714/2009 [6]). The biennial TYNDP reports analyze the European grid to detect any deficiencies in infrastructure based on modeling exercises. Additionally, the reports analyze new cross-border transmission projects that have been filed by project developers.

This evaluation is made using a Cost–Benefit Analysis (CBA). The process of identifying system needs involves doing a thorough techno-economic optimization analysis to identify linkages that would lower the overall cost of supplying electricity, gas, and hydrogen throughout Europe. This analysis takes into account the constraints of reducing emissions and achieving renewable energy targets. This analysis is vital because it justifies the significant investments required for such projects by assessing whether the expected benefits, such as increased energy security, integration of renewable energy, and price convergence, outweigh the associated costs, including construction, maintenance, and environmental impact.

Consequently, CBA provides a structured approach to determining the overall viability of an interconnector project. Furthermore, CBA plays a pivotal role in facilitating stakeholder decision-making. By quantifying the anticipated economic, social, and environmental impacts, CBA enables governments, regulators, and investors to make informed choices about whether to pursue or support an interconnector project. This structured analysis allows for easy comparison between different projects, helping stakeholders prioritize those that offer the most substantial value. Moreover, CBA is instrumental in risk management by identifying and quantifying the risks associated with an interconnector project, such as fluctuating energy prices, demand uncertainty, and potential environmental impacts. This analysis enables stakeholders to develop strategies to mitigate these risks, further enhancing the project's viability.

A CBA assesses the submitted projects based on many factors, including the social cost of emissions, system adequacy, and security of supply. According to ACER [54], the computation of net effects is elucidated by the equation:

$$\int_{t=f}^{c+(x-1)} \frac{B_t + F_t - C_t}{(1+r)^{(t-y)}} \quad (1)$$

where f represents the initial year when costs are incurred, c represents the first complete year of operation of the project or project cluster, x represents the time horizon considered for the assessment, y represents the year of analysis or the year when the investment request is submitted, r represents the social discount rate used to discount benefits and costs, B represents all the benefits evaluated by the project-specific CBA, F represents all the benefits evaluated in the analysis of other cross-border monetary flows, and C represents the total costs.

The term "benefits" is employed to quantify, in monetary terms, all the positive or negative outcomes of a project for society or certain segments of society, such as TSOs and market participants. For TSOs, interconnectors enhance system reliability and optimize grid management by providing access to backup power and reducing congestion. Additionally, they offer revenue opportunities through trading fees supporting infrastructure investments. Consumers benefit from lower electricity prices through price convergence and increased access to renewable energy, while energy producers gain market access to

surplus energy, particularly from renewables. Interconnectors also support decarbonization efforts and contribute to energy security by reducing reliance on single energy sources and facilitating regional cooperation. However, these positive outcomes come with potential negative ones. TSOs face increased operational complexity and significant upfront costs in managing cross-border flows. Consumers might experience short-term price volatility as interconnected markets stabilize, and there could be pass-through costs in the form of higher network charges. Energy producers in higher-cost regions may face increased competition from neighboring markets, potentially impacting their profitability. Furthermore, the construction of interconnectors may have environmental impacts and lead to greater dependence on foreign energy markets, which could pose risks during geopolitical instability. Some, but not necessarily all, of the economic advantages (or negative impacts) can be converted into monetary inflows. When this is not the case, they are considered externalities. The investment expenditures that are efficiently incurred, excluding maintenance costs, are paid by the applicable TSOs (or project promoters) of the transmission infrastructure in the countries that benefit from the project's net positive impact. Moreover, countries that experience an overall unfavorable impact from the project may receive compensation. If the overall negative effect exceeds the total anticipated cost of efficient investment, decisions regarding cross-border cost allocation can offset the negative effect up to the maximum anticipated cost of efficient investment or until countries reach a point of neutrality towards the project proceeding. The ENTSO-E Guideline for Cost Benefit Analysis of Grid Development projects [55] outlines the indicators to assess the effects of infrastructure projects on sustainability, market integration, and security of supply in accordance with the standards and criteria specified in EU Regulation 2022/869 [10]. The guideline includes several key benefit indicators that measure the overall impact of grid development projects. One of these indicators is "Security of Supply (SoS)", which evaluates the project's contribution to maintaining or enhancing the reliability of electricity supply. It assesses how the project can reduce the risk of power outages or blackouts, ensuring that the electricity grid can meet demand even during peak periods or in the case of unexpected disruptions. Another important indicator is "Socio-Economic Welfare", which measures the economic benefits by estimating the change in overall welfare for consumers and producers. This includes the impact on electricity prices, market integration, and the reduction of generation costs due to improved grid efficiency and the integration of more cost-effective energy sources.

The guideline [55] also emphasizes the project's ability to facilitate the "Integration of RES" into the grid. This indicator measures how well the project enables the connection of new renewable energy generation, supporting the transition to a low-carbon energy system and contributing to climate goals. Closely related is the indicator for "Greenhouse Gas Emissions", which assesses the project's impact on reducing emissions by estimating the potential decrease in emissions due to enhanced grid infrastructure that allows for more efficient energy use and greater penetration of renewables. In terms of efficiency, the grid losses indicator quantifies the expected reduction in energy losses within the electricity transmission system as a result of the project, which leads to more efficient electricity delivery and lower overall energy consumption.

Another key indicator is "Adequacy to Meet Demand", which measures how the project improves the grid's capacity to meet future electricity demand, considering forecasted growth in consumption and changes in demand patterns. The guideline [55] also considers flexibility, evaluating how the project enhances the grid's ability to respond to changes in supply and demand, including the integration of variable RES and the accommodation of new technologies such as storage or demand-side management. Resilience is another critical indicator, assessing the project's contribution to the grid's ability to withstand extreme events, such as natural disasters or cyber-attacks, ensuring a stable and secure supply of electricity under various scenarios. Environmental impacts are also addressed through the "Other Environmental Impacts" indicator, which considers broader environmental effects beyond greenhouse gas emissions, including the impact on land use, biodiversity, and local ecosystems. Finally, the impact on the "Other Sectors" indicator

measures the potential benefits or drawbacks of the project on other economic sectors, such as industry, transport, or residential consumers, capturing the wider economic impacts beyond the energy sector [55]. These benefit indicators are designed to capture the full range of impacts that grid development projects may have on the economy, society, and the environment, ensuring a comprehensive assessment of their value.

As already discussed, projects labeled as PCIs or PMIs are eligible for financial support from the CEF to support the covering of the high costs associated with the planning, development, and construction of large-scale cross-border energy projects, reducing financial barriers and attracting investment. This access to EU funding makes it easier for project promoters to secure financing for critical infrastructure while benefiting from accelerated regulatory approval processes. The EU provides streamlined permitting procedures, which significantly reduce the time needed for planning and obtaining approvals. Attaining the PCI/PMI status is a prerequisite for qualification, although it does not ensure receiving EU funds under the CEF. These projects have the opportunity to request funds from the CEF by taking part in the yearly calls for proposals through which they can apply for grants for studies and construction works. The selection procedure for these projects is determined by collaboration among Regional Groups that are established under the TEN-E Regulation [10]. These groups consist of representatives from the European Commission, EU MSs, National Regulatory Authorities (NRAs), TSOs, ENTSO-E, the ACER, and the European Distribution System Operators (EU DSO) entity. The selection criteria are explicitly outlined in Article 4 of the TEN-E Regulation [10].

For a project to be classified as a PCI, it must meet two criteria. First, it must be deemed necessary for at least one of the energy infrastructure priority corridors and areas. Second, it must involve the participation of at least two MSs, either by crossing their borders or by having a significant cross-border impact, even if the project is located solely within the territory of one MS. In order for a project to be recognized as a PMI, it must make a substantial contribution to the decarbonization goals of both the Union and the third country involved. This includes the incorporation of renewable energy into the power grid and the transmission of renewable generation to important consumption centers and storage sites. For both scenarios, the project's potential overall advantages must exceed its expenses. This requirement underscores the importance of CBA in advancing interconnector projects through regulatory processes. Creating a standardized or coordinated CBA can be difficult since all parties involved need to reach a consensus on a shared approach for finding and measuring the advantages gained. Developing new interconnectors in complex, interconnected systems can have extensive and far-reaching effects. For instance, investing in domestic network capacity to alleviate internal congestion can enhance the utilization of interconnectors. This can be achieved by enabling power from the interconnector to reach a larger number of customers or by facilitating greater utilization of the interconnector by domestic generation sources.

However, these benefits often accrue to multiple countries. Thus, it is essential to determine the extent to which each country benefits. The most highly suggested approach for cost allocation is the "beneficiary pays" principle, which straightforwardly asserts that costs should be distributed in accordance with the benefits that the transmission line offers. When used correctly, the "beneficiary pays" principle can effectively address stakeholder opposition by showing evident net advantages and by minimizing the risk of excessive investment. This is also known as Cross-Border Cost Allocation (CBCA). In this context, the CBA identifies the beneficiaries of the interconnector, quantifying the benefits such as improved grid reliability, reduced electricity prices, and increased renewable energy integration. Based on this distribution of benefits, the CBA informs the CBCA process by providing a data-driven basis for cost sharing. For example, if a CBA shows that one country derives 60% of the benefits from an interconnector, it might be expected to bear a proportionate share of the costs. This ensures that the costs are allocated in a way that reflects the distribution of benefits, making the process fair and equitable. Additionally, CBCA ensures a fair and transparent process using the CBA to prevent any

single country from being disproportionately burdened with costs. The data from CBA is critical to achieving this equitable distribution, thus avoiding potential disputes among participating countries.

Besides benefits identified through CBA and CBCA, electricity interconnectors are also linked with significant investment risks. Developing these large-scale infrastructure projects involves high capital expenditures, long development timelines, and complex regulatory environments. Additionally, uncertainties such as fluctuating energy prices, changing regulatory frameworks, and geopolitical risks further compound the financial risks involved. These factors often result in a higher Weighted Average Cost of Capital (WACC), as investors demand a risk premium to compensate for these uncertainties. The WACC represents the regulator's estimation of the expenses associated with utilizing capital, including both loan and equity. In order to determine both the loan cost and the equity required return, it is necessary to evaluate the risks associated with the investors. The risks faced by debt providers are reflected in the debt premium, which is the additional compensation above the risk-free interest rate required to compensate them for the additional risks associated with providing debt capital to the project. This risk pertains to the company's capacity to meet its regular interest payments and repay its debt. The magnitude of the risk premium is contingent upon both the attributes of an investment endeavor and the financial robustness and ownership structure of the organization. Regulators ensure that the WACC is set at a reasonable level to prevent excessive profits for investors while protecting consumers from high electricity costs. Since interconnectors are often considered natural monopolies (the infrastructure that serves public interest without competition), regulators play a key role in balancing investor returns with public affordability [56,57]. It should be noted that regardless of the various financial incentives and established mechanisms to balance the associated risks, the success of interconnector projects is closely tied to the integration and stability of the European IEM, as it directly influences both the economic feasibility and the operational efficiency of these critical infrastructures.

5. An In-Depth Analysis of Cross-Border Electricity Trading in Europe

The inception of IEM coupling marks a significant chapter in the continent's journey towards a unified energy market. The concept, rooted in the idea of harmonizing the electricity markets of different European countries, was envisioned to enhance efficiency, reduce prices, and ensure energy security across the region. The journey towards market coupling was both a response to the growing interdependence of national energy markets and a proactive step towards greater economic and political integration within Europe. In the late 20th century, European countries began to recognize the potential benefits of integrating their electricity markets. The disparities in energy prices, driven by differing national policies, market structures, and resource availability, highlighted the inefficiencies of isolated national markets. The EU, committed to fostering a single market across various sectors, saw energy as a critical domain where integration could yield substantial benefits.

The first tangible step towards market coupling can be traced back to the early 2000s, with the launch of several regional initiatives. One of the pioneering projects was the Trilateral Market Coupling (TLC) involving Belgium, the Netherlands, and France in 2006. This initiative aimed to optimize the use of interconnectors—physical links that allow the transfer of electricity between countries—and align market prices by coordinating cross-border trading activities. In 2007, a bilateral market splitting was realized between Portugal and Spain (SWE). This merger allowed the Portuguese and Spanish DAMs to grow together into an integrated market called MIBEL with the joint electricity exchange OMIE. Simultaneously, Scandinavia established connections to the Western European electricity market through submarine cables. Since 2007, electricity has been transmitted between Germany and Denmark, and since 2011, between the Netherlands and Norway.

In 2013, Austria became a member of the CWE group and established connections between its market and the electrical markets of other Western European countries. Furthermore, the Pentalateral Energy Forum has decided to grant Austria full membership status

and Switzerland observer status. One of the landmark achievements in the evolution of market coupling was the launch of the North-Western European (NWE) market-coupling initiative in 2014. This project integrated the electricity markets of 13 countries, including major economies like Germany, France, and the UK. The NWE market coupling represented a significant leap forward, covering a substantial portion of the European electricity market and setting the stage for further expansions.

In 2015, Italy implemented a significant modification by establishing a connection between its borders with those of France, Austria, and Slovenia. In July 2016, the markets of Austria and Slovenia were successfully integrated. The area in Europe referred to as Multi-Regional Coupling (MRC) currently consists of 19 European countries. The journey of European market coupling is also a testament to the power of collaboration and regulatory alignment. The successful implementation of market coupling required significant coordination among national regulators, TSOs, and market participants. The development of standardized rules, common platforms for trading, and robust governance structures were essential in overcoming the technical and regulatory challenges of integrating diverse markets.

The inception and evolution of European market coupling represent a monumental achievement in the region's energy landscape. By fostering price harmonization, optimizing resource use, and enhancing energy security, market coupling has paved the way for a more efficient, sustainable, and resilient European energy market. This journey, characterized by collaboration and innovation, underscores the potential of regional integration in addressing complex challenges and driving collective prosperity. Market coupling's significance extends beyond economic efficiency. By promoting price convergence and enhancing cross-border electricity flows, market coupling helps to optimize the use of RES. Wind, solar, and hydroelectric power, which are often subject to geographical and weather-related variances, can be better utilized across a wider area, therefore reducing reliance on fossil fuels and contributing to the EU's climate goals. Furthermore, market coupling enhances energy security by facilitating mutual support among countries during periods of supply shortages or system imbalances. For instance, if one country faces a sudden spike in demand or a generation shortfall, it can swiftly import electricity from neighboring markets, mitigating the risk of blackouts and ensuring stable supply. This interconnectedness fosters resilience and underscores the importance of solidarity among European nations.

As already discussed in Section 2, market coupling is the process of determining day-ahead energy prices and volumes for each local market. This is carried out by collecting all day-ahead bids and offers (referred to as orders) from different local markets and matching them at a European level based on marginal pricing. The objective of this method is to increase competition in the DAM by matching the most competitive orders in Europe, taking into account the available interconnection capacities that are distributed implicitly. Market coupling will result in a gradual reduction of energy price disparities between local markets as their interconnection capacities are expanded. Price variation occurring due to different levels of interconnection can be better understood by considering three scenarios: (a) decoupled markets, (b) coupled markets with scarce interconnection capacity, and (c) coupled markets with enough interconnection capacity. In the first scenario, markets operate independently with no coordination of electricity prices or interconnection capacities between them. Due to the lack of coordination, significant price disparities can occur between markets. For example, a region (Market A) with surplus generation (e.g., high renewable energy output) may experience very low or even negative prices. Conversely, a neighboring region (Market B) with a supply shortage (e.g., due to low renewable output or high demand) may face high electricity prices. The absence of interconnection means that surplus electricity in one market cannot be exported to balance the supply in the neighboring market, leading to inefficiencies. Consumers in high-price areas pay more for electricity, while low-price areas do not benefit fully from their surplus. Overall welfare is not maximized because the potential for cross-border electricity trading is not utilized.

For the second scenario, it is assumed that the two markets are coupled, meaning they coordinate electricity prices based on available interconnection capacities; however, the interconnection capacity is limited and may become congested. In this case, when the interconnection capacity is scarce, it can become a bottleneck, leading to partial price convergence. Prices in the two markets will start to converge, but due to the limited capacity, the convergence is incomplete. For example, if Market A has a surplus and Market B has a deficit, electricity flows from A to B. However, once the interconnection capacity is fully utilized, any additional surplus in A cannot be transmitted to B. As a result, Market A's prices may remain lower than Market B's, but the price difference will be smaller compared to the decoupled scenario. While the efficiency improves compared to decoupled markets, the limited interconnection capacity prevents full price convergence, leading to remaining inefficiencies. Investments in grid expansion or enhancements in capacity allocation methods could help alleviate this issue. The third scenario considers that markets are coupled with sufficient interconnection capacity to facilitate the free flow of electricity between them. When interconnection capacity is adequate, markets can achieve full price convergence. Surplus electricity from a low-priced region (Market A) can flow freely to a high-priced region (Market B), balancing supply and demand across the interconnected markets. In this scenario, price differences are minimized or even eliminated, resulting in a uniform price across the coupled markets. This scenario represents the most efficient use of resources, where electricity flows from areas of surplus to areas of deficit, maximizing social welfare. Consumers benefit from more stable and often lower prices, and generators can operate more efficiently. This setup also promotes the integration of RES, as surplus renewable generation can be distributed more effectively across the region. The three scenarios are illustrated in Figure 8.

The key to the pan-European electricity market is the Price Coupling of Regions (PCR), which is considered a crucial measure for achieving a unified electricity market in Europe through market coupling. The PCR initiative was launched in 2009, and it is a joint effort by European Power Exchanges to provide a unified method for optimally determining energy pricing across Europe and effectively managing cross-border allocations. This method takes into account the capacity of the necessary network components and operates on a day-ahead basis. It is essential to accomplish the overarching objective of establishing a unified European electricity market to meet the EU's target. The integration of the European power market enhances the availability of funds, effectiveness, and overall societal well-being. PCR is presently being executed by nine Power Exchanges, namely EPEX SPOT, GME, HenEx, Nasdaq, Nord Pool, OMIE, OPCOM, OTE, and TGE [58]. PCR is employed to connect the countries of Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Republic of Ireland, Romania, Slovakia, Slovenia, Spain, Sweden, and the UK.

Targeting the adoption of a common marginal-price-based algorithm for the day-ahead determination of prices and traded energy volumes in all bidding zones, the PCR project developed the so-called EUPHEMIA algorithm, which is an acronym for Pan-European Hybrid Electricity Market Integration Algorithm [59]. This algorithm is utilized to compute the distribution of energy, net positions, and electricity prices throughout Europe based on a system-wide optimization process. The algorithm is capable of simultaneously processing a wide range of order types, as per the local market regulations, that are accessible to market participants. The order types handled are (a) aggregated hourly orders, (b) block orders, and (c) merit orders and PUN orders (PUN stands for "Prezzo Unico Nazionale"—in the Italian market, there is a specific regulation known as the PUN market clearing condition that is used to clear demand hourly bids). Through aggregated hourly orders, all market players within the same bidding zone will have their demand (supply) orders combined into a single curve known as the aggregated demand (supply) curve. This curve is defined for each period of the day. Orders in demand are arranged in descending order based on their price. In contrast, supply orders are arranged in ascending order based on price, from

the lowest to the highest. Complex orders consist of a group of individual supply orders, referred to as hourly sub-orders, that are issued by a single market player. These sub-orders are spaced out over multiple time periods and are subject to a condition that impacts the entire set of sub-orders. Complex orders subject to minimum income condition constraints are called MIC orders, while complex orders on which a load gradient constraint applies are called load gradient orders. In the simplest case, a block order is established for a continuous sequence of time periods with identical volume and a minimum acceptance ratio of 1 (fill-or-kill block orders); however, typically, the block orders can have non-consecutive intervals, varying volumes throughout these times, and a minimum acceptance ratio that is less than 1.

Merit orders are sequential orders assigned to particular steps throughout a specific period, each step being assigned a corresponding merit order number. A merit order number is a distinct identifier assigned to each period and order type (Demand, Supply, PUN). It is utilized to prioritize merit orders inside the bidding zones that include this specific order type. A lower merit order number corresponds to a higher priority for acceptance. PUN orders refer to a specific category of demand merit orders. They deviate from traditional demand merit orders in that they are settled at the PUN price.

Its purpose is to optimize social welfare and enhance the transparency of price calculation and power flow, leading to net positions. Social welfare refers to the total value derived from the combination of the producer's surplus, the consumer's surplus, and the congestion rents paid to TSOs in the event of planned congestion. According to the algorithm, market players initially commence the process by submitting their orders to the power exchange that corresponds to their specific jurisdiction. EUPHEMIA receives and reviews all the orders, determining which ones will be carried out and which ones will be declined based on the published prices. This decision-making process aims to achieve two objectives: (a) maximize the overall social welfare, which includes the combined benefits to consumers and producers, and the reduction of congestion across different regions, and (b) ensure that the power flows resulting from the executed orders do not exceed the capacity of the relevant network elements.

Maximization of the social welfare is reflected by the maximization of the total market value of the day-ahead auction expressed as a function of the consumer surplus, the supplier surplus, and the congestion rent, including tariff rates on interconnectors if they are present. In essence, the program is a mathematical model that includes complementarity constraints (MPCC) and involves integer decision variables. This problem falls into the category of Mixed Integer Non-Linear Programs, which indicates that the continuous relaxation of the problem is not convex. For each feasible solution,

EUPHEMIA solves the price problem that minimizes the distance from the mid-point price as follows:

$$\min \sum_{m,h} (MCP_{m,h} - \frac{UpperBound_{m,h} + LowerBound_{m,h}}{2})^2 \quad (2)$$

that is subject to complementarity slackness conditions, price bounds as wells minimum income conditions, and PUN imbalance constraints. However, constraints related to the paradoxical acceptance of block orders are not considered. The variable MCP stands for the Market Clearing Price.

PCR is also used as an indicator for estimating the interconnectivity level of each country. More specifically, the level of interconnectivity of MSs is calculated as the annual average offered import capacity of every MS as a percentage of peak electricity demand, as well as the annual average offered export capacity of every MS as a percentage of peak electricity generation. As depicted in Figure 9, MSs experience large disparities in interconnectivity levels for 2023, which are mainly driven by geographical differences, variations in cross-border infrastructure scales as well as diversities in network operation. The presented values do not consider the capacities traded between bidding zones within a

single MS, which is especially important for Italy or Sweden, thus excluding any national interconnectivity level assessment for trades within each MS.

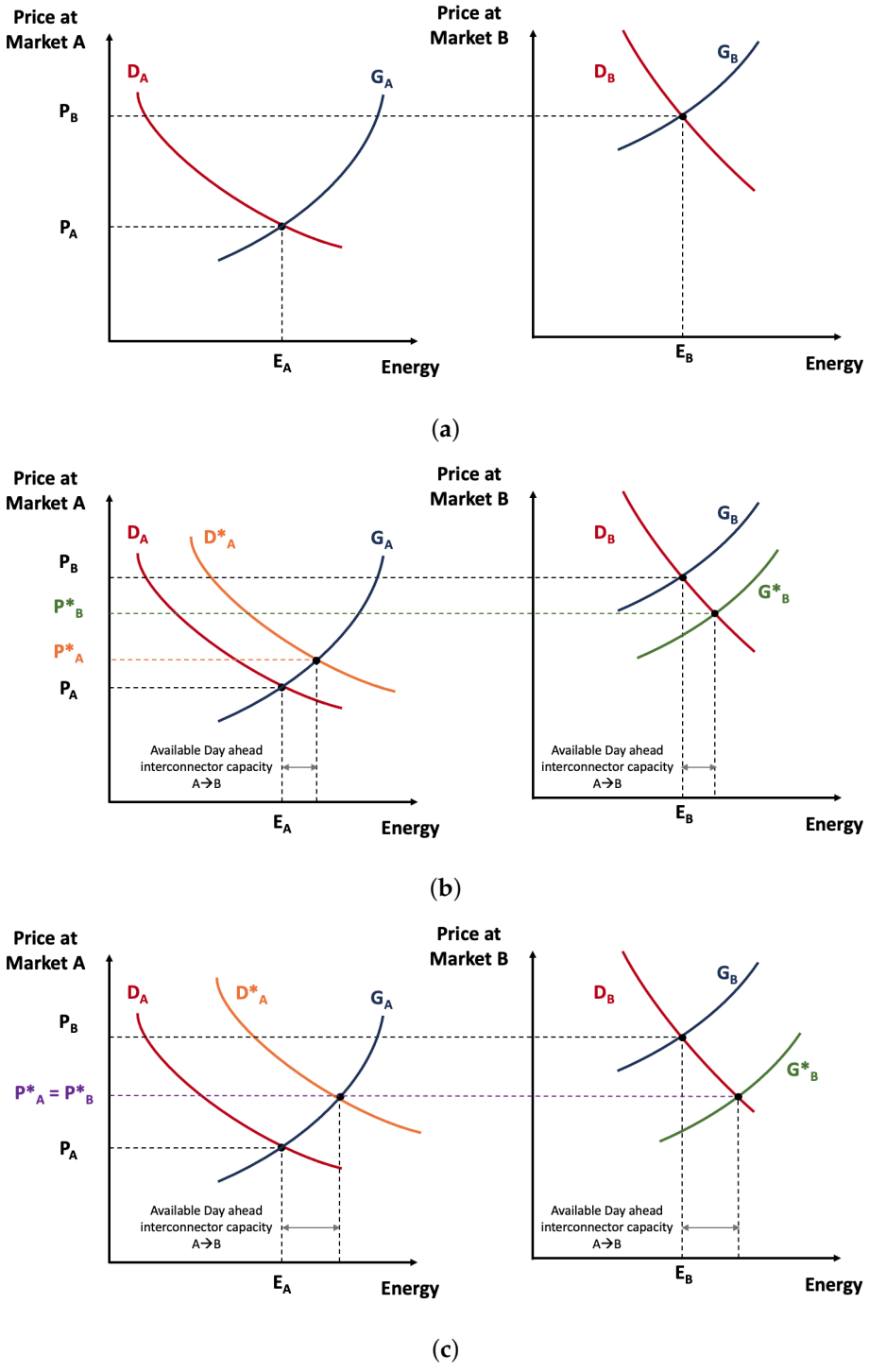


Figure 8. Price differences with interconnection capacities due to market coupling. (**a**) Decoupled markets. (**b**) Coupled markets with scarce interconnection capacity. (**c**) Coupled markets with enough interconnection capacity. Demand and Generation curves of Region A (B) are represented by D_A (D_B) and G_A(G_B), respectively.

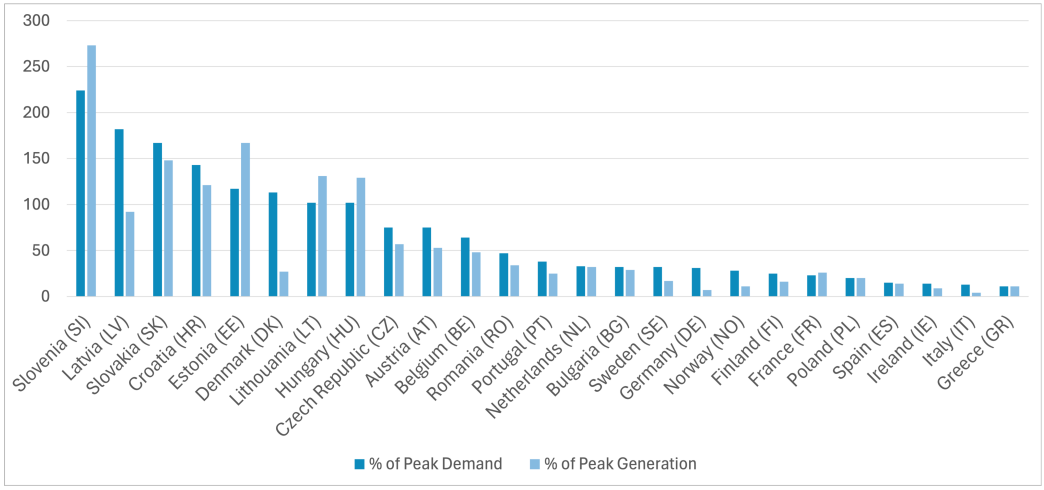


Figure 9. Pan-European interconnectivity level for the year 2023.

In the context of European coupled markets, where countries are interconnected through a common electricity market, the hourly marginal cost is a key factor that influences cross-border electricity trade. In a coupled market, electricity flows from areas with lower marginal costs to those with higher marginal costs, helping to optimize the overall efficiency of the electricity system across the continent. The hourly marginal cost of electricity refers to the cost of producing one additional unit of electricity, typically one MWh, at a given hour. This cost varies throughout the day based on factors such as the availability and cost of fuel, the efficiency of power plants, and the demand for electricity. In interconnected electricity markets like those in Europe, the hourly marginal cost is crucial in determining electricity prices and guiding power flows across borders. The difference in hourly marginal costs between electrically interconnected countries arises from several factors, including differences in energy resource availability, generation technology, market regulations, and grid infrastructure. Countries with abundant and cheap natural resources, such as hydropower, wind, or solar, tend to have lower marginal costs for electricity production compared to countries relying on more expensive or less efficient energy sources like coal or gas. For example, Norway, with its extensive hydropower capacity, often has lower electricity prices compared to Germany, which relies more on coal and gas. Additionally, the type of power plants in operation significantly affects marginal costs. RES, such as wind and solar, have near-zero marginal costs because they do not require fuel, whereas fossil fuel plants incur significant fuel costs.

Therefore, countries with a higher share of renewables in their energy mix can produce electricity more cheaply, leading to price differentials when interconnected with countries that rely on fossil fuels. Market regulations and policies also play a significant role in creating these cost differences. Electricity markets operate under different regulatory frameworks, affecting pricing. For instance, carbon pricing in the EU increases the cost of producing electricity from fossil fuels, especially in countries where carbon-intensive generation is prevalent. Conversely, countries with subsidies for renewables or price caps might have artificially lower or higher prices compared to neighboring countries without such interventions. Furthermore, even when countries are interconnected, physical limitations on the transmission network, known as congestion, can prevent electricity from flowing freely from a low-cost area to a high-cost area. This can create price differences between countries, as the marginal cost in the importing country may remain high due to limited supply from the cheaper exporting country.

Additionally, grid losses during transmission can increase costs in the importing country. Hourly demand variations, driven by factors like weather, economic activity, and time of day, also contribute to differences in marginal costs. If one country experiences a peak in demand while another has a surplus, the country with higher demand might see higher marginal costs unless sufficient interconnection capacity allows for balancing. In

interconnected markets, electricity tends to flow from regions with lower marginal costs to those with higher marginal costs, helping to balance prices. However, due to the aforementioned factors, complete price equalization rarely occurs, leading to persistent hourly differences in marginal costs between countries. These differences are important because they provide signals for where investment in generation and transmission infrastructure is needed. Persistent high marginal costs in one country may indicate a need for more generation capacity or better interconnections with neighboring countries. Conversely, countries with consistently lower marginal costs might attract energy-intensive industries, benefiting from cheaper electricity. Understanding these cost differences is essential for policymakers and market participants in setting policies, designing market mechanisms, and making investment decisions that support the goals of the European Green Deal and energy transition, which aim to decarbonize the energy system while ensuring affordable and secure energy for all. The hourly marginal cost of electricity is a fundamental concept in the European coupled markets, driving cross-border electricity flows, supporting market integration, and providing crucial economic signals for the future development of the European energy system. The average annual difference of the hourly marginal cost to produce electricity between two countries for 2023, as estimated by ACER [60], is illustrated in Figure 10.

In a perfectly liquid electricity market, or if there were no physical hurdles to the exchange of electricity (capacity constraints/congestions), this value would always be zero. Grid development facilitates the connection between a larger number of end-customers and producers, resulting in more efficient utilization of the most cost-effective energy-producing methods. Consequently, European nations can trade power, substituting costly thermal generating with more affordable alternatives, leading to a convergence of costs across Europe. It is foreseen that in 2030 and 2040, the increase in cross-border capabilities will cause European marginal costs to converge to an average spread of 10 EUR/MWh and 7 EUR/MWh, respectively [61]. Conversely, restricting the ability to trade reduces market integration and leads to divergences in regional market prices. Fragmented markets result in artificially inflated marginal costs in certain nations, which directly affects customers' electricity rates.

In 2023, European electricity markets experienced an unprecedented and notable increase in negative pricing events, a trend largely driven by the rapid expansion of RES, particularly wind and solar. The frequency of negative prices has surged, with 27 out of 50 bidding zones experiencing the highest amount of negative pricing since 2017. Notably, the Nordic countries recorded over 380 instances of negative prices, illustrating the scale of the issue. This surge in negative prices can be attributed to several factors, but the rapid growth of renewable energy stands out as the primary driver. Wind and solar power generation have increased dramatically, from 139 TWh in 2009 to 721 TWh in 2023, accounting for 27% of the EU's power mix [28]. This rapid expansion has transformed the energy landscape, but it has also introduced new challenges. A deeper look into the situation reveals that the variability of RES leads to imbalances between supply and demand.

During periods of high renewable output, such as sunny summer days or windy winter nights, combined with low demand, the electricity supply often exceeds demand, driving prices into negative territory. This dynamic reflects the changing nature of electricity generation in Europe, where traditional, controllable power plants are increasingly supplemented by renewables that depend on weather conditions. As a result, these negative prices are not merely economic phenomena but also indicators of the need for improved integration of renewables into the power grid. By the end of 2023, renewables made up 46% of the EU's electricity generation, marking a substantial increase from 37% the previous year [62]. Countries like Germany and Spain have significantly increased their wind and solar capacities, contributing to these dynamics. This shift underscores the potential of renewables to provide clean energy at scale, but it also highlights the need for better market mechanisms to handle their variability.

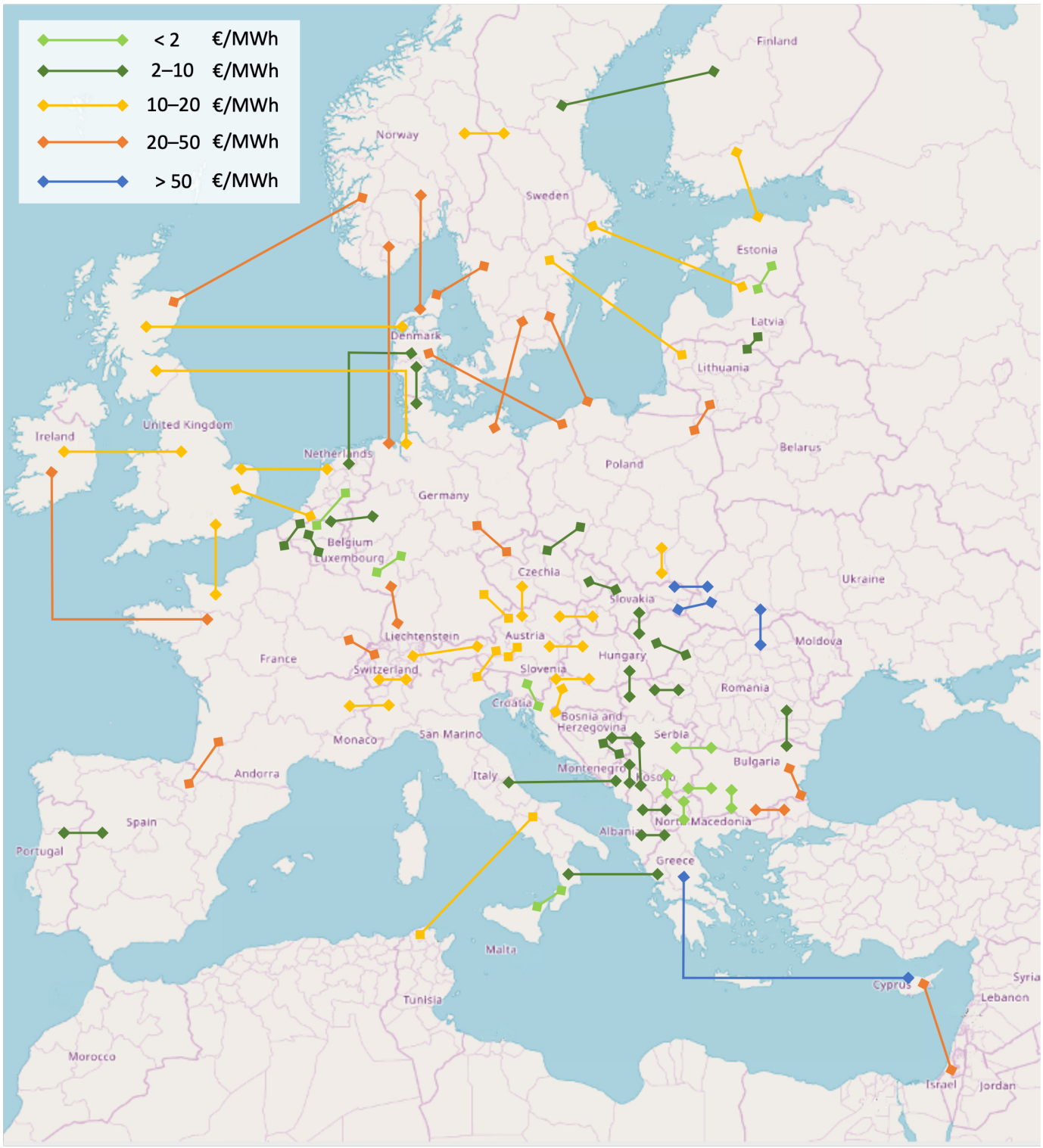


Figure 10. Marginal costs difference between countries at the pan-European level for 2023 (data from [60]).

The importance of market integration emerges as a crucial factor in addressing the challenges posed by negative pricing. A unified European electricity market can facilitate cross-border trading, allowing countries with excess electricity to export surplus energy to regions experiencing higher demand, therefore mitigating negative prices. Additionally, the development of demand-side responses and the enhancement of market flexibility are essential to adapting to the challenges posed by renewable energy variability. Infrastructure improvements and policy coordination are also vital in managing the integration of renew-

able energy, improving market efficiency, and reducing the impact of negative prices. While the increase in negative electricity prices highlights the challenges of integrating renewable energy into the grid, it also underscores the importance of a unified and flexible European electricity market. By facilitating cross-border trading and enhancing market flexibility, Europe can effectively manage these changes and harness the potential of renewable energy for a more sustainable future.

A major indicator of the impact of negative prices is the total number of yearly occurrences. It is worth noting that the early occurrences of negative prices in the EU for 2023 have risen to 6470, compared to the total of 558 events recorded in the previous year [63]. The total occurrences of day-ahead negative prices in EU Bidding zones for the year 2023 are graphically depicted in Figure 11.

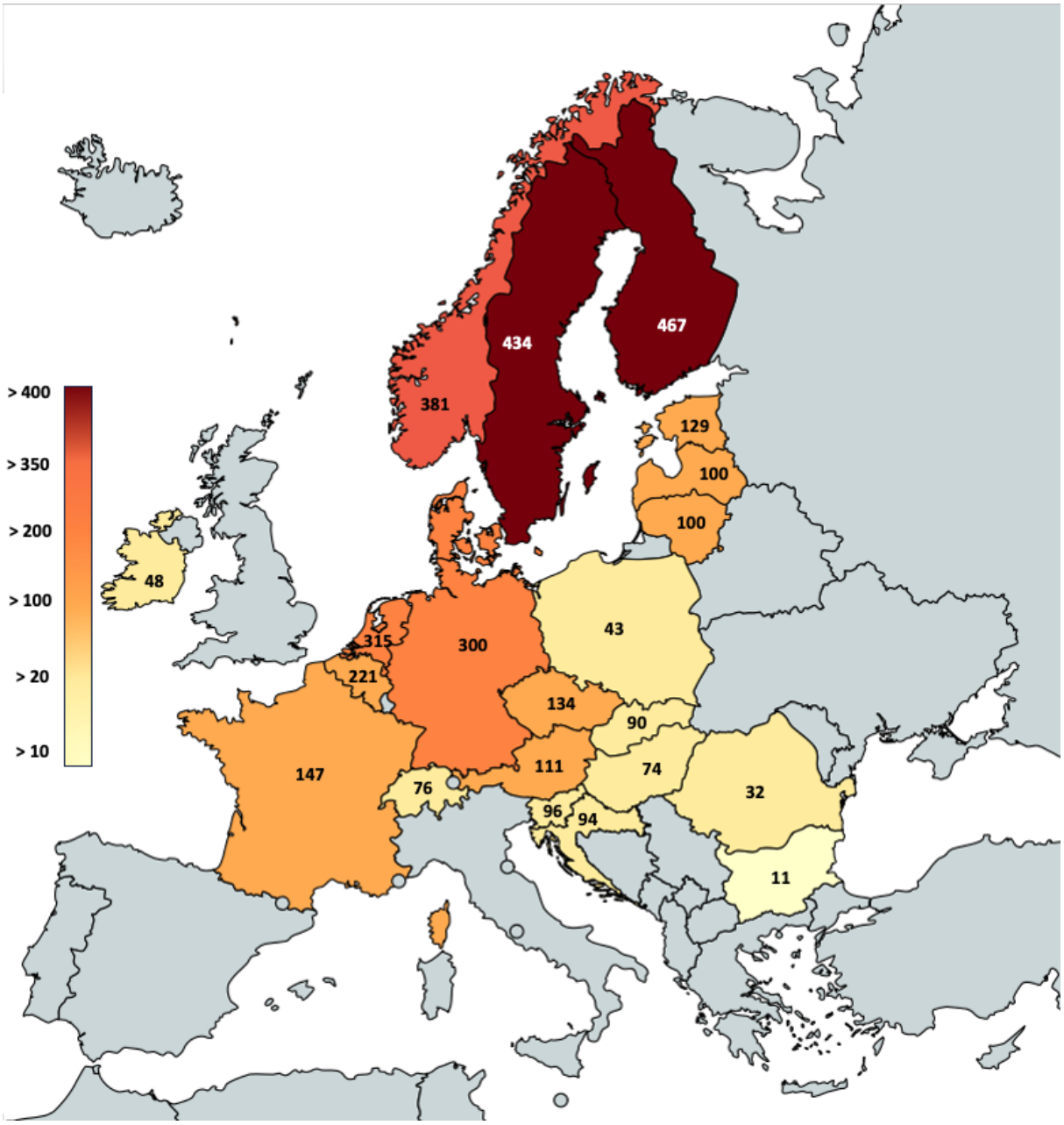


Figure 11. Occurrences of day-ahead negative prices in EU bidding zones (2023) (data from [63]).

In terms of trading volumes, according to ENTSO-E [64] and ACER [65] data for 2023, France continued to be the major exporter of electricity in Europe, taking advantage of

its significant nuclear power capacity. On the other hand, the UK emerged as the largest importer of electricity, relying on interconnectors with neighboring countries, particularly France, to meet domestic energy demand. Cross-border electricity trading volumes reflected this dynamic, with France exporting to multiple European countries, helping balance supply in regions experiencing shortages or higher demand. These trading flows play a crucial role in stabilizing electricity markets across Europe. A mapping of the volumes (TWh) traded across Europe for 2023 is shown in Figure 12, where positive values indicate exports and negative represent imports.

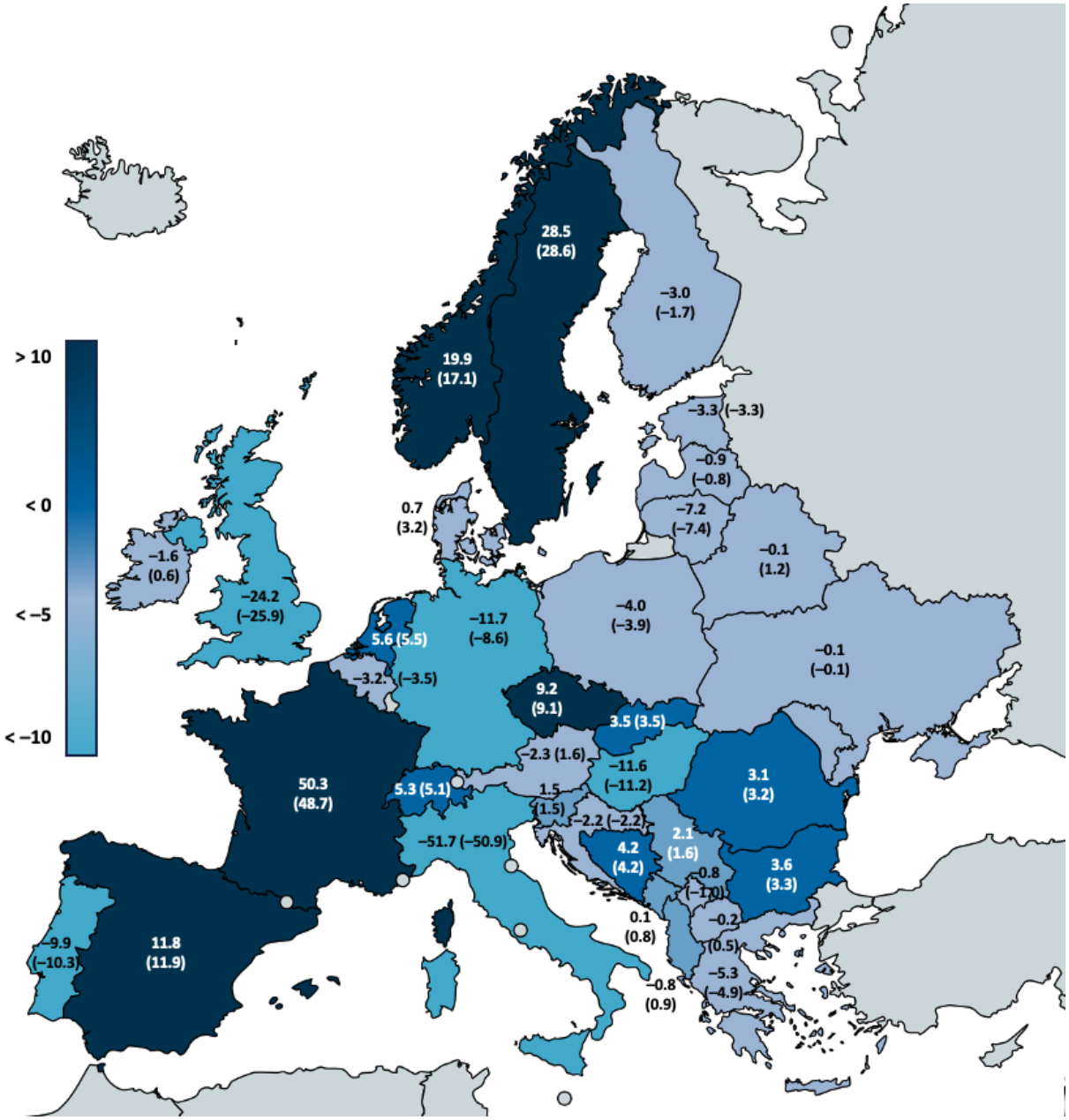


Figure 12. Cross-border trading volumes (physical flows) at the pan-European level for 2023 (data from [64,65]).

6. Recent Research Direction in Cross-Border Electricity Interconnectors and Trading

Recent research on cross-border electricity interconnectors and trading has been dynamic, reflecting the increasing importance of regional and international energy cooperation to enhance grid stability, optimize resource utilization, and facilitate the energy transition.

The investment implications of cross-border infrastructures and electricity trade are being closely studied by many researchers, particularly in terms of investment costs, operational savings, and the economic benefits of increased energy security and market efficiency. The progress of cross-border interconnections in the Mediterranean basin is examined in [66]. The authors emphasize the difficulties of existing investment models and provide insights into the requirements of a sustainable business strategy. A feasible business model for the Mediterranean region must tackle the challenges associated with (i) stimulating investment and ensuring efficient operation, (ii) effectively managing risks and uncertainties, and (iii) implementing coordinated planning and governance.

The regulated investment, which serves as the primary business model for interconnections in the EU region, has not been successful in providing the necessary investment. The authors highlight that the merchant transmission investment is considered an exception under EU laws and is permitted only if the investor can demonstrate that the risk is sufficiently severe that investment would not occur under the regulated model. The presence of differences among EU and Non-EU nations makes it difficult to apply polar models (regulatory and commercial transmission initiative). Thus, a hybrid company model that preserves the primary advantages of a merchant model while operating within a regulated framework is proposed. The model comprehensively considers the essential components of a sustainable business model, specifically focusing on incentives, risks, and governance. The assumption is that the interconnections will primarily be established to export surplus electricity from Europe to North Africa. However, this system is also adaptable to accommodate any changes in the electrical generation mix of these regions in the future, including the potential export of renewable energy from North Africa to Europe.

The work presented in [67] delves deeper into the foundations of investment decisions in interconnectors, with a specific focus on using CBA as a reference point. The economic basis for constructing two interconnectors in Europe—NorNed, connecting the Netherlands and Norway, and the East–West Interconnector, linking Ireland and the UK—are investigated in this study. Analysis outcomes reveal that the primary advantage is enhanced security of supply, quantified as the avoidance of the cost associated with acquiring a new generator that would otherwise be necessary to maintain the same level of supply security. Imports from the UK are consistently presumed to be feasible. Nevertheless, the UK has failed to consider the non-dispatchable capacity, as well as the reality that UK generators will decrease their investments to minimize the surplus capacity, thus limiting the potential for cost-effective imports. Furthermore, the business case highlights the advantages of decreased carbon credit payments for imported electricity, as it fails to acknowledge that Irish power importers will now be required to purchase these permits from the UK rather than Ireland. Furthermore, the discounting appears excessively pessimistic as the social benefits are computed using the pre-tax WACC instead of the post-tax WACC.

The study of [68] examines the economic aspects of a cross-border transmission interconnector. The domestic spot energy price is represented as a stochastic process characterized by mean reversion and leaps, incorporating a deterministic component that captures hourly and daily seasonal patterns, as well as non-working days. To exemplify the methodology, the authors examine the specific scenario of the interconnection between Spain (a self-contained electricity network) and France. The domestic prices are initially adjusted and subsequently employed to simulate the random fluctuations in the price difference between the two countries. Furthermore, the specific import/export patterns in relation to the price difference are accurately represented by a Tobit model that is calibrated using real data. Subsequently, this model is integrated with the simulated discrepancies in prices to calculate a series of various hourly prices and the import/export of power through the interconnector. Utilizing these simulations, the authors calculate the probability distributions of revenues and expenses related to exports and imports, as well as various risk measures. Based on our findings, the economic viability of this interconnector is influenced by various domestic seasonal patterns (hourly and daily), the increasing price discrepancy trend, and certain random peculiarities.

The work conducted in [69] aims to measure the economic capacity of cross-border transmission in the transition towards a decarbonized power system in NWE. The scenario with the modeled optimal transmission capacity, which minimizes the total system costs, is compared to the scenario with the predetermined capacity level of current and future projects. Investing more in transmission infrastructure reduces overall system costs and narrows the price gap between different regions. It specifically aids in the expansion of wind power and therefore reduces CO_2 emissions in the electricity and heat industry.

The impacts, however, are dispersed unevenly across stakeholders in the northern and western regions. Consumers in the northern regions experience elevated electricity prices, but wind and hydropower producers also observe a rise in their revenues. Meanwhile, consumers in the western region benefit from reduced electricity costs, while gas power producers experience a decline in their income. An interconnection investment model that incorporates negotiations between interconnected regions in the market is proposed in [70]. The model considers strategies for allocating investment costs fairly in scenarios with and without compensations. The case study results demonstrate various cost distribution patterns that are influenced by transmission investment costs. According to the authors, as the expenses rise, the distribution shifts from the importing nation to the exporting nation. It is also highlighted by the authors that even though the proposed model results in an increase in total social welfare, this comes at the cost of increased electricity prices for consumers in the exporting region and potential challenges for producers in the importing area in operating their most costly generators. The authors conclude that policy makers must be cognizant of these trade-offs, while decentralized discussions for connectivity extension could result in a fair share cost distribution that leads to a negative proportion, meaning that one of the areas would receive direct economic compensation. In order to implement these investments, the authors suggest that it would be advantageous for the extension of the interconnectivity to obtain financial assistance from the EU. This help might come from initiatives such as the CEF, the Structural Funds, the European Fund for Strategic Investment, or the European Investment Bank.

Significant contributions by the research community have also been achieved in the area of cross-border energy trading and market coupling. Work presented in [71] aims to quantify the potential advantages of integrating interconnectors to enhance the effectiveness of cross-border trading in the day-ahead, intraday, and balancing services. The authors conclude that market coupling results in significant overall benefits that are expected to greatly outweigh the costs associated with the necessary modifications in market architecture. Additional benefits could be obtained by implementing nodal pricing; however, these advantages must be weighed against the potential drawbacks of reduced liquidity and increased susceptibility to market manipulation. A clear and prominent observation is the increasing demand for greater interconnection, and the policy implication is to guarantee that interconnectors are adequately compensated for the whole range of services they offer.

The research presented in [72] evaluates the consequences of inaccurately depicting cross-border trade flows in regionally limited long-term planning models. In order to achieve this objective, the authors employ a planning model for the linked power system of CWE to analyze technology options and assess the welfare implications for Belgium under two scenarios: (i) disregarding cross-border electrical trade and (ii) incorporating cross-border trade flows as an integral component of the planning model. In addition, this work introduces two sets of approaches to incorporate transmission fluxes into planning models. One approach is to expand the geographic range of the model and set the capacity variables in neighboring nations according to predetermined scenarios for those countries. Another approach significantly decreases the computing expense by utilizing custom-designed import and export curves to depict the trade possibilities of each country. The findings suggest that in complex systems with extensive interconnections, failing to consider cross-border commerce or using a simplified model of cross-border flows can result in imprecise welfare estimates and biases in technology assessment. Furthermore,

this article highlights the significant contribution of congestion rents to the overall welfare improvements achieved through energy trading. The most precise approach to address cross-border trade is to incorporate the dispatch decisions of neighboring nations into the analysis. Although computational time can be decreased by appropriately modeling cross-border trade curves, this may result in less accurate outputs of the planning model.

The mathematical concept and parameters of the FB market-coupling method and its impact on the ATC one are examined in [73]. The results indicate that the FB market-coupling mechanism results in greater social welfare and cross-border flows compared to the simpler ATC model. Nevertheless, according to the authors' comparative analysis, traders will have challenges in predicting prices beyond the DAM if transmission system operators persist in solely releasing projections of power transfer distribution parameters for this duration.

The interconnection capabilities between the electrical market in Switzerland and the markets of bordering countries are investigated in [74]. The Swiss electricity market is a prime example of a minor sector that is increasingly influenced by the advancements in larger bordering countries. In order to examine the impact of these effects across borders, particularly on Swiss power prices, two distinct approaches are utilized: an econometric model and a Nash–Cournot equilibrium model. The results indicate a substantial correlation between the Swiss power price and the German electricity price during the summer, whereas in the winter, the Swiss electricity price tends to align with the French electricity price. Moreover, the results showcase that the oil prices and the electricity demand of adjacent nations exert a substantial impact on prices. Specifically, the electricity demand from France and Italy is causing Swiss prices to increase during the winter season, while the German electricity demand and the output of renewable energy have a greater impact on Swiss pricing during the summer.

An enhanced approach for calculating the cross-border capacity in manual balancing markets is presented in [75]. The method employed is based on the FB approach and relies on a network forecast that is updated one hour prior to real time while considering the constraints of topological operations that can be implemented in balancing markets. A simulation of the manual balancing market process in conducted, which involved five distinct steps: calculating the capacity for the day ahead, conducting a day-ahead market, computing the balancing capacity, conducting a balancing market, and performing a security analysis. The simulation is based on a 73-node network that was utilized to evaluate the effects of the existing cross-border capacity and a projected increase in capacity. Derived outcomes reveal that the suggested cross-border capacity calculation results in a 26% enhancement in social welfare over six days. The primary benefits are shown in market welfare, but there is an increase in overall congestion management costs. According to the authors, the results suggest that improving FB parameters could potentially lead to further improvements in social welfare; however, it is advisable to extend the duration of the case study to validate this initial finding.

The study presented in [76] proposes a regional congestion management market framework that utilizes demand-side flexibility resources across borders. The architecture primarily focusses on flexible load connected or aggregated at the transmission level but also takes into account the flexibility of storage and RES. This study examines the capacity market potential of domestic and international resources in a connected transmission system in SEE, based on how factors like location, flexible capacity, resource availability and kind, and the cost of congestion removal can impact the success of congestion management. The cost-effectiveness of congestion management is evaluated by a rigorous analysis that takes into account various bidding situations, predetermined line flow decrease on a vital line, and the operational limitations of the transmission network. When considering realistic restrictions, the bid selection algorithm demonstrates that flexibility resources with high individual cost-effectiveness may not be cost-effective for capacity management. According to the authors, while DSO assets are spread out across the studied SEE region, the potential for congestion management in RES is still greater due to its larger capacity for flexibility,

primarily concentrated in the northern half of the region. Thus, by increasing the flexibility of DSO resources, without necessarily increasing their dispersion, congestion management markets can obtain advantages from DSO and TSO with improved cost-effectiveness, leading to a more sustainable operation of regional transmission networks.

Work of [77] presents a non-cooperative game model to analyze cross-border electricity trading. The authors' approach focuses on analyzing the trading modes of many participants that are influenced by cross-border trading centers. The model uniquely integrates trading regulations and service costs, creating a realistic simulation framework. The findings demonstrate a clear link between the extent of strategic planning and the reliance of trading strategies on electricity pricing determined by trading centers. This study enhances the theoretical comprehension of applying game theory in energy markets and provides practical perspectives for policymakers and market operators, namely in devising strategies for price determination and overseeing cross-border transactions.

An intraday market design that utilizes a coordinated multilateral trade approach is proposed in [78]. The suggested method leverages power transfer distribution factors and other network information provided by TSOs to generate profitable trades based on nodal bids. The trades aim to be both feasible and potentially involve multiple parties. Profitable deals can be identified through the services of independent brokers or by utilizing a power exchange that conducts periodic batch auctions at specific time intervals. The TSO accepts each trade provided there are no network violations; otherwise, it is limited. When the network flow is possible at the beginning of the intraday market, the process reaches the optimal economic dispatch. This proposal aims to facilitate intraday trading by considering basic information about network limitations and adhering to the operational principles of the European intraday market.

By doing so, it can effectively bridge the gap between zonal DAMs and the real-time constraints of the power system. The research presented in [79] examines the two distinct techniques for calculating transmission capacity in the continuous intraday electricity market: ATC and FB Capacity allocation. An agent-based model is used to examine the impact of these two strategies on the continuous intraday electricity market, which includes several types of trading agents. Additionally, it simulates the behavior of a market operator agent and a TSO agent, drawing inspiration from the SIDC initiative in Europe. The price–volume decisions for the orders posted by market players are influenced by two distinct methods. The first strategy is adaptive, taking into account changing market conditions and new information, while the latter is naive, without such adaptability. The model incorporates scaling limitations, allowing for the examination of trade behavior and agent interaction across numerous delivery goods concurrently. The purpose of the presented case studies is to showcase the practicality and potential of the suggested agent-based model. The primary objective of the authors is to develop an open-source tool that can be tested by the user in many simulated scenarios. The agent-based model delves into the modeling of each market player, yielding profound insights into the behavioral patterns of major actors in the market under varying situations.

The cross-border trading through market coupling in the SEE region is also examined in [80]. The case study encompasses the use of both the ATC and FB approaches within a scenario including four countries: Greece, North Macedonia, Bulgaria, and Serbia. The topic is expressed mathematically as an optimization problem, with a shared objective function for both ATC and FB approaches, where the coupling of the FB market is assumed to result in a more effective use of generation and transmission resources, while under the ATC methodology is assumed that TSOs estimate capacity levels by considering forecasts and historical data. However, the FB mechanism enables TSOs to assess the effect that trading will have on the actual flows inside the network. FB market coupling provides additional trading alternatives to the market, leading to an overall increase in welfare and improved price convergence. The derived findings confirm the theoretical advantages that FB brings to cross-border trading in the SEE region and enhance the efficient utilization of

interconnected networks. Furthermore, cross-border trading leads to a rise in total social welfare and a decrease in domestic energy prices.

The study presented in [81] proposes a novel strategy to enhance the overall efficiency of FB market coupling and redispatching. The authors suggest a new approach to managing congestion in a zonal market using FB market coupling with a goal of improving cross-border trading by including preventive redispatch into the DAM. This strategy involves selecting a group of integrated redispatch units that have a high potential to decrease congestion and, consequently, increase the capacity of the grid for cross-border exchange. To illustrate the advantages of the improved zonal market with integrated redispatch, the authors employ three multi-step optimization models. These models are used to compare the enhanced zonal market with the nodal market model and a zonal market model that incorporates FB market coupling. The case study illustrates the potential of the suggested methodology to substantially enhance cross-border capacity and diminish the requirement for expensive ex-post-redispatch. The technique is demonstrated to be a viable choice for enhancing European market integration and thus achieving overall welfare benefits.

A clear and detailed explanation of the FB market-coupling process, including its decomposition and representation inside a model, is presented in [82]. The authors demonstrate an open-access model that outlines the key stages of FB market coupling while discussing how other users to replicate the results reported in their work as well as generate new results by adjusting the model's parameters. The case studies conducted on a test network demonstrate how modifications in the parameters of FB market coupling impact market results and the necessity for corrective measures. The results indicate that the minimum trading capabilities requirement may not be met if the base case is not explicitly modeled in accordance with it. Therefore, when the requirement for a minimum trading capacity is enforced, the TSO must take action on many crucial network elements for a significant number of hours throughout the year. This is carried out to decrease line flows and increase trading capabilities available to the market.

The impact of implementing FB market coupling on the convergence of day-ahead power prices and the volumes of cross-border electricity exchange is experimentally quantified in [83]. The results showcase that, after the implementation of FB market coupling, there was a significant increase of 1700 MWh/h in hourly cross-border exchange volumes. Additionally, the prices between nations were more aligned, with a convergence of 10.4 EUR/MWh. Subsequently, a decline of 400 MWh/h is observed in the cross-border volumes compared to their levels before the implementation of FB market coupling. Nevertheless, after accounting for fluctuating market conditions in the years subsequent to the implementation of FB market coupling, it is evident that this method continues to have a consistent and favorable impact of approximately 1150 MWh/h on hourly cross-border exchange volumes and 2 EUR/MWh on price convergence. Ultimately, the findings offer compelling indications that a reduction in commercial transmission capacity on crucial branches may have played a role in the gradual diminution of the advantages over time, hindering the relevancy of expanding the usage of FB market coupling to other regions and market zones other than the EU's energy market.

The impact of including foreign generators and interconnectors into national capacity mechanisms on the issue of generating adequacy policies in a multi-market setting is investigated in [84]. The findings indicate that the lack of cross-border involvement may result in substantial reductions in social welfare due to the risks of both over- and under-capacity procurement. According to the authors, this approach creates a self-perpetuating cycle: when capacity mechanisms acquire too much or too little capacity, it distorts cross-border electricity commerce, which then weakens the effectiveness of capacity mechanisms. The results also indicate that incorporating interconnectors into national capacity mechanisms could stimulate investments in merchant interconnections by offsetting network externalities and aligning profit levels with interconnection costs. Nevertheless, the effectiveness of the market-based plan is compromised by the exclusion of foreign generation, notwithstanding the involvement of interconnectors in capacity procedures. The authors conclude

that without a broader EU single capacity mechanism, incorporating foreign generators and interconnectors into national capacity mechanisms should promote optimal coexistence between the EU Single Market and national capacity mechanisms.

The analysis presented in [85] aims to evaluate the existing legislation concerning balancing markets and practices in the SEE region while seeking to identify the primary obstacles and provide solutions for the development and regional integration of balancing markets. The inquiry is carried out in collaboration with the TSOs from eight countries in SEE. The authors discuss the existing practices of procuring reserves and balancing energy, the balancing market prices, settlement, as well as expected future changes in this area and conclude that limited competition and secondary legislation safeguarding national resources are posing significant barriers to advancement, while establishing a regional balancing market will promote competition and enable the establishment of actual market prices, hence encouraging investments in RES and sophisticated technologies.

The work presented in [86] introduces a methodology for modeling FB market coupling. The study examines the impact of various market-coupling scenarios on electricity prices, exchange positions, and the quantity and kind of binding constraints in the market. The findings indicate that higher minimum trading capacity in the CWE market can lead to a reduction of the German net export position by up to 7 TWh or 23%, while French exports grow by up to 10 TWh or 9%. The varying transfer capacity in the scenarios results in a price discrepancy of up to 13%. Enhanced trade capacities enable a greater amount of base load generation, resulting in commensurate impacts on the system's CO_2 emissions. The authors stress that the coupling constraints exhibit a high level of dynamism and reliance on the system state.

The current state of intraday auctions in Europe, as well as a forecast for the future trend of European intraday auctions, are presented in [87]. This research examined current national intraday auctions, the upcoming pan-European cross-border intraday auctions, and the planned or partially implemented regional intraday auctions that complement them. Key auction attributes, including the number of auctions, tradable market period(s), gate opening time, and gate closure time, and observing a diverse range of auction designs are also considered. Through an analysis of pertinent European legislation and recent regulatory rulings, the authors showcase that forthcoming European intraday auctions can be executed as either cross-border auctions or as supplementary regional auctions.

In an effort to thoroughly examine the environmental advantages of customers engaging in the electricity and carbon emission trading markets through active demand-side management, a two-stage scheduling model is presented in [88]. The following approach for emission allocation utilizes a multi-criteria allocation scheme based on a developed zero-sum gains–data envelopment analysis model. Concurrently, the "virtual" carbon flow that accompanies electricity flow is tracked using the carbon emission flow model. Case studies on the IEEE 24-bus and IEEE 118-bus systems highlight that, in some situations, the suggested approach can successfully reduce carbon emissions and give customers additional environmental benefits.

With the global push towards renewable energy, the research community is examining how cross-border interconnectors can be used to optimize the use of renewable resources. This includes studies on balancing supply from diverse sources like wind, solar, and hydro across regions with varying renewable potentials. The study of [89] utilizes hourly demand and weather data from 155 places worldwide to evaluate the impact of integrating renewable energy on the economic value of interconnecting electrical networks. In a scenario with a high proportion of RES, a greater number of interconnections across power systems are financially beneficial and result in significant cost reductions compared to a scenario dominated by conventional power generation. Derived findings indicate that the distribution of benefits from the interconnection was frequently unequal between the two regions. On average, the regions with a larger electrical market enjoyed a greater portion of the benefits. Additionally, in a scenario involving RES, the region farthest from the equator received a larger proportion of the benefits. The allocation of finance for an

HVDC project between the two regions is affected by this; however, any imbalances may be offset by the cash generated from energy sales in the long run. A sensitivity study was conducted to assess the robustness of the results to variations in cost parameters and input data. Regardless of the specific situations examined, a substantial number of profitable linkages in the renewable generating scenario is observed, resulting in savings that are much higher than those in the conventional generation case. The authors conclude that in a situation with a high proportion of renewable energy, the construction of more cross-border interconnections will be economically viable compared to battery energy storage.

A model-based evaluation of the potential impact of cross-border cooperation on Hungary and its bordering nations is presented in [90]. The monetary benefits are computed and displayed for the countries involved based on three different scenarios of collaboration. Choosing the appropriate partner country is a complex policy decision that involves more than just economic factors. Diplomatic relationships, technical considerations such as interconnection and net trade with the country, and additional commitments like opening up aid to renewable energy schemes all play a significant role. Timing is crucial for establishing cooperative programs. Continuing to reduce support costs in the future may justify delaying the joint auctions. However, this approach could prove to be erroneous due to the growing grid connection bottlenecks. The conducted modeling studies suggest that collaborating on RES between Hungary and its neighboring countries could result in a redistribution of RES investments across national borders while also yielding some cost savings in terms of policy expenses.

The work in [91] examines the concepts and correlation between RES and cross-border energy trading by utilizing a nonparametric regression model. According to the authors, the method is more flexible because it does not presume any predetermined functional form for the desired relationship. After confirming the positive impact of cross-border trading on increasing renewable energy production, the authors support the idea of collaborative policy intervention by trades to address the obstacles that hinder the promotion of interconnection infrastructures. The authors stress that this will contribute to the attainment of the sustainable development objective of providing affordable and sustainable energy to everyone.

The influence of electricity interconnection on the balance of energy sources and carbon emissions when intermittent RES is demonstrated in [92]. The developed model was constructed and calibrated using data from the EU electricity market and specifically the interconnection between Germany–Poland, and France–Spain. The obtained results indicate that when there is interconnection, there is a reduction in investments made towards renewable power, and this situation negatively impacts carbon emission levels, especially when the carbon price is low. On the other hand, connectivity leads to an increase in renewable energy generation and a decrease in carbon emissions when there is a high price on carbon taxes. Furthermore, according to the simulation results, meeting the EU2030 connectivity goal can potentially lead to a rise in overall carbon emissions when the carbon price is set at 100 EUR/tCO_2.

The advantages of electricity interconnection in a global power grid that is entirely sourced from renewable energy are examined in [93]. The investigated case-grid consists of 14 regions and 20 potential routes, while the study aims to compare 24 different combinations of wind, solar, hydro power, storage systems, and load curtailment. The analysis is based on a co-optimized planning and full-year dispatch model that incorporates a more stringent "N-1" criterion, while an economic evaluation of an electrical network powered by 100% renewable energy generation is also examined. The study demonstrates that the economic advantages of interconnection are substantial, especially when the energy sources transition to complete reliance on renewable sources. This provides a unique opportunity to efficiently trade renewable energy that is diverse in terms of time and location on a global scale, hence facilitating the effective implementation of net-zero targets.

A predictive model that can identify instances of convergence and congestion in the CWE region is presented in [94]. The presence or absence of convergence is regarded as a

dichotomous result for constructing a probit model that integrates significant data on the electrical market characteristics of the interconnected nations from 2016 to 2018, including projections on RES. The study findings highlight the significant role that Germany and France play in the process of integration. The calculated parameters of the model indicate that the significant growth of solar and wind power in Germany serves as a crucial factor contributing to congestion in CWE. To enhance the advantages of market integration and advance the internal energy market, this study suggests that policymakers should foster collaboration and coordination among all stakeholders in the electricity market.

A model that simulates the clearing of a joint day-ahead energy and balancing capacity market is proposed in [95]. The model includes coordinated purchase and sizing of balancing capacity, as well as the co-optimized allocation of cross-zonal transmission capacity. The authors verify the model by analyzing a case study situated in CWE, which has a high level of RES, with the objective is to demonstrating how the coordination of balancing capacity markets at a regional level can lead to significant advantages. The results indicate that coordinating the balancing capacity allows for more efficient and economical scheduling of energy output in advance. Significantly, the scheduling of peak-load technologies is affected. The primary advantage of coordinating capacity is its potential to significantly decrease the requirement for additional backup capacity. The authors note that, by sharing rarely utilized generation capacity between countries instead of maintaining separate self-sufficient control regions, particularly when combined with alternate methods of balancing capacity such as demand response, there is potential for a significant reduction in generation capacity requirements.

7. Discussion and Concluding Remarks

The European Union's (EU's) journey from the initial Electricity Directive in 1996 to the current state of a functioning pan-European electricity network demonstrates that what was once a forward-looking vision is now an operational reality. This evolution not only marks a milestone in the EU's energy policy but also serves as a model for how coordinated efforts can lead to the successful integration of diverse energy systems. The future of the pan-European network and electricity market is shaped by the imprints of technological progress, evolving regulatory frameworks, and geopolitical forces. As countries strive to meet decarbonization goals, innovations in power electronics such as multi-terminal high-voltage direct current systems and ultra-high-voltage direct current technology are expected to transform the traditional point-to-point nature of interconnectors by allowing multiple interconnections to function as a network, enhancing flexibility and resilience, while enabling the transfer of renewable energy from regions with abundant resources to areas with high demand, facilitating international energy trading and contributing to global energy security. These technological evolutions are anticipated to be driven by policy shifts and market reforms. The new Network Code on Demand Response is poised to play a critical role in this transformation, setting common rules that will facilitate the aggregation of resources, harmonize demand response regulations, and enable the integration of energy storage systems across the pan-European network. These developments will support more efficient market coupling, particularly in day-ahead and intraday trading, which is expected to further align electricity prices across borders, reduce inefficiencies, and promote market liquidity. However, geopolitical risks pose significant challenges to the development of a truly integrated energy market. Political tensions between neighboring countries, shifting alliances, and conflicts over energy resources can disrupt cross-border electricity trading and undermine market stability. Furthermore, the dependence on external energy imports exposes the region to vulnerabilities in global energy supply chains, making it susceptible to disruptions triggered by international conflicts, trade disputes, or sanctions. Addressing these risks will require Europe to not only invest in resilient infrastructure but also pursue more coordinated foreign policy strategies, diversify its energy sources, and reduce reliance on external actors. In this domain, the realization of a pan-European electricity market has been underpinned by a dynamic engagement between major regulatory revisions,

significant investments in interconnection infrastructure, and revolutionary adjustments to electricity market frameworks. Understanding this engagement is essential for developing future strategies and innovations that address the challenges of a rapidly evolving energy landscape. This work holds significant importance for the research community as it presents and discusses the interplay between market dynamics, grid management, regulatory frameworks and technological innovation by overviewing the developments and recent trends in the context of electricity interconnectors and cross-border trading. By bridging gaps in current literature and presenting an extensive analysis of key developments, the work significantly advances both academic research and practical applications in the field by:

- Conducting a comprehensive exploration of recent trends shaping the development of cross-border electricity interconnections and electricity trading.
- Connecting technological, regulatory, and market developments to broader goals of energy transition policies.
- Providing valuable insights for research, policy formulation, and technological innovation in the relevant field of the energy sector.

Regulatory frameworks have been the driving force behind market integration and the efficient use of electricity interconnector catalysts by setting targets, providing incentives, and removing barriers to market entry, while technological innovations have responded and shaped regulatory changes by providing the tools needed for a more interconnected and flexible grid. Market dynamics have evolved in parallel with regulatory and technological changes, leading to more integrated and liquid electricity markets. Market coupling, introduced through regulatory efforts and supported by technological advancements, allows electricity prices to converge across borders by optimizing cross-border flows. The day-ahead and intraday market-coupling mechanisms have been particularly successful in aligning prices between interconnected markets, reducing inefficiencies, and enhancing market liquidity. This dynamic interaction has not only facilitated the creation of a more integrated and competitive electricity market but has also supported the transition toward a more sustainable and resilient energy system. By providing a comprehensive view of these developments, this work serves as a valuable reference point for interdisciplinary research endeavors. It underscores the necessity of a holistic approach to studying energy systems, wherein policy, technology, and market structures are analyzed in tandem to address the complex challenges and opportunities in achieving a sustainable, integrated, and efficient energy future. This knowledge is vital not only for advancing research as well as academic discourse but also for informing policy decisions and guiding technological innovation in the energy sector. Based on the findings of this work, several avenues for future research can be explored towards advancing the field. One key area is the investigation of uncertainties in the long-term planning of networks consisting of electricity interconnectors, particularly in light of increasing renewable energy integration and fluctuating demand. Other promising research frontiers for future work are the interaction of electricity and emission trading markets, how geopolitical developments could disrupt or reinforce cooperation in cross-border electricity trading, the role of blockchain and artificial intelligence in enhancing transparency in cross-border trading, as well as the network code for cross-border flexibility trading, particularly as the market adapts to more dynamic and decarbonized energy systems. Interdisciplinary studies on policy frameworks, market mechanisms, and consumer engagement will be instrumental in supporting a just and sustainable transition. As Europe strives for carbon neutrality, research and innovation will remain at the heart of the continent's efforts to create a secure, sustainable, and competitive energy system.

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