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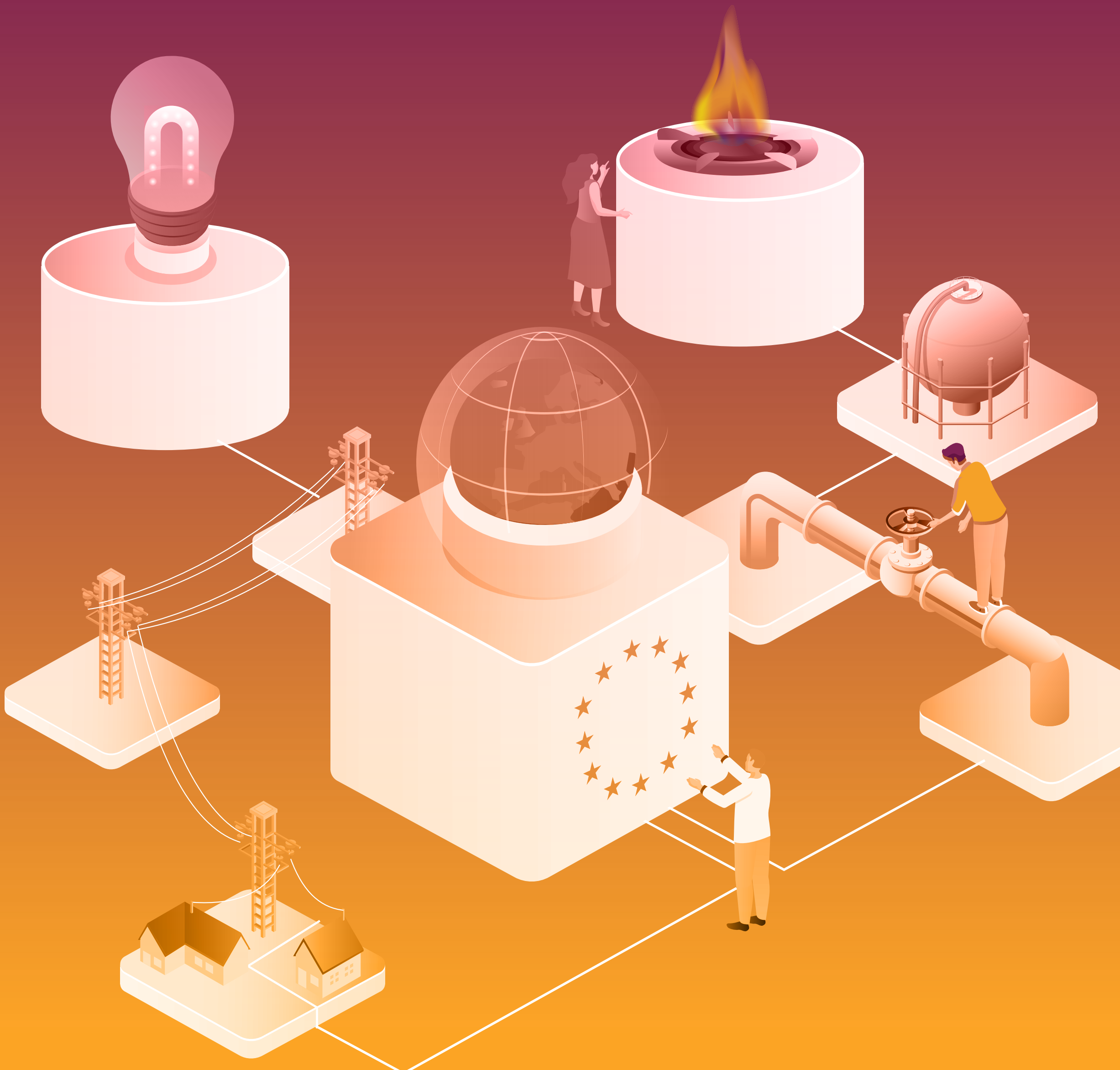
French interconnections at the heart of Europe: vital in times of the crisis, essential for decarbonisation



Report on electricity and gas interconnections 2020-2023

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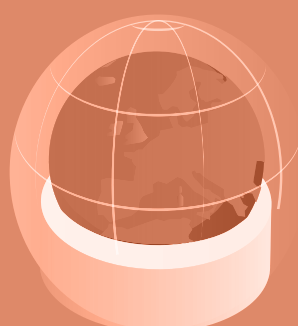

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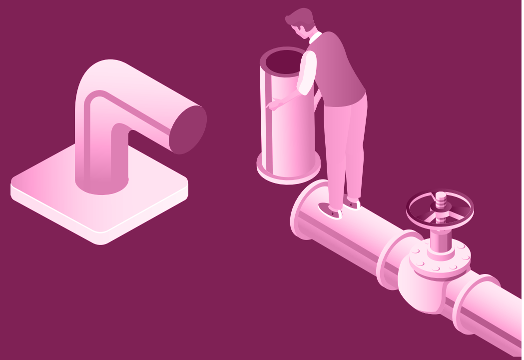


MESSAGE FROM **EMMANUELLE WARGON**

PRESIDENT OF CRE

In calm conditions, interconnections are a long-term means to unify and optimise the European energy market. They are an obvious achievement of the European integration process, to which we collectively pay too little attention.

In tough conditions, it is a different matter: interconnections become the essential thread in our French security of supply, and the very expression of European solidarity between Member States, demonstrating that unity is strength.

With this in mind, this report is unique. Historically, it has been a classic stocktaking exercise. However, the years 2020-2023 have not been peaceful: this report covers four turbulent years that have seen a succession of major shocks for our societies, with Covid-19 and the Russian invasion of Ukraine. The energy sector, which fundamentals in terms of security of supply and prices have been extremely disrupted, could rely on interconnections in France and in Europe to overcome the crises and emerge transformed and strengthened from these years.

Interconnections are in fact the cornerstone of our energy model. Developed since the 1960s in gas and electricity, they enable to export the excess of production and to resort to imports when consumption needs exceed domestic production, particularly during the winter consumption peaks. These cross-border networks enable to keep the adequacy between supply and demand at any moment and ensure France's security of supply. With regards to gas, France has 8 interconnections with 5 countries. For electricity, France has 37 interconnections with 7 countries. Thereby, we have in France the ability to export on average 20 GW of electricity at any one time, equivalent to the production of around 20 nuclear reactors, and to import almost as much.

Since the early 2000s and the creation of the single energy market, the harmonisation of interconnection operating rules and the introduction of volume- and price- coupling have enabled to increase interconnection efficiency and optimise supply costs for the community. The implementation of the rules of the single European market to interconnections between France and its neighbours has enabled to increase transaction volumes and limit price spreads between France and its neighbouring countries, to the benefit of French consumers.

In calm conditions, this integration thus allows to take advantage of the economic value of production surplus, to benefit from interconnection revenues which are deducted from consumers' bills, and to access supplies at the lowest economic and environmental cost, giving priority to renewable production from our neighbours when there is a surplus.

In rough conditions, interconnections guarantee a high level of security of supply and are the symbol of European solidarity. The year 2022 is the most striking example, marked by a historic drop in electricity production in France and an almost complete disruption of gas pipeline supplies from the east of Europe. Two elements illustrate the contribution of interconnections during the energy crisis. France is used to being a net exporter of electricity every year. However, in 2022, gross imports provided 16% of its electricity supply, and exceeded exports. In gas, France has become one of the gateways for liquefied natural gas (LNG) on the European continent with its substantial regasification infrastructure and networks able to quickly reverse flows. This enables France to secure its domestic supplies while making a major contribution to the supply of our European neighbours, with whom our exchanges doubled in 2022 compared with the previous year. Without interconnections and the common rules of the European market, the continuity of supply in France and the rest of Europe would have been much more compromised.

In 2024, while the energy crisis is behind us, we are looking to the future. Accelerating the development of electricity networks across the European continent is a prerequisite to achieving carbon neutrality in 2050. As the European Commission points out in the networks action plan published in November 2023, cross-border networks and their operation will have to support the optimisation of the production park, the increase in decarbonised production including from renewables, and will be a major source of flexibility to support the electrification of final energy uses.

To prepare for the future, it is therefore necessary to keep investing in new electricity interconnections. Two new infrastructures are currently under development with Spain (Bay of Biscay) and Ireland (Celtic). These projects are carried out within a strict financial framework guaranteed by the *Commission de régulation de l'énergie*. Improving the use of these interconnections is also a constant concern for CRE, which is highly involved in the work carried out at regional and European levels on the interconnection operating rules.

Gas interconnections are facing other concerns: an overall drop in consumption, the transformation necessary to receive new energy carriers and green gases and the development of flexibility resources. CRE will keep a close eye on these developments.

Electricity and gas interconnections are playing an increasingly crucial role in the French and European energy system. In a common framework with our neighbours, they ensure a fluid and optimal flow of energy among countries, support the development of renewable energies, and reduce the risks of shortages and instability, ensuring a more reliable supply at lower cost for consumers.

The *Commission de régulation de l'énergie* is pleased to present its report on electricity and gas interconnections covering the period 2020-2023.

Enjoy your reading.

Key takeaways of the report

Thanks to interconnections, EU Member States share their energy systems within a common market that enables solidarity between them and economic efficiency at European level, as this report shows. Solidarity has been fully expressed in the face of the crisis affecting the EU in 2021 and 2022, and the European market has demonstrated its ability to fully optimise the operation of the electricity and gas systems.

1. Interconnections have enabled the European Union to overcome the supply crisis

Member States have been affected by the crisis in very different ways, depending on their energy mix, and this period has demonstrated how interconnections have enabled us to be more resilient together. They have helped to cope with supply difficulties by transferring electricity and gas flows from countries with overcapacities to countries facing shortages. Import and export status have changed significantly over the 2021-2023 period. As a result of its production deficit, France switched from being an electricity exporter in 2021 (43 TWh) to an importer in 2022 (-18 TWh), before getting back to its usual exporter position in 2023 (50 TWh). Massive reorganisations of flows have taken place in the gas sector, with volumes of Russian gas delivered to Eastern Europe being replaced by massive imports of LNG, particularly from French LNG terminals. Electricity and gas interconnections have thus enabled solidarity between Member States to be fully expressed to provide support to the countries in greatest difficulty, particularly in the east of the continent for gas, and to support France during the height of its nuclear production crisis.

2. The European market enables more efficient use of interconnections

The European market, which directs cross-border flows according to the needs reflected by price signals, has ensured that supplies matched demand in real time in all Member States. European rules have enabled the dynamic adjustment of imports and exports in line with price differences that reflect the degree of tensions experienced by each country with regards to its supplies. This allowed a maximisation of the shared value of energy between Member States. This real-time adjustment, made possible by the integration into the European market, is a powerful tool to reduce costs for European consumers. It is thus not observed in the same proportions outside the European market. For example, French interconnections with Great Britain (since the Brexit) and with Switzerland do not achieve the same level of optimisation.

3. Electricity interconnections ensured security of supply in France at the height of the nuclear generation unavailability

At the height of the unavailability of France's nuclear generation park, electricity interconnections enabled France to cover its consumption while a large part of its nuclear reactors were unavailable. In 2022, imports reached 73 TWh, while exports amounted to 55 TWh. The import balance of 18 TWh represented 4% of French consumption. Annual imports exceeded exports for the first time. Germany, Belgium, Spain, and Great Britain have been key partners in tackling the crisis. Between 2021 and 2022, volumes imported from the Germany-Belgium region rose by 50%, those from Spain doubled and those from Great Britain tripled.

4. Thanks to its diversified supplies, as well as its robust and flexible infrastructures, France has contributed to the resilience of the European gas market

As pipeline supplies of gas to the EU from Russia declined, the French gas market has demonstrated its proper functioning and its attractiveness. Indeed, it has enabled French storage facilities to be filled, much larger volumes of liquefied natural gas to be received and flows to be redirected towards the northern borders with Germany and Belgium. As a result, French gas imports have increased by 23% in 2022 compared with 2020-2021, mainly to be re-exported to the rest of Europe. Gas exports from France have reached 160 TWh in 2022, twice as much as in previous years.

5. Interconnections have demonstrated their cost-efficiency

Historically, interconnections have been used by France to export electricity. Throughout the crisis, they have been particularly solicited by market participants, particularly for electricity imports, and capacity allocations at French interconnections have generated high revenues for network operators. Over the period 2022-2023, the net income collected by RTE at interconnections reached €2.9 billion. These revenues are then deducted from the bills of network users in France. For natural gas, the interconnection capacity auctions held in 2022 generated a record €441 million in auction premiums, which are also passed on to consumers.

6. The reform of the European market design recognises the long-term timeframe as crucial at electricity interconnections for an effective market

Protecting consumers from short-term price volatility while preparing for the future is one of the main focuses of the reform of the European electricity market design. To support the development of forward markets, long-term interconnection rights must be available earlier and over longer periods of time. The new European rules will encourage the multiplication of products and longer maturities. Allocation windows will be more frequent, and subscriptions could be offered up to three years in advance. France has successfully experimented this type of initiative at several of its borders.

7. To develop renewable energies where they are abundant and provide flexibility, the EU will need more electricity interconnections

Moving away from fossil fuels involves electrifying energy uses. Thus, decarbonisation in Europe will lead to a significant increase in electricity consumption and production. The large-scale development of renewable energies will change the geographical distribution of electricity production and increase the need for flexibility. Interconnections are essential for the smooth transmission of electricity generated within the European Union. More decarbonised generation capacity will require more interconnection capacity, which is the aim of the European grid action plan adopted at the end of 2023. The direction of flows at borders has already been frequently reversed and will increasingly do so. The coupled management of interconnections and short-term markets provides the European electricity system with the flexibility that will become increasingly valuable as non-controllable renewable generation develops.

8. In France, investments in electricity interconnections should be continued where they make an effective contribution to energy resilience and decarbonisation

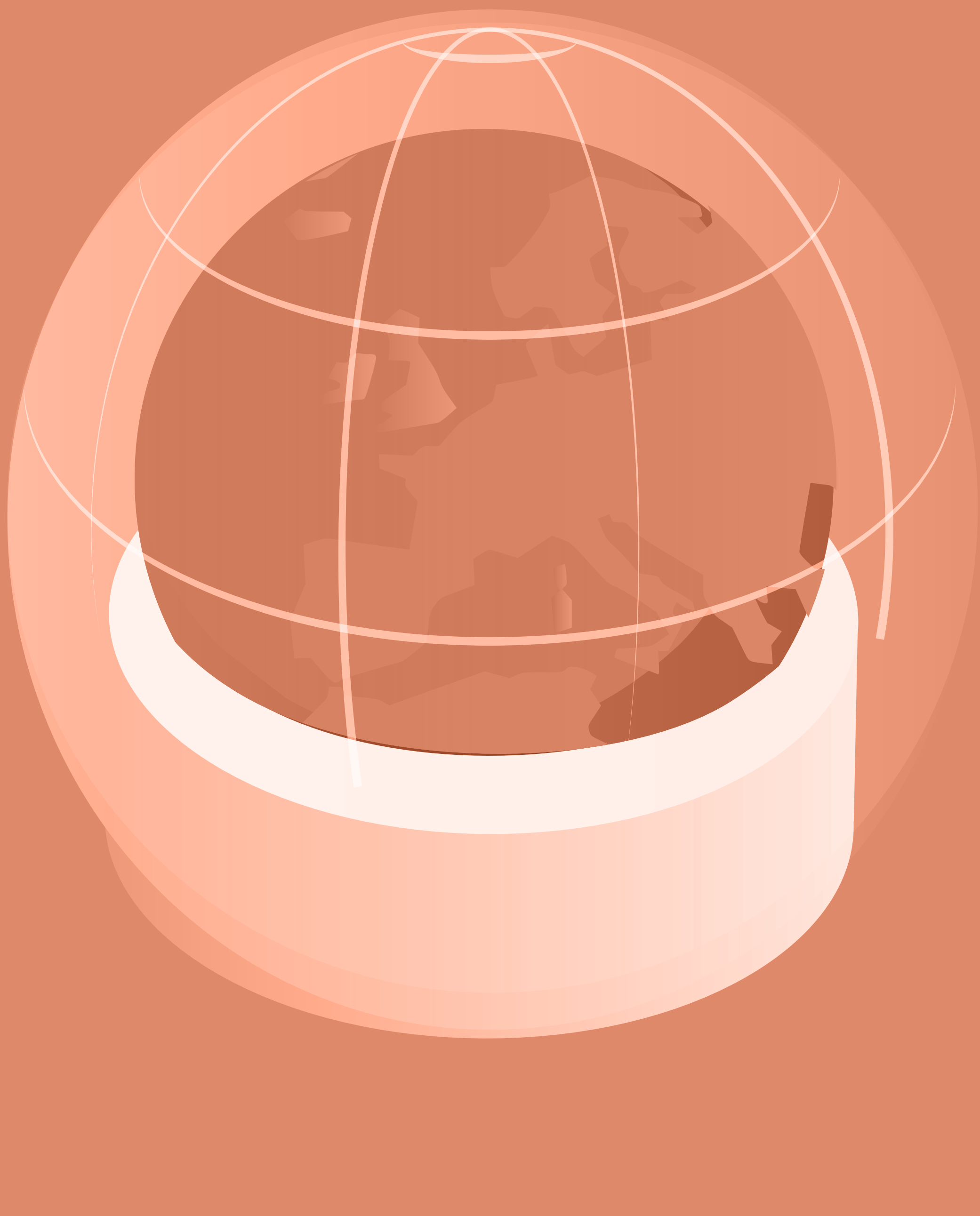
With three new electricity interconnectors commissioned since 2020 with Great Britain (IFA 2 and ElecLink) and Italy (Savoie-Piémont), France's import capacities represent more than 12% of its generating capacity. Export capacities enable France, which has regained its position as Europe's main exporter, to maximise the production of its nuclear power park when the French system is in a situation of overcapacity. It is beneficial for France which exports electricity, and for its neighbouring countries, which emit less carbon dioxide than they would with their own generation capacities. Current projects will further enhance the integration of France and its partners within the European market: a further 2 GW will be commissioned in 2028 with Spain and 0.7 GW in 2027 with Ireland. Before deciding on new projects and their financing through network tariffs, CRE will ensure that they are technically and economically relevant to the characteristics of the electricity mix. New projects will have to provide benefits for French consumers.

9. Existing gas interconnections will remain important for security supply, including in a context of falling consumption

Gas will continue to play a key role in securing energy supplies and ensuring the overall flexibility of the European energy system. Although the decline in consumption and the development of biomethane production are shifting the use of interconnections towards more short-term arbitrage, the European integration will remain an essential asset to cope with consumption and production contingencies, by relying on gas imports and complementarities between neighbouring countries.

10. The development of hydrogen, a promising energy carrier, could lead to the creation of interconnections

The EU has major ambitions for hydrogen and has made it a priority sector for infrastructure development. Several French interconnection projects have been identified as projects of common European interest. CRE is closely monitoring the consolidation of hydrogen industry business models. The realisation of interconnection projects will depend on the creation of regional or national networks and the emergence of a need for cross-border exchanges where demand cannot be met by local production.



Introduction

Interconnections: an asset in times of crisis, an opportunity for decarbonisation

Since the adoption of the first directives in 1996 and 1998, the European Union (EU) has prioritised the development of interconnections and the harmonisation of their operating rules in order to create an internal electricity and gas market. The regulatory frameworks that apply to the electricity and gas markets have followed similar trends, despite different structural conditions: massive imports of gas from countries outside the EU on the one hand, and domestic electricity production with a growing share of renewable energies on the other hand. The European market has been built around interconnections, which are physical links between national markets run by Transmission System Operators (RTE, GRTgaz and Teréga for France) and wholesale market platforms. Short-term wholesale prices direct energy flows from low-price areas, where there is more supply, to areas where meeting demand would require resorting to more expensive supplies in the absence of interconnections. This overall optimisation enables production and supply costs to be minimised on a European scale. The Agency for the Cooperation of Energy Regulators (ACER)[1] estimates that the existence of interconnections between Member States provided, in 2021, a benefit of €34 billion at the European scale, compared to a theoretical scenario without interconnections.

Regulators have been playing a leading role in the development of the European regulation, by providing their expertise on local supply conditions and on competition issues. They have played an active part in the collective work led by the European Commission and ACER to prepare the rules. While decarbonisation has gradually become the central focus of the European energy policy, the principles of the internal energy market have been supplemented by provisions designed to provide better support for the large-scale deployment of renewable energies. The crisis of late 2021 to early 2023 has shown the relevance of past choices regarding the use of interconnections, particularly the coherence between the price system and cross-border energy exchanges. Now, it is time to prepare for the future. Lessons have been learned from the crisis to enhance the contribution of interconnections to the European market. Decarbonisation will go along with a profound change in Europe's energy mix, reinforcing the role of interconnections in distributing decarbonised energy to all consumers.

1. ACER's Final Assessment of the EU Wholesale Electricity Market Design (April 2022) : https://www.acer.europa.eu/sites/default/files/documents/Publications/Final_Assessment_EU_Wholesale_Electricity_Market_Design.pdf

The phases of an unprecedented crisis

Since 2020, the EU has been confronted with a series of unprecedented shocks which have challenged the principles of the European single market design, while demonstrating their usefulness and effectiveness in ensuring security of supply.

The course of the crisis

The year 2020 has experienced a sudden slowdown in the economy and the lockdown of populations due to the Covid-19 pandemic, which created uncertainties about the continuity of supplies.

In that context, a first significant price increase was observed on the European gas market in 2021 and especially in the summer of 2021, when it appeared that Gazprom was not filling its European storage facilities (in Germany particularly). The impact on European wholesale prices has been immediate: concerns about the coming winter combined with lower-than-expected supplies and strong demand for LNG on the Chinese market have pushed prices above €180/MWh in December 2021 on the Dutch TTF market. The rise in gas prices on the short-term market quickly spread to all long-term gas supplies.

The year 2022 saw the worsening of the crisis following Ukraine's invasion by Russia on February 24th. During the summer of 2022, the gradual reduction in Russian pipeline supplies, combined with strong demand to fill European storage facilities, pushed prices to an all-time high of €311/MWh for the yearly product Y+1 on the TTF. In order to offset the significant decline in Russian supplies in the countries most affected, flows have been reversed at the French borders, moving towards the northern borders. The European market then eased from the first quarter of 2023 onwards, thanks to LNG deliveries compensating the drop in supplies from Russia and to the decrease in European gas consumption. Prices returned to a level close to the pre-crisis period at the end of 2023.

The evolution of electricity wholesale prices has been very similar to the one observed for gas prices. Indeed, alongside the gas crisis, French nuclear production felt to an historically low level due to the discovery of anomalies in some reactors, announced on December 15th, 2021. The consequences of this drop were observed in the first half of 2022, exacerbated by low filling levels in hydroelectric reservoirs. The simultaneous crises affecting the gas market and the French power generation fleet have both contributed to an unprecedented rise in prices on the wholesale electricity markets.

Day-ahead prices reached nearly €500/MWh in March 2022 and an average of €611.6/MWh in the week of August 22nd, 2022. On August 30th, 2022, the day-ahead price peaked at €743.8/MWh. In France, forward electricity prices for the first quarter of 2023 and the entire year 2023 were the highest in Europe for most of 2022, as market participants anticipated supply disruptions in the winter of 2022-2023.

In 2023, the fall in wholesale gas prices and the improved availability of French nuclear power plants led to a gradual decline in electricity prices in Europe, until they returned to levels close to the historical trend at the end of the year, although higher than before the crisis. The supply crisis was therefore particularly intense over a period of 18 months, between October 2021 and March 2023, but its impacts on forward prices were felt well beyond this period.

The EU's responses to the crisis

Faced with the scale of the crisis, the European Union reacted and was able to take strong measures, in compliance with the emergency procedures laid down in the European treaties.

By autumn 2021, the unprecedented price levels reached at the end of the summer had alarmed the national and European authorities. On October 13th, 2021, the European Commission presented a plan aimed at alleviating the effects of the exceptional price rise within the existing legislative framework. The purpose was to allow Member States to take a series of emergency measures targeting vulnerable consumers (direct support, deferral of payments to avoid power interruptions, tax reductions), final consumers (cost reductions) or businesses (aids, access to renewable electricity purchase contracts).

Russia's invasion of Ukraine on February 24th, 2022 highlighted the EU's vulnerability regarding its main gas supplier. On March 8th, 2022, the European Commission presented a plan to reduce the dependence on Russian gas imports by mobilising alternative sources, including the massive development of LNG imports. These proposals constituted the basis of the REPowerEU plan published on May 18th, 2022, which relied on three pillars: reducing energy demand, diversifying gas supplies, and accelerating the energy transition.

In the meantime, several legislative initiatives were launched by the European Commission to address the consequences of the crisis. Regulation (EU) 2022/1032, passed on June 27th, 2022, introduced the principle of a collective gas storage filling target, broken down into individual targets for the Member States. Interconnections would enable countries without storages to purchase storage capacity in neighbouring countries. The Regulation set a filling target of 80% on November 1st, 2022, then 90% on November 1st of the following years. Two Regulations have been added in December 2022 to complete the package: "Solidarity and joint gas purchases" (EU/22/2576) and "Gas price correction mechanism" (EU/22/2578). The first one included a pooled purchase on 15% of the stored volumes, the second one aimed at capping the wholesale price in case a threshold was reached (prices above €180/MWh on the TTF).

Finally, the very high wholesale prices generated exceptional benefits for decarbonised electricity producers. On October 6th, 2022, the Council of the European Union passed a Regulation (EU) 2022/1854 on an emergency intervention in response to high energy prices, which introduces a tax on the inframarginal rents of electricity producers in order to reduce consumers' electricity bills. This Regulation also states that excess congestion income collected by TSOs at interconnections should be transferred to consumers. Thus, in 2022, almost €2 billion of interconnection income collected by RTE has already been passed on to consumers, with additional surpluses to be passed on through the network tariff.

Interconnections have played a key role in the ability of France and the European Union to deal with the crisis

In the context of disruptions to the European Union's energy supplies, the quality of national markets' integration has emerged as a pivotal determinant of resilience. The infrastructures and operating rules established through successive legislative packages have allowed solidarity between Member States to demonstrate its full value.

When it comes to electricity, interconnections have played a decisive role in France's security of supply, enabling the country to cope with historically low levels of nuclear production and low levels of hydroelectric reservoirs. From 2021 to 2022, the share of interconnections as a marginal supply source in France rose from 28% to 46.7%, thereby preventing prices from rising further during these periods. In August 2022, this rate even reached 70%. Consequently, in 2022, France became a net electricity importer for the first time since 1980. This shift was driven by a sharp decline in exports, while imports peaked at 73 TWh (equivalent to over 16% of French consumption).

When it comes to gas, the flexibility of the transmission network, resulting from the significant reinforcements implemented over the past fifteen years, has enabled the EU to offset the shortage of gas from Russia by importing additional LNG volumes in France and Spain for Central Europe and Germany. Gas interconnections have therefore supported the EU emergency reforms and have given a concrete expression to European solidarity. Wholesale price formation was consistent with changes in European supplies. The differences in wholesale prices between countries have been very significant, with higher gas prices in the north and east than in France and the Iberian Peninsula. As a result, France has saved several billion euros on its gas bill compared with the rest of Europe, excluding the Iberian Peninsula.

Given France's central geographical position and its significant LNG regasification capacity, the flows could be reversed from south to north. Exports to Belgium and Italy reached particularly high levels, and France exported gas to Germany for the first time. Against this backdrop, thanks to LNG terminals operating at full capacity, French LNG imports have doubled between 2021 and 2022, and trade with Spain has shifted mainly from south to north.

Trades between France and Germany are an emblematic example of how interconnections played a crucial role during the crisis. In the gas sector, Germany faced significant challenges due to its strong reliance on Russian gas and the lack of LNG importing capacity, while France benefited from a more diverse supply and robust regasification capacity. The situation was opposite in the case of electricity. France faced a more significant supply deficit than Germany due to the difficulties on its nuclear production park. Following a political agreement between the two countries, France set up a gas export capacity to Germany in October 2022. Meanwhile, Germany postponed the closure of its last three nuclear power plants from January 1st to April 1st 2023, which helped France to get through the winter of 2022-2023.

The general observation is that interconnections have made a decisive contribution to the ability of the EU to deal with the crisis. The solidarity between Member States has been grounded in interconnections, making it possible to exploit the complementarities between countries. France has fully benefited from this during the electricity supply crisis it experienced. Conversely, it has made a major contribution to ensuring the continuity of gas supplies to the Central European countries.

The major role of interconnections in the ongoing transformation of the energy system

By 2050, the European Union has set itself the goal of becoming carbon neutral. This will require the electrification of major sectors such as transport and industry, which will result in a significant increase in electricity consumption and production. Obviously, the new electricity production will have to be decarbonised, namely from renewable or nuclear sources. By 2035-2040, growth in generation is likely to be primarily driven by renewable energies, due to lead times associated with the commissioning of new nuclear reactors.

Interconnections in the transformation of the electricity sector

Networks will play a major role in the transformation of the electricity system. On the one hand, they will be required to connect a large number of new producers and consumers in an efficient manner. On the other hand, they will have to enhance their capacity in order to be able to transport these additional volumes. In France, RTE has announced an investment programme of approximately €100 billion by 2040, and its counterparts in Europe have published similar or even higher investment plans (Germany, Italy, the Netherlands, for instance).

Furthermore, these developments will result in a significant increase in flexibility needs, as fossil-fuel power plants, which emit CO_2 and are dispatchable, will be replaced by renewable generation, which is largely non-controllable.

Electricity interconnections have played a very important role in providing hedging, solidarity, and efficiency during the crisis. Under normal conditions, they support the functioning of the single electricity market, from which they draw their profitability.

Their role is set to expand as the electricity system undergoes transformation. On the one hand, trade between countries will automatically increase as the electricity system grows due to electrification. On the other hand, the market coupling inherent to the European single market makes interconnections a perfect tool for flexibility between countries.

France will benefit from this enhanced role of interconnections. At the end of the crisis, France has wholesale prices that are among the lowest in Europe. Interconnections will continue to play a stabilising role, firstly by limiting episodes of excessively low prices through exports, and secondly using imports to reduce the cost of peak periods.

As in the past, CRE will study new interconnection projects to ensure that they create value at both the French and European levels.

There is still room for improvement in the management of electricity interconnections at the European level. While short-term trading has reached a high level of sophistication and efficiency, the same cannot be said for the mid-term horizon. The revision of the EU electricity market design adopted in May 2024, based on the lessons of the crisis, rightly prioritises the development of the single market in the medium and long-term timeframes.

The aim is to move towards a single electricity market that enables arbitrage and hedging opportunities in the medium and long-term timeframes. Within the European regulators, CRE has advocated for the allocation of interconnection capacity in a manner that is both efficient and aligned with the functioning of the wholesale market, namely in a predictable manner and up to three years ahead.

The specific cases of biogas and hydrogen

In the short and medium terms, existing gas interconnections will continue to support the common gas market. The south-north reorientation of flows observed since the crisis is likely to persist in France. In the event of a new crisis, these interconnections will once again play a crucial role as an insurance tool and for ensuring security of supply. In the long term, gas will have to be decarbonised thanks to the development of green gases and especially biomethane. Forecasting gas consumption and the level of interconnection utilisation at a long-term horizon is challenging. The European legislative package adopted in 2024 aims to support the development of renewable and low-carbon gases and to promote their cross-border trade.

The legislative package on gas decarbonisation establishes the operating rules for a future hydrogen market. The package conceives the hydrogen market in two distinct parts: on the one hand, production, and transport and storage infrastructures on the other hand. In order to foster competition, it provides a transparent and non-discriminatory access to hydrogen networks and infrastructures. Given its geographical position, France is a natural interface between Southern Europe and the Mediterranean area, which is ideal for the production of competitive carbon-free hydrogen, and Central-Northern Europe, which will be a major consumer of green hydrogen. Yet, the potential role of France as a transit route within a European hydrogen market remains uncertain. Just as several of its European counterparts, CRE will play an active role in the regulation work on hydrogen infrastructures.

Chapter 1

Electricity interconnections and cross-border trade in France

SUMMARY

The French electricity network is physically interconnected with all neighbouring grids, including with the United Kingdom. These interconnections allow cross-border energy trades that strengthen security of supply and ensure the efficient use of complementarities between national generation fleets.

Historically, France, which is mainly an electricity exporter, has relied on interconnections to cope with winter consumption peaks. France was particularly reliant on imports to cope with the unavailability of a large part of its nuclear reactors during the height of the crisis in the summer of 2022 and in winter 2022-2023. In 2022, for the first time, imports exceeded exports. While France continued to export to Italy and Switzerland, other countries, including Germany, Belgium, Spain and the United Kingdom provided crucial support in coping with the consequences of the decline in nuclear and hydroelectric generation in France.

On any given day, even if France is an overall exporter, it may find itself importing at certain borders at certain moments while exporting at others. The European internal market is designed to automatically direct trade flows according to hourly differences in electricity prices. This ensures that the cheapest and least carbon-intensive means of production are used on a European scale, within the sole limit of the network's capacity. During the crisis, France was often faced with higher prices than its neighbours, which ensured that supplies matched demand.

The pivotal role played by interconnections during the crisis has been reflected in financial terms. The large price spreads between countries resulted in substantial revenues for RTE (approximately €3 billion in surplus interconnection revenues over the period 2022-2023), all of which is passed on to electricity consumers through the electricity network tariff (TURPE). European rules have permitted the effective utilisation of interconnections, facilitating the transfer of electricity to the most energy-stressed countries by jointly optimising generation and cross-border transmission capacity at the EU internal market level. Borders with non-EU countries, such as Switzerland and the United Kingdom, have not reached the same level of optimisation.

As the internal market has been gradually developed, interconnections between France and its neighbouring countries have been strengthened. Between 2020 and 2023, France's import capacity increased by 31% and its export capacity by 21%. Two new interconnections are under construction, Golfe de Gascogne with Spain and Celtic with Ireland. The creation of new interconnection capacity is decided based on RTE's proposal and after CRE's validation, which, on the one hand, ensures that the cost-benefit analysis of a new interconnection is positive on both a European and a French scale, and, on the other hand, determines the sharing of costs with the neighbouring regulator concerned when relevant.

Improving the use of interconnections is a constant concern for CRE and its European counterparts. CRE is therefore actively involved in regional and European work on the rules applied to interconnections.

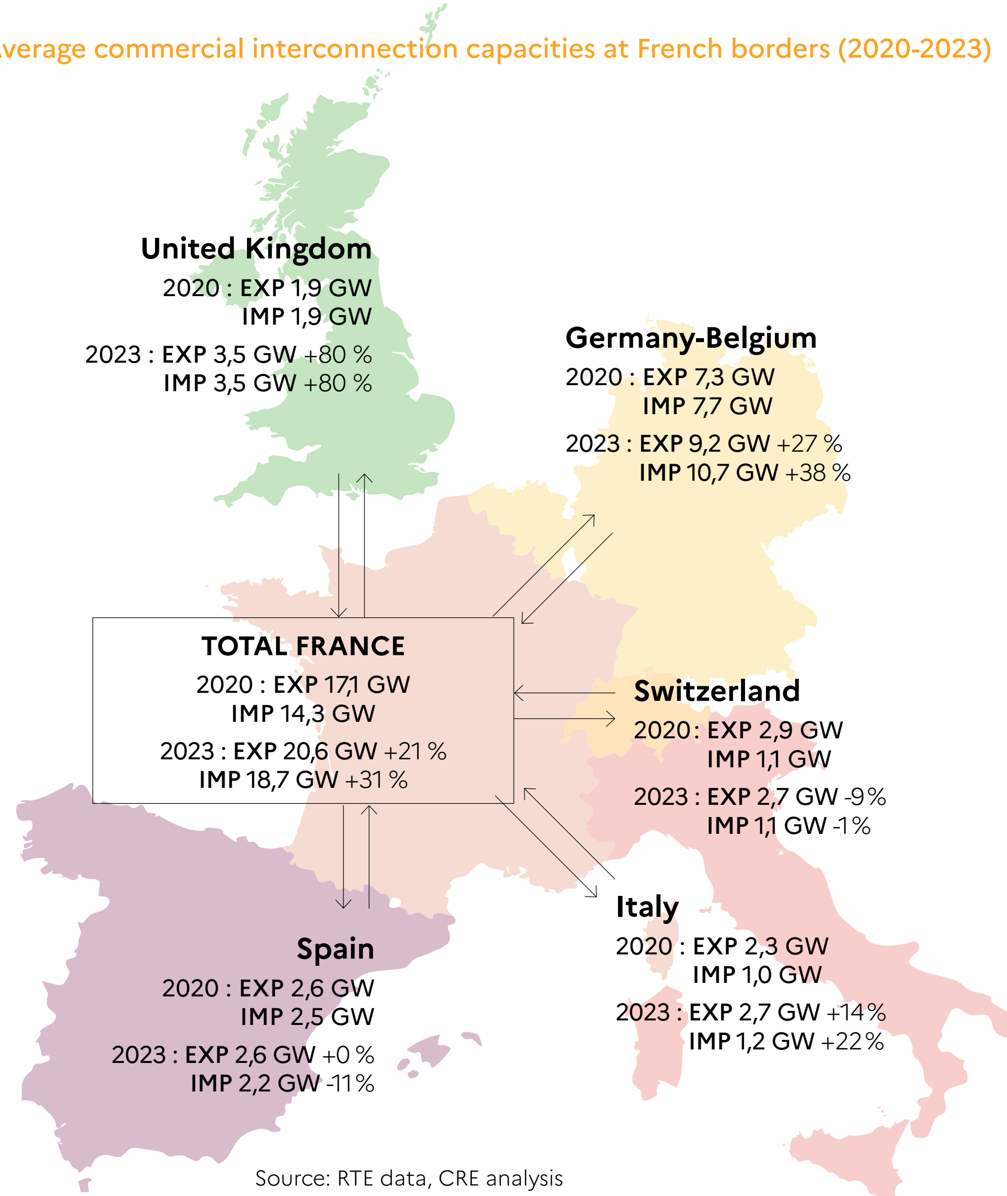
1.1. Overview of the use of electricity interconnections

Interconnections are a means of improving the economic efficiency of the electricity system by prioritising the use of the lowest-cost generation resources at European level. Cross-border trades are therefore made from the cheapest production zones to the most expensive ones. The European carbon tax mechanism (EU ETS), which applies to power plants, also contributes to the reduction of Europe's CO_2 emissions by prioritising the production of electricity from the lowest-emitting power plants, thereby supporting the switch from coal-fired to gas-fired power plants. Electricity interconnections also contribute to security of supply by exploiting the complementarities between national generation capacities. In times of tension, the production surplus of some countries enables to compensate for the deficits of others.

1.1.1 Interconnection capacities have significantly increased since 2020

France, which is already largely interconnected with its six neighbouring countries, has gradually increased its interconnection capacity. In 2023, the average commercial capacity made available by RTE reached 20.6 GW for exports (a 21% increase compared with 2020). For imports, it reached 18.7 GW (+31% compared with 2020), equivalent to more than 12.5% of the total installed generation capacity in France (or 16% if the load factors of wind and solar farms are taken into account). In 2023, this import capacity represented 22% of France's maximum peak consumption. The difference between import and export interconnection capacity at a given border is due to the characteristics of the electricity systems. For instance, a country that is structurally reliant on imports is likely to have a network that has been optimised for imports and is not technically designed to export production surpluses. This is taken into account when determining interconnection capacities.

Figure 1 Average commercial interconnection capacities at French borders (2020-2023)



Source: RTE data, CRE analysis

NOTE 1: The interconnection capacities made available to market participants for their trades correspond to the average commercial capacities calculated on a daily basis for the market coupling sessions of the following day (NTC D-2) at all borders, except for the Germany-Belgium region. For the Germany-Belgium region, they correspond to the average maximum import and export positions of France, which are rarely reached in practice (see section 1.2.2.2).

NOTE 2: Commercial interconnection capacities do not correspond to maximum physical capacities, they are calculated by the transmission system operators (TSOs), taking into account a range of parameters such as safety rules and the state of networks located upstream and downstream of interconnections. Therefore, the levels of trade capacity that can actually be used vary over time depending on network configurations, planned or unplanned maintenances, specific interconnection capacity calculation methodologies, technologies used for the interconnection (direct current or alternating current) and weather conditions. This explains why reductions can be observed at certain borders.

The increase of interconnection capacity in France

The expansion of France's cross-border trade capacity is particularly notable at the border with Great Britain. The commissioning of the IFA 2 (1 GW) and ElecLink (1 GW) interconnectors in January 2021 and May 2022, respectively, has resulted in doubling the physical interconnection capacity at this border. Commercial capacity on the German-Belgian border has also increased considerably, primarily as a result of several reinforcements on the French-Belgian border (reinforcement of the Aubange-Moulaine cable in 2021 and the Avelin-Avelgem cable in December 2022). These reinforcements have enabled increasing the commercial interconnection capacity with Belgium by approximately 1.5 GW by the end of 2022, by reducing the bottlenecks that previously limited cross-border trade on this border. On the Italian border, the commissioning of the Savoie-Piémont interconnector (1.2 GW), initially at half capacity from November 2022 and then at full capacity from August 2023, has also strengthened physical interconnection capacity with Italy. Furthermore, improvements to capacity calculation have released additional capacity on the interconnections with the Germany-Belgium region and Italy.

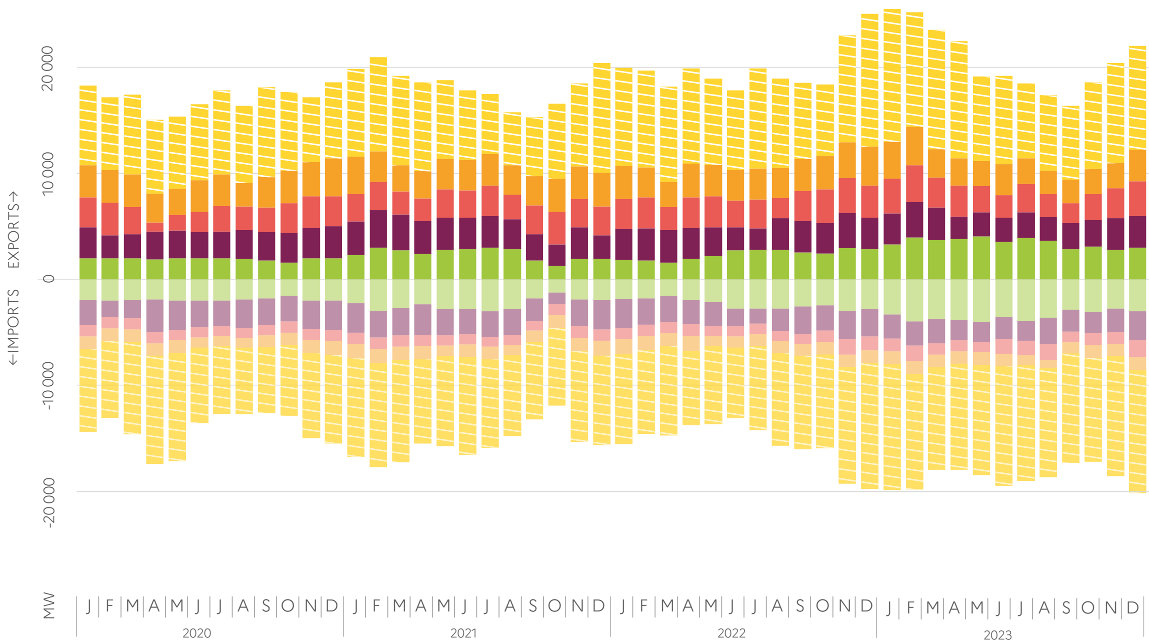
Short-term variations reducing the availability of interconnection capacities

Interconnection capacities available for commercial trade varies greatly throughout the year, as illustrated in Figure 2. In general, they are lower in summer than in winter (on average 8% lower over the period 2020-2023). This is mainly due to scheduled maintenance conducted by TSOs during periods when electricity systems are usually less stressed. This was particularly the case at the Spanish border in October 2021 and during summer 2022 from June to the end of July, with the greatest impact observed in the import direction. This was due to scheduled maintenance work on a line that is particularly critical for cross-border trade. Major scheduled maintenance work was also carried out at the German-Belgian border in summer 2021. Finally, capacity reductions are also frequently observed at the Italian border in spring and summer in the export direction, due to import restrictions on the Italian side on days of low consumption and high renewable generation. Such restrictions are put in place in order to guarantee the stability of the Italian electricity system. They were particularly pronounced between March and May 2020, during the first lockdown related to the COVID epidemic.

Finally, a number of incidents led to unplanned capacity reductions, particularly at the border with Great Britain, due to a fire on the English side which halved IFA interconnection capacity from the end of 2021 and throughout 2022, followed by an internal cable defect on IFA 2 in November 2023. On the Italian border, the commissioning of the Savoie-Piémont interconnector was affected by several incidents reducing its availability (detection of technological defects, consolidation works on a viaduct on the Italian side, fire on the Italian side in June 2023). On the Spanish border, storm Gloria led to maintenance work on a number of lines in Catalonia between February and March 2020, which severely limited cross-border capacity.

Nevertheless, TSOs are making efforts to guarantee that these capacity limitations, excluding incidents and unforeseen events, are not imposed during the winter season, when the national electricity systems are under the most significant stress. The unavailability resulting from scheduled maintenance helps to ensure the reliability of the network and secure interconnection capacity. When these unavailability periods are intended to carry out reinforcements, they contribute to the expansion of interconnection capacity.

Figure 2 Monthly evolution of commercial interconnection capacities at French borders (2020-2023)



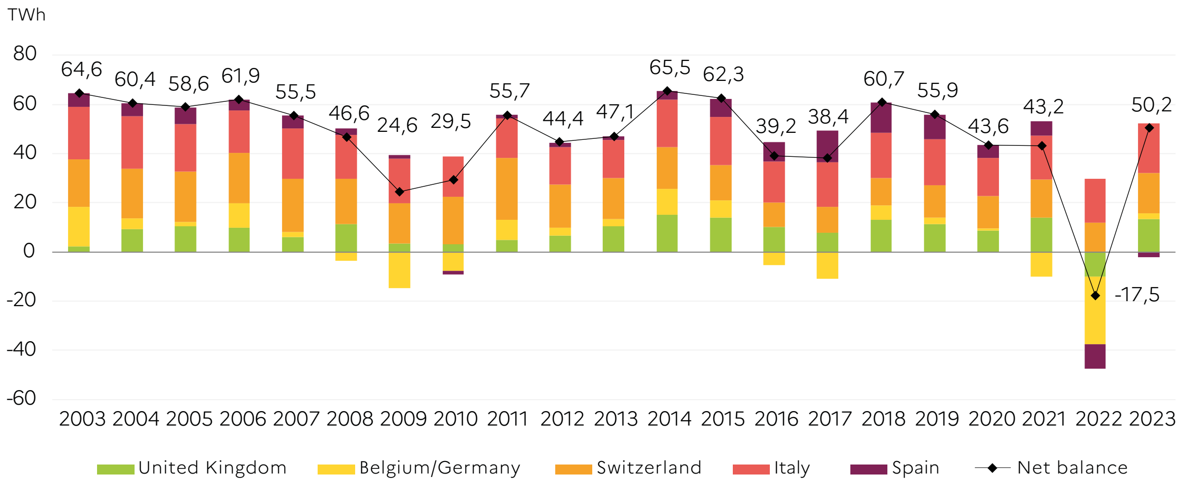
NOTE: The commercial capacities represented correspond to average NTC D-2 capacities for the borders with Spain, Italy, Great Britain and Switzerland, and to average maximum import and export positions of France for the Germany-Belgium border.

France > United Kingdom
France > Spain
France > Italy
France > Switzerland
France > Germany/Belgium
United Kingdom > France
Spain > France
Italy > France
Switzerland > France
Germany/Belgium> France

Source: RTE data, CRE analysis

1.1.2 Commercial trades have been affected by the impacts of the pandemic and tensions on French production facilities

Figure 3 Annual net commercial flows by border (2003-2023)



NOTE: This graph represents annual commercial flows balances by border, calculated as the difference between volumes exported and imported during the year.

READING: In 2022, France's commercial flows balance at the border with the Belgium-Germany region was 27.5 TWh of imports.

Source: RTE and ENTSO-E Transparency Platform data, CRE analysis

A first decline in France's export balance in 2020 and 2021

France has historically been an electricity exporter in Europe, with average annual net commercial exports of around 50 TWh before 2020. France's export balance began to decline in 2020-2021 compared with 2018-2019, to around 43 TWh. On the one hand, French electricity exports fell significantly in 2020, before returning in 2021 to a level comparable to 2018. On the other hand, imports rose for the first time in 2020, before reaching their highest level in over 10 years in 2021. This situation is largely due to the COVID-19 pandemic, which caused a general drop in electricity consumption in Europe and a decline in the availability of French nuclear power plants due to maintenance delays. In 2020 and 2021, France nevertheless remained a net exporter to all its neighbouring countries, with the exception of the Germany-Belgium region.

After an exceptionally negative trade balance in 2022, France returned to its historical export position in 2023

In 2022, France's electricity trade balance turned negative (-17.5 TWh), due to the crisis of the nuclear fleet and low hydro reservoir levels. Gross exports fell sharply, while gross imports peaked at an all-time high of 73 TWh. The net import balance of 17.5 TWh represented 4% of French consumption. Over the year, France was a net importer nearly 70% of the time, compared with 38% in 2020 and 21% in 2021.It remained a net importer from the German-Belgian border as in 2021, and became more exceptionally a net importer from Great Britain and Spain. On the other hand, France maintained its net export position to Italy and Switzerland.

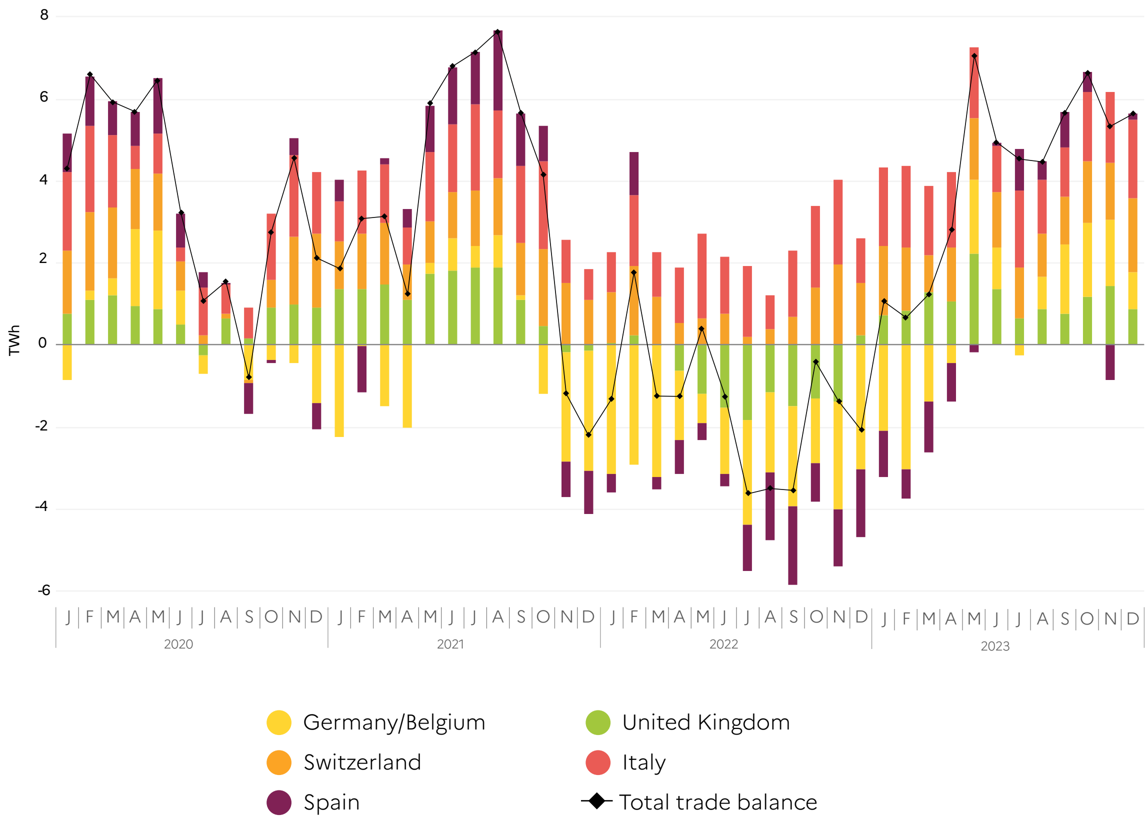
In 2023, France returned to an export balance equivalent to its historical average (50.2 TWh), on all borders except for Spain. Volumes traded in 2023 reached their highest level in 10 years, with exports returning to the high levels of 2014-2015, and imports remaining above pre-crisis levels. In 2023, France was a net importer for only 11% of the hours of the year.

Monthly variations in France's trade illustrate the role of interconnections in exploiting complementarities between national systems

In 2020-2021, France's monthly balance became negative on three occasions. In September 2020, a month of high exports in normal times, delays in the nuclear power plant maintenance programme due to the COVID-19 pandemic led France to become a net importer. In November and December 2021, France's usual importing position in winter at certain borders (Germany-Belgium, Spain) was accentuated by the progressive discovery of anomalies in several nuclear reactors.

In all months of 2022, France remained a net importer, with the exception of February and May, when the balance was slightly positive. It remained a net importer with the Germany-Belgium region and Spain for all months of the year, and with Great Britain from April to November. The monthly import balance peaked in the summer of 2022, when nuclear and hydro power plant availability was at its lowest.

Figure 4 Monthly net commercial flows by border (2020-2023)



NOTE: This graph represents monthly commercial flows balances by border, calculated as the difference between volumes exported and imported during the month.

READING: In September 2022, France recorded a positive monthly trade balance of 2.5 TWh with the Belgium-Germany region.

Source: RTE and ENTSO-E Transparency Platform data, CRE analysis

From January 2023, France regained its net export position, which was maintained throughout all months of 2023. The export balance remained limited over the first months of the year in winter, with sustained imports from the Germany-Belgium region and Spain, before returning to levels similar to the historical trend in the second semester. In the last quarter of 2023, the export balance reached its highest level in the last ten years for this period, thanks in particular to high wind generation, mild temperatures and greater availability of the French nuclear fleet than in the previous two years. Notably, France was a major exporter to the Germany-Belgium region over the last three months of 2023; this is in contrast to the preceding eight years where it had consistently been a net importer from this region at this period.

Table 1 Annual commercial flows by border (2020-2023)

TWh [% annual variation]	2020	2021	2022	2023
Exports	**77.5**	**86.2** [+11%]	**55.3** [-36%]	**93.1** [+68%]
Germany-Belgium	15.9	12.1	5.8	21.2
Italy	16.3	18.7	19.5	21.1
Spain	12.8	14.2	5.2	9.1
Great Britain	13.2	19.8	6.8	20.7
Switzerland	19.4	21.5	17.9	20.9
Imports	**34.0**	**43.1** [+27%]	**72.8** [+69%]	**42.9** [-41%]
Germany-Belgium	15.0	22.2	33.3	18.7
Italy	0.9	1.0	1.6	1.1
Spain	7.5	8.2	15.1	11.1
Great Britain	4.4	5.8	16.8	7.4
Switzerland	6.2	6.0	6.0	4.5
Trade balance	**43.6**	**43.2**	**-17.5**	**50.2**

NOTE: data excluding mutual assistance between TSOs and recovery of losses and deviations

Source: RTE and ENTSO-E Transparency Platform data, CRE analysis

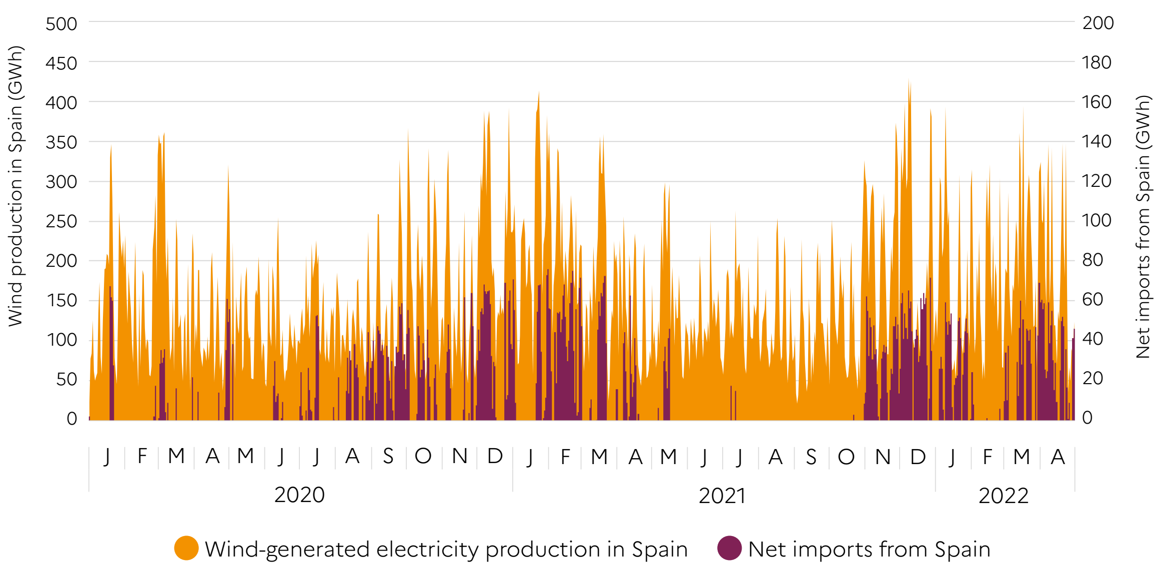
With Great Britain, trade trends followed the availability of interconnections: upwards, with the commissioning of the new IFA 2 interconnection in 2021 and the ElecLink interconnection in 2022, and downwards with the damage affecting IFA (from September 2021 to early 2023) and IFA 2 (from November 2023). France's export balance to Great Britain fell slightly in 2020, before settling in 2021 at a level as high as in 2015. In 2022, the trade balance with Great Britain, usually a major exporter, was exceptionally reversed (-10 TWh).

With Switzerland, the trade balance remained positive between 2020 and 2023, up to 16 TWh in 2023, but declined in 2022 due to the low availability of French nuclear power plants. On average, the interconnector is used at 70% of its capacity, sometimes in the opposite direction to price spreads. The absence of day-ahead coupling and the presence of historical long-term contracts with priority access to this interconnector mean that its use cannot be optimised.

The trade balance with Italy, which has almost exclusively been export-oriented, remained very high between 2020 and 2023, averaging 18 TWh. Over the period, the interconnection utilisation rate averaged 85%, and the interconnection was used in the export direction more than 90% of the time.

With Spain, the trade balance, historically net exporter, is more contrasting and highly dependent on weather conditions. France is generally a major exporter in summer, in line with strong Spanish demand driven by air conditioning use. In winter, on the other hand, Spain's surplus wind generation during episodes of abundant wind enables the country (which has over 30 GW of wind generation capacity) to export to France (see Figure 5). The increase in exports in 2021 is explained by the deterioration in weather conditions in Spain (harsh winter, heatwaves in summer and low wind generation). In 2022, France imported almost four times more from Spain and exported half as much as the average of the previous five years, due to the low availability of French nuclear power and the implementation of the so-called "Iberian mechanism" from June 2022 (see Zoom n° 1). The border between Spain and France is the only one characterised by very similar import and export utilisation rates, due to the frequent reversal of flows between the two countries.

Figure 5 Daily wind power generation in Spain and positive daily net imports from Spain to France (January 2020-April 2022)

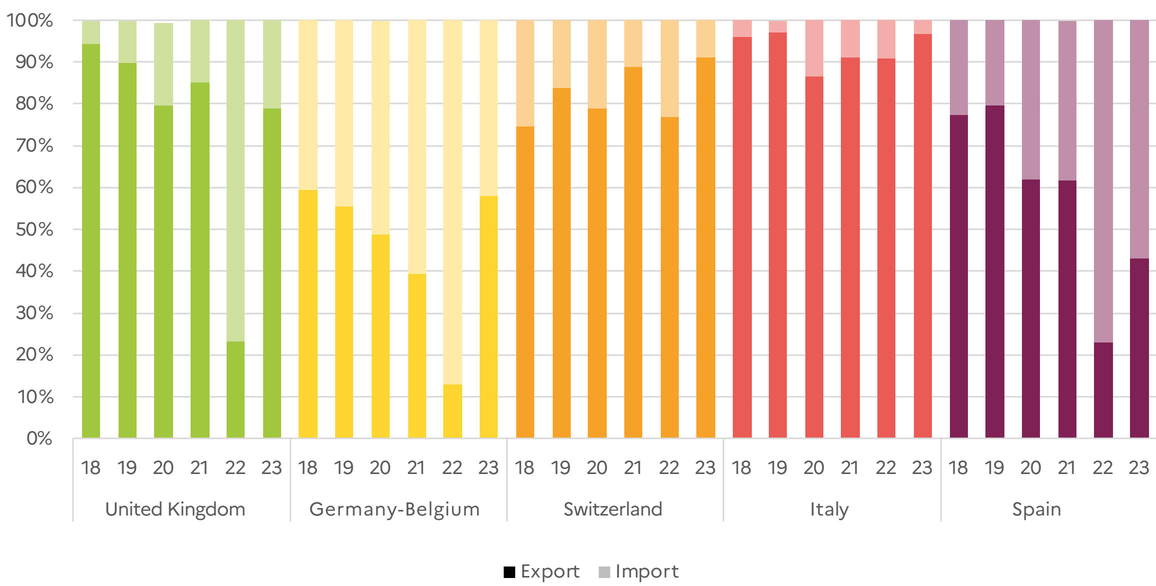


Source: Red Eléctrica and RTE data, CRE analysis

At the German-Belgian border, the trade balance, which was almost at equilibrium in 2020, turned into an import balance again in 2021. This was due to the very high availability of Belgian nuclear power plants and surplus German wind generation in winter, but also to the unavailability of French nuclear power plants, first at the start of the year and then more significantly from autumn 2021 onwards. In 2022, the import balance rose sharply to 27.5 TWh, making the German-Belgian border France's primary source of imports by volume. In 2023, France regained its export position to this region (albeit with a limited balance), thanks to the good availability of the French generation fleet and mild winter temperatures.

Figure 6 below reflects the direction of use of the various French interconnections (as a percentage of time), regardless of the level of flows. Between 2020 and 2023, interconnections with Italy and Switzerland remained overwhelmingly used in the export direction, respectively 91% and 84% of the time. Interconnections with Spain were used less in the export direction than in previous years (60% in 2020-2021 then 33% in 2022-2023, compared with 80% between 2015 and 2019). Since 2018, the interconnection with Germany and Belgium has been increasingly used to import electricity, up to 87% of the time in 2022, before being used 58% of the time in the export direction in 2023. The interconnection with Great Britain remained heavily used in the export direction over the period, up to 85% in 2021, excluding 2022 when it was predominantly used for import (77% of the time).

Figure 6 Direction of use of French interconnections (as a percentage of time) (2018-2023)



Source: RTE data, CRE analysis

BOX N° 1

The role of electricity interconnectors during periods of tension in France in 2022-2023

At the height of the energy crisis, electricity interconnections have played a major role in enabling France to meet its consumption when national production margins were tight, or even potentially insufficient, due to difficulties affecting France's nuclear and hydroelectric generation resources. The short-term optimisation of all production resources at the European level has helped to maintain a satisfactory level of electricity supply in France. Faced with electricity supply shortfalls but benefiting from a relatively unconstrained gas supply, France was thus able to export gas and import electricity, particularly with Germany which had symmetrical constraints (problems with gas supply but not with electricity).

Summer 2022

From mid-June to the end of September 2022, France was a net importer for almost every hour (with the exception of the week of 7 to 15 August), due to the historically low availability of the French nuclear fleet, which averaged only 27 GW over this period (i.e. less than half the installed capacity). During this period, France imported almost systematically from Germany-Belgium, Spain and Great Britain (on average 3 GW was imported from Germany-Belgium, 2 GW from Spain and 2 GW from Great Britain). It was also a frequent importer from Switzerland at peak times (19:00-20:00) but remained an exporter to Italy. Net imports peaked at 12.9 GW on August 24 at 23:00.

Winter 2022-2023

While the French electricity system was under strain during the winter of 2022-2023, France's import interconnection capacity reached high levels (19.7 GW on average from November 2022 to February 2023, i.e. 30% more than the previous winter). Several factors have contributed to this:

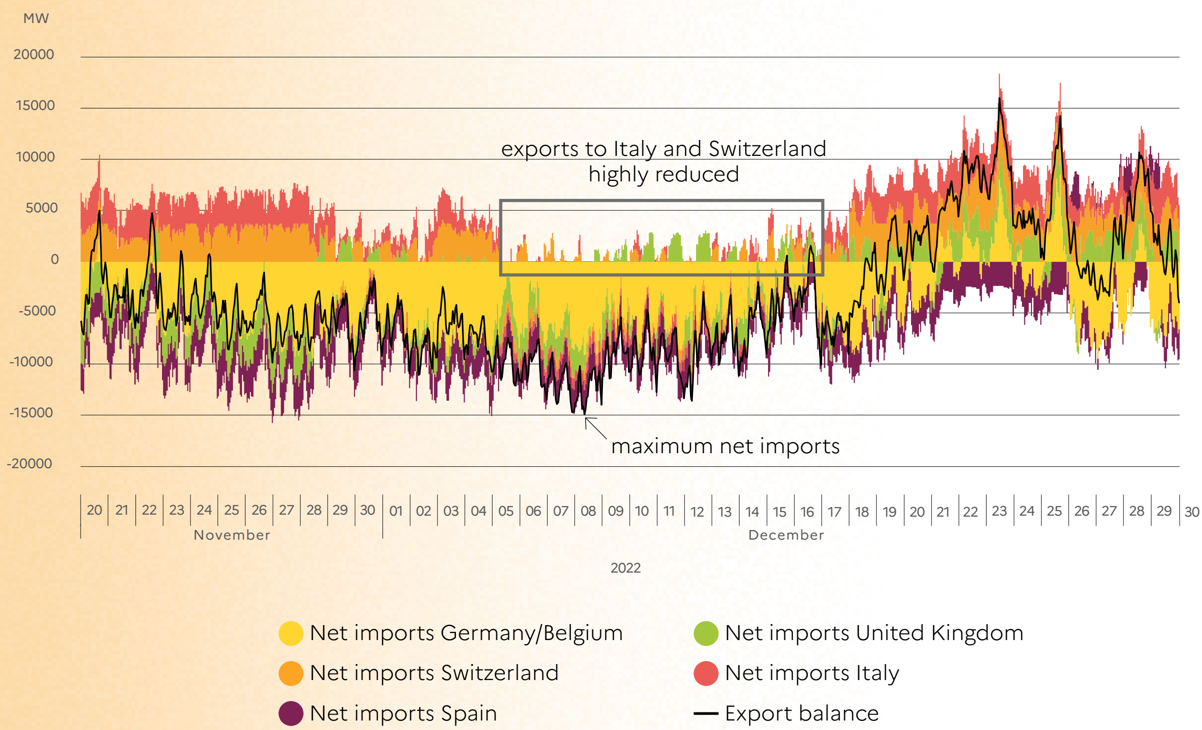
- The partial commissioning of the Savoie-Piémont interconnector at the beginning of the winter allowed France to have 30% more import capacity from Italy than the historical average (since 2017) from 8 November 2022 until the end of February 2023. This capacity was particularly useful in December, when France frequently imported electricity from Italy.
- At the British border, the available import capacity during the winter was 65% higher than the average observed since 2017, thanks to the exploitation of the new ElecLink interconnector and the restoration of IFA after the damage in the second half of the winter.
- At the Germany-Belgium border, the reinforcement of the Avelin-Avelgem interconnector has helped to increase import capacities from Belgium from the beginning of December 2022. As part of the Franco-German solidarity agreement on electricity and gas signed on 25 November 2022[2], Germany raised by anticipation the minimum exchange capacity threshold used to calculate daily interconnection capacity from 31% to 41% with effect from November 16th 2022 instead of January 1st 2023.

2. Political declaration of 25 November 2022 on Franco-Germany Solidarity

– At the Spanish border, RTE postponed some maintenances in the south-west of France so as not to limit the available cross-border trade capacity in anticipation of a tight winter.

France's import balance reached its highest level between 25 November and 15 December. During this period, France was a net exporter for only one hour (out of 500 hours), importing on average 5.8 GW from the Germany-Belgium region, 2.6 GW from Spain and 1.1 GW from Great Britain, while flows to Italy and Switzerland were strongly reduced, and even import-oriented in some cases.

Figure 7 Evolution of the French export balance on an hourly basis between 20 November and 30 December 2022

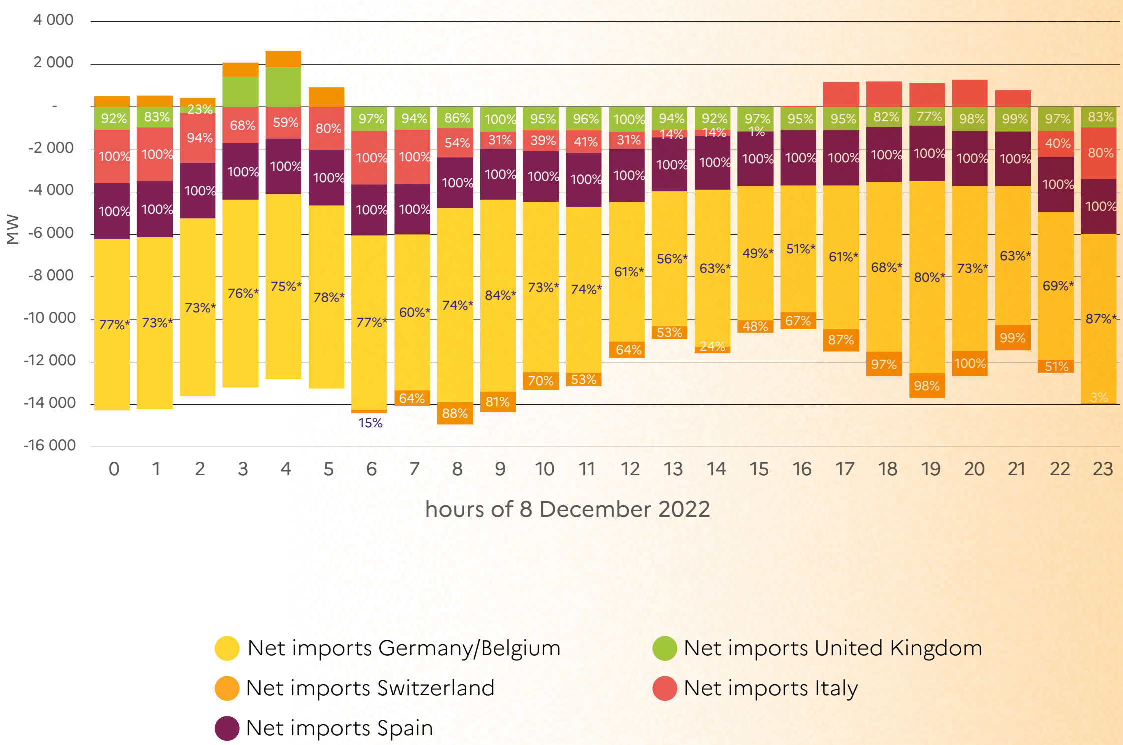


Source: RTE data, CRE analysis

The example of 8 December 2022 illustrates the role of imports on tight days for the French power system. On that day, which was reported by RTE as a particularly tight day (a so-called "PP2" day), imports peaked at 14.9 GW at 08:00. Over the hours of the day, imports accounted for an average of 18% of French consumption (and up to 22% at certain times of the day).

As shown in Figure 8, on 8 December interconnection capacity with Spain was systematically used at its full capacity to supply France, and the interconnection with Italy was used on average at 89% of its capacity to import. Imports from Great Britain saturated the interconnection during certain hours in the morning, and the interconnection with Switzerland was used extensively during the morning and evening peak hours. Finally, France imported large volumes of electricity from Germany and Belgium to levels exceeding 80% of France's maximum import capacity with this region.

Figure 8 French imports per hour and % use of the interconnections for imports on 8 December 2022



NOTE: Import utilisation rates correspond to the ratio of imported volumes over commercial capacities calculated on a daily basis for the following day (D-2 NTC) at all borders except Germany-Belgium. For the Germany-Belgium border, it corresponds to the ratio of imported volumes over maximum flow-based domain positions.

Source: RTE data, CRE analysis

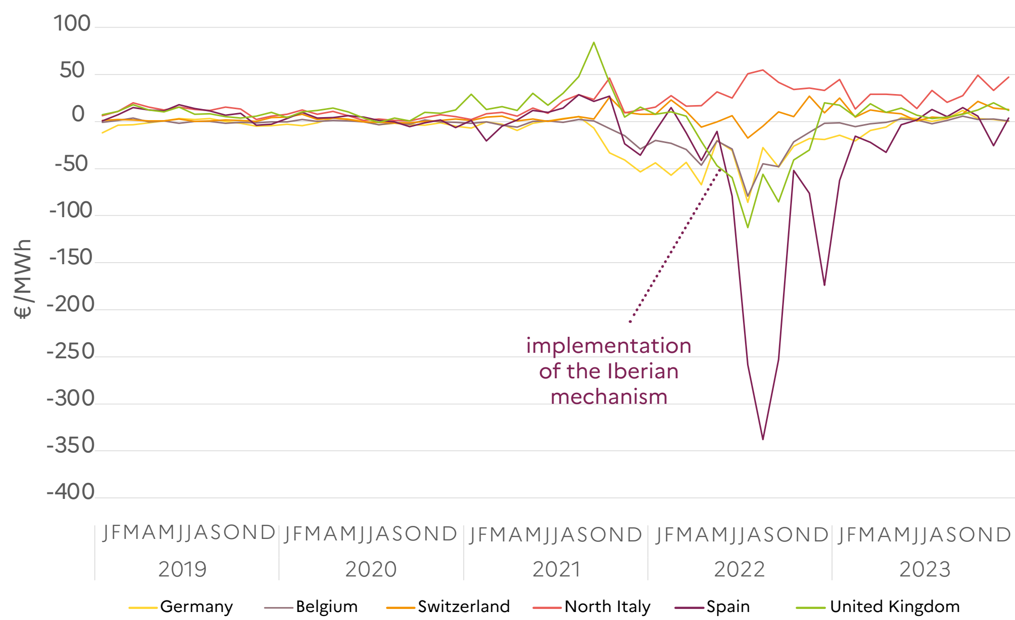
1.1.3 Widening price spreads with neighbouring countries

In the short term, the European electricity system is organised around a common wholesale market. The day-ahead market (commonly referred to as the spot market) provides a price for electricity in each country (or each bidding zone for countries with several zones, such as Italy) every day, for every hour of the following day. These short-term prices play an essential role in the organisation of cross-border trade between countries, as they drive trade flows from the cheapest zones to the most expensive zones, using interconnections. The functioning of the short-term market is explained in more detail in section 1.2.2.

The convergence of day-ahead prices between two countries means that there is sufficient interconnection capacity to allow the cheapest marginal generation resources to be shared between these countries. Conversely, when interconnection capacity is limiting, namely when the electricity that could be generated by the cheapest resources cannot be fully transported to the other zone (due to "physical congestion"), day-ahead wholesale prices cannot be equalised, resulting in price spreads.

After a year of high convergence in day-ahead prices between France and its neighbours in 2020, linked to the widespread fall in wholesale prices caused by the COVID-19 pandemic, an exceptional increase in price spreads with neighbouring countries was observed from the summer of 2021, with differences depending on the borders. These day-ahead price spreads widened even further in 2022, peaking in the summer of 2022.

Figure 9 Day-ahead wholesale price spreads between 2019 and 2023, monthly average (difference between the price in the neighbouring country and the French price)



Source: EPEX, ENTSO-E and Gestore Mercati Energetici data, CRE analysis

Table 2 Day-ahead price spreads between 2016 and 2023, annual average (difference between the price in the neighbouring country and the French price)

€/MWh	Great Britain	Germany	Belgium	Switzerland	Italy	Spain
2015-2020	11	-6	2	1.5	10	6.5
2021	28.5	12	-5	6	16	3
2022	-34	-40	-31	6	32	-108
2023	11	-2	0.4	11	31	-10

Source: EPEX, ENTSO-E and Gestore Mercati Energetici data, CRE analysis

Table 3 Day-ahead price convergence rate with neighbouring countries participating in the Single Day-ahead Coupling (share of hours of total convergence)

	Germany	Belgium	Italy	Spain
2020	46%	48%	37%	39%
2021	49%	51%	31%	32%
2022	34%	34%	38%	27%
2023	29%	30%	16%	33%

NOTE: With Switzerland and the United Kingdom, the price convergence rate is almost zero because these countries, which are not Member States of the EU, are not part of the Single Day-ahead Coupling.

Source: EPEX and Gestore Mercati Energetici data, CRE analysis

Historically, France has a lower average day-ahead wholesale price than Great Britain (-€11/MWh over the period 2015-2020), Italy (-€10/MWh) and Spain (-€6.5/MWh), but higher than Germany (+€6/MWh). With Belgium and Switzerland, the average prices are generally very close.

From the summer of 2021 until the end of 2022, German and Belgian prices remained significantly lower than French prices (-40 €/MWh and -31 €/MWh over the year 2022, respectively). French prices converged with German and Belgian prices for only a third of the hours of the year in 2022, after reaching a high convergence rate of 50% in 2021.

Conversely, French prices remained on average below Italian prices over this period (-€32/MWh in 2022), due to the high dependence of the Italian electricity mix on gas (half of its electricity production comes from gas, compared with 6% in France) and higher wholesale gas prices.

With Great Britain and Spain, the situation reversed during the crisis: while France benefited from lower average prices at the beginning of the crisis, price spreads became negative from the spring of 2022. Those negative price spreads then significantly widened in the following months.

In 2021, Great Britain faced a number of difficulties that reduced the margins of its electricity system (low wind production, maintenance work on its nuclear fleet, damage to several interconnectors), leading to higher prices than in the rest of Europe. Conversely, in 2022, Great Britain benefited from lower prices than most European countries, including France (-€34/MWh), thanks in particular to abundant renewable production and a gas system less exposed to the crisis (very low dependence on Russian gas and significant LNG import capacity).

With Spain, the price spreads, which were positive for most of 2021, turned occasionally negative at the end of 2021, due to high Spanish wind generation. From May 2022, the introduction of the so-called "Iberian mechanism" capping the price of gas used for power generation (see Zoom n° 1 below) resulted in Spanish prices being structurally lower than in the rest of Europe. This led to a sharp widening of the price spread between France and Spain. The largest decorrelation occurred in August, when prices on all European markets reached an exceptional peak caused by the sharp fall in Russian gas supplies, the very low availability of the French nuclear power fleet, a heatwave and the impact of the drought on the availability of hydroelectricity. While day-ahead spot prices in France, Germany, Belgium, Switzerland, Italy and the United Kingdom exceeded €400/MWh in August 2022, Spanish prices were limited to €155/MWh. On average in 2022, Spanish day-ahead prices were €100/MWh lower than French prices, and prices on the two markets converged for only 27% of the hours of the year (with almost no convergence from July to September).

In 2023, the average day-ahead price spreads with Belgium, Germany and Great Britain returned to levels similar to those before 2020. With Spain, negative price spreads persisted in the first few months of 2023, before returning to historical levels. On the other hand, the positive spreads with Italy remained as high as in 2022, due to persistently higher wholesale natural gas prices in Italy. In 2023, the price convergence rates with neighbouring countries were even lower than in 2022, reflecting more frequent congestion on French cross-border capacities.

ZOOM N° 1

The Iberian mechanism, an example of an emergency measure to tackle the energy crisis

In April 2022, the Spanish and Portuguese governments proposed to the European Commission a mechanism for capping the wholesale price of natural gas used for power plants in Spain and Portugal (known as the "Iberian mechanism", or "Iberian exception"). It aimed at temporarily reducing the electricity bills of consumers exposed to wholesale electricity price variations.

In fact, before the mechanism was implemented, consumers in the Iberian Peninsula were particularly affected by the crisis, notably because a large proportion of residential consumer contracts were indexed to short-term wholesale prices. In Spain in particular, the regulated tariff paid by around 40% of residential consumers was indexed to hourly prices on short-term wholesale markets.

On 8 June 2022, the European Commission approved this mechanism[3] for an initial period running from 14 June 2022 to 31 May 2023, which was later extended to 31 December 2023.

Principles of the mechanism

In the European short-term wholesale electricity markets, the spot price for each bidding zone is set by the marginal cost of the last generation plant activated to meet demand. The principle of the Iberian mechanism is to reduce the supply costs of thermal power plants (mainly gas-fired, but also coal-fired power plants) directly through subsidies. This artificially lowers the operating costs of these plants, which are often the last to be dispatched (so-called "marginal" power plants), and therefore reduces spot electricity prices throughout the Iberian Peninsula.

Therefore, this mechanism enables to reduce wholesale electricity prices for all consumers, without disrupting the merit order principle according to which power plants are dispatched based on ascending production costs. It exploits the leverage effect provided by the short-term electricity market design: by intervening in only a part of the Iberian production, the mechanism leads to a reduction in the wholesale price for all the electricity consumption exposed to the market.

In practice, the daily price cap for natural gas was initially set at €40/MWh (a level significantly lower than the spot price on the Iberian wholesale gas market, which was around €95/MWh in June 2022), with an automatic monthly increase planned after six months of application. Gas and coal-fired power plants were thus compensated with

3. Press release of the European Commission of 8 June 2022 – State aid: Commission approves Spanish and Portuguese measure to lower electricity prices amid energy crisis

a daily amount reflecting the difference, when positive, between the price paid for purchasing natural gas on the Iberian wholesale market and this price cap. Although the Iberian mechanism was extended from March 2023 to apply until December 2023, it was not activated during this period as wholesale natural gas prices remained below the cap.

The mechanism was financed through two streams: a tax on the electricity consumers that benefited from this emergency measure, and the congestion revenues collected by the Spanish TSO, which were expected to increase as a result of the anticipated widening of day-ahead price spreads between France and Spain[4].

The European Commission approved this aid for a total of €8.4 billion (€6.3 billion for Spain and €2.1 billion for Portugal), under the State aid rules. This decision was taken on the grounds that the mechanism would not undermine the functioning of the European wholesale electricity market based on the merit order, and that subsidising the cost of fossil fuels used for electricity generation would contribute to reducing wholesale electricity prices to the benefit of consumers particularly exposed to wholesale price volatility. The aid was strictly limited in time and applied only to the Iberian Peninsula, which has limited interconnection capacity with the rest of the European market.

The impact of the introduction of the Iberian mechanism

According to the Portuguese energy regulator ERSE[5], the mechanism would have reduced the energy component of retail prices for Iberian consumers with contracts indexed to the spot market by an average of around €43/MWh between June 2022 and January 2023. This corresponds to a 18% reduction compared with a scenario in which the mechanism would not have been introduced. This net benefit is derived from the difference, over the period, between the benefit linked to the fall in the Iberian spot price compared with a situation without the Iberian mechanism (estimated at €112/MWh on average) and the cost borne by consumers to finance the mechanism (estimated at €69/MWh on average). However, this analysis is based on a simplified theoretical counterfactual scenario[6].

This mechanism resulted in a sharp increase in electricity flows from Spain to France, as Spanish wholesale electricity prices remained consistently lower than French prices. During the period of its application, electricity cross-border trade was almost systematically oriented from Spain to France. It also led to an increase in natural gas consumption in Spain and Portugal, which was partly used to export electricity.

4. Most of the costs of the mechanism were borne by the electricity consumers concerned by the mechanism (€6.7 billion), while a smaller share was financed by interconnection revenues with France (€0.6 billion). Initially, 56% of Spanish consumers and 37% of Portuguese consumers had to contribute to financing the mechanism. This share gradually increased, reaching 84% and 66% respectively at the end of February 2023. This increase was the result of the inclusion of consumers renewing their fixed-price contracts, who also benefited from the fall in prices on the wholesale market, in addition to consumers with contracts indexed to spot prices.
5. Medreg report of April 2024, Energy price surge: Impacts and lessons learnt for Mediterranean energy markets 2023 update
6. This counterfactual scenario is based on a projection of the market prices that would have been observed if the mechanism had not been implemented. In this analysis, the theoretical price corresponds, for each hourly step, to the spot price that was actually observed, plus the cost of fossil fuel subsidies borne by consumers calculated by the market operator. This methodology does not, for example, take into account the effect of wholesale prices on demand levels in the Iberian Peninsula and in the interconnected countries.

Finally, the high price spreads between the two countries led to a surge in congestion incomes, shared equally between the French and Spanish TSOs RTE and REE (see section 1.1.4), as well as the costs of remedial actions (see Zoom n° 4) which are used by the TSOs to remove congestion on the interconnections to guarantee cross-border trade.

A mechanism that fed into the discussions on the reform of the European electricity market design

The idea of extending the Iberian mechanism to the whole EU was one of the options discussed as part of the European emergency regulations and the reflections on the reform of the European electricity market design. In October 2022, the European Council invited the European Commission to consider this option which could limit the impact of rising wholesale gas prices on electricity prices.

The cost-benefit analysis carried out by the European Commission[7] following this request highlighted several difficulties associated with the extension of the measure to the whole EU, especially the risks of leakage of electricity production to neighbouring countries outside the EU (in particular Switzerland, the UK and Norway), the difficulties associated with sharing the costs of the mechanism between Member States (subsidies would be higher for countries whose electricity mix is heavily dependent on gas-fired power plants), and the risks of an increased gas consumption in Europe in the midst of a supply crisis.

This option was eventually not included in the European legislative texts. The emergency Regulation of 6 October 2022[8] includes a measure to redistribute part of the exceptional inframarginal rent received by decarbonised electricity producers (the so-called "inframarginal revenue cap") to electricity consumers. Unlike the Iberian mechanism, which is applied on the short-term market, this measure is based on the *ex-post* collection of part of the producers' revenues, outside the market. These revenues are then redistributed to consumers, in a targeted manner.

During the period of application of the Iberian mechanism, Spain and Portugal remained fully integrated into the European internal market. The fall in Spanish spot prices led to sustained exports from Spain to France and to exceptionally high interconnection revenues at this border, half of which was collected by RTE and redistributed to French consumers.

The Iberian option would not have been viable in France alone, as an artificially low wholesale electricity price in France would have led to massive exports to neighbouring countries, in contradiction to France's strong need for electricity imports at the time.

7. Non-paper – Policy Options to Mitigate the Impact of Natural Gas Prices on Electricity Bills, October 2022: https://www.euractiv.com/section/electricity/news/brussels-cautions-against-eu-wide-gas-price-cap-for-electricity/
8. Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices

1.1.4 Evolution of interconnection revenues at French borders

Interconnection revenues collected by the French Transmission System Operator (TSO) RTE include revenues from price spreads between bidding zones resulting from the allocation of interconnection capacity for commercial trades (so-called "congestion income"), and revenues from the participation of interconnections in French and foreign capacity mechanisms.

Revenues from the sale of interconnection capacity ("congestion income")

Interconnection capacity enables to buy or generate electricity in one bidding zone for sale or consumption in a neighbouring zone. TSOs sell part of this interconnection capacity to market participants in advance (at the so-called "long-term" timeframe), currently up to one year before the physical delivery of electricity, for their physical or financial hedging needs.

At the day-ahead timeframe, TSOs receive, *via* the European market coupling operators (power exchanges), the product of price spreads between bidding zones and volumes traded on the interconnection concerned, when there is physical congestion, which constitutes "congestion income". At the balancing timeframe, TSOs receive income from the participation of French interconnections in European platforms for the exchange of balancing energy.

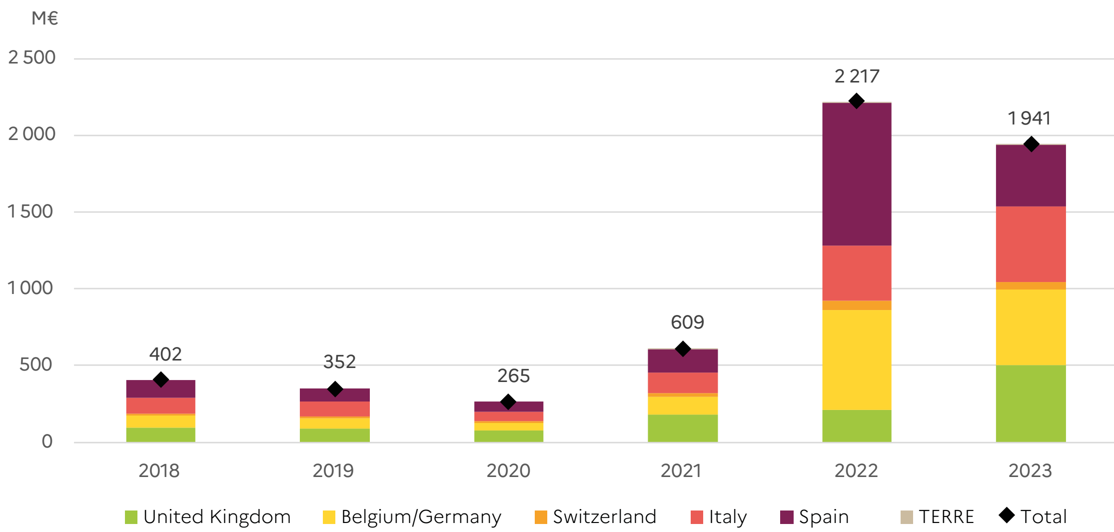
Unless otherwise agreed, congestion income is shared equally between adjacent TSOs. They are used first and foremost to guarantee the effective availability of allocated capacity and to develop new interconnection capacity. The remaining revenues are deducted from the transmission tariff paid by electricity consumers.

Figure 10 shows the evolution of RTE's annual "net congestion income", which corresponds to congestion income after deduction of the costs incurred by RTE in remunerating market participants who have acquired long-term interconnection capacity (the functioning of long-term transmission rights market is explained in section 1.2.1).

After a decline in 2020 due to the COVID-19 pandemic, net congestion income rose sharply during the energy crisis, reflecting the greater volumes traded, but above all the magnitude of price spreads between countries. For the year 2022, net congestion revenues reached €2.2 billion (RTE collected €3.6 billion in gross congestion revenues, while long-term costs amounted to €1.4 billion). The largest increase in 2022 occurred on the borders with Spain and the Germany-Belgium region, where spot price spreads were particularly high. At the UK border, the increase was limited due to the IFA damage and moderate price spreads at the start of the year.

For 2023, net congestion income remained high at €1.9 billion (€2.7 billion in gross income was collected by RTE at the French borders, of which a cost of €785 million related to the long-term timeframe can be deducted). This is particularly due to the persistence of significant forward price spreads at the time of the auctions of long-term transmission capacity organised at the end of 2022, linked to uncertainties concerning the outlook for the 2022-2023 winter, high spot prices in the first quarter and the high volumes traded.

Figure 10 Congestion income on RTE's French interconnections, net of the costs incurred to ensure firmness and remuneration of long-term transmission rights (2018-2023)



NOTE: This graph reports the net congestion income collected by RTE at French interconnections (excluding the capacity mechanism), calculated after deduction of costs linked to compensation for unavailability of capacity (firmness) and remuneration of long-term transmission rights. Also included are congestion revenues linked to the participation of French interconnections in the European balancing platform TERRE (complementary tertiary reserve - see section 1.2.3).

Source: RTE data, CRE analysis

CRE regularly publishes communications on the use of congestion income at European borders[9], in application of the 2019 Electricity Regulation. The low level of congestion income at the Swiss border is explained by the historical presence of long-term contracts that benefit from priority access to interconnection capacity.

By deducting from gross congestion income all the costs incurred by RTE in operating existing interconnections – namely, in addition to the costs of remunerating long-term transmission capacity, the costs of remedial actions by TSOs to guarantee firm capacity (see Zoom n° 4), as well as the capital costs of the part of the French network used by cross-border flows and the associated operating costs – a surplus of €1.6 billion in 2022 and €1.3 billion in 2023 was cleared. The rise in total interconnection operating costs during the crisis has thus been largely offset by the high level of gross congestion income.

9. CRE report of 28 March 2024 on the use of congestion income in 2023, sent to ACER pursuant to Article 19§5 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

Revenue from the participation of interconnections to capacity mechanisms

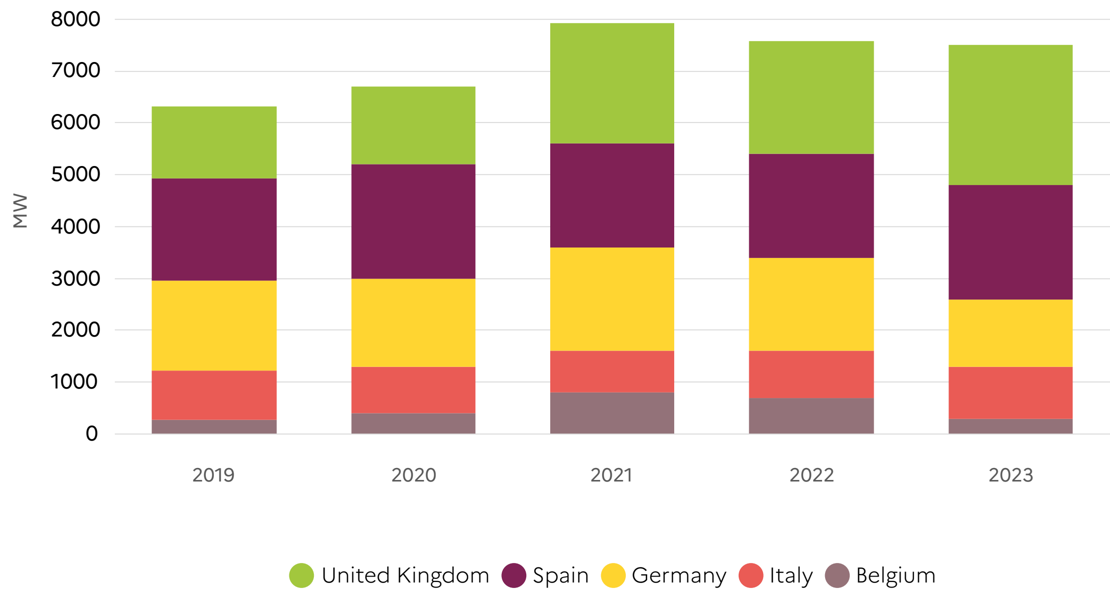
Since 2019, all French interconnections have participated in the French capacity remuneration mechanism through RTE (with the exception of the 1,000 MW ElecLink interconnector between France and the UK). On the UK border, the IFA (2,000 MW) and IFA 2 (1,000 MW) interconnectors have participated in the British capacity mechanism since 2017. RTE therefore receives a remuneration via the French and British capacity mechanisms.

The volumes of interconnection capacity certified and sold by RTE as part of the French capacity mechanism are established on the basis of simulations conducted by RTE for the French adequacy studies (so-called *Bilans Prévisionnels*). In these assessments, RTE estimates the contribution of each border to the French security of supply, readjusted according to the contingencies that may affect the actual availability of interconnections.

In total, 6.7 GW were certified for the 2020 delivery year, 7.9 GW for 2021, 7.25 GW in 2022, and 7.33 GW in 2023[10] (see Figure 11). For the 2021, 2022 and 2023 delivery years, RTE had initially certified higher volumes of capacity, but had to buy back some of these certificates during the delivery year due to lower-than-expected availability on certain interconnections. In particular, the fire that occurred in September 2021 on IFA reduced the available capacity of the interconnection with the UK, particularly during the winter of 2021-2022 when the days of mandatory availability of certified capacity are placed. During the delivery year, RTE had thus to buy back around 200 MW of certificates for the 2021 delivery year, and 325 MW for the 2022 delivery year. For the 2023 delivery year, the lower-than-expected availability of interconnections at the Spanish and UK borders led RTE to buy back 172 MW during the delivery year. Conversely, for the 2020 delivery year, the contribution of interconnection capacity with Spain to the French security of supply was higher than expected, leading RTE to sell an additional 200 MW of capacity certificates during the year.

10. For each delivery year of the capacity mechanism, the interconnection capacities are sold during the last auctions of the previous year. Some adjustments may also be applied afterwards (during or after the delivery year) if the contribution of an interconnection to the French security of supply is reassessed upwards or downwards by RTE.

Figure 11 Volumes of interconnection capacity certified by RTE under the French capacity mechanism, by delivery year (2019-2023)



NOTE: For the 2023 delivery year, the certified interconnection capacities correspond to the volumes initially sold by RTE at the last auction in 2022, without taking into account subsequent readjustments. The certified capacities at the British border do not take into account the ElecLink interconnection, which is not operated by RTE.

Source: RTE data, CRE analysis

Until 2021, interconnection capacity certified under the French capacity mechanism was increasing, reflecting a growing contribution of neighbouring countries to the French security of supply. As from 2022, volumes have decreased, mainly due to reductions at the Belgian and German borders resulting from the decommissioning of nuclear and thermal power stations in these two countries. The contribution of interconnections to the capacity mechanism depends not only on the interconnections transmission capacity, but also on the actual ability of the country to export to France during periods of stress on the French power system. Conversely, the contribution of interconnections at the British border increased significantly from 2021, with the commissioning of the IFA 2 interconnector. The contribution of the UK border increased further from the 2023 delivery year with the certification of an additional 900 MW of interconnection capacity for the ElecLink interconnector.

Since 2022, the countries that have contributed most to France's security of supply from the point of view of the capacity mechanism are Spain and the UK. For the Spanish border, the certified capacities (2.2 GW in 2023) are almost equal to the maximum available interconnection capacities, as Spain has sufficient generation margins to export electricity at the full interconnection capacity when France faces a tense situation. In the new capacity mechanism rules approved in October 2023[11], the contribution of the border with the Germany-Belgium region is projected to increase substantially from 2025, due to the commissioning of new gas-fired generation plants and the strong development of renewable energies planned in these two countries.

Interconnection revenues collected by RTE for the participation to the French capacity mechanism raised significantly for the 2021 delivery year compared to the 2020 delivery year. This development was driven by the higher capacity price at the December 2020 auction (€39,095/MW), reflecting the tensions anticipated on the security of supply for 2021. In terms of the 2022 delivery year, revenues were lower due to a lower capacity price at the December 2021 auction (€23,900/MW). For the following year, the maximum cap price was reached at the December 2022 auction (€60,000/MW) when RTE sold certified capacity for the 2023 delivery year, leading to a strong increase in revenue for RTE.

The French participation to foreign EU capacity mechanisms should be implemented in the coming years, following the conclusion of bilateral agreements with TSOs in neighbouring countries. Exchanges with Belgium are already underway.

The revenues collected by RTE under the UK capacity mechanism have remained relatively stable over the period 2020-2023. They amounted to €12.3 million in 2020, €15.5 million in 2021, €10 million in 2022 and €12.4 million in 2023[12].

Table 4 Interconnection revenue collected by RTE from the French capacity mechanism (excluding readjustments), by delivery year (2020-2023)

Revenue collected by RTE (M€)	Delivery year of the capacity mechanism			
	2020	2021	2022	2023
Revenue from the initial sale of interconnection capacity at the last auction of year N-1	95.0	266.9	154.7	368.7
Subsequent adjustments according to the actual availability of interconnections	1 Additional sale of 200 MW at the Spanish border	-2.98 Purchase of 152 MW on the UK border (fire on IFA)	-4.66 Purchase of 325 MW on the UK border (fire on IFA)	-8.05* Purchase of 162 MW on the Spanish border

NOTE: The readjustments for the 2023 delivery year only include transactions completed before 25 May 2024. Capacity buybacks are planned for the 2023 delivery year at the September 2024 auction.

Source: RTE data, CRE analysis

11. Decree of 5 October 2023 modifying the rules of the capacity mechanism taken in application of articles R. 335-1 et seq. of the Energy Code
12. This refers to revenue received by RTE over the course of the year, and not according to the delivery year.

BOX N° 2 :

Interconnections and capacity mechanisms

In the European Union, security of supply is a major component of national energy policies. At the same time, as the national electricity systems are interconnected, the Member States contribute to the security of supply of their neighbours. If there is a risk that the available domestic generation capacity will not be sufficient to meet demand, imports can be used to restore the balance between supply and demand.

In order to control the implementation of national mechanisms designed to ensure security of supply (so-called "capacity mechanisms"), which constitute State aid under European law, and in particular to avoid the oversizing of national generation parks, Regulation (EU) 2019/943 on the internal market in electricity[13] (hereinafter "2019 Electricity Regulation") promotes the mutualisation of generation capacity at European level through the participation of cross-border trades in national capacity mechanisms. The contribution of neighbouring countries, defined according to the methodology published by ACER in 2020[14], depends on interconnection capacity constraints and on the production margins that would be available to export electricity to the neighbouring country during periods of tension on its electricity system.

When implementing its capacity mechanism in 2017, France committed to the European Commission to include the participation of foreign generation capacity[15]. Initially, interconnections participated implicitly: their contribution was estimated statistically and was deduced from the national generation capacity needs. Since 2019, interconnections have been taken into account explicitly. A "simplified" procedure has been applied, whereby interconnections are valued by RTE without directly involving the generation resources of neighbouring countries. The revenue from the sale of these interconnection capacity certificates is collected by RTE and passed on to electricity consumers through the network tariff (TURPE).

Currently, the interconnection capacities certified by RTE for the French capacity mechanism are calculated according to the contribution of each interconnection to the French security of supply, namely to the reduction in the risk of imbalance between supply and demand for a delivery year. This contribution is calculated on the basis of forecasts of the availability of the interconnection capacity and the generation resources of the country concerned during peak days in France (between 15 and 25 days selected by RTE during the electricity winter period from the beginning of November to the end of March), in order to meet the security of supply criterion (the so-called "reliability standard") set in France at three hours of supply-demand imbalance, or two

13. Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity
14. Decision no. 36/2020 of 22 December 2020 on technical specifications for cross-border participation in capacity mechanisms
15. Press release of the European Commission of 8 November 2016 - State aid: Commission approves revised French market-wide capacity mechanism

hours of load shedding[16]. From 2026, as part of the revision of the French capacity mechanism, the introduction of an "advanced" procedure with certain neighbouring countries will allow foreign generation capacity operators to be remunerated in the same way as certified French generation capacity.

The 2019 Electricity Regulation provides that the introduction of a capacity mechanism in a Member State should be temporary and conditional on the identification of an adequacy problem in the European Resource Adequacy Assessment (ERAA) carried out by ENTSO-E and in the national adequacy study, if it exists. In these studies, which must model cross-border trades according to a methodology published by ACER[17], the choice of the key parameters related to interconnections can have a significant impact on the identified risks of inadequacy.

In particular, it is important to ensure that market imperfections and network constraints are properly taken into account to avoid underestimating the inadequacy risks. In certain situations, it may not be possible to import electricity at peak times, particularly if the interconnections are already saturated or if the neighbouring country's generating capacities are already fully used for domestic consumption or for exports to other countries. The latter can occur when several neighbouring countries simultaneously face load-shedding risks.

Therefore, the French adequacy assessment (*Bilan Prévisionnel 2023*) published by RTE in 2023[18] assumes in its reference trajectories a stable contribution of interconnections to security of supply by 2035 compared to today, despite the development of new interconnectors. This cautious approach reflects the uncertainties in terms of the development of generation capacities in neighbouring countries (for example, the trajectories for the phasing out of thermal power plants or the pace of development of renewable energies).

In the light of the resurgence of security of electricity supply risks in Europe, particularly during the winter of 2022-2023, the European electricity market design reform adopted in May 2024[19] has brought forward some changes to the framework for the introduction of capacity mechanisms. While these mechanisms were previously considered as last resort measures, the revised Electricity Regulation now conceives them as structural components of the European market. Measures are foreseen to streamline the European Commission's approval process for capacity mechanism, including a review of ACER's ERAA methodology.

16. It RTE's national adequacy assessment (*Bilan Prévisionnel*), it refers to the scenario "after adjustments to meet the 3 hours standard", that is, after adding or removing certain capacities in France in order to meet the reliability standard set by the public authorities in France at an average of three hours of supply-demand imbalance per year.
17. ACER Decision 24/2020 of 2 October 2020 on the methodology for the European resource adequacy assessment
18. Les bilans prévisionnels | RTE (rte-france.com)
19. Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design, and Directive (EU) 2024/1711 of the European Parliament and of the Council of 13 June 2024 amending Directives (EU) 2018/2001 and (EU) 2019/944 as regards improving the Union's electricity market design

The crisis has demonstrated the high insurance value of French interconnections

During the crisis, the sharp rise in congestion income collected by RTE boosted the profitability of French interconnections, leading to a surplus of €2.9 billion over the 2022-2023 period.

The financing of interconnections, particularly the generally high investment costs, is borne by RTE's tariff for the use of electricity transmission networks (TURPE), i.e. mainly by electricity consumers. In the pre-crisis period, interconnection revenues collected by RTE (congestion revenues and revenues from capacity mechanisms) represented around €400 million a year, or around 10% of RTE's allowed income. These revenues were used to cover the annual depreciation and remuneration of interconnections already in service.

The major role played by interconnections in maintaining the physical balance of the power system during the crisis has resulted in an extraordinarily high level of revenue for RTE in 2022 and 2023, thanks to the functioning of the internal market. These revenues, which are ultimately passed on to consumers, embody the insurance value of interconnections, which only comes into play in the event of exceptional supply tensions.

For 2022, CRE decided[20] that RTE's surplus tariff income over the forecast trajectory set out in the current TURPE[21], mainly linked to exceptional congestion income, should be returned to network users in advance, in a context of a sharp rise in the final price of energy. This amounted to €1.9 billion, representing a 48.2% reduction in TURPE for RTE customers[22].

20. CRE deliberation of 8 December 2022 on the implementation of an exceptional early payment of a portion of the balance of RTE's income and expenditure adjustment account ("CRCP")
21. CRE deliberation of 21 January 2021 deciding on the tariffs for the use of public transmission electricity grids (TURPE 6 HTB)
22. CRE press release of 6 February 2023: CRE sets the amount of RTE's exceptional payment at €1.939 billion for 2022

1.2. Evolution of the rules governing the use of electricity interconnections

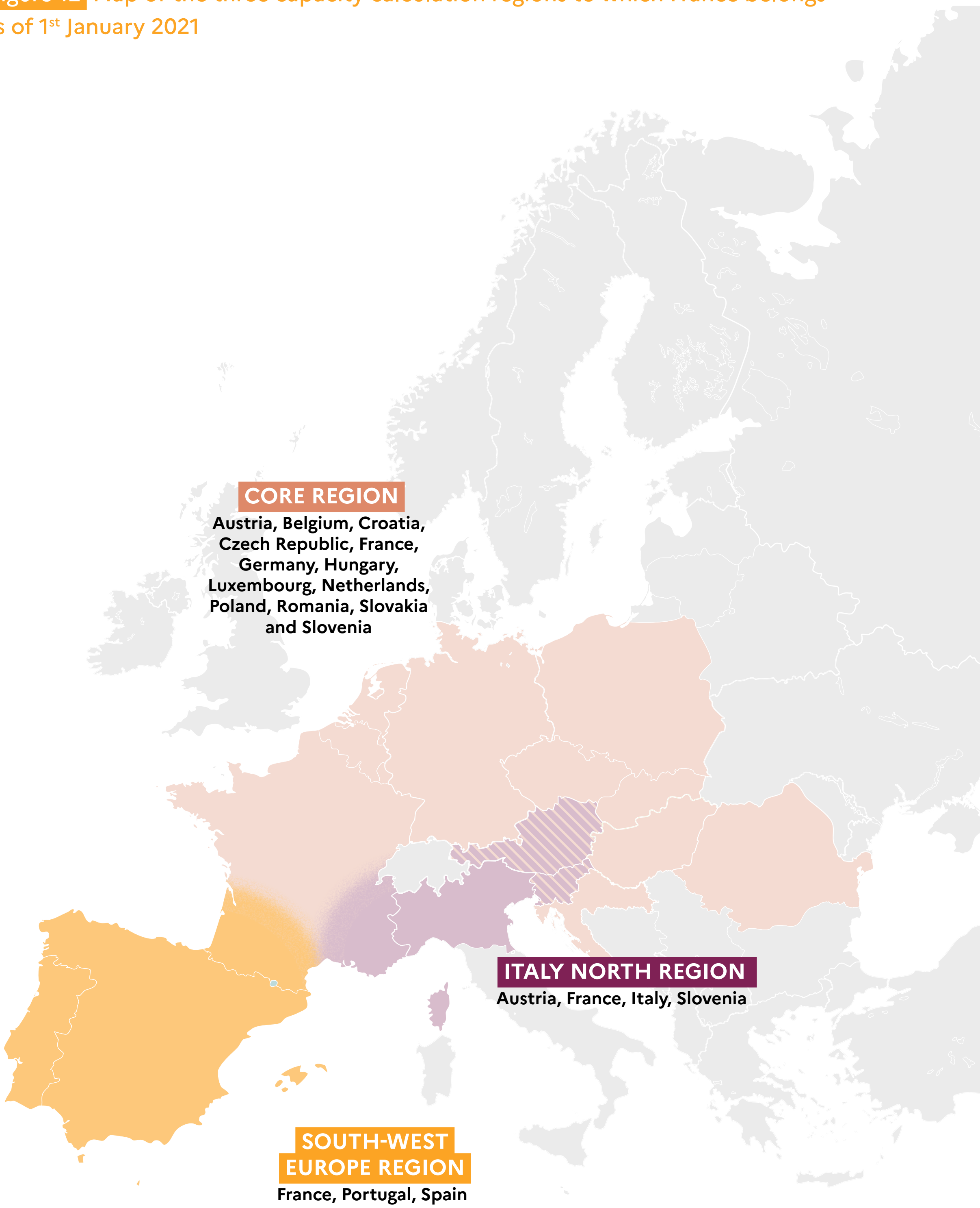
The European internal electricity market is composed of a set of bidding zones, within and between which market participants can trade electricity, either anonymously on the power exchanges, or bilaterally ("over the counter") at various timeframes, from the very short-term to the long-term (up to several years in advance in the case of forward trading). These zones are linked by interconnections, which are a central element of the internal market, enabling cross-border trades.

To obtain interconnection capacity and trade with another bidding zone, a market participant has two options. It can purchase long-term transmission rights in one direction, which are commercialised by TSOs (up to one year in advance in the EU); this is known as "explicit" capacity allocation. It can also carry out an energy trade on the European short-term markets, and if this trade triggers a cross-border flow, the corresponding transmission capacities are allocated simultaneously. This is referred to as "implicit" allocation and market coupling.

The interconnection capacities available for trades are determined by the TSOs at several timeframes, from the previous year(s) to the day of delivery. The calculations used to determine interconnection capacities are refined as their physical use approaches, and as knowledge of their actual operating conditions increases. In the long-term timeframe (e.g. one year in advance), the uncertainty about the network situation in real time is such that TSOs determine interconnection capacity while keeping a larger margin than for short-term and balancing calculations. The actual cross-border trades are then determined by the market coupling algorithm, based on the orders placed by market participants on power exchanges.

Since the United Kingdom's definitive withdrawal from the European Union on 1st January 2021 (see Box n°3 below), France has been integrated into three capacity calculation regions: Core, Italy North and South-West Europe. Several network codes and guidelines have been drawn up in application of the European legislation, setting out the operational details of the process of integrating electricity markets and managing interconnections at every stage.

Figure 12 Map of the three capacity calculation regions to which France belongs as of 1st January 2021



Source: CRE

BOX N°3:

The legal framework for the use of interconnections with the United Kingdom post-Brexit

On 1st February 2020, the United Kingdom officially left the European Union, which *de facto* led to its withdrawal from the internal electricity market on 1st January 2021, after the end of the transition period that had been instituted to extend the application of the so-called "*acquis communautaires*". This withdrawal from the internal market has had little impact on the long-term time-frame (see section 1.2.1), as the UK retains the existing capacity allocation mechanisms. However, the UK can no longer participate in European day-ahead and intraday couplings, which has deoptimised trade flows between the UK and its neighbours (see Zoom n° 3). During the crisis, the UK exported large quantities of electricity to France, but the flows were not always fully consistent with the price spreads between the two countries. Market coupling would have allowed better optimisation of flows according to price spreads, and therefore a higher level of exports to the continent.

On 30 December 2020, the European Union and the United Kingdom concluded a Trade and Cooperation Agreement (hereinafter "the Agreement"), which definitively entered into force on 28th February 2021.

The interconnections within the single market including Ireland and Northern Ireland have been excluded from the scope of the Agreement. Cooperation between European and British TSOs and regulators is provided for in each of these areas, under the aegis of a "Specialised Committee of Energy".

The Agreement incorporates the main European principles governing the operation of energy markets (efficient price formation on wholesale markets, free choice of energy suppliers, efficient use of interconnections) and network regulation (competition, non-discrimination and ownership unbundling).

The Agreement stipulates that capacity allocation and congestion management must be coordinated between EU and UK TSOs, market-based, transparent and non-discriminatory. At all timeframes, the maximum level of electricity interconnection capacity must be made available to the market in a way that guarantees the security of the network and its most efficient use. Electricity interconnection capacity may only be reduced in emergency situations, and in a non-discriminatory manner.

The Agreement provides for the termination of the energy arrangements on 30 June 2026, unless the Partnership Council, made up of representatives of the EU and the UK, decides to extend their application. If the political conditions are met, the most efficient solution from a technical and economic point of view would be for the UK to reintegrate into all European electricity processes, which are governed by network codes relating to the operational management of the electricity network, the market and interconnections.

1.2.1 Long-term timeframe

Part of the interconnection capacity is marketed by TSOs before the day-ahead timeframe, to enable market participants to secure their cross-border electricity trades in advance, in addition to the hedging products offered on national forward markets. The functioning of this hedging market is governed by the Regulation on Forward Capacity Allocation, known as the FCA network code[23]. This network code, which is in force since 2016, defines harmonized rules for calculating and allocating interconnection capacity in the European Union for monthly to yearly timeframes.

1.2.1.1 The functioning of the market for long-term transmission rights at interconnections

Market design and type of rights offered

At the long-term timeframe, TSOs issue long-term transmission rights by default at all borders they cover, unless national regulatory authorities decide otherwise. The volumes of rights marketed depend on the results of capacity calculations carried out by the TSOs, while the characteristics of the rights (type, form, duration) are defined in the rules for splitting the capacity between maturities.

Long-term products in Europe are allocated through explicit auctions on the Joint Allocation Office (JAO), including for Swiss and British borders. The auction algorithm ranks capacity requests in descending order of price, with the auction clearing price corresponding to the price of the last accepted bid. Any available capacity unsold after an allocation is offered at a subsequent auction for the products with the nearest lower maturity.

At the French borders, there are two types of long-term transmission rights: Physical Transmission Rights (PTR) and Financial Transmission Rights (FTR). Physical transmission rights give the holder the right either to use the interconnection capacity for cross-border energy trade at the day-ahead timeframe (referred to as the "nomination" process), or to sell the right to receive the day-ahead price spread between two bidding zones, if this is positive in the direction of the right: this is the so-called *use-it-or-sell-it* mechanism. Financial transmission rights imply an automatic *sell-it,* meaning the automatic payment of the day-ahead price spread when it is positive in the direction of the right, but do not offer the possibility of nominating the capacity.

Until the end of 2019, only physical transmission rights existed on French borders. At the Belgian and German borders, the increasing financial use of long-term transmission rights led the TSOs to replace physical rights with financial rights from 1st January 2020, with no noticeable impact on market operation

23. Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation

Table 5 Characteristics of long-term transmission rights allocated at the different borders

Border	Type of products	Form of products	Timeframes
Great Britain: IFA and IFA 2	PTR	Base	Yearly «Y+2»/Yearly/Seasonal/Quarterly/Monthly/Weekend
Belgium	FTR	Base	Yearly/Monthly
Germany	FTR	Base	Yearly/Monthly
Switzerland	PTR	Base	Yearly/Monthly
Italy	PTR	Base	Yearly/Monthly
Spain	PTR	Base	Yearly/Monthly
Great Britain: ElecLink	PTR	Base	Yearly/Seasonal/Quarterly/Monthly/Weekly/Weekend

Source: CRE

As shown in Figure 13, nominations of long-term transmission rights have fallen on borders where market coupling was implemented in 2015 (market coupling was not applied at the Swiss border), indicating that those products have been increasingly used as financial hedge against day-ahead price fluctuations rather than as a means of securing the physical delivery of energy. Market participants have gradually shifted to the day-ahead market for their physical electricity trading, with the share of day-ahead nominations averaging 70% of total nominations over the period 2020-2023.

However, at the British border, the UK's exit from the day-ahead market coupling has led market participants to switch back to the long-term timeframe for their energy trades from 2021. In 2021, the share of long-term nominations at this border exceeded the day-ahead share (45% vs. 41%), which had not happened since 2015. It then felt back in 2022 (34%) and 2023 (18%), albeit to a level above the 2017-2020 average (6% of nominations).

Holders of physical transmission rights may be encouraged to nominate their rights for several reasons, such as the relative certainty of the direction of the price spread or the desire to secure energy supply in times of market tension.

Figure 13 Distribution of nominations by border and timeframe (2014-2023)

Source: RTE and ENTSO-E Transparency Platform data, CRE analysis

Firmness and remuneration of long-term transmission rights

For TSOs to fulfill their commitments, it is important that there is a match between the volumes of long-term transmission rights sold and the transmission capacity available in the short-term, when the rights are utilised. TSOs must ensure this correspondence. However, unforeseen events may reduce the transmission capacity actually available at delivery date. In that case, TSOs may either use exceptional physical means to ensure that the capacity volumes sold are fulfilled, or curtail the long-term transmission rights allocated, provided that the holders are compensated. The terms of this compensation determine the degree of "firmness" of long-term transmission rights: a right is deemed firm if there is a guarantee that it will remain unchanged or that compensation will be paid in the event of a change.

In the event of a curtailment of long-term transmission rights, the TSO informs the capacity holder that it will not be able to honour them and pays him a financial compensation. For the borders that are included in the day-ahead market coupling, this compensation is equal to the day-ahead price spread between the two bidding zones. In the absence of market coupling, the compensation is based on the initial price paid by the market participant to acquire the long-term transmission rights.

These compensations are currently capped, to prevent TSOs from being exposed to excessive financial risk (which could ultimately be passed on to consumers *via* network tariffs), particularly in the event of a prolonged failure of an interconnector. These caps ensure that, at each border, the compensation paid to all holders of long-term transmission rights does not exceed the congestion income received by TSOs.

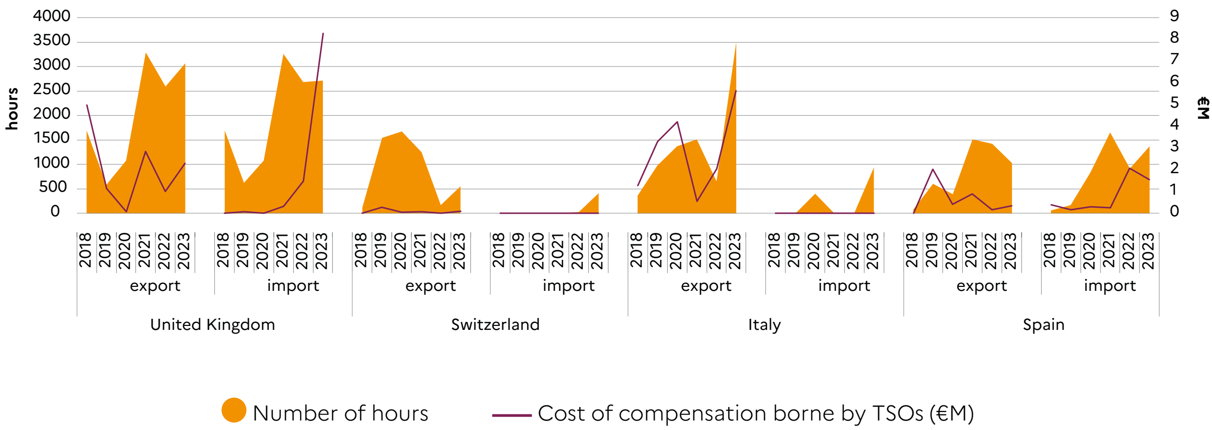
Figure 14 shows that capacity curtailments and associated compensation vary greatly from one border to another. These differences can be explained by several factors:

– The methods used to calculate the capacity offered on long-term timeframes, which provide greater or lesser margins to cope with contingencies, as well as the splitting of capacity between the different long-term timeframes: the day-ahead flow-based capacity calculation, in force since 2015 in the CWE region and extended in June 2022 to the Core region, guarantees at least the availability of capacity already allocated at the long-term timeframe (through the so-called "LTA Inclusion" process). The long-term capacity calculation in the Italy North region, in force since the end of 2021, includes criteria for the availability of long-term products.

– The interconnection network: on the German, Belgian and Swiss borders, the networks are dense and offer a degree of flexibility. The UK and Spanish borders, on the other hand, are poorly meshed. As a result, a large volume of long-term capacity is exposed to curtailments in the event of a failure of an interconnector.

– The occurrence of outages on the network or on generation facilities, as well as scheduled maintenance, which affect borders differently. This was particularly the case at the British border, affected by faults on IFA (between September 2021 and early 2023) and IFA 2 (from November 2023 to early 2024). Similar situations were observed with Italy in particular in 2023, and with Spain and Switzerland to a lesser extent.

Figure 14 Number of hours of long-term capacity curtailments per border and associated compensation, excluding Germany-Belgium and ElecLink (2018-2023)



READING: In 2023, the TSOs curtailed long-term interconnection capacity from France to Italy for 3504 hours and paid out €5.64 million in compensation.

Source: RTE data, CRE analysis

Table 6 Average volume of capacity curtailments by border, excluding Germany-Belgium and ElecLink (2018-2023)

Average volume of curtailment (MW)		2018	2019	2020	2021	2022	2023
Great Britain	Export	179	296	214	603	642	470
	Import	176	275	216	610	624	430
Switzerland	Export	29	97	241	345	233	125
	Import	0	0	0	0	3	53
Italy	Export	242	349	380	62	109	266
	Import	0	0	54	0	0	543
Spain	Export	149	248	311	253	149	242
	Import	437	133	194	414	96	109

Source: RTE data, CRE analysis

1.2.1.2 Current status of long-term capacity calculation and allocation

The FCA network code prescribes the systematic implementation of a coordinated capacity calculation for forward cross-border capacity before each allocation timeframe and within each capacity calculation region, and details the principles involved. It also requires the implementation of a regional methodology for splitting this capacity between the different long-term timeframes. The aim is to maximise the levels of capacity offered, while ensuring the safe operation of the network.

To calculate commercial capacities for cross-border trades, the FCA network code recommends using the so-called coordinated "net transmission capacity" (NTC) approach, which consists in determining in advance a maximum cross-border trade value per border and per direction (import or export) for each hourly step. A "flow-based" approach may alternatively be applied to the long-term capacity calculation according to the FCA network code, if it is justified in terms of economic efficiency. The flow-based approach consists of calculating cross-border capacities in a dynamic way by making explicit certain network constraints and giving priority to those borders on which trade has the highest value.

With regard to the splitting of long-term capacity between different timeframes, the FCA network code stipulates that TSOs must offer at least yearly and monthly products, which provide hedging for the following year or month. At present, only these products are offered at French borders within the EU. A wider variety of products is offered at the UK border (see Table 7 below). The splitting of forward capacity may vary from one border to another and must strike a balance between the hedging needs of market participants and the financial risks borne by TSOs.

The FCA network code recommends the use of a deterministic approach to capacity calculation, based on the use of scenarios that establish projections of consumption and generation, and on an assessment of the impact on networks. A statistical approach, which consists in determining interconnection capacity based on past trade capacities observed on a day-ahead basis, can be used if it improves economic efficiency and takes better account of the uncertainties specific to the long-term timeframe, while maintaining the same level of system reliability. Thus, the methods applied to the long-term timeframe vary according to capacity calculation regions and borders.

Table 7 Summary of regional methodologies for calculating and allocating long-term capacity at French borders

French borders	Capacity calculation region	Type of calculation	Uncertainty management	Implementation status	Splitting per product
Germany, Belgium	Core	Flow-based	Deterministic approach	By November 2025	80% yearly/20% monthly
Spain	South-West Europe	Coordinated NTC	Deterministic approach	By April 2025	40% yearly /40% monthly
Italy	Italy North	Coordinated NTC	Statistical approach	Implemented in November 2021	85% yearly /100% monthly recalculations Products quality criteria
Great Britain	-	Interim unilateral NTC	Deterministic approach	Implemented in March 2022	IFA/IFA 2: 10% yearly « A+2 » / 35% yearly « A » / 10% seasonal / 15% quarterly / 10% monthly ElecLink: 50% yearly / 10% seasonal / 15% quarterly /15% monthly

Core region

At present, the long-term capacities available at the borders with Germany and Belgium are determined by an uncoordinated bilateral calculation carried out by the TSOs at each border. Since the FCA network code came into force, several approaches to a coordinated capacity calculation methodology have been studied by TSOs and national regulators in the Core region. However, in the absence of a consensus, ACER established a long-term flow-based capacity calculation in November 2021[24], following the principle already applied in the Core region for the short-term timeframe.

ACER estimated that the long-term flow-based approach would provide a higher economic benefit than the NTC approach, while recognising the risk that the long-term cross-border capacities offered would be lower. To offset this effect, TSOs have the possibility, in the absence of network security constraints, to increase the margins available for long-term cross-border trades at their borders.

24. ACER Decision 14/2021 of 3 November 2021 on the long-term capacity calculation methodology of the Core capacity calculation region

For the long-term capacity calculation, the flow-based approach consists of defining a domain representing all the capacity combinations at the various borders that can be offered for long-term trades, given the interdependencies between them. To take account of the uncertainties associated with the network situation in the distant future, ACER has adopted a deterministic, scenario-based approach. The calculation takes as input parameters the European network models of ENTSO-E, representing a "snapshot" of the network situation at different time steps throughout the year. The final domain corresponds to the fusion of all the domains derived from the different network situations.

For the long-term capacity allocation, the flow-based approach consists of putting all the borders of the region into competition in a single auction. The long-term flow-based allocation algorithm prioritises the borders with the highest "value" by selecting market participant's bids so as to maximise the "economic surplus" at the regional level. This means that prior to the auction, market participants do not know the exact volumes that will be allocated to each border, or even an order of magnitude of these volumes. In addition, they will have to take account of market developments on the other borders of the region when participating in the auctions. Finally, the principle of a single auction increases the volumes of financial guarantees that need to be mobilised to participate in the auctions, for market participants wishing to acquire capacity on several borders of the region. In order to limit these financial guarantees, a ceiling price was set for the calculation of these guarantees[25].

For the management of financial flows, a principle of socialising day-ahead congestion revenues, as well as the costs incurred to ensure firmness and remuneration of long-term transmission rights on a regional scale, was introduced[26].

25. ACER Decision 18/2023 of 22 December 2023 on the TSOs' proposal for amendment of the harmonised allocation rules for long-term transmission rights
26. ACER Decision of 4 October 2021 on the methodology for sharing costs incurred to ensure firmness and remuneration of long-term transmission rights

BOX N° 4

Long-term flow-based, CRE takes a stance

The decision taken by ACER in 2021 to implement a flow-based approach for long-term timeframes needs to be reviewed. This is the position supported by CRE in the working groups led by ACER in the Core region. The deterioration in capacity levels resulting from TSO estimates highlights technical difficulties that had not been properly identified. The network models and data available for capacity calculations are subject to levels of uncertainty that cannot be overcome in the short term. Yet, the ambition of better coordination of TSO calculations only makes sense if it effectively leads to an increase in the levels of capacity offered to market participants. As things stand, it is preferable to maintain the approach whereby TSOs combine the results of their national calculations to set the volumes offered.

CRE is also opposed to the principle of competition between borders in the allocation process. The underlying principle is to concentrate allocated capacity on those borders where auction prices are the highest. This means that, in a given year, the long-term capacity allocated to an interconnection may be zero, whereas it was very high in previous years. This introduces further complexity for market participants, who will have to factor this uncertainty into their strategies when estimating the value of long-term transmission rights. The financial guarantees required will be higher, which may exclude some of the market participants currently active.

The long-term flow-based approach contravenes two fundamental principles for CRE: long-term transmission rights are intended to provide market participants with hedging tools, at all borders, according to an insurance rationale. The second principle is that long-term transmission rights should play a stabilising role and should not be affected, in terms of volume, by potential forecast errors made by market participants. This stability is essential to ensure a proper interaction between long-term transmission rights and the consolidation of forward markets.

CRE considers that the long-term flow-based approach needs to be thoroughly reviewed before any implementation, a view shared by the vast majority of European market participants. As implementation has been postponed for one year, CRE sees this as an opportunity to re-examine the calculation and allocation of long-term capacity based on the lessons learned from the crisis, in two aspects: visibility in terms of volumes, and allocation over more distant timeframes.

South-West Europe Region

At the Spanish border, the implementation of a coordinated long-term capacity calculation, initially scheduled for the second half of 2022, was postponed to mid-2025. In the coordinated approach adopted, the capacity profile is determined based on scenario analysis and the definition of an explicit safety margin, which is deducted from the capacity calculated on the assumption of an optimal power system situation. This makes it possible to take account of possible contingencies, such as unexpected flow deviations, emergency trades to re-establish the supply-demand balance, or forecasting errors.

Although the calculation methodology is currently being implemented, TSOs have studied and agreed with regulators to use a lower level of security margin to increase cross-border capacity, in line with historical practice. The splitting of capacity allocated at the long-term timeframe is evolving in line with this new security margin, rising from 66% (33% yearly, 33% monthly) to 80% (40% annual, 40% monthly).

Italy North region

The Italian border is currently the only French border where a coordinated long-term capacity calculation is carried out on a regional scale. This coordinated calculation, which was introduced in November 2021, is based on a statistical approach, which makes it possible to determine a capacity profile corresponding to the reality of network operation over the three years preceding the allocation. Long-term capacity calculations thus benefit from the improvements made to day-ahead calculations. When a new interconnection is commissioned during the year, it is included in the monthly recalculations with a discount to reflect the higher operational risks associated with the running-in period.

Product quality criteria have also been introduced across the region: long-term products must be entirely available at least 80% of the time and must not contain more than 25 scheduled maintenance reduction periods for the yearly products and 5 for the monthly products. Finally, in the export direction from France to Italy, there is a yearly base product fully available throughout the year (100% of the time), as well as a yearly product with reductions, whose value may vary according to scheduled network maintenance.

The UK border

Since the UK's withdrawal from EU market rules in January 2021 (see Box n°3), projects for coordinated methodologies for calculating and allocating long-term capacity in the former Channel region[27] have been indefinitely postponed. The guidelines covering these methodologies will be issued by the Specialised Committee on Energy. In the meantime, TSOs may develop interim solutions.

The successive commissioning of two new 1 GW interconnectors at the UK border, the existence of an electricity hub in the north of France and the structural changes observed in the production mix of the area prevent RTE from guaranteeing the full interconnection capacity in the event of maintenance on the French upstream network. In this context, RTE proposed an interim long-term capacity calculation methodology, based on the principles of the project developed for the former Channel region. The capacity calculation, which is based on the determination of a predetermined trade value according to scenarios, is organised around two independent zones of influence: IFA and ElecLink on the one hand, and IFA 2 on the other. This methodology ensures the safe operation of the network during maintenance operations, while guaranteeing the most efficient use of interconnections in a fair and non-discriminatory manner.

The Switzerland border

The France-Switzerland border is not part of European processes such as the day-ahead market coupling. But above all, it is characterised by the existence of historical long-term contracts, which give priority and free access to interconnection capacity, which has not been the case at other EU borders since the 2000s. These contracts were signed in the second half of the 20th century and, in some cases, run beyond 2050. The flexibility clauses contained in these contracts allow their holders to submit late nominations, which limits the possibility of offering unused capacity at the day-ahead timeframe.

In the export direction to Switzerland, until the first long-term contracts expired in the 2010s, long-term contracts mobilised the entire cross-border capacity, representing around 3,100 MW. CRE and its Swiss counterpart then decided that the capacity freed up by the expiry of long-term contracts would be made available to market participants and offered on long-term yearly and monthly timeframes. In this way, 370 MW are commercialised each year for the yearly product, representing around one third of the total cross-border capacity made available to the market. Additional capacity resulting from monthly recalculations (after deducting capacity reserved under long-term contracts and capacity already allocated at the yearly timeframe) is offered each month as monthly products.

In the import direction to France, no long-term capacity products were commercialised until 2022: long-term contracts reserved almost all interconnections during the winter months, while any additional available capacity was allocated to short-term timeframes. After analyses conducted by the TSOs in 2020 showed the possibility

27. The Channel capacity calculation region included Belgium, France, the Netherlands and the United Kingdom.

of offering monthly products, only during the summer (between May and September), a first monthly auction took place in 2022 for delivery in June. Then, in 2023, a monthly product was marketed for each summer month. To provide market participants with longer-term hedging opportunities, particularly in a context of energy prices crisis, a 100 MW yearly product was offered for the first time in 2023 for the delivery year 2024.

1.2.1.3 Overview of interconnection capacity allocation at French borders

The implementation of early auctions at French borders in response to the crisis

Until 2023, interconnection capacities (except at the British border) were only made available to the market at a late stage, namely a few days or weeks before the start of the delivery period. In particular, yearly products, which offer the hedge for the most distant time horizon and which are the most commonly used products by electricity suppliers, were only commercialised in November or December of year Y-1 for the year Y product, once the European network maintenance programme was known.

In response to the surge in forward prices observed on the French market in 2022, CRE, in cooperation with RTE as well as the regulators and the TSOs of neighbouring countries, initiated a process to anticipate the commercialisation of interconnection capacity with the objective of providing greater visibility to market participants. One of the main objectives of the early allocation of interconnection capacity was to promote liquidity on the French forward market, by enabling market participants to take positions on the forward markets on both sides of the border to secure their cross-border hedge at an earlier stage.

For the winter 2023-2024, RTE reached an agreement with its German, Belgian and Swiss counterparts, with the approval of the respective regulatory authorities, to commercialise a portion of the 2024 yearly capacity as early as in September 2023. The volumes of capacity that could be allocated at the yearly timeframe prior to the results of the yearly capacity calculation, without increasing the operational risks for the TSOs, were determined through a statistical approach based on the historical commercial capacities available at the day-ahead timeframe.

On the borders with Belgium and Germany, half of the capacity to be offered at the yearly timeframe for 2024 (in both directions) was allocated at an early auction held in September 2023, while the other half was offered at the usual auction in December 2023. At the Swiss border, all the capacity for the 2024 yearly product (in both directions) was commercialised in September 2023.

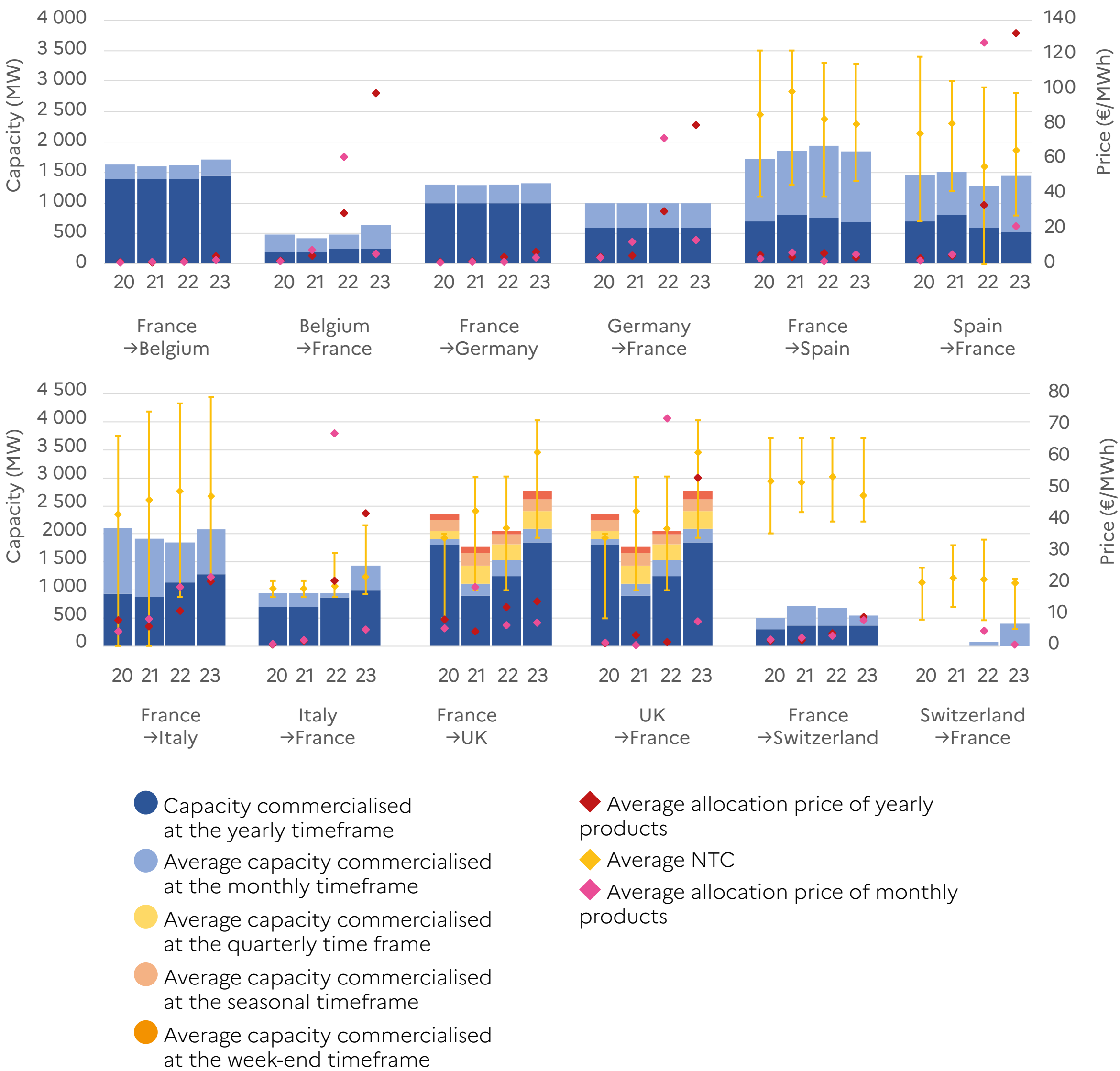
The outcomes of these early auctions substantiated market participants' interest in securing yearly interconnection capacity further in advance. At these three borders, demand was consistently more than ten times higher than the volumes offered, and market participants priced the capacity at a higher level than the price spread observed on the futures markets at the time of the auction. This indicates that they included a premium linked to the optional value of long-term transmission rights.

Furthermore, the early interconnection capacity auctions for the 2024 yearly product increased the liquidity on the French forward market in September 2023, shortly after the auctions. Indeed, some market participants, who aim at securing a full hedge for their cross-border trades, await until they have interconnection capacity before trading electricity on the national forward markets on both sides of the border (otherwise they would be exposed to fluctuations in price spreads between the national markets).

Review of the allocation of long-term transmission rights

Figure 15 below gives an overview of the long-term transmission rights that have been allocated at French borders between 2020 and 2023.

Figure 15 Volumes and prices of long-term transmission rights allocated at French borders between 2020 and 2023



Source: RTE and JAO data, CRE analysis

The volumes of long-term transmission rights allocated at the French borders are relatively stable over time. They increased slightly in 2022 and 2023 at the British and Italian borders (as a result of the commissioning of new interconnections and the return in operation of IFA), and at the Swiss border with the introduction of long-term transmission rights in the Switzerland-France direction.

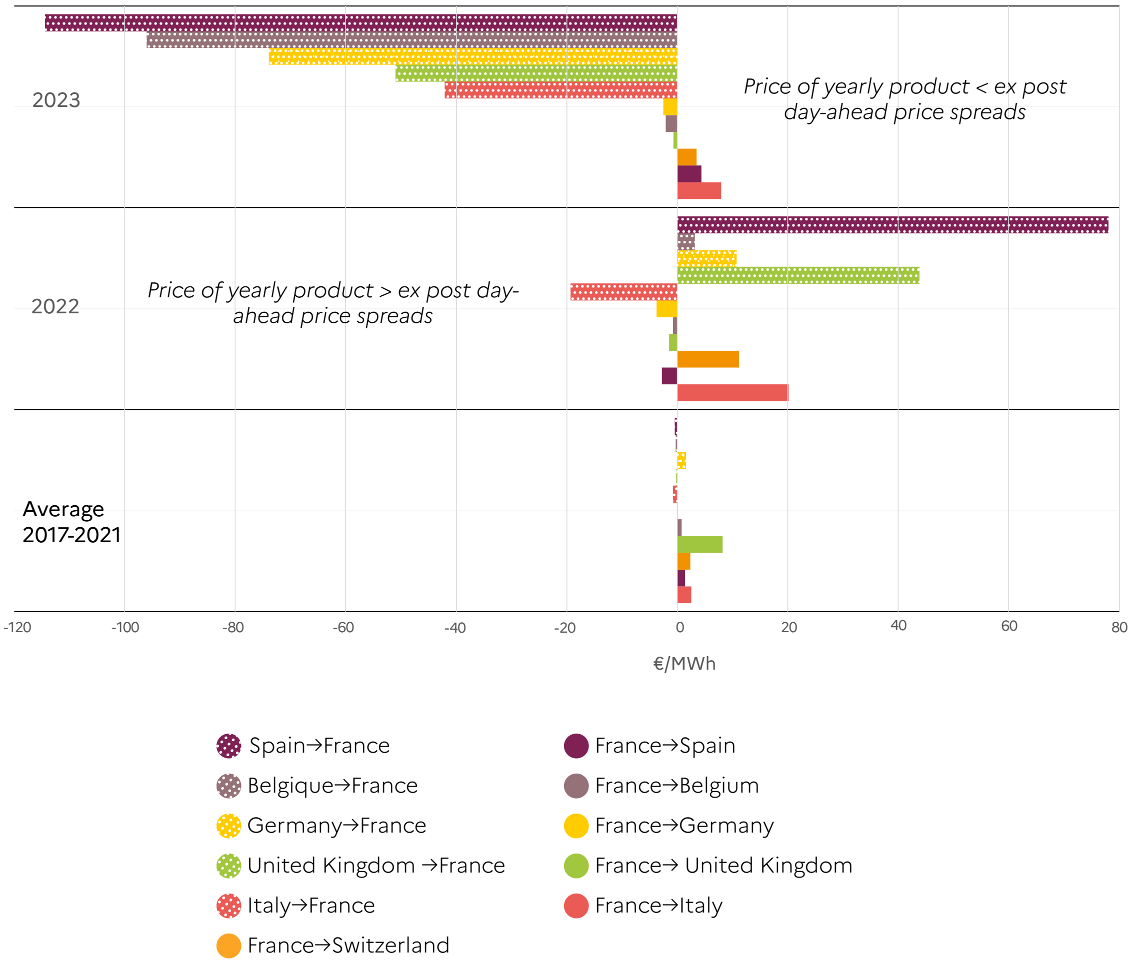
Depending on the borders, the volumes commercialised at the long-term timeframe may represent a large proportion of the interconnection capacity available at the day-ahead timeframe (for example at the Italian border, where on average more than 85% of the day-ahead commercial capacity was already allocated at the long-term timeframe), or a smaller share (for example at the Spanish border, where more than a quarter of the capacity was allocated at the short-term timeframe, and the Swiss border, where a large proportion of the capacity is reserved for long-term contracts outside the market).

The value of these rights corresponds, in theory, to the expected average price spread between the two zones during the delivery period, taking into account only the situation where the spread is positive in the given direction. Clearing prices resulting from the auctions for these long-term transmission rights are therefore supposed to reflect structural price spread between zones. However, the day-ahead price spread observed *ex-post* rarely coincides with the allocation prices, because the state of the electricity systems is not known with certainty at the time of allocation of the products.

For the delivery years 2022 and 2023, the clearing prices for yearly long-term transmission rights in the import direction to France (excluding the Swiss border) increased significantly, as market participants anticipated wider price spreads when France would be an importer. While these products on the import direction were allocated on average at €3.5/MWh in 2020-2021, their price increased by more than ten times in 2022 and 2023. The price surge for long-term products was particularly sharp for autumn and winter 2022-2023 monthly products (reaching an average of €194/MWh for the month of December 2022), as well as for the 2023 yearly product.

Figure 16 presents an analysis of the valuation of annual long-term transmission rights, by comparing the prices at which they were acquired with the average positive day-ahead price spreads observed *ex-post* on the relevant time steps which are paid out to the holders of these rights. For 2022, the yearly products on the import direction were largely undervalued compared with the day-ahead price spreads observed *ex-post* (except for the Italian border in the Italy to France direction), as market participants underestimated the magnitude of the price spreads when France would import. This phenomenon was most pronounced at the Spanish border, where import price spreads reached very high levels after the introduction of the Iberian mechanism in June 2022. For 2023, conversely, market participants purchased these yearly products on the import direction at prices much higher than the price spreads observed retrospectively, in line with market participants' strong uncertainties about the evolution of day-ahead prices at the time of the yearly interconnection capacity auctions at the end of 2022, and with the gradual easing of the markets in 2023.

Figure 16 Valuation of yearly long-term transmission rights between 2017 and 2023 (difference between the average ex-post day-ahead positive price spread and the long-term transmission right clearing price)



Source: RTE and JAO data, CRE analysis

READING: At the Spanish border, in the direction of imports to France, the yearly long-term transmission rights providing a hedge for the 2022 delivery year were purchased by market participants at a €78/MWh discount compared with the revenue they received in return over the delivery period (when France was importing from Spain). For the 2023 delivery year, conversely, the yearly product from Spain to France was purchased with a €114/MWh premium above the compensation received by the market participants over the delivery period of the rights.

ZOOM N° 2

Outlook on future developments in the long-term transmission rights market

Reinforcing the long-term timeframe as a cornerstone of the European electricity market reform

The energy price crisis has once again highlighted the importance of long-term maturities, which enable producers, suppliers and consumers to reduce their exposure to short-term price volatility, whereas the European internal market has until now developed mainly on short-term maturities.

Strengthening the long-term timeframe has thus been one of the major objectives of the electricity market design reform initiated by the European Commission in March 2023[28] and adopted in May 2024. In particular, in an interconnected European market, improving the functioning of the market for long-term transmission rights at interconnections was identified as a priority to provide market participants with hedging opportunities beyond national forward markets.

In its initial legislative proposal, the European Commission proposed to reform the functioning of European forward markets, moving from a model where different national forward markets coexist to a model of "virtual" regional forward markets.

For this model to emerge, the Commission proposed abandoning the concept of long-term transmission rights issued at each border to introduce a model where these rights would be issued between bidding zones and the regional virtual hub.

Following the negotiations with the European Parliament and the Council, the final text requires the European Commission to carry out an impact assessment[29] on the functioning of forward markets before implementing this model, given the many uncertainties and associated risks. In addition, this study will have to analyse other possible improvements to the functioning of forward markets, in particular measures to allocate long-term transmission rights further in advance (up to three years in advance) and more frequently, to allow their resale on a secondary market, or to change their nature (for example by moving to products in the form of obligations, which requires market participants to pay back price spreads to TSOs when they are in the opposite direction to the right).

28. In its legislative proposal published in March 2023, the European Commission stated that one of the main aims of this reform was to enable long-term instruments to play a greater role in the electricity market, to reduce consumers' exposure to short-term price peaks on energy markets. In particular, the proposal included measures to encourage the development of long-term *power purchase agreements* (PPAs) and contracts for difference (CfDs), which guarantee a minimum purchase price for new decarbonized generation assets, to improve the liquidity of forward markets (with the introduction of regional virtual hubs), and to oblige suppliers to cover part of their demand with long-term contracts and to offer fixed-price contracts.
29. In the revised Electricity Regulation, adopted in May 2024, the new Article 9 on forward markets requires the European Commission to carry out this impact study within 18 months of its entry into force.

Improving the existing model for long-term transmission rights, a priority for CRE

Long-term transmission rights are a major component of market participants' hedging strategies. The role of TSOs in this area is essential: as reliable counterparties, they provide stability and visibility to market participants. TSOs must ensure that interconnection capacity sold at a long-term timeframe is available during the delivery period, and the amounts that TSOs pay out to market participants who acquired long-term transmission rights come from the revenues generated by the sale of this same capacity. The allocation of long-term transmission rights in the form of options also means that market participants are not exposed to financial risks in the event of price spreads in the opposite direction to the right.

This model has proved its worth but needs to be improved. At present, long-term transmission rights make only an imperfect contribution to market participants' hedging strategies, notably because they are not made available to the market until late before delivery. Moreover, they only offer hedging up to a year in advance (excluding the UK border), whereas nothing would prevent interconnection capacity being allocated several years in advance.

As part of the European Commission's public consultation on reforming the functioning of the European electricity market, launched in January 2023, CRE responded that[30] one of the objectives of the reform should be to preserve the current functioning of the wholesale market, while strengthening and developing it over the longer term. In this respect, improvements in long-term transmission rights at interconnections should support forward markets. Several measures were proposed by CRE, some of which have already been implemented at several French borders, such as the allocation of long-term interconnection capacity *via* early auctions, an increased allocation frequency and the introduction of hedging products with longer maturities, up to two or three years in advance.

These developments are now being hampered by the prospect of the forthcoming implementation of long-term flow based.

30. CRE's answer to the European Commission's public consultation on the functioning of the European electricity market, 14 February 2023

1.2.2 Short-term timeframe

At the short-term timeframe, TSOs must commercialise all available interconnection capacity to enable market participants to undertake cross-border electricity trades, from the day before the delivery at the day-ahead timeframe and up to one hour before real time at the intraday timeframe. The functioning of this physical short-term market is governed by Regulation (EU) 2015/1222 on Capacity Allocation and Congestion Management, known as the "CACM network code", in force since 2015[31], which aims at harmonising the rules for calculating and allocating short-term capacity within the common European electricity market.

1.2.2.1 The functioning and role of interconnections in the short-term timeframe

Design of the common European market

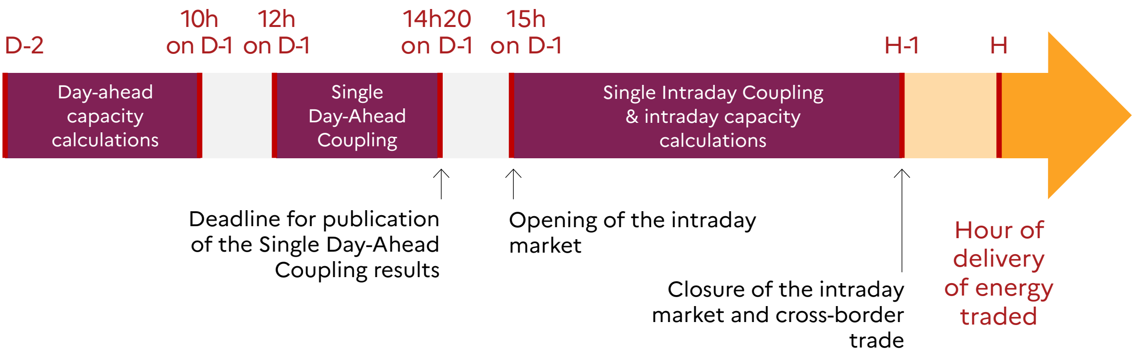
The short-term timeframe is organised into two successive markets: the day-ahead market, which is a market for the physical delivery of energy contracted the day before, known as the "Single Day-Ahead Coupling" (SDAC), and the intraday market, known as the "Single Intraday Coupling" (SIDC), which is a continuous market, also for physical delivery.

These two markets are based on the principle of "implicit allocation", which means that the interconnection capacity needed for cross-border trading is allocated together with energy trades. For market participants, this means that they do not need to book the interconnection capacity on which to send electricity: they simply place orders to buy and sell electricity in the different European bidding zones. The market algorithm then optimises the allocation of interconnection capacity to deliver electricity at the lowest cost across Europe. Thus, the model guarantees the optimal dispatch of European production resources.

The interconnection capacities that can be made available to the day-ahead and intraday markets are defined by capacity calculations conducted by the TSOs prior to the day-ahead market and then alongside the intraday market.

31. Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management

Figure 17 Timeline of the common European market at the short-term timeframe



Source: CRE

To buy or sell electricity on the short-term markets, market participants submit to the power exchanges orders to buy and sell electricity on each local market. These orders are then anonymised and aggregated at a European level. For the day-ahead market, the various orders are received at the power exchanges until 12:00. Each day during the single day-ahead market coupling which starts at 12:00, an algorithm selects the orders that optimise the system at the European scale, while respecting the limits on available interconnection capacities. Once a day, the single day-ahead market coupling thus enables supply and demand to be matched on a European scale and to determine the dispatch of production, storage and demand-side response capacities for all the hours of the following day.

The single intraday market coupling does not optimise the whole system at once but enables electricity to be traded continuously across Europe up to one hour before delivery. It is based on an algorithm that matches each new buy (or sell) order with a sell (or buy) order submitted to the various power exchanges almost instantaneously, at the best price throughout Europe and taking into account the interconnection capacity still available for trading.

Single day-ahead coupling

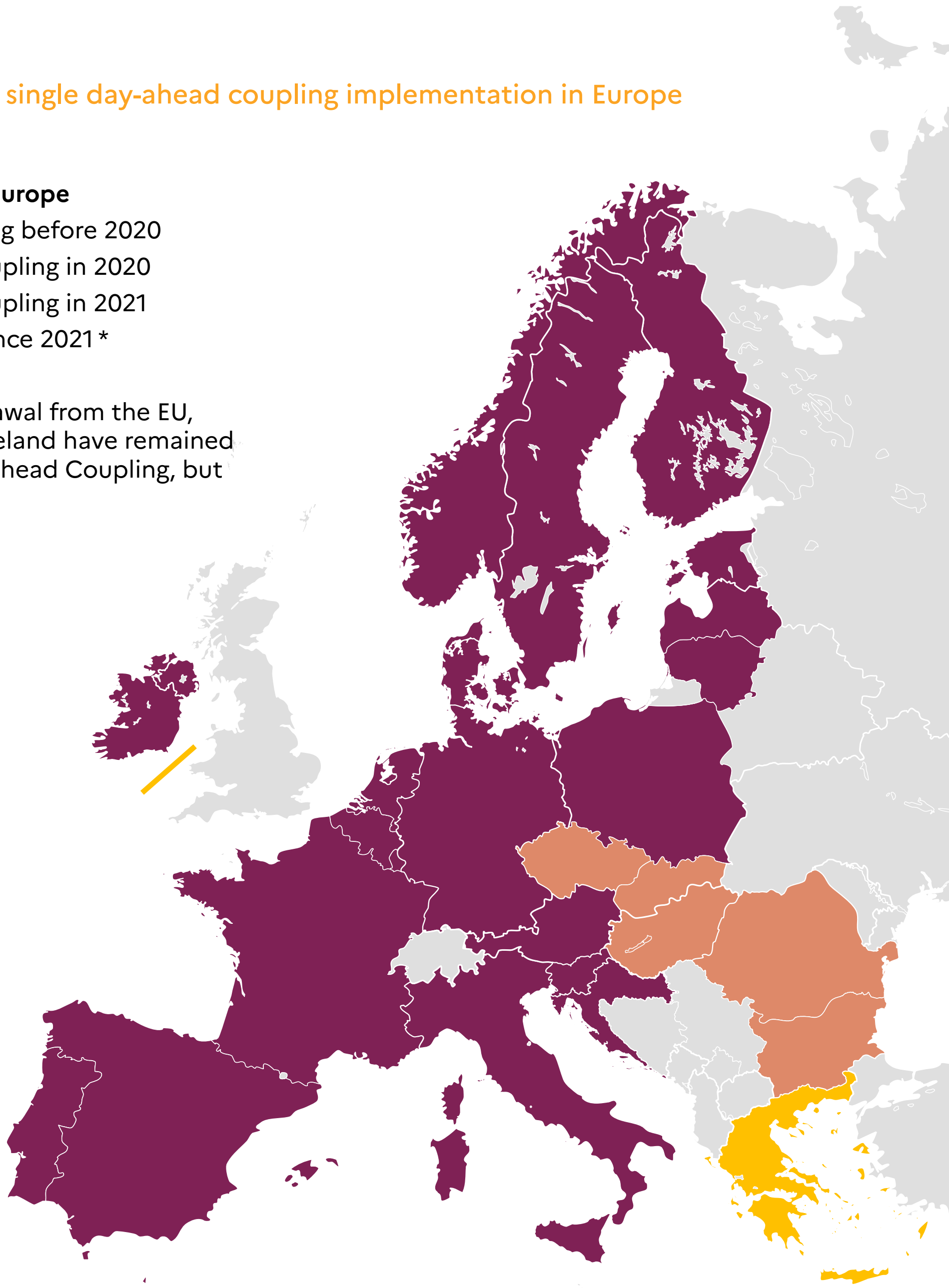
Currently, 24 Member States and Norway participate in the single day-ahead coupling. Greece joined in December 2020 and the Czech Republic, Hungary, Romania and Slovakia, which had been part of a separate coupling region since 2014, joined in June 2021.

Figure 18 Map of the single day-ahead coupling implementation in Europe

Day-ahead coupling in Europe

- Participate in coupling before 2020
- Integrated to the coupling in 2020
- Integrated to the coupling in 2021
- Isolated operation since 2021 *

* Since the UK's withdrawal from the EU, Ireland and Northern Ireland have remained part of the Single Day-Ahead Coupling, but operate in isolation.



Source: CRE

Since 2015, all French borders with EU countries have thus been in the European day-ahead coupling.

Future developments in capacity calculation and allocation will have to be carried out while ensuring that the EUPHEMIA single day-ahead coupling algorithm runs smoothly in a time window constrained by an increasing number of data and parameters. In particular, the switch from day-ahead products with an hourly granularity to products with a 15-minute granularity, to be implemented by 1st January 2025, constitutes a technical challenge that must be met without limiting or restricting the algorithm's functionalities.

ZOOM N° 3

The benefits of market coupling in the EU

The European electricity market design is based on a group of bidding zones, most often corresponding to the territories of different Member States, linked together by interconnectors. On a daily basis, a single day-ahead electricity price emerges, for each hour of the day and for each bidding zone, as a result of the matching of supply and demand on the power exchanges through the day-ahead market.

The efficiency of the internal electricity market stems from the optimised use of interconnections allowed by European rules. Interconnections help minimising production costs on a European scale by applying the principle that between two bidding zones (1) interconnection capacity is always used to export electricity from the cheapest zone to the most expensive one[32] and (2) all available capacity is used whenever there is a price spread between two zones. This optimisation is automatically achieved using an algorithm that jointly optimises supply, demand and interconnection capacity. In this case, the allocation of capacity is called implicit.

The benefits of the implicit allocation of interconnection capacity

There are two methods for allocating interconnection capacity. In the first method, TSOs commercialise interconnection capacity via an auction mechanism ("explicit" allocation). The capacity holder then decides whether or not to use it to trade electricity from one zone to another. In this case, cross-border trades are based on the individual arbitrages made by all the market participants who own physical transmission rights. Each market player assesses whether it is more valuable to make a transaction locally, or whether it is more profitable to do so in a neighbouring zone using an interconnector.

These complex arbitrages, which are based on price forecasts, can lead to a sub-optimal use of interconnections, such as (1) electricity flows in the opposite direction to prices or (2) underutilised capacity despite a price spread between two zones. Allocations are explicit at the United Kingdom and Switzerland borders.

The single European day-ahead coupling mechanism solves this problem by simultaneously determining the prices and volumes of electricity trades between zones, so as to activate the cheapest generation resources needed to meet demand on a European scale, while taking account of interconnection capacity limits.

This is made possible by the second allocation method, known as "implicit": the market coupling mechanism implicitly allocates interconnection capacity to the most efficient cross-border electricity transactions, in a completely automatic way for market participants.

32. In the case of regions with a flow-based allocation, as it is the case for the Core region, exceptions to this principle can occur with so-called "non-intuitive" flows.

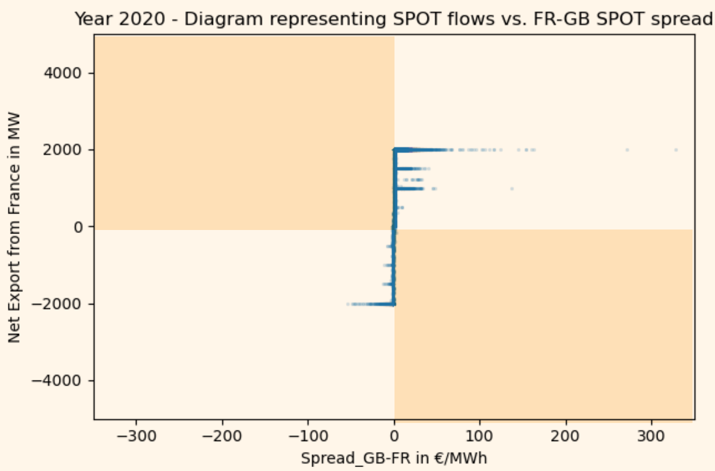
The France-UK border shows the added-value of the EU market coupling

The France-UK border can be used to compare the respective efficiencies of using interconnections under the single day-ahead market coupling and under an explicit allocation mechanism.

Until 1st January 2021, the UK was part of the common electricity market and therefore participated in the single day-ahead coupling. Its interconnection capacity with France, of up to 2,000 MW (sometimes reduced in the event of damage or maintenance), was allocated implicitly.

In 2020, as shown in Figure 19, when prices were lower in France than in the UK, i.e. when "spread_GB-FR" was positive, 100% of the interconnection capacity was used for commercial flows from France to the UK while no flows from the UK to France were observed. The opposite occurred when prices were higher in France than in the UK. This can be seen in the Figure by the presence of a "straight S" shape. Several levels can be observed on the vertical axis formed by the "S", representing cases where the maximum available interconnection capacity was less than 2,000 MW, but was still fully utilised.

Figure 19 Representation of oriented trade flows (import/export) on the France-UK border as a function of the day-ahead price spread between France and the UK in 2020 (coupled border)

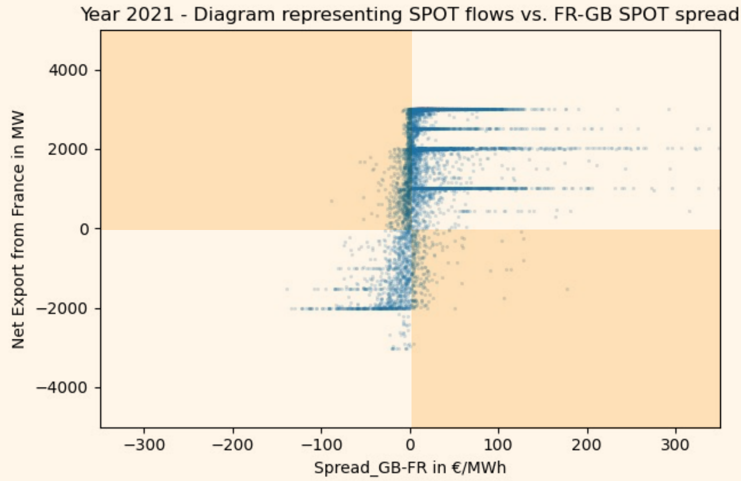


Source: RTE, ENTSO-E and EPEX SPOT data, CRE analysis

Since Brexit, capacity allocation has been explicit. Market participants buy capacity individually through auctions for all timeframes, based on their expectations and needs. With this system, cross-border trades are therefore based on price forecasts that may prove to be incorrect and may lead to flows in the opposite direction to the price spread.

As shown in Figure 20, in 2021 there were many cases where flows at the France-UK border did not go from the cheapest to the most expensive zone (1), or where interconnection capacity was not fully used despite the existence of a price spread (2). This can be seen in the Figure by the cloud of points around the central axis. Many points indicating a price spread in one direction while the flow was in the opposite direction can be observed (orange area in the Figure).

Figure 20 Representation of oriented trade flows (import/export) on the France-UK border as a function of the day-ahead price spread between France and the UK in 2021 (coupled border)



Source: RTE, ENTSO-E and EPEX SPOT data, CRE analysis

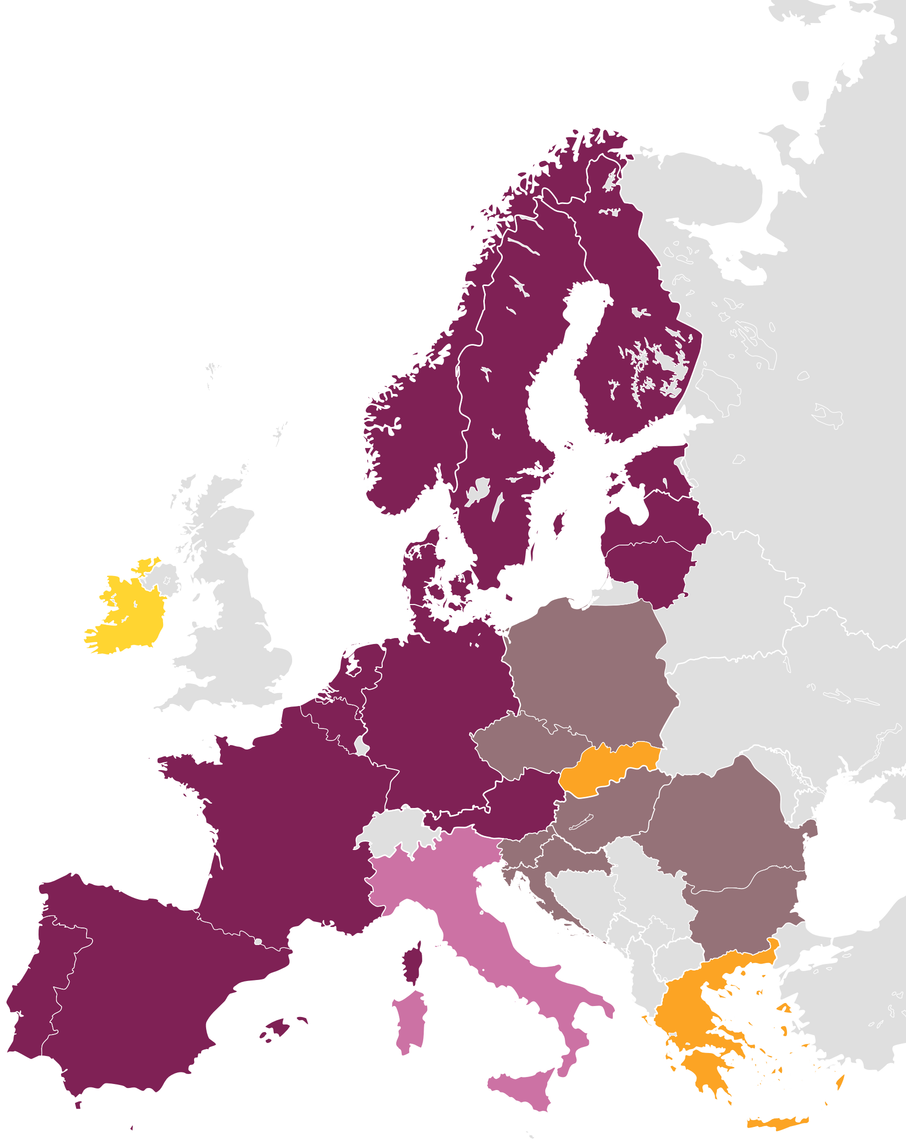
The example of the France-UK border illustrates the economic benefits of the single European day-ahead coupling. The sole cost for the system related to the presence of flows in the "non-economic direction" (flows from the most expensive zone to the cheapest one, as indicated by points located in the orange zone in Figure 20 for the year 2021) is estimated at around a dozen million euros a year for this border alone over the last few years (around €6 million in 2021, €20 million in 2022 and €11 million in 2023). On top of this cost, one should add the opportunity cost for the system for not having used all the available capacity in the economic direction.

With Switzerland, cross-border trades are mainly based on historical long-term contracts which benefit from unrestricted access to interconnection capacity. The freedom given to these market participants to use capacity based on their contractual commitments is an obstacle to the full use of interconnection capacity, unlike what is achieved under the EU model. On average, 70% of interconnection capacity is used, and sometimes in the opposite direction to price spreads.

European intraday coupling

The European project for the implicit allocation of intraday cross-border capacity, known as XBID, allows market participants to engage in cross-border energy trades from the day before the delivery until one hour before the delivery, provided there is capacity available on the interconnections. Thanks to this continuous trading platform, market participants can react to changes affecting the market in real time and adjust their positions accordingly. Since Italy joined the XBID project in September 2021, all EU French borders have been included in the project. In the future, XBID will be able to manage flow-based parameters in order to make the best use of the results of the day-ahead flow-based capacity calculations (for the moment, extractions are made from flow-based domains in order to convert them into NTC data).

Figure 21 Map of the intraday coupling (XBID) implementation in Europe



Source : CRE

In parallel, a continuous explicit allocation mechanism remains in place at the German border. The CACM Regulation also foresees the introduction of three implicit intraday auctions to establish a price for the intraday capacity. These auctions will use the same mechanism as the single day-ahead coupling. They were introduced in June 2024.

By January 2025, the XBID continuous trading platform and the three intraday auctions will have to integrate products with a 15-minute time step, as for the single day-ahead coupling.

The specific case of the UK and Switzerland

Following the UK's withdrawal from the single day-ahead coupling on 1st January 2021 and in accordance with the Trade and Cooperation Agreement (see Box n°3), TSOs in the EU and the UK are required to work on a so-called "Multi-Region Loose Volume Coupling" solution. Implementing this approach, while preserving the proper functioning of the single European day-ahead coupling, appears to be highly complex, and would not bring to the system as a whole all the benefits that could be expected from the UK's reintegration into the single day-ahead coupling. Until such a solution is implemented, the UK conducts its day-ahead auctions independently, a few hours before the coupling, allowing market participants to react and modify their orders during the pan-European coupling at 12:00.

In the absence of a global agreement with the EU, and in accordance with the CACM Regulation, Switzerland does not participate in this coupling and carries out its day-ahead auction independently at 11:00. This allows market participants to react and modify their bids during the pan-European coupling at 12:00.

1.2.2.2 Current status of short-term capacity calculations

The capacity calculation methodologies applied to borders participating in the single European day-ahead and intraday market coupling are either pan-European or determined within the three capacity calculation regions to which France belongs since the UK's withdrawal from the European Union.

Cross-border commercial capacities can be calculated with two methods. The first approach, known as coordinated "Net Transfer Capacity" (hereinafter "NTC"), involves determining in advance a maximum trade value per border and per direction (import or export) for each hourly step. The second approach, so-called "flow-based", determines cross-border capacity dynamically by making explicit network constraints and by giving priority to those borders on which trade has the highest value. The flow-based approach does not allow cross-border capacity to be calculated in the same way as the NTC approach. It consists of calculating a range of possible cross-border trades at regional level. Actual cross-border trade levels are then determined by the market coupling algorithm underlying the European internal market, which receives as an input the orders from market participants on the power exchanges.

The CACM Regulation states that the flow-based calculation and allocation should be the target solution. However, the NTC capacity calculation may remain in force within a capacity calculation region if it has been demonstrated that the implementation of a flow-based calculation would not bring added value, for example in regions where cross-border capacity is less interdependent.

The CACM Regulation requires the implementation of day-ahead and intraday capacity calculations. Day-ahead capacity calculations were the first to be developed as they are the most important for the system. The cross-border capacity made available for intraday trades corresponds to capacity that remains after the day-ahead timeframe.

All the methodologies set out in the CACM Regulation for the capacity calculations have been adopted. Their implementation varies from one region to another.

ZOOM N° 4

CRE's approach for an effective implementation of the 70% rule

The role of making commercial interconnection capacity available by TSOs is the key element in the integration of European electricity markets in the short-term timeframe. Indeed, these capacities enable electricity trades between different bidding zones, thus giving reality to the internal electricity market.

The 2019 Electricity Regulation introduces an obligation for all European TSOs, from 1st January 2020, to guarantee that 70% of interconnection capacities is available for cross-border trade.

Although this threshold is set at 70% of the thermal capacity of a network element, it may be temporarily lower if the TSO has been granted an exemption, implements an action plan on its network or in the event of an operational safety problem on the network. CRE must therefore ensure that RTE guarantees cross-border capacity in compliance with the Electricity Regulation at the French borders belonging to the three capacity calculation regions.

The topological remedial actions, an approach to congestion management specific to France

The minimum 70% cross-border capacity threshold must be guaranteed by the TSOs both on the interconnections and on the network elements located upstream of the interconnections. TSOs must also ensure that electricity trades generated thanks to these capacities do not lead to physical congestion on these same network elements.

To do so, TSOs have access to operational tools such as redispatching and countertrading, which consist in activating generation units downwards on one side of the border and upwards on the other side to prevent any anticipated physical congestion on the network while guaranteeing the planned commercial trade. These mechanisms therefore enable to simulate an electricity transit without increasing the actual physical flow on the congested element. They induce a cost linked to the activation (upwards and downwards) of generation units.

While countertrading and redispatching are costly remedial actions, RTE also introduced a congestion management approach based on non-costly remedial actions: the topological remedial actions.

Thanks to the investments made in the French electricity network, RTE is able to modify the topology of the network and accordingly the electricity flows. This French specificity allows the network to be controlled in order to avoid congestion as much as possible, and at a lower cost. Indeed, topological remedial actions do not require any modification of the production plan, which would otherwise entail additional costs and would require the activation of generation units, most often thermal units that emit CO_2. CRE believes that topological remedial actions are essential assets that should be used more widely in the operation of the European electricity market.

The French "Smart Compliance", an incentive method that integrates the economic aspects

The literal reading of the Electricity Regulation requires the 70% threshold to be reached in all circumstances, unless if it would compromise the operational safety of the network. Therefore, meeting this threshold does not depend on economic factors. CRE considers that it is necessary to reintegrate the economic parameter into the analysis of compliance with the 70% criterion in order to incentivise TSOs to be economically efficient.

To this end, CRE has developed a so-called "Smart Compliance" method to distinguish, *a posteriori*, the two configurations for which an increase in the capacity made available for cross-border trade would not provide any added value for the European electricity system.

An interconnection that is not saturated at a border during the day-ahead market coupling reflects a situation where energy allocation has been able to take place without being constrained by interconnection capacities. This results in equal electricity prices in the two zones. Consequently, increasing the capacity made available for cross-border trade on this border would not have generated any additional value because this capacity would not have been used by the market. In this case, CRE considers that the 70% threshold is met because more capacity than the market needs has been made available for cross-border trade. It would thus not be cost-effective for the TSO to deploy costly measures to make more capacity available to the market.

The network element limiting cross-border trade may be the interconnector itself or an internal network element in one of the zones on either side of the interconnector. When no French network element limits the capacity available for cross-border trade, this capacity may nevertheless be limited by a network element on the other side of the interconnection, in the neighbouring zone. In this case, CRE considers that the 70% criterion is met, because increasing the capacity margins available on the French elements would not make additional capacity available for cross-border trade. In fact, these network elements have no influence on the interconnection capacity made available to the market. In this case too, it would not be efficient for the TSO to undertake actions to make more capacity available to the market.

The introduction of these criteria provides an appropriate incentive for TSOs to maximise the capacity made available for cross-border trade while avoiding unnecessary costs. CRE considers that these criteria should be introduced in the other European countries.

Central-Western Europe/Core region

The Central-Western Europe ("CWE") region[33] is a pioneer in electricity market integration. In this region, developments in coordinated flow-based capacity calculation were launched at the end of the 2000s on the initiative of TSOs, power exchanges and regulators. In June 2022, this region was replaced by the Core region[34], which includes 13 countries with highly interdependent networks.

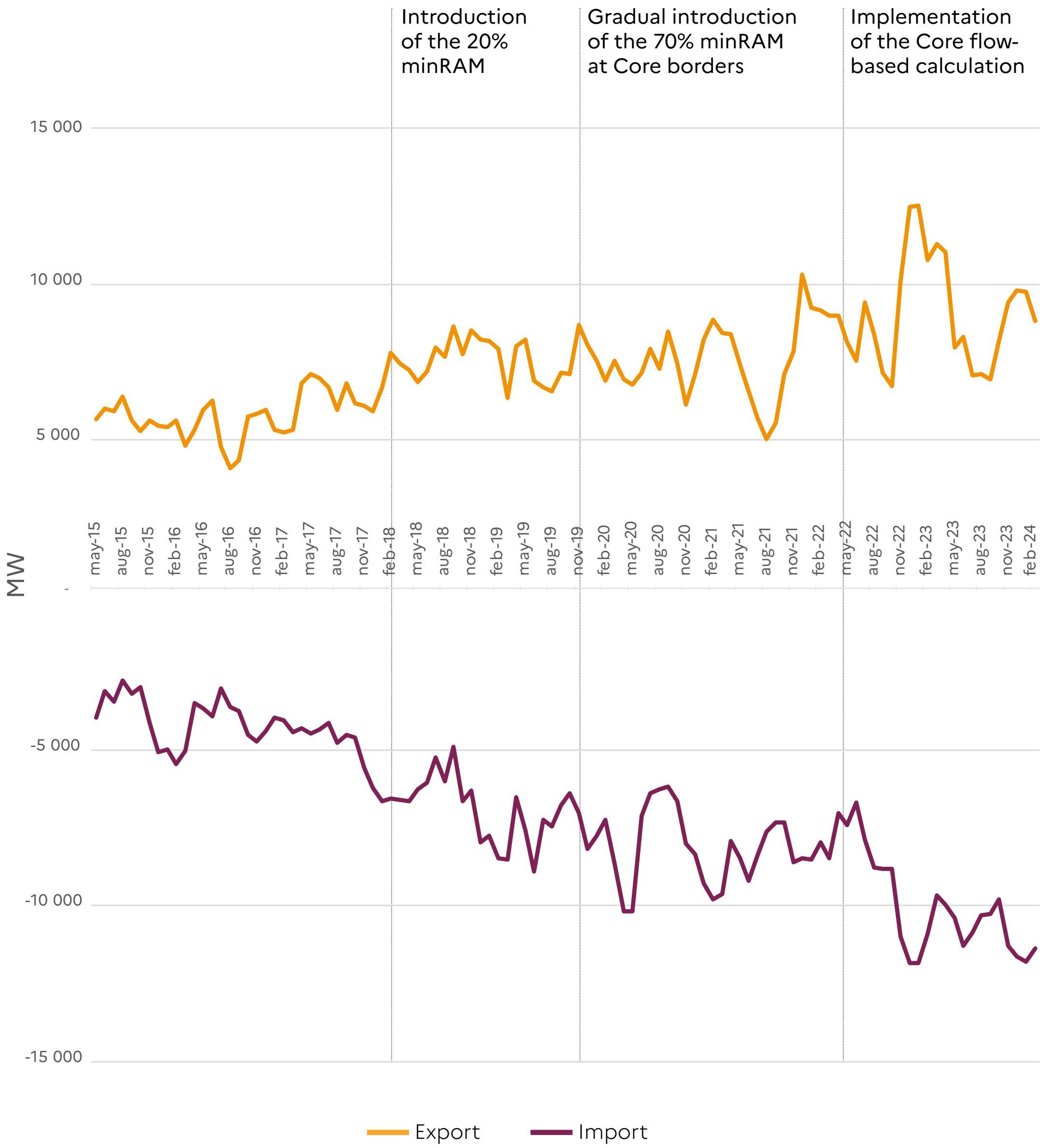
At the day-ahead timeframe, a flow-based capacity calculation was implemented in 2015 in the CWE region. This calculation method has then undergone a number of improvements, in particular to improve the modelling of network constraints and to increase the capacity available for cross-border trade.

In particular, in April 2018 the TSOs of the CWE region introduced an obligation to guarantee a threshold of 20% of capacity available for cross-border trade within the CWE region, known as "minRAM" (minimum remaining available margin). From 1 January 2020, this 20% threshold was progressively complemented by the new 70% threshold to comply with the Electricity Regulation. The 70% aims at guaranteeing at least 70% of the capacity for cross-border trades whether they are in the Core region or not (for instance, the France-Italy flows that impact the Core capacities). TSOs in the region committed to maintain the "20% minRAM" for cross-border trade within the Core region.

These evolutions have been maintained in the new day-ahead flow-based capacity calculation which has replaced the CWE calculation since June 2022. The various changes in the capacity calculation have resulted in a steady increase in capacity (enhanced by the physical network reinforcement). This is shown by the increase in France's maximum import and export positions in the CWE and Core regions observed in Figure 22.

33. The CWE region included Austria, Belgium, France, Germany, Luxembourg and the Netherlands.
34. The Core capacity calculation region includes Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia and Slovenia.

Figure 22 Monthly average of the maximum import and export positions of French borders (France-Belgium and France-Germany) in the former CWE region and then in the Core region since the introduction of the day-ahead flow-based capacity calculation in May 2015



Note: In practice, France's maximum import and export positions are never reached because they would require a situation where all the flows in the region would be oriented in such a way as to maximise France's exports or imports. Yet, they provide an interesting picture of the development of French interconnection capacity in a flow-based region.

Source: data from the TSOs of the CWE and then the Core region, CRE analysis

At the intraday timeframe, the development of a flow-based capacity calculation in the CWE region has been suspended in order to focus on the capacity calculation in the Core region. The methodology requires the development of several intraday capacity calculations to ensure that the capacity made available to the market is frequently updated. The first two intraday calculations have been operational since 28 May 2024. The first consists in the update of the day-ahead capacity calculation with the single day-ahead coupling results to determine the residual capacity remaining at 15:00 on the day before delivery (D-1). The second consists of a complete flow-based calculation before 22:00 on day D-1. Three additional calculations will then be progressively developed and implemented in the future. These will be carried out on day D, before 4:00, 10:00 and 16:00 for the remaining hours of the day.

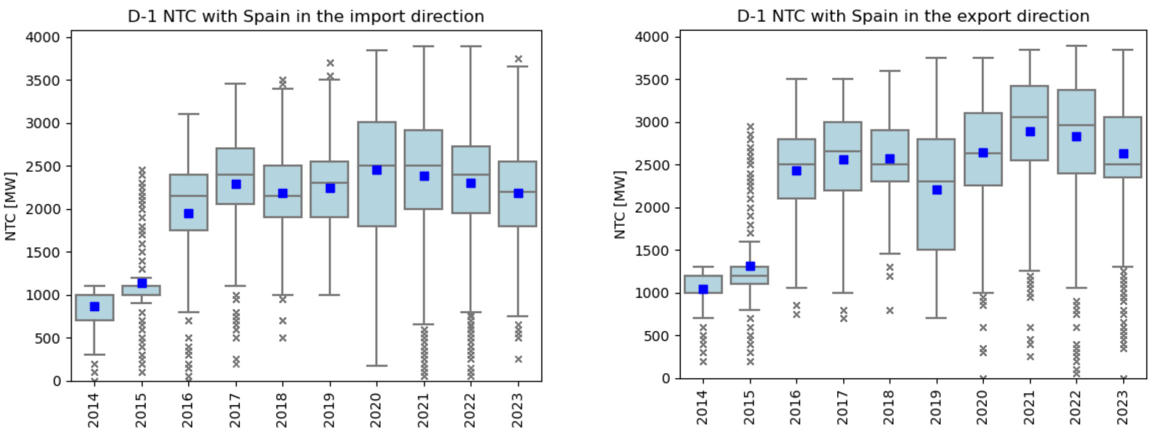
As the single intraday coupling cannot use flow-based capacity directly for the time being, an additional step is performed in the intraday capacity calculations to convert flow-based capacity into NTC capacity.

Historically, the French internal network has imposed very few limitations on the capacity made available at the border with Belgium and Germany. It is important for the effective functioning of the internal market that this remains the case. CRE pays particular attention to this issue during the development and implementation of Core capacity calculation methodologies at the day-ahead and intraday timeframes (calculation parameters, network elements considered, capacity reduction applied) as well as to the results of these calculations.

South-West Europe region

At the end of January 2020, the South-West Europe ("SWE") capacity calculation region introduced a coordinated day-ahead capacity calculation whose methodology had been approved by CRE in November 2018. The calculation, initially carried out for four hourly time steps, was extended to six hourly time steps in May 2020. Simulations carried out by the TSOs between July 2019 and January 2020 showed that the coordinated capacity calculation resulted in an average increase of around one hundred megawatts at the France-Spain border compared to the weekly analyses. These estimates are confirmed by the results of the capacity calculation since its implementation at the end of January 2020. In fact, in the period 2020-2021, the results of the capacity calculation in both the import and export directions tended to be higher than the values observed in previous years, excluding exceptional one-off events (see Figure 23).

Figure 23 Box plot representing commercial capacity resulting from the day-ahead capacity calculation in the import (left) and export (right) directions from the French point of view at the Spanish border



READING: The central line represents the median capacity observed over the period, while the lower and upper ends of the blue boxes represent the first and third quartiles respectively. The blue dots represent the average values calculated over the corresponding period.

Source: RTE data, CRE analysis

However, from 2021 onwards, a downward trend can be observed in the capacities made available at the day-ahead timeframe in both directions. Although this can be partly explained by several circumstantial factors (unavailability of network elements, redirection of flows), this phenomenon nevertheless reflects the increasing complexity in managing this border, which is experiencing an east-west imbalance between import flows passing on either side of the Pyrenees. This imbalance is driven by the presence, on the Spanish side, of two nearby areas with contrasting profiles: on the one hand, an area west the Pyrenees with strong wind power capacity that is a major producer of electricity, and on the other hand, an area east of the Pyrenees that is rather a consumer region with the influence of the city of Barcelona. Several approaches are being considered to offset this phenomenon. RTE anticipates that the development of the new Bay of Biscay electricity interconnector to the west should partially solve this problem.

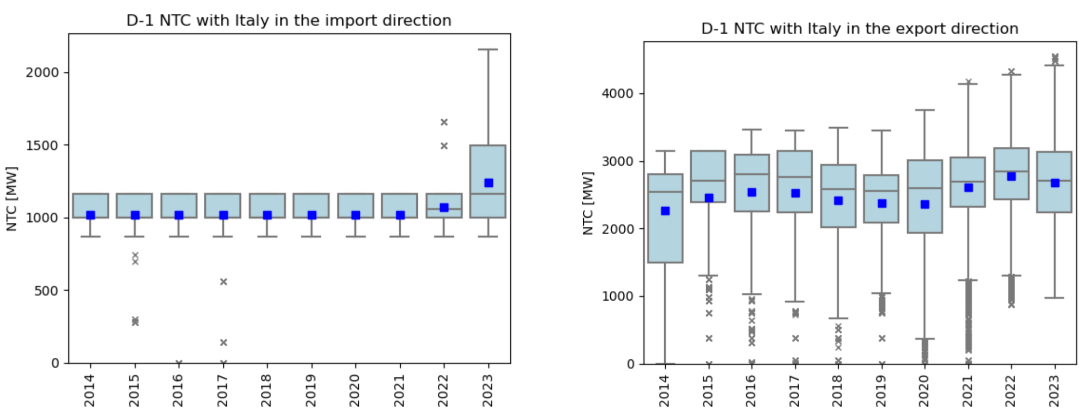
For the intraday timeframe, a first coordinated capacity calculation carried out in the evening for all 24 hours of the following day was successfully introduced in March 2022. A second calculation intended to update this capacity during the morning for the second half of the day (12:00 – 00:00) is scheduled for early 2025.

Italy North Region

The day-ahead and intraday capacity calculations within the Italy North Region were initially developed only in the export direction to Italy. This is because Italy has a central position in this region and is structurally an importer.

At the day-ahead timeframe, the coordinated capacity calculation, in place since 2016, has been improved as part of the implementation of the CACM Regulation, with the approval of a new methodology in 2020. In view of the increasing likelihood of export flows from Italy, the new methodology includes the introduction of a day-ahead capacity calculation in the direction of export from Italy (ie. in the import direction from the French point of view). Initially scheduled for September 2020 and then postponed on several occasions, this calculation was finally implemented in June 2024.

Figure 24 Box plot representing commercial capacity resulting from the day-ahead capacity calculation in the import (left) and export (right) directions from the French point of view at the Italian border



READING: The central line represents the median capacity observed over the period, while the lower and upper ends of the blue boxes represent the first and third quartiles respectively. The blue dots represent the average values calculated over the corresponding period.

Source: RTE data, CRE analysis

At the end of 2021, a validation mechanism has been added to the day-ahead capacity calculation to enable the 70% threshold of available capacity for cross-border trade to be reached, using countertrading if necessary to then ensure network security in real time.

At the intraday timeframe, an initial calculation covering only the end of the day (16:00–00:00) was introduced in October 2019. It was extended in February 2021 to cover the entire second half of the day (12:00–00:00). A second capacity calculation carried out in the evening and covering all the hours of the following day is also planned, but its implementation is pending. The development of the "Export Corner" functionality, which enables to address cases where Italy is not an importer on all of its northern borders, was successfully implemented at the end of November 2023.

The UK border

With the withdrawal of the UK from the EU on 1st January 2021, the calculation of interconnection capacity at the France-UK border is not coordinated. The capacity offered corresponds to the minimum of the values calculated by each TSO. Nevertheless, given the specific nature of the region, and in particular the fact that all the interconnectors use direct current technology, all their physical capacity is offered to the market, after any adjustments for unavailability. The Trade and Cooperation Agreement (see Box n°3) foresees the eventual development of a coordinated day-ahead capacity calculation.

The Switzerland border

As Switzerland is not part of the EU, it is not involved in the capacity calculation regions. Therefore, there is no coordinated day-ahead capacity calculation at the France-Switzerland border. The capacity made available to the market corresponds to the minimum of the values calculated by each TSO. However, as the Swiss network is highly interdependent with the networks of its EU neighbours, the Swiss network has a strong impact on the capacity calculations carried out in the Core and Italy North regions. In order to better take these constraints into account, an agreement was signed in 2021 between the TSOs of the Italy North region and the Swiss TSO, granting the latter the status of "technical counterparty". This allows the Swiss TSO to be involved in the capacity calculation process. This agreement must be renewed annually. A similar agreement is currently being prepared between the TSOs of the Core region and the Swiss TSO to establish a coordinated capacity calculation on Switzerland's northern borders (Germany, Austria and France). This calculation will include a joint validation step with the Core region to ensure that the results of the capacity calculations are compatible.

1.2.3 Balancing timeframe

Close to real time, TSOs are responsible for balancing the electricity system, and are in charge of ensuring the balance between consumption and production at all times. The functioning of the various balancing markets is governed by Regulation (EU) 2017/2195 on electricity balancing, known as the "EB Regulation"[35],, which came into force in 2017. This Regulation aims to strengthen the European integration of balancing markets, in particular with regard to the trade of balancing energy in real-time and imbalance settlement.

1.2.3.1 The functioning and the role of interconnections at the balancing timeframe

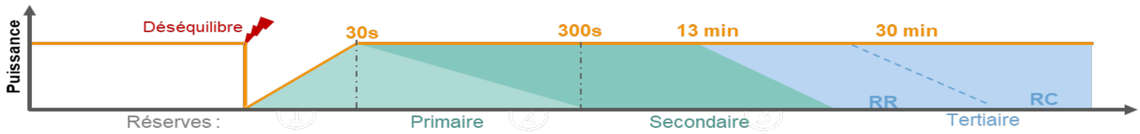
As European countries are interconnected within a single electricity system, an imbalance in one TSO's zone is immediately reflected in a frequency variation across the entire continental European network. Concretely, a decline in generation or a rapid increase in consumption causes generation plants to "slow down", thereby reducing the frequency of the network. Conversely, a drop in consumption or a sudden increase in production raises the frequency of the grid. Since electrical interconnections ensure frequency synchronisation, TSOs share responsibility for frequency quality.

To ensure network balancing, TSOs use the reserves contracted before real-time with producers, consumers or storage operators, who can vary their power injections or withdrawals. In real time, rapid action to limit frequency variations is taken simultaneously by all TSOs, irrespective of the origin of the initial imbalance: the automatic frequency containment reserve (FCR) fulfils this role. Then, in a second phase, it is up to the TSO of the zone in which the imbalance occurred to "compensate" for the energy deficit or surplus in its zone. This is done by activating the automatic frequency restoration reserve (aFRR), the manual frequency restoration reserve (mFRR) and the replacement reserve (RR).

In this context, interconnections enable RTE and the other European TSOs to trade balancing capacity or energy when it is economically relevant, thereby reducing the balancing costs borne by network users.

35. Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

Figure 25 Schematic diagram of the use of reserves in case of a network imbalance



1.2.3.2 European integration of balancing markets: overview of cross-border cooperation

The EB Regulation strengthened the European integration of balancing markets, by establishing European platforms for real-time energy activations of the automatic frequency restoration, manual frequency restoration and replacement reserves. The model adopted requires each TSO to collect the energy bids submitted by national market participants and transmit them to the activation optimisation function of the European platform, along with its energy demand and its calculation of available interconnection capacity at the borders. The European balancing platforms enable the economic optimisation of the activation of balancing reserves at European level, taking into account the trade capacities available at the interconnections. Since 2020, the three European balancing platforms provided for in the EB Regulation have become operational at European level.

Table 8 Summary of the three European balancing platforms and their implementation status

Platform	Description	Type of reserve	Launch date	TSOs connected
PICASSO	Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation	Automatic Frequency Restoration Reserve (aFRR)	June 2022	Germany, Austria, Czech Republic
MARI	Manually Activated Reserves Initiative	Manual Frequency Restoration Reserve (mFRR)	October 2022	Germany, Austria, Czech Republic
TERRE	Trans European Replacement Reserves Exchange	Replacement Reserve (RR)	January 2020	Spain, France, Italy, Portugal, Czech Republic, Switzerland

To enable European TSOs to prepare in the best possible conditions for the structural change resulting from the switch from national balancing energy markets to integrated European markets, the EB Regulation allows national regulators, at the request of a TSO, to grant exemptions from the deadlines for connection to balancing platforms. Once all European TSOs have secured connections to these various platforms, a significant increase in the use of interconnections for balancing is expected at European level.

Finally, in addition to the gradual implementation of these platforms for real-time energy activation, other previous cooperation initiatives, to which France belongs, are also contributing to the European integration of balancing markets:

– The frequency containment reserve (FCR) cooperation is a common procurement process for FCR, ahead of real time. At the end of 2023, the member countries were Austria, Germany, Belgium, Denmark, France, the Netherlands, the Czech Republic, Slovenia and Switzerland.
– The international grid control cooperation (IGCC) enables the TSOs that are members of this cooperation to compensate each other for their demands of balancing energy from aFRR, and therefore to limit activations in opposite directions on either side of an interconnection. At the end of 2023, 18 countries were members of this cooperation: Austria, Belgium, Croatia, the Czech Republic, Denmark, France, Germany, Greece, Italy, the Netherlands, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain and Switzerland.

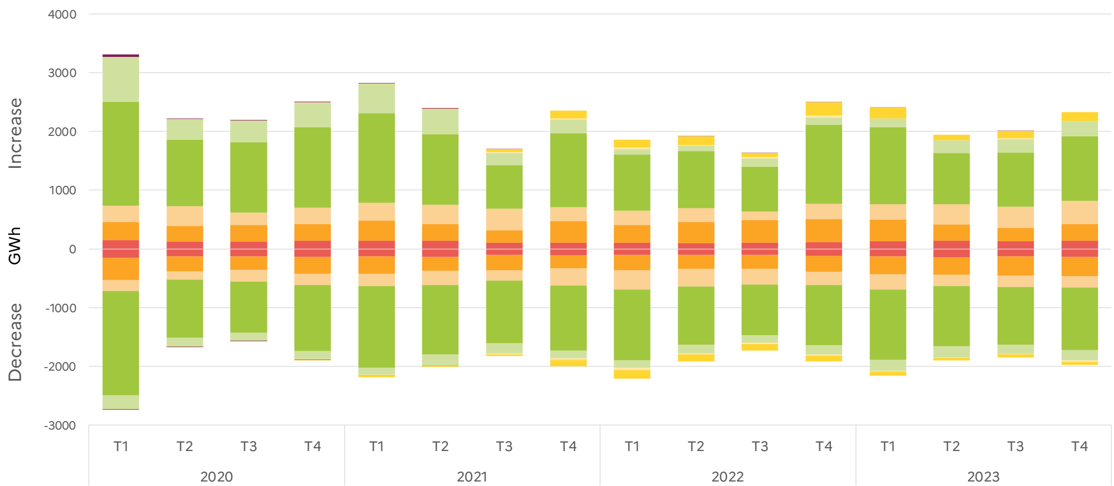
1.2.3.3 RTE fully exploits interconnections to ensure supply-demand balance in real time

Over the period 2020-2023, RTE's use of interconnections for balancing needs was carried out through the following European mechanisms:

- The "FCR cooperation", which enables RTE to contract all its FCR capacity requirements through a joint call for tenders for the 9 countries participating in the cooperation. FCR activations represent between 5 and 7% of the balancing energy supplied upwards and downwards between 2021 and 2023
- The "IGCC process" enabled RTE to avoid 48% of upward aFFR activations, and 45% of downward aFFR activations between 2021 and 2023.
- The "TERRE" platform covered 10% of mFRR upwards requirements, and 4% of mFFR downwards requirements in 2023.
- Bilateral mechanisms also enable RTE to use balancing energies located in neighbouring countries. It may be done through the activation of balancing service providers directly by RTE (for the German and Swiss borders, this is done through balancing entities known as "exchange points"), or through agreements established with other TSOs (through the "Mutual Emergency Assistance System", known as MEAS, for emergency situations, and the now obsolete "BALIT" mechanism). In 2023, the "exchange point" entities covered 23% of the upwards needs and 17% of the downward needs. The use of European balancing platforms is intended to replace these mechanisms.

Figure 26 shows the quarterly volumes activated by RTE to ensure the supply-demand balance.

Figure 26 Volumes of balancing electricity activated for RTE's upwards and downwards needs, by quarter between 2020 and 2023



NOTE: Volumes activated upwards correspond to offers activated to resolve an energy deficit in RTE's zone. These offers may be physically linked to an increase in production, a decrease in consumption or an increase in imports. Conversely, downwards offers are used to resolve an energy surplus, and are physically linked to a reduction in production or an increase in exports.

Source: RTE data, CRE analysis

The FCR cooperation

In 2017, RTE joined the "FCR cooperation", leading to cross-border procurement of FCR capacities between TSOs that are members of the cooperation. This cooperation does not require ensuring the availability of trade capacity at borders, as primary reserve energy exchanges use the safety margins provided for this purpose by the TSOs when calculating capacity. The FCR cooperation currently includes nine European countries: Austria, Germany, Belgium, Denmark, France, the Netherlands, the Czech Republic, Slovenia and Switzerland.

The purpose of the cooperation is twofold:

- On the one hand, it aims to optimise the procurement costs of this reserve by using the cheapest resources across the nine member countries through a joint cross-border call for tenders.
- On the other hand, it is intended to attract investment in new resources able to provide this type of reserve, in particular battery storage, as the cross-border call for tenders is open to all resources capable of providing primary reserve (producers, consumers, storage).

With FCR procurement costs of €34 million for RTE in 2023, the participation in the FCR cooperation enabled a significant reduction in the costs borne by the TURPE network tariff compared to the previous regulated costs of around €100 million per year. In 2022, at the height of the European crisis, these procurement costs, which amounted to €95 million, did not exceed the level of the previous regulated costs, demonstrating the robustness of this cross-border call for tenders at a time of stress for the electricity system. Thanks to these particularly competitive procurement costs, France is now Europe's leading exporter of FCR, with an average of around 130 MW of FCR exported to other member countries at each time step in 2023.

In addition, the switch from a mandatory regulated scheme to a cross-border call for tenders open to all technologies enabled the deployment of an electricity storage battery fleet to be initiated in France without public subsidy. Since the completion of the first FCR certification by RTE in early 2020, this deployment has been steady. It resulted in a total of around 600 MW of batteries certified for the FCR at the end of 2023, contributing to a significant reduction in the FCR procurement costs and an increase in FCR exports by RTE.

Cross-border cooperation on FCR procurement has therefore been a resounding success, with the two main objectives of this cooperation being achieved to the benefit of the community during the years covered by this report.

The TERRE platform

The TERRE platform is the result of a cooperation launched in 2014 by the European TSOs that use replacement reserves products to balance their zones, including RTE. All TSOs using these products must participate, in accordance with the EB Regulation.

Any balancing service provider with balancing capacity that can be mobilised in less than 30 minutes can participate, from a minimum of 1 MW. The TERRE platform allows the exchange of so-called "standard" replacement reserve (i.e. with certain predefined technical characteristics that have been harmonised between the TSOs participating in the platform), within the limits of the interconnection capacity available after the closure of intraday exchanges. The activation optimisation function performs an optimisation every hour, for the next four quarters of the following hour, to select the offers to be activated. Balancing offers are remunerated at the marginal price for the zone in which they are activated.

The platform was officially launched on 15 January 2020. By the end of 2022, 6 TSOs were connected to it. RTE has been connected since 2nd December 2020 and increased its participation throughout 2021 and early 2022. Since 21 March 2022, the initial period of operation under control has been completed and RTE has been participating in the TERRE platform on a continuous basis.

Figure 27 shows the quarterly volumes activated in France on the TERRE platform, for the needs of RTE or other TSOs, as well as the volumes imported for the needs of RTE.

Figure 27 Quarterly volumes activated by RTE and imported for RTE's needs on the TERRE platform (2020-2023)

NOTE: In this figure, French offers are considered to be activated for RTE's needs when the fulfilment of a need submitted by RTE on the TERRE platform coincides with the activation of French offers on this platform. When the volume of French offers activated is greater than the volumes satisfied for RTE's needs, the surplus is activated for the needs of other TSOs. When it is lower, the missing volume corresponds to the activation of foreign offers.

Source: RTE data, CRE analysis

The volume of French bids submitted on the TERRE platform remains limited, and the majority of French demand is met by foreign offers, whose prices are currently lower on average than those of French players' bids. On this platform, the interconnections at the French borders therefore contribute mainly to satisfying RTE's demand by importing balancing energy.

1.2.3.4 Medium-term prospects for the use of interconnections at the balancing timeframe

Several regulatory changes are expected to strengthen the role and use of interconnections in balancing markets.

In the short term, RTE's connection to the European balancing platforms for the exchange of balancing energy from the automatic frequency restoration reserve ("PICASSO" platform) and from the manual frequency restoration reserve ("MARI" platform) is planned for the end of 2024 and the end of 2025 respectively. It will complete the European integration of RTE with regard to the activation of balancing energy from these reserves. The connection to these platforms is expected to lead to significant increase in imports and exports of balancing energy is expected at the French borders, in response to imbalances observed on the national grid or on the grids of other European countries.

In the medium term, the implementation by the European TSOs of methodologies for calculating the cross-border capacity that can be made available to the balancing markets (on the model of the coordinated calculations already implemented for longer-term timeframes), will refine the TSOs' vision of the interconnection capacity that can be made available to the European balancing platform. It may lead to an increase in cross-border exchanges. CRE approved coordinated capacity calculation methodologies for the balancing timeframe for each of the capacity calculation regions in which RTE participates (approval of the SWE methodology in July 2023, the Italy North methodology in December 2023, and the Core methodology in May 2024).

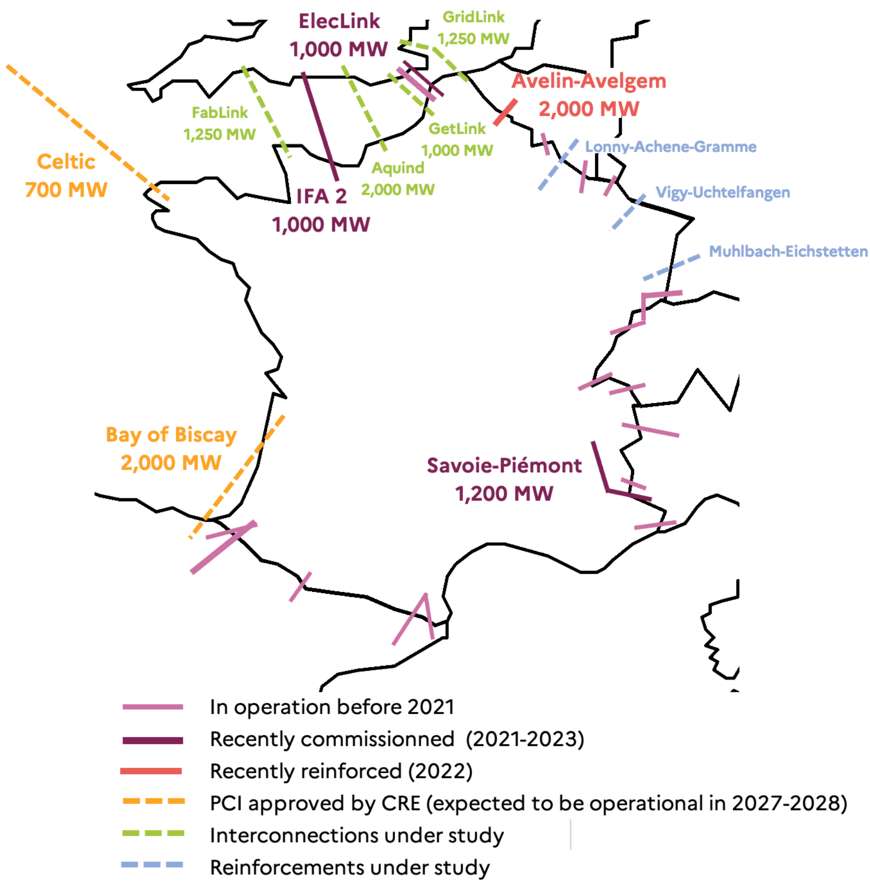
In the long term, the implementation of new cross-border cooperation cooperations for the procurement of balancing capacity ahead of real time, based on the FCR cooperation model, would be considered with a view to optimising the procurement costs of the automatic frequency restoration, manual frequency restoration, or replacement reserves, which are borne by consumers *via* the network tariff (TURPE). The EB Regulation allows European TSOs to implement this type of cooperation on a voluntary basis.

1.3. Recent and future development of electricity interconnections at the French borders

Since its creation, CRE has been fully committed to the development of new cross-border electricity interconnections, in favour of greater European integration of national energy systems for the benefit of end consumers. Over the period 2020-2023, France has seen its cross-border capacity increase by 4.7 GW, with the commissioning of three new electricity interconnections: 2 GW with Great Britain (IFA 2 and ElecLink) and 1.2 GW with Italy (Savoie-Piémont), and the reinforcement of the existing Avelin-Avelgem interconnection, coupled with the reinforcement of the Aubange-Moulaine axis, which will increase cross-border capacity with Belgium by 1.5 GW.

CRE also approved two other projects of common interest (PCI), with Spain (Bay of Biscay, 2 GW) and Ireland (Celtic, 0.7 MW), for a total of 2.7 GW.

Figure 28 Recent and future developments in electricity interconnections at France's borders



Source: CRE

In its ten-year network development plan (*Schéma décennal de développement du réseau, SDDR*) published in 2019, RTE planned to double interconnection capacity by 2035. New interconnections are costly and complex projects, frequently requiring internal network reinforcements and at a total cost often more than one billion euros. CRE has welcomed the sequencing of interconnection projects proposed by RTE, which gives priority to the most mature projects with the greatest benefits[36]. The "package" approach ensures the financial and industrial sustainability as well as the social and environmental acceptability of these projects.

Projects for new interconnections are presented by RTE and approved by CRE. CRE has a dual role:

- It ensures that the project is profitable, according to cost-benefit analyses based on robust and prudent long-term scenarios. CRE analyses profitability at both French and European levels.
- Together with the other regulator concerned, it defines the rules for sharing interconnection development costs.

CRE therefore takes every precaution to ensure that new interconnections do not result in uncovered costs that would ultimately be passed on to the network tariff (TURPE), as has been the case to date.

1.3.1 Electricity interconnectors recently commissioned or under development

1.3.1.1 Completion of the Savoie-Piémont interconnector at the Italian border

The Savoie-Piémont direct current interconnector (1.2 GW) has been a project of common interest (PCI) since 2013. It was commissioned at half capacity at the end of November 2022 and then at full capacity in the third quarter of 2023. The project has encountered scheduling difficulties due to the COVID-19 pandemic and various technical problems relating to the design, construction and commissioning of the converter stations. Using the Fréjus tunnel, this 190 km cable will increase the cross-border capacity between France and Italy by 40% and bring it up to 4,450 MW in the export direction.

In France, the two links are owned and managed by RTE. In Italy, an initial 350 MW section of the interconnector has been granted a ten-year derogation from the rules on ownership unbundling[37] and the use of congestion income, in accordance with EU Electricity Regulation 714/2009. This will enable Italian large industrial consumers to finance part of the project. A second request for exemption for the remaining 250 MW section was rejected by the European Commission in its decision of 11 September 2020[38], without affecting the operation by the Italian TSO Terna.

36. CRE deliberation of 23 July 2020 examining RTE's Ten-Year Transmission Network Development Plan drawn up in 2019
37. Under ownership unbundling, an electricity or natural gas transmission network is managed by legal entities that are separate from those involved in the production or supply of electricity or natural gas.
38. Commission Decision of 11 September 2020 on the derogation in favour of Piemonte Savoia 2 S.r.l (Italy) pursuant to Article 63 of Regulation (EU) 2019/943 for an electricity interconnector between Italy and France

1.3.1.2 Progress on the Celtic and Bay of Biscay projects with Ireland and Spain

Because of its geographical position, France has an important role to play in the integration of several countries into the European market. This is particularly the case with Ireland, which has no longer been interconnected with the EU following the Brexit, and with the Iberian Peninsula. Among the interconnection projects with these countries that have been included in the European Projects of Common Interest (PCIs) (see section 1.3.2), two were approved by CRE and its counterparts: Celtic and Bay of Biscay. Cross-border cost allocation agreements were concluded for both projects, which were allocated significant subsidies by the EU. Works began on these two projects in 2023.

Celtic, the first subsea interconnector project between France and Ireland, aims to connect Ireland directly to the European electricity market by 2027. The 575 km-long cable, with a maximum physical capacity of 700 MW, will contribute to the integration of intermittent renewable energies and enhance the security of supply of both countries. Given the positive externalities generated by the interconnector and the risks associated with the project, it has received a €530.7 million grant from the European Union under the Connecting Europe Facility (CEF) programme.

Despite a significant increase in project costs, mainly due to tensions in the cable and converter station markets, the French and Irish regulators confirmed the project and updated at the end of 2022 the cross-border cost-sharing agreement initially reached in 2019[39]. The 2022 decision confirms the 2019 cross-border allocation[40], under which 65% of investment costs are allocated to Ireland and 35% to France, with additional costs shared on a 50/50 basis.

Bay of Biscay, a partly submarine interconnector project between France and Spain (2 GW), aims at bringing the physical cross-border capacity at this border to 5 GW by 2028. The project, which connects Gatica (near Bilbao) and Cubnezais (near Bordeaux), gave rise to a cross-border cost allocation decision between the French and Spanish regulators in 2017[41]. The project was also awarded a €578 million European subsidy under the CEF. Difficulties in crossing the Capbreton submarine canyon led the TSOs to revise the route. As a result of the significant increase in the project's costs, linked, as for Celtic, to tensions on the interconnection equipment markets, the French and Spanish regulators updated the cross-border cost-sharing reference for the project in 2023 to adjust it to inflation[42]. Spain will bear 62.5% of the initial additional costs and France 37.5%, with any additional costs being shared on a 50/50 basis.

39. CRE deliberation of 25 April 2019 adopting the joint decision on cross-border cost sharing for the Celtic project
40. CRE deliberation of 3 November 2022 adopting the decision reviewing the joint decision on cross-border cost allocation for the Celtic Interconnector project
41. CRE deliberation of 21 September 2017 adopting the joint decision on cross-border cost allocation for the Biscay Gulf project
42. CRE decision of 2 March 2023 amending the joint cross-border allocation decision for the Bay of Biscay project

In addition to the Bay of Biscay project, other developments have been discussed since 2015 within the high-level group on interconnections for South-West Europe. CRE considers that the various projects should be addressed in a sequential manner, with priority given to the completion of the Bay of Biscay project. At this stage, the cost-benefit analyses carried out have not demonstrated that the benefits of additional projects outweigh their costs, in particular because of the high cost of congestion on the French network, the significant need to reinforce upstream networks and the major issues of local acceptability.

1.3.1.3 Projects under study on the France-UK border

France has three interconnectors with Great Britain, with a total physical capacity of 4 GW. The IFA 2 direct current interconnector (1 GW), between Tourbe (Calvados) and Chilling (Hampshire), was commissioned on 22 January 2021. IFA 2 is jointly owned by the French transmission system operator RTE and National Grid Interconnectors (NGIC) and operates under a regulated regime. The direct current interconnector ElecLink (1 GW), connected to the same converter stations as the IFA interconnector between Les Mandarins (Pas-de-Calais) and Sellindge (Kent), started commercial trade on 25 May 2022. Using the Channel Tunnel, this interconnector had to overcome technical challenges concerning the compatibility of the electrical interconnection with the rail system. This interconnector, which is owned by the Channel Tunnel operator GetLink, was granted a partial exemption from the rules on ownership unbundling and on the use of interconnector revenues by CRE and Ofgem in 2014 for a period of 25 years[43].

Several additional interconnection projects with Great Britain are under study, although at different stages of maturity: GridLink (1.4 GW), FAB (1.4 GW) and Aquind (2 GW). CRE has also been informed of Getlink's intention to study a new interconnector project using the Channel Tunnel. With the United Kingdom's withdrawal from the European Union, these projects lost their status as Projects of Common Interest (PCIs) granted under the European Regulation on Trans-European Networks for Energy ("TEN-E Regulation"). However, they can now apply for the status of Project of Mutual Interest (PMI) with third countries created by the revised TEN-E Regulation. The reinforcement of electricity transmission capacity with Great Britain remains of interest for CRE. In 2022, CRE rejected the investment request submitted by GridLink[44], due to strong uncertainties about the economic benefits of the project, reinforced by the context of the UK's withdrawal from the EU.

CRE commissioned a new study on the opportunity of a new UK interconnector, in relation to the revision of the greenhouse gas emission reduction targets in the "Fit for 55" package and the crisis on the wholesale electricity markets in 2022 and 2023. The study, published in July 2023, highlights the possible economic interest of a new interconnection project between France and the UK of around 1 GW[45], with insufficient additional benefits beyond this capacity. The benefits of additional interconnection capacity are primarily derived from the improved

43. CRE deliberation of 28 August 2014 on the final decision on ElecLink Ltd's exemption request under article 17 of Regulation EC No. 714/2009 of 13 July 2009 for an electricity interconnector between France and Great Britain
44. CRE deliberation of 19 January 2022 deciding on the investment request submitted by GridLink Interconnector Limited
45. Public consultation no. 2024-01 of 5 March 2024 on the opportunity for new electricity interconnection capacity between France and the United Kingdom

integration of renewable energy in the UK and a reduction in the use of fossil-fired generation on a European scale. The study indicates that the benefits are significantly higher for the UK than for France, which should be reflected in the cost sharing between the two countries if a new project were to be implemented.

1.3.1.4 Other interconnection reinforcement projects under study with Germany, Belgium and Switzerland

In addition to the borders mentioned above, RTE's ten-year network development plan (SDDR) lists projects to reinforce interconnections with Germany, Belgium and Switzerland. These are considered relatively easy to carry out at limited cost.

The two reinforcement projects with Germany, which include upgrading the 225 kV interconnector between Muhlbach (Alsace) and Eichstetten (Baden) to 400 kV and reinforcing the interconnection capacity of two circuits between Vigy (Moselle) and Uchtelfangen (Sarre), were approved successively by CRE and its German counterpart[46]. These projects will increase the physical interconnection capacity at this border by 1.8 GW, with commissioning scheduled for 2030.

With Belgium, recent projects to reinforce existing interconnections (Aubange-Moulaine in 2021 and Avelin-Avelgem in 2022) have increased cross-border capacity by 1.5 GW. The Lonny-Achène-Gramme project currently under study, the last stage in a series of reinforcements scheduled to come on stream between 2030 and 2032, is showing initial positive results.

Following the commissioning of the Génissiat (France)-Verbois (Switzerland) interconnector upgrade in 2018, the strategy for increasing interconnection capacity with Switzerland is currently being defined by the TSOs concerned.

46. CRE deliberation of 23 July 2020 examining RTE's Ten-Year Transmission System Development Plan drawn up in 2019 - CRE. On 14 January 2022, the German regulator (BNetzA) approved the German TSOs' 2035 investment plan: Bundesnetzagentur - Presse - Bundesnetzagentur bestätigt Netzentwicklungsplan Strom 2021-2035.

1.3.2 European electricity infrastructures planning in time of decarbonisation

Europe's electricity infrastructures are a cornerstone for achieving the ambitious European energy and climate targets adopted in 2021 in the "Fit for 55" package. These targets include reducing greenhouse gas emissions by at least 55% by 2030 compared to 1990 and achieving climate neutrality by 2050. The massive integration of low-carbon renewable energies, the sustained electrification of energy uses as well as the need for energy independence mean that electricity networks need to be adapted and strengthened. This requires greater coordination between Member States and renewed planning of European electricity infrastructures.

Since the third energy package in 2009, the European Union has gradually developed energy infrastructure planning tools with the Ten-Year Network Development Plan (TYNDP), which is published every two years by the European Network of Transmission System Operators for Electricity (ENTSO-E). Its objective is to identify the main electricity infrastructures to be built over the decade and to ensure consistency with national plans.

The role of these non-binding plans changed in 2013 with the entry into force of Regulation (EU) 347/2013 on Trans-European Energy Networks[47] (also referred to as the TEN-E Regulation, or the Infrastructure Regulation), which provides a framework for the selection of projects of common interest (PCIs). This Regulation has made the TYNDP a decision-making tool, since only the projects included in the most recent TYNDPs are eligible for PCI status. The selection of PCIs is based on the TYNDP scenarios and cost-benefit analyses of candidate projects. These PCIs could concern infrastructures for the transport of electricity or gas, for gas storage or LNG regasification. The PCI status facilitates the implementation of projects considered as priorities by accelerating the permitting procedures.

PCI status also paves the way for sharing investment costs between Member States benefiting from the same project, and for obtaining European financial aid. The cross-border cost allocation (CBCA) mechanism, established between the regulators of the countries concerned, aims to align the financial contribution of each State with the benefits it derives from the project. The infrastructure Regulation includes the possibility of receiving a grant for studies or for work *via* the Connecting Europe Facility (CEF) mechanism, for projects that have been the subject of a CBCA decision, if they present significant positive externalities and are not commercially viable under existing market conditions and on the basis of a cost-benefit analysis.

47. Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009

Over the course of the selection campaigns for PCI, there has been a strengthening of the requirement for joint planning between sectors. This is to ensure consistency and to take account of the interactions between electricity, natural gas and, in the future, hydrogen. Since the TYNDP 2020, this has resulted in a joint scenario planning exercise for ENTSO-E and its gas equivalent ENTSO-G. Furthermore, the decentralisation of the electricity system brought about by the development of renewable energies requires closer coordination between TSOs and distribution system operators in infrastructure planning.

The list of PCI projects is adopted every two years by the European Commission, based on lists drawn up by regional groups made up of representatives of the Member States, regulators, TSOs, the Commission, ACER and ENTSOs[48].

The TEN-E Regulation has enabled to significantly increase interconnection between Member States. Its revision, completed in May 2022, intends to bring the selection of projects of common interest more closely into line with the Green Deal for achieving carbon neutrality by 2050. This is set out by the European Commission in three complementary sectoral strategies: energy system integration [49], hydrogen[50] and offshore renewable energies[51].

In parallel with the publication of the first selection list of PCIs and PMIs in November 2023, adopted under the revised infrastructure Regulation[52], the European Commission presented a European Union action plan for networks[53] to achieve the 2030 European decarbonisation targets. This plan is structured around three areas: long-term investments planning, acceleration of network deployment and better use of existing networks.

48. The fifth and final PCI list developed under Regulation (EU) 347/2013 was approved on 19 November 2021. Commission Delegated Regulation (EU) 2022/564 of 19 November 2021 amending Regulation (EU) No 347/2013 of the European Parliament and of the Council as regards the list of projects of common interest

49. Communication COM(2020) 299 final of 8 July 2020, "Powering a climate-neutral economy: An EU Strategy for Energy System Integration"

50. Communication COM(2020) 301 final of 8 July 2020, "A hydrogen strategy for a climate-neutral Europe".

51. Communication COM(2020) 741 final of 19 November 2020, "An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future".

52. Commission Delegated Regulation (EU) 2024/1041 of 28 November 2023 amending Regulation (EU) 2022/869 of the European Parliament and of the Council as regards the Union list of projects of common interest and projects of mutual interest

53. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions : Grids, the missing link - An EU Action Plan for Grids

BOX N° 5

Revision of the European Regulation on Trans-European energy networks (TEN-E)

The revision of the Trans-European Energy Networks Regulation (TEN-E Regulation), which came into force in 2022[54], introduced three major changes to adapt the development of cross-border energy infrastructures to European decarbonisation objectives.

Firstly, the categories of infrastructure projects eligible for PCI status have been reviewed, with the removal of natural gas transport and storage infrastructure (except for gas projects on the 5th PCI list, which include projects to convert to hydrogen transport and storage and interconnections in Malta and Cyprus). In addition, new categories of eligible projects have been introduced to promote the development of low-carbon and renewable energies, including electrolysers, hydrogen transport and storage infrastructure, offshore electricity networks, and smart gas grids. The categories of electricity and carbon dioxide transport and smart electricity grids have been maintained. Alongside these priority areas, the TEN-E Regulation defines eleven priority geographical corridors and as many regional groups to work together to achieve the European energy policy objectives. France belongs to five corridors: one for electricity, three for offshore energy networks and one for hydrogen (see Figure 29 below).

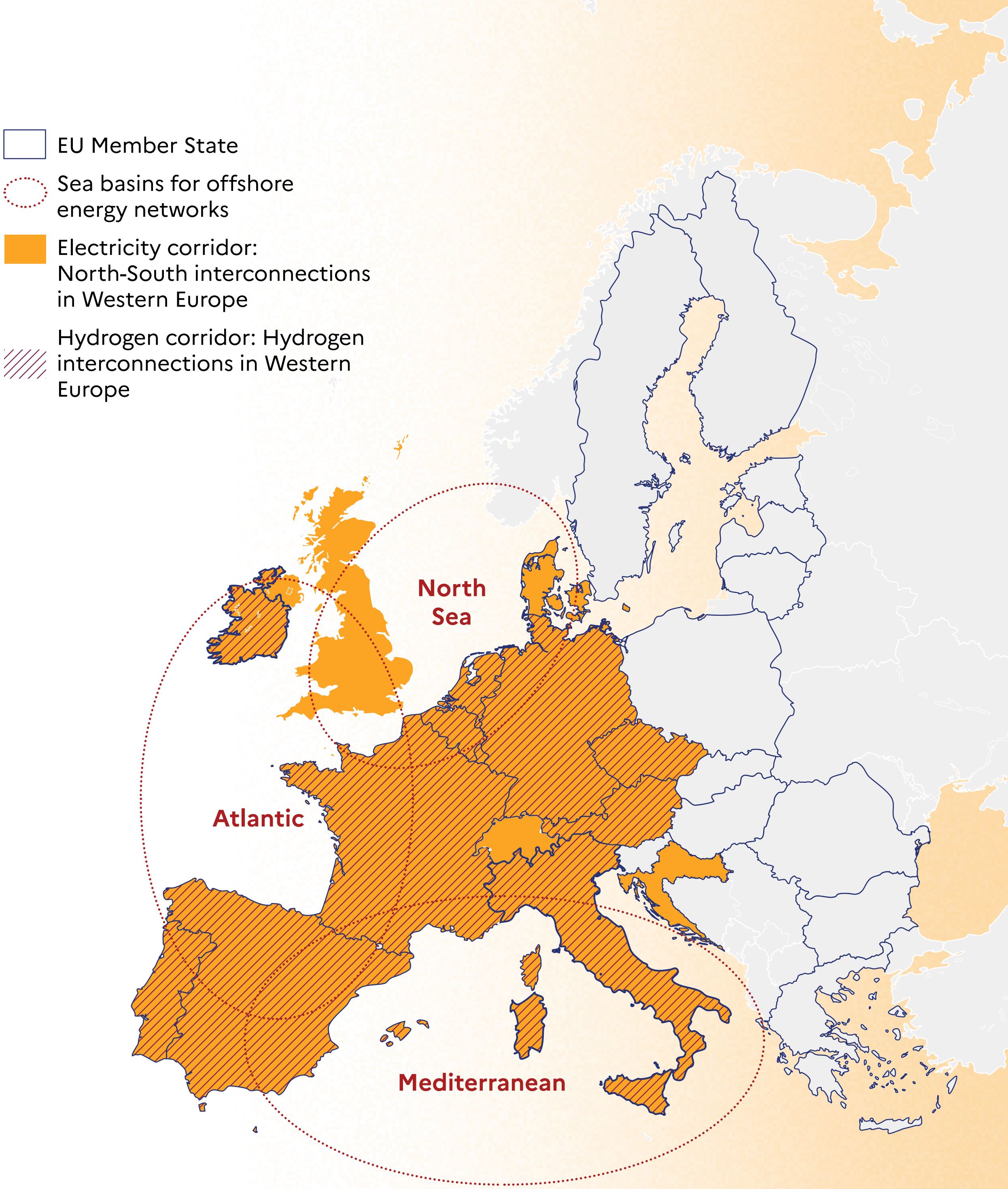
Secondly, the revised TEN-E Regulation introduces the concept of Projects of Mutual Interest (PMIs) to provide a framework for cross-border infrastructure projects partly located on the territory of a third country, outside the European Union. Although they follow the same procedure as PCIs, they differ in certain respects: PMIs must be backed by a letter of support from the governments concerned, make a significant contribution to the EU's climate and energy objectives and present a positive cost-benefit analysis at EU level. The third country's legal framework must also show a high degree of convergence with that of the EU. PMIs will be eligible for European subsidies in the same way as PCIs.

Finally, the revised TEN-E Regulation establishes a dedicated framework for offshore networks. This framework first involves the Member States, which have to conclude non-binding cooperation agreements on offshore renewable energy production targets by 2050. Then, it involves the TSOs (via ENTSO-E), which must develop planning tools dedicated to offshore networks (Offshore Network Development Plans, ONDPs). The purpose of these ONDPs is to provide a high-level outlook on offshore network needs resulting from the potential for offshore generation capacity, in terms of both connections and sector coupling. Lastly, the Regulation entrusts the European Commission the task to publish guidelines on cost-benefit analysis and cross-border

54. Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013

Figure 29

Map of priority electricity and hydrogen corridors to which France belongs



Source : CRE

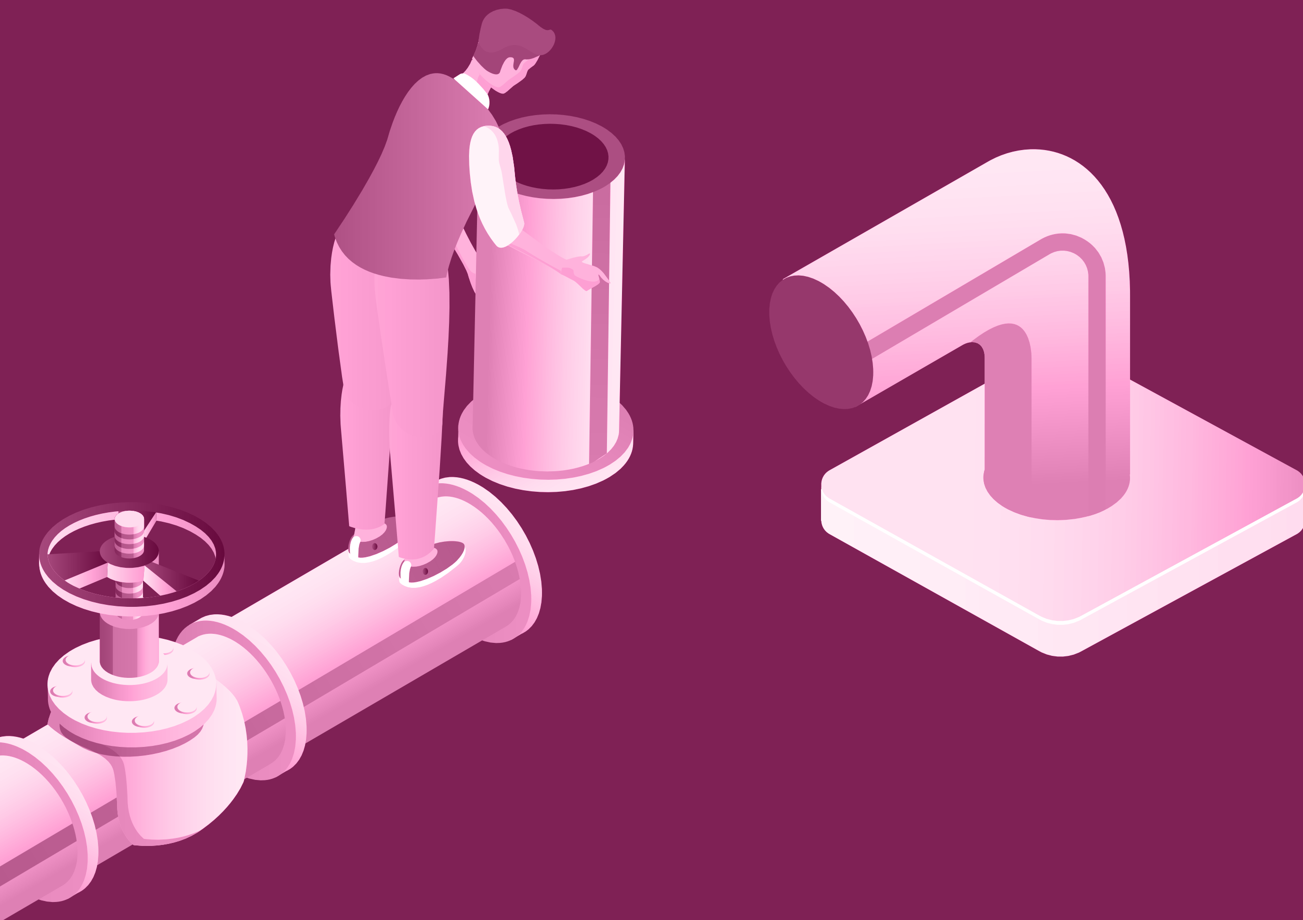
cost-sharing to encourage the development of offshore renewable energies, in particular "hybrid" projects, i.e. offshore infrastructures connecting offshore production facilities to several Member States *via* interconnections.

The eligibility criteria on which the project selection process is based, such as cross-border impact and contribution to EU energy policy objectives (security of supply, integration of the internal market), changed only marginally. In line with the decarbonisation objective, the assessment of the sustainability criterion, previously optional, became mandatory. CRE will pay particular attention to assessing the cost-benefit analysis methodologies proposed by the ENTSOs to guarantee robust criteria and a uniform comparison of projects.

Regarding the assessment of investment requests, the regulators retained their powers over the scope of investment costs to be included in network tariffs, the need for joint appeal to ACER in the event of disagreement, and the possibility of joint rejection of an investment request, which may be the subject of ACER guidelines. Investment requests made by project promoters must be based at least on the joint scenarios developed by the ENTSOs and must be made when the project is ready to start construction within 36 months. The Regulation also requires the involvement of a scientific committee on climate change and enhanced stakeholder consultation.

Since the adoption of the infrastructure Regulation in 2013, CRE has adopted four CBCA agreements: two in electricity (Bay of Biscay, Celtic) and two in gas (Val de Saône pipeline with Spain in 2014, L-gas to H-gas conversion process with Belgium in 2018). CRE's experience shows that the selection of interconnection projects as projects of common interest can only be conceived as a presumption of utility. Only in-depth analyses can lead to a joint decision on cross-border cost-sharing, which must be based on an assessment of the sufficient maturity of a project and contrasting scenarios for the future needs of the energy system. In this respect, CRE rejected in 2019, along with its Spanish counterpart, an investment request for the STEP gas project due to a lack of maturity.

In general, when making a decision on an interconnection project, CRE focuses on the economic performance of the project, by conducting systematic cost-benefit analyses based on a range of contrasting European and French scenarios.



Chapter 2

Gas interconnections and cross-border trade in France

SUMMARY

In 2021 and 2022, as well as during the first semester of 2023, the EU gas market experienced a historic crisis. The very sharp decrease in Russian supplies had to be compensated by a reorganisation of gas flows towards the most impacted countries and by an access to new gas supplies. Thanks to performant infrastructure, the French market proved very flexible with its capacity to receive volumes of liquefied natural gas much more significant than ever before and with its ability to modify the flow patterns towards the Northern borders, with Germany and Belgium. The regulatory choices made these past years are now time-tested: the French single market area (Trading Region France, or TRF) has facilitated gas imports from Spain and the regulated access rules to the gas storages have supported shippers' capacity bookings without public intervention, even during the height of the crisis. Key facts arising from the crisis included the commissioning of a liquefied natural gas floating storage and regasification unit (FSRU) in Le Havre, the reversal of gas flows towards Germany thanks to a network adaptation, and the import of massive volumes of American LNG which made the United States one of France's top suppliers in 2022 and 2023.

The French gas system proved to be efficient and resilient during the crisis: the storage, regasification, transmission and interconnection capacities were used to their maximum and made a significant contribution to the security of supply of the European Union.

The post-crisis period opens up a new reflection on the future of gas. The gradual decrease in gas consumption, the development of renewable and low-carbon gases and the flexibility needs that go with the decarbonisation of the electricity sector are all important workstreams for market participants, operators and regulators. A new Directive and a new Regulation were adopted by the EU during the first semester of 2024 to keep adapting the market to the energy transition and to establish a regulatory framework for the hydrogen market. A first area of work has been initiated for the revision of the EU rules for interconnection capacity allocation (CAM network code) towards more agility. The purpose is to make capacity allocation better adapted to a market that is getting more and more flexible. Another area of work will consist in setting out the rules applicable to hydrogen infrastructure, taking into account that the sector is still at an early stage of development. The crisis led the EU to renew its approach towards security of supply, and several provisions adopted in emergency have been enshrined in the EU law (storage obligations, joint gas purchasing platform).

2.1. Overview of the use of gas interconnections

2.1.1. France benefits from diversified supply sources and from a solid and flexible infrastructure

Imports played a critical role in the development of the French gas market. Algeria and the Netherlands were the first external suppliers, followed by Russia and Norway. In recent years, the number of suppliers to France has further increased. This diversity of supply sources enabled France to cope with the drop in Russian supplies, which began in 2021 and increased after the Russian invasion of Ukraine. The shortfall in gas volumes was offset by deliveries of liquefied natural gas (LNG) from the United States.

The French gas system presents a wide range of supply options and large import capacities, which offer flexible supplies. As such, France's dependence on Russia is relatively low compared with the rest of the European Union (17% of imports on average between 2010 and 2021). The almost total dependence on imports has been accompanied by the development of robust infrastructures, including underground storage facilities, which provide a high degree of stability in terms of covering the variations in demand and reacting to any unforeseen events affecting security of supply. France also has significant LNG import capacities located in the North and in the South of the country. All this infrastructure enables the French system to offer a high level of security of supply and makes it easier for market players to arbitrate between supply sources.

France has land pipeline interconnections with four countries:

— It is connected to Belgium with three physical interconnections. Two of them allow to import gas from Belgium, which either comes from the Dutch gas field of Groningen (Taisnières L) or from the North Sea (Taisnières H). The Alveringem IP is essentially dedicated to exports of non-odourised gas from the Dunkirk LNG terminal or from the Franpipe pipeline to Belgium. Since 2017, Taisnières H and Alveringem have been commercially united within the Virtualys virtual interconnection point (VIP).

— France has got one interconnection point with Germany, in Obergailbach. It has historically been the main supply route for Russian gas imports. The Obergailbach interconnection was adapted to exporting gas to Germany as from October 2022 (see Box n° 7).

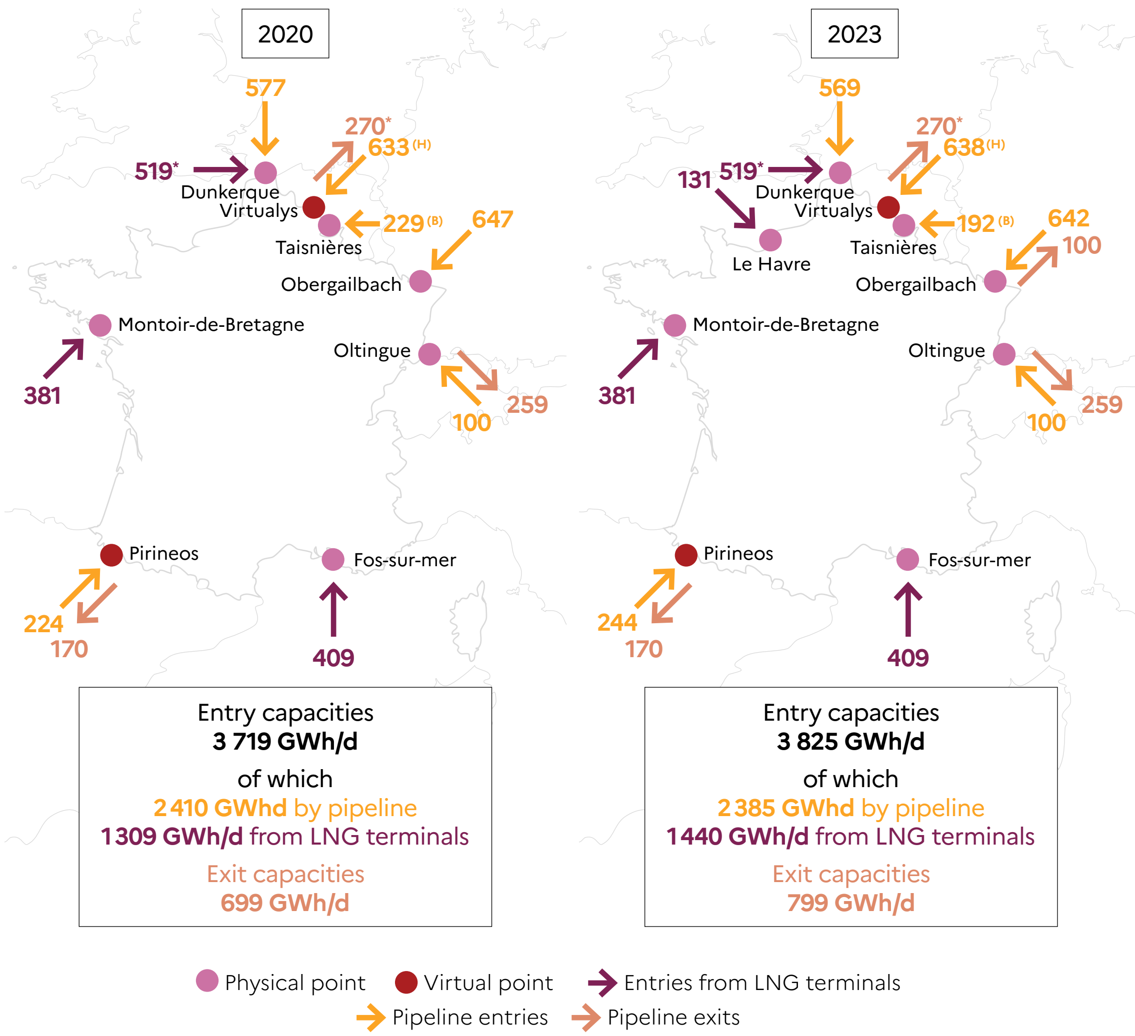
— With Switzerland, the Oltingue interconnection point allows for bidirectional flows. It is mainly dedicated to exchanges with Italy.

— France has two interconnections with Spain, at Larrau and Biriatou. Both interconnections can work in both directions. Commercially, they are grouped within the Pirineos virtual interconnection point.

France is also directly connected to the gas fields located in the Norwegian North Sea with the 840-kilometre-long undersea Franpipe pipeline landing in Dunkirk, that was commissioned in October 1998.

France has four onshore LNG terminals: Fos-Tonkin, Fos-Cavaou, Montoir-de-Bretagne and Dunkirk LNG[54], which were commissioned between 1972 and 2016. A floating storage and regasification unit (FSRU) was put into service in Le Havre in October 2023 for 5 years, to help mitigating the European energy crisis.

Figure 30 Evolution of gas entry and exit capacities in France between 2020 and 2023 (firm capacities yearly average) in GWh/d



Source: GRTgaz & Teréga data, CRE analysis

NOTE: Entry capacity at the Dunkirk terminal and exit capacity at the Virtualys interconnection point include capacities available to Belgium for the transit of gas from the Dunkirk terminal to the Belgian market (up to 250 GWh/d of capacity available to Belgium). At the Obergailbach interconnection point, a flow reversal was introduced in October 2022. Exit capacity at Obergailbach is sold as a day-ahead product on a firm basis.

54. It should be noted that part of the capacity of the Dunkirk terminal can be used to supply directly Belgium, *via* the Alveringem point.

A slight increase in the entry capacities with the commissioning of a new LNG terminal

In total, France had 3,825 GWh/d of entry capacities in 2023, a slight increase of 106 GWh/d since 2020 (+ 3 %).

Firm pipeline entry capacities into France have been relatively stable in recent years, averaging at 2,385 GWh/d in 2023. Since 2021, entry capacity at the Taisnières L interconnection has been gradually reduced as a consequence of the end of operations at the Dutch Groningen field and the gradual conversion of the gas market in the North of France from low to high calorific value gas (Box n° 6 below). The fall in L-gas flows has led Belgium to reallocate some of its exit capacity from France to other points on its network. From 2023, entry capacity from Spain has increased from 224 GWh/d to 244 GWh/d on average over the year, thanks to the conversion of 40 GWh/d of interruptible capacity into firm capacity during the summer period (from May to October). This firming-up by Teréga accompanies the increase in imports from the Iberian Peninsula.

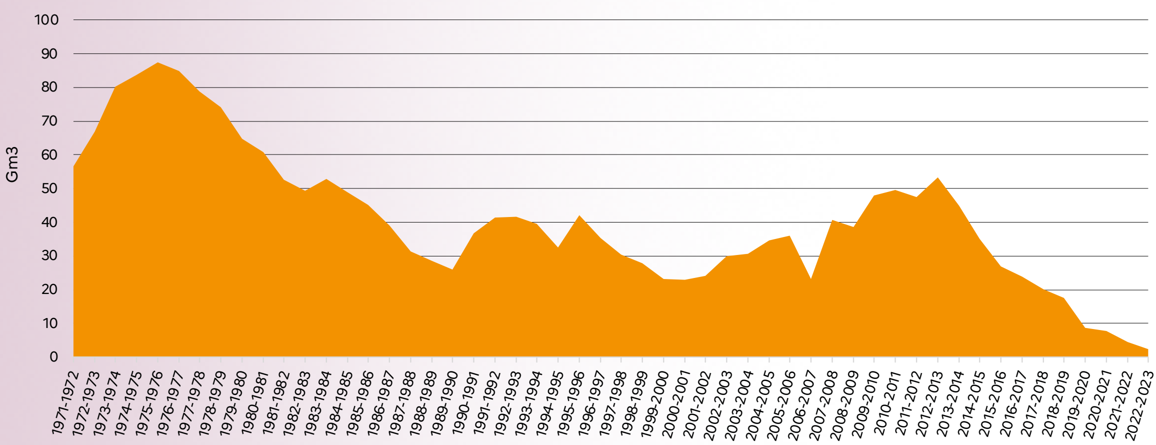
At LNG terminals, entry capacities have risen by 130 GWh/d in 2023 compared to 2020, reaching 1,440 GWh/d since the commissioning of the FSRU in Le Havre. This terminal's injection capacity into the French transmission network was initially 131 GWh/d and was brought to 150 GWh/d from December 2023.

BOX N° 6

The end of operation of the Groningen field and the L-gas / H-gas stakes

Operated since 1963, the Dutch Groningen gas field, the largest in the European Union, has supplied part of North-West Europe with low-calorific natural gas ("L-gas") until 2023. However, since the end of the 1980s, this exploitation had triggered seismic activity in the region (the first earthquake was measured in December 1986), which increased in intensity as the field was depleting. As a result, the Dutch government began phasing out production in 2014, and had planned to end operations in 2030. The recurrence of more frequent earthquakes led the Dutch government to announce at the beginning of 2020 that the site would be shut down earlier than planned, in the summer of 2022. The supply crisis in Europe led the Dutch authorities to postpone the end of production until 1 October 2023, although leaving open the possibility of extracting smaller quantities of gas in exceptional circumstances. On 16 April 2024, the Dutch Senate voted to definitively end production of the field on 1 October 2024, bringing to an end more than 60 years of production.

Figure 31 Evolution of gas production at the Groningen field per gas year (1971-2023)



Source: Dutch government, NLOG data, CRE analysis
https://dashboardgroningen.nl/

In anticipation of the end of supplies from the Groningen field, the L-gas-consuming regions of Germany, Belgium, Luxembourg, the Netherlands and France initiated plans to convert the consumption areas concerned to H-gas. In the Hauts-de-France region of France, 1.3 million consumers connected to the distribution network and 96 consumers connected to the transmission network were supplied with L-gas, representing around 10% of French consumption. Their conversion to H-gas was decided by decree in March 2016. By the end of 2023, the areas converted to H-gas totalled more than 330,000 consumers. The conversion is due to be completed in 2029, when the import contracts expire. Once production has stopped at Groningen, the Netherlands will continue to honour their commitments by converting H-gas to L-gas.

Creation of export capacities to Germany

Onshore exit capacities have increased by 14% since 2020 to 799 GWh/d in 2023, due to the creation of 100 GWh/d of exit capacity to Germany from October 2022, to help Germany cope with the fall in Russian gas supplies (see Box n° 7 below). Previously, the latest significant increase in exit capacity took place at the Swiss border in 2020, when it was raised from 222 GWh/d to 259 GWh/d.

BOX N° 7

Implementation of physical export capacities to Germany at the Obergailbach interconnection point

In response to the decline in Russian gas deliveries to Europe, and to strengthen French and German security of supply, a reciprocal solidarity agreement between the two countries covering gas and electricity was announced on 5 September 2022.

On the gas side of the agreement, France committed to carry out the necessary works to enable gas to be exported to Germany in time for the winter of 2022/2023 at the Obergailbach interconnection point – which had historically been designed to operate only in the import direction (in particular to supply France with Russian gas from Germany) – in order to take advantage of the LNG arrivals in France.

Previously, the odourisation of natural gas on the French transmission system prevented the reversibility of flows at this interconnection point, since in Germany the gas is not odourised on the high-pressure transmission network. GRTgaz and its German counterparts proceeded to technical adaptations during the summer of 2022 and carried out manual works on the metering installations.

Time constraints did not allow to include gas quality adaptation facilities to fulfil gas quality specifications in Germany. Technical complexity and cost were additional obstacles to such adaptation. It was thus agreed to export odourised gas to Germany. This decision followed positive technical tests and the adoption by the German regulator of the Volker Regulation, covering damages odourised gas would cause to German consumers (extended until 2025-2026).

After CRE established the terms and conditions for marketing and pricing these new capacities, GRTgaz started auctioning firm bundled[55] daily exit capacity products from 12 October 2022, at a maximum level of 100 GWh/d. The level offered was assessed every day according to network conditions. Exports to Germany amounted to 3.7 TWh in the last quarter of 2022 and 9 TWh in 2023, generating almost €48 million in tariff revenues for GRTgaz.

Increasing firm export capacity to Germany would require substantial investment, in particular the partial doubling of the pipelines between the Voisines and Morelmaison substations, adaptation of the Obergailbach, Voisines and Morelmaison stations, and reinforcing the Voisines compression station. The estimated budget for implementing such adaptations is €180 to €280 million, which would enable to reach 130 to 200 GWh/d of firm capacity, respectively.

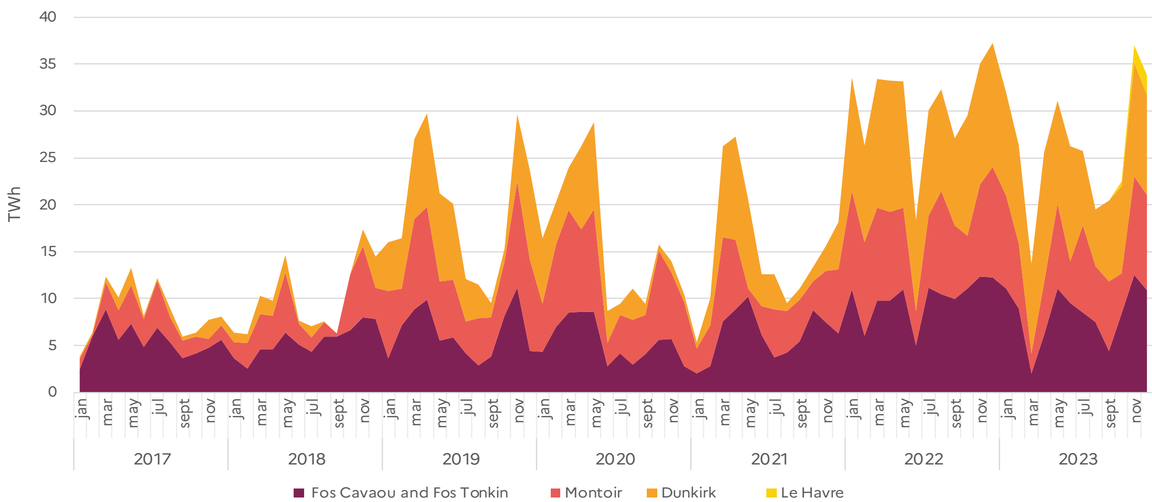
55. A bundled capacity product combined in a single product the exit capacity on one side of the border and the entry capacity on the other side of the border at an interconnection point.

2.1.2. Supply overview: the major role of LNG during the crisis

LNG arrivals had already experienced a first sharp increase in 2019, before declining slightly in 2020 and 2021. From 2022 onwards, the energy crisis led to a surge in LNG arrivals in France, which doubled between 2021 and 2022, reaching an all-time high of 369 TWh in 2022 (see Table 9). They remained at a very high level in 2023, at 314 TWh. As a result, France became Europe's leading LNG importer in 2022 and 2023, ahead of Spain, with import volumes representing 29% of LNG arrivals in the European Union in 2022 and 24% in 2023. While LNG imports accounted for only 36% of French supplies between 2019 and 2021, they exceeded pipeline imports for the first time in 2022 (58% of imports in 2022 and 59% in 2023 – see Figure 33).

Entry flows from French LNG terminals were the highest in the months of November 2022 and 2023, with monthly entries exceeding 35 TWh.

Figure 32 Monthly gas flows on the transmission networks from LNG terminals (at PITTM) (aux PITTM) (2017-2023)



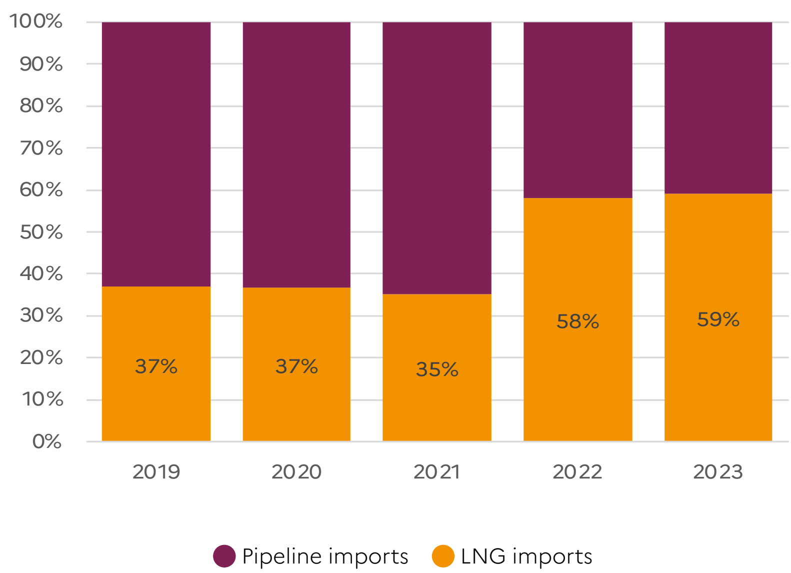
Source: GRTgaz data, CRE analysis & editing

Table 9 Yearly gas flows on transmission networks from LNG terminals (at PITTM) (2017-2023)

	2017	2018	2019	2020	2021	2022	2023
Yearly flows at PITTM (TWh)	103	120	232	194	182	369	314
Yearly change	+30%	+17%	+93%	-16%	-6%	+103%	-15%

Source: GRTgaz data, CRE analysis

Figure 33 Evolution of LNG share in French gas supplies from 2019 to 2023

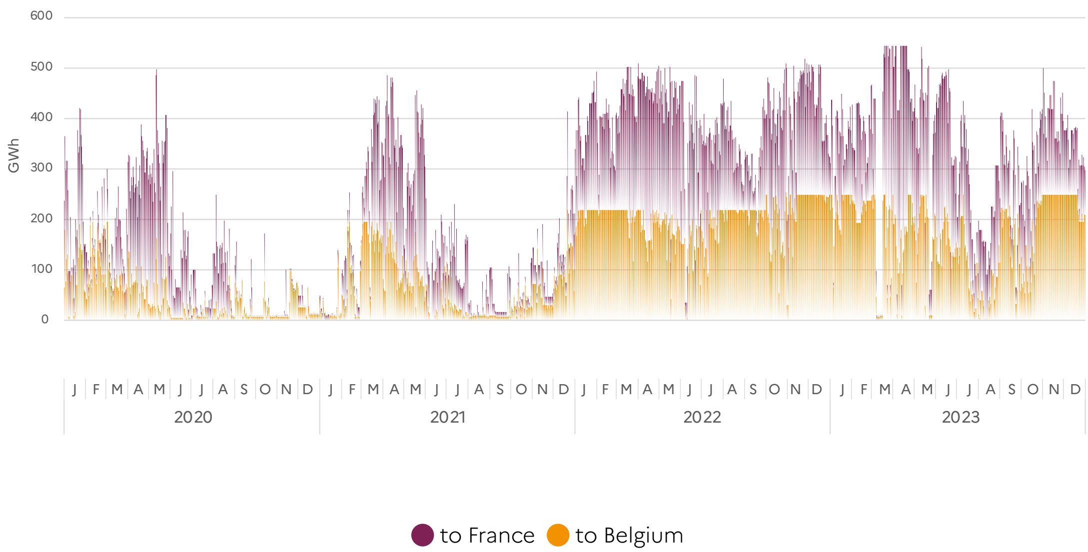


Source: GRTgaz data, CRE analysis

The most significant increase in LNG imports in 2022 and 2023 was observed at the Dunkirk terminal, which supplies both France and Belgium. Physical gas arrivals at the Dunkirk terminal were three times higher in 2022 and 2023 than in 2021, reaching 144 TWh and 123 TWh respectively.

This increase is primarily due to greater use of the Dunkirk terminal by Belgium: in 2022 and 2023, half of the volumes unloaded were destined for the Belgian market, compared with only 38% in 2020-2021. The other half was intended for the French market, representing approximately 72 TWh in 2022 and 61 TWh in 2023.

Figure 34 Daily commercial gas flows from the Dunkirk LNG terminal (2020-2023)



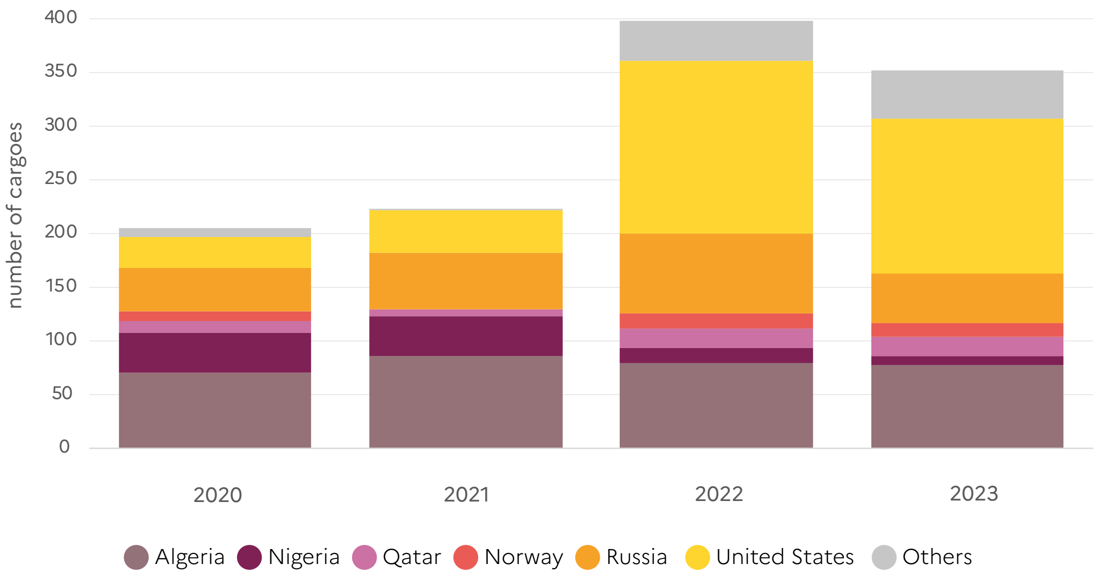
Source: GRTgaz and Fluxys data, CRE analysis

Gas injections into the French network from the Montoir and Fos (Fos Cavaou and Fos Tonkin) terminals also increased significantly in 2022, by 87% and 63% respectively compared to 2021. In 2022, 106 TWh were injected from the Montoir terminal and 119 TWh from the Fos terminals. LNG injections at Montoir and Fos decreased slightly in 2023 but remained well above the historical average. The commissioning of the floating LNG terminal in Le Havre from October 2023 allowed an additional 4.5 TWh to be imported in the last quarter of 2023.

The United States was one of France's main gas suppliers during the crisis

The large majority of the additional volumes of LNG imported in 2022 and 2023 originated from the United States. While only 18% of the LNG tankers arriving in France in 2021 were carrying American gas, this proportion rose to 40% in 2022 and 2023. France has also received more LNG tankers carrying Norwegian and Qatari LNG since the crisis started. The number of ships transporting Russian LNG was reduced in 2023, after increasing in 2022, to represent only 13% of LNG arrivals (compared with 23% over the period 2019-2021).

Figure 35 Origin LNG arrivals to France (2020-2023)



Source: Argus data, CRE analysis

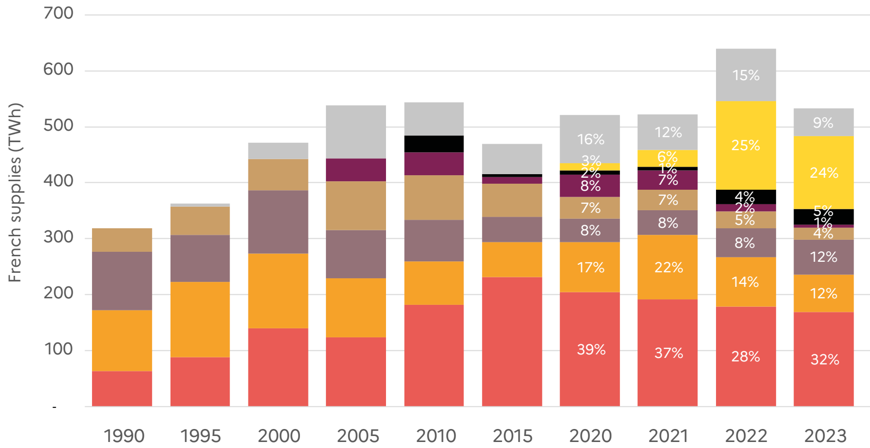
In general, the decline in Russian gas imports to Europe in 2022 led to a greater diversification of French supplies (see Figure 36). The share of Russian gas, which reached 22% in 2021, fell to 14% in 2022 and then to 12% in 2023, representing the lowest level since 1990. At the same time, the share of American gas increased significantly, resulting in the United States becoming France's second largest supplier in 2022 and 2023, accounting for a quarter of supplies.

The trends observed over the last decade have continued. Norway, which has been France's main supplier since the late 1990s, has seen its share gradually decline since 2015, when it peaked at 48%. In 2022 and 2023, Norway remained France's largest supplier, accounting for more than a quarter of supplies (28% and 32% respectively). Imports of Dutch gas continued the downward trend that started in 2011, accounting for only 5% of imports in 2022 and 4% in 2023.

The share of Algerian gas remained stable at 8% between 2020 and 2022, rising to 12% in 2023. Gas deliveries from Nigeria, which stood at almost 8% in 2020, fell to less than 2% in 2022 and 1% in 2023. Qatar's share has increased since 2020, rising from 2% to 5% in 2023.

While gas consumption in France fell during the energy crisis, the significant increase in gas arrivals in France in 2022 (+23% compared to 2021), shown in Figure 36, demonstrates the strong use of the French gas system to support European security of supply.

Figure 36 French natural gas imports by origin from 1990 to 2023, and evolution of the share of export countries in French supplies from 2020 to 2023*



Source: SDES data (Ministry of Ecological Transition and Territorial Cohesion), CRE analysis

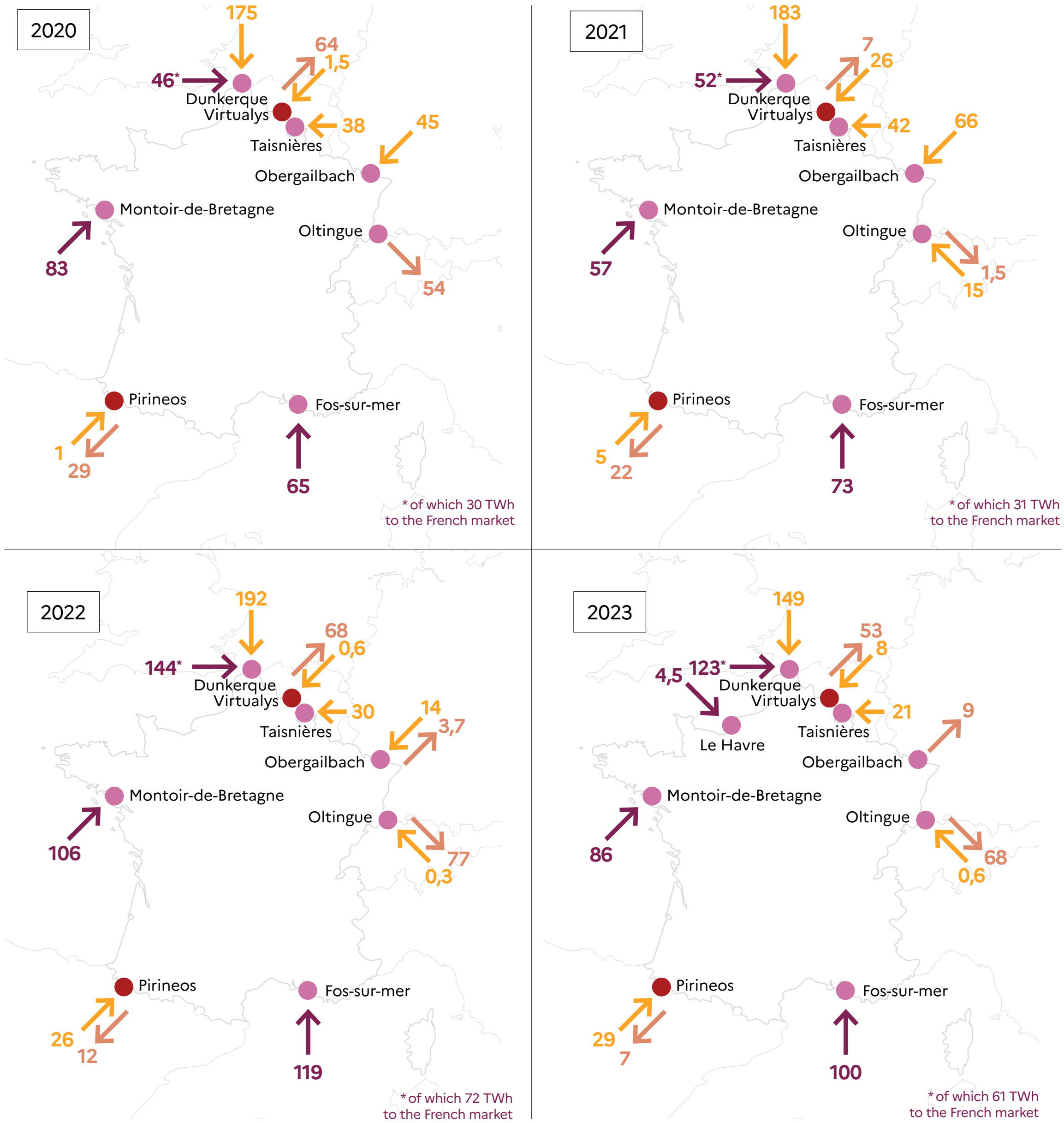
2.1.3. The reshuffling of gas flows at French borders

Historically, France's gas pipeline imports have been channelled through its northern interconnections (the Dunkirk IP connected to Norwegian gas fields, the Taisnières L and Virtualys IPs at the Belgian border, and the Obergailbach IP on the German border). France used to export to Spain (Pirineos IP) and to Italy via Switzerland (Oltingue IP).

The Covid-19 crisis in 2020 resulted in a general drop in gas demand in Europe and, consequently to a decrease in flows in and out of the French network. The gas crisis that affected Europe from the second half of 2021 led to an unprecedented reorganisation of flows at the French borders. Since 2022, France has assumed a more prominent role as a transit country, with exports increasing sharply to European countries further north and east, particularly affected by the fall in Russian supplies. The sustained exports to Belgium, Italy and Switzerland, as well as to Germany from October 2022, have been made possible by increased LNG arrivals in France and imports from Spain.

In 2022, French gas imports were 23% higher than the average volumes observed in 2020 and 2021, reaching 630 TWh, while French consumption dropped as a result of the energy crisis. The increased use of imports during the crisis helped exports to the rest of Europe, which doubled to 160 TWh in 2022 compared to 2020-2021. The total volume of flows exchanged at French borders then fell in 2023, with imports returning to pre-crisis levels, while exports remained at high levels.

Figure 37 Yearly physical flows of gas at French interconnection points (land and LNG terminals) (2020-2023)



Total physical flows

ENTRY		EXIT	
2020	**518 TWh**	2020	**85 TWh**
2021	**507 TWh**	2021	**45 TWh**
2022	**630 TWh**	2022	**160 TWh**
2023	**514 TWh**	2023	**138 TWh**

Physical point · Virtual point · Entries from LNG terminals · Pipeline entries · Pipeline exits

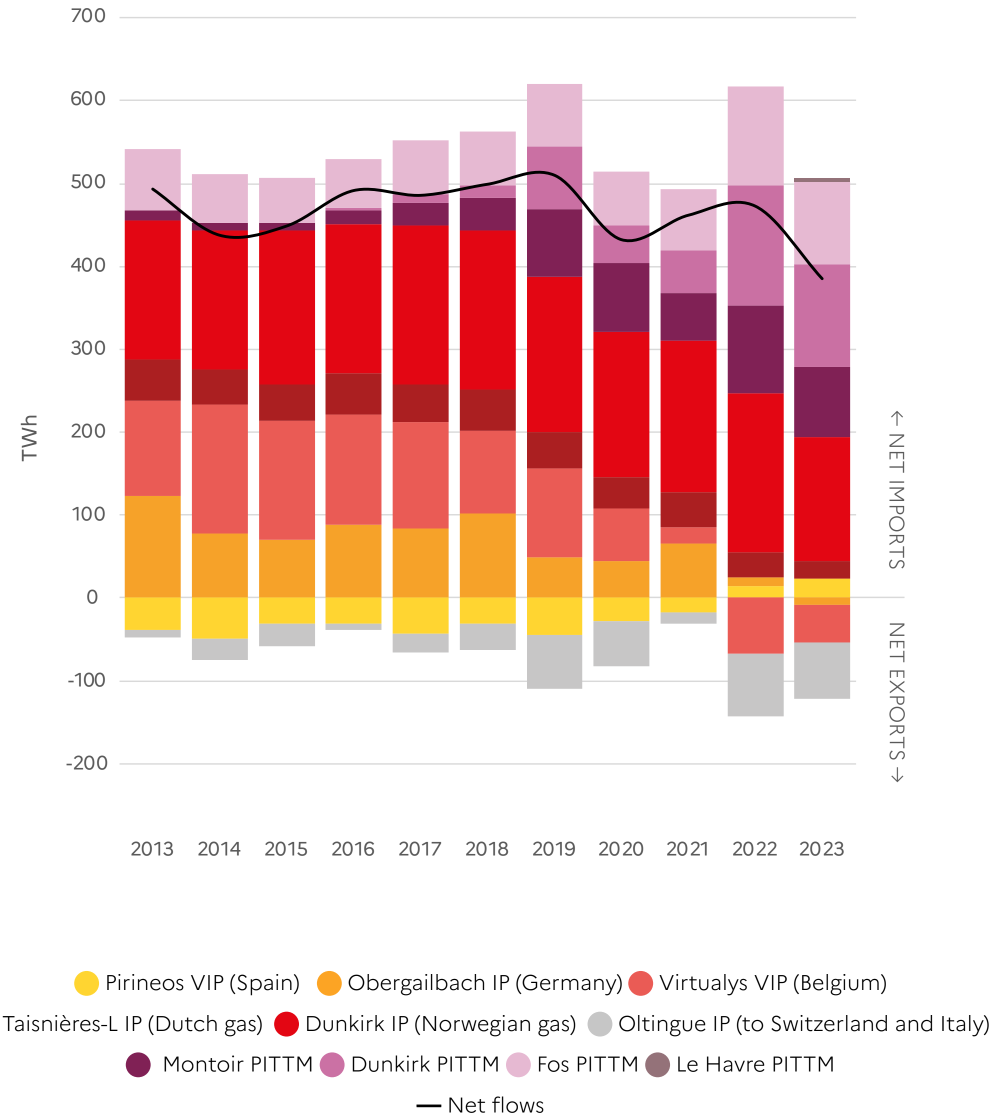
Source: GRTgaz and Teréga data, CRE analysis

Table 10 Yearly physical flows of gas at French interconnection points (land and LNG terminals) (2020-2023)

TWh [% yearly change]	2020	2021	2022	2023
GAS ENTRIES	**518**	**507 [-2%]**	**630 [+24%]**	**514 [-18%]**
Pipeline entries	**323**	**324**	**260**	**200**
Dunkerque IP (Norway)	175	183	192	149
Virtualys VIP (Belgium)	64	26	0,6	8
Taisnières L IP (Belgium)	38	42	30	21
Obergailbach IP (Germany)	45	66	14	0
Oltingue IP (Switzerland)	0	1,5	0,3	0,6
Pirineos VIP (Spain)	1	5	26	29
Entries from LNG terminals	**194**	**182**	**369**	**314**
Fos-sur-mer PITTM	65	73	119	100
Dunkirk PITTM	46 (from which 65% to French market)	52 (from which 60% to French market)	144 (from which 50% to French market)	123 (from which 50% to French market)
Montoir-de-Bretagne PITTM	83	57	106	86
GAS EXITS	**85**	**45 [-47%]**	**160 [+256%]**	**138 [-14%]**
Virtualys VIP (Belgium)	1,5	7	68	53
Obergailbach IP (Germany)	-	-	4	9
Oltingue IP (Switzerland)	54	15	77	68
Pirineos VIP (Spain)	29	22	12	7

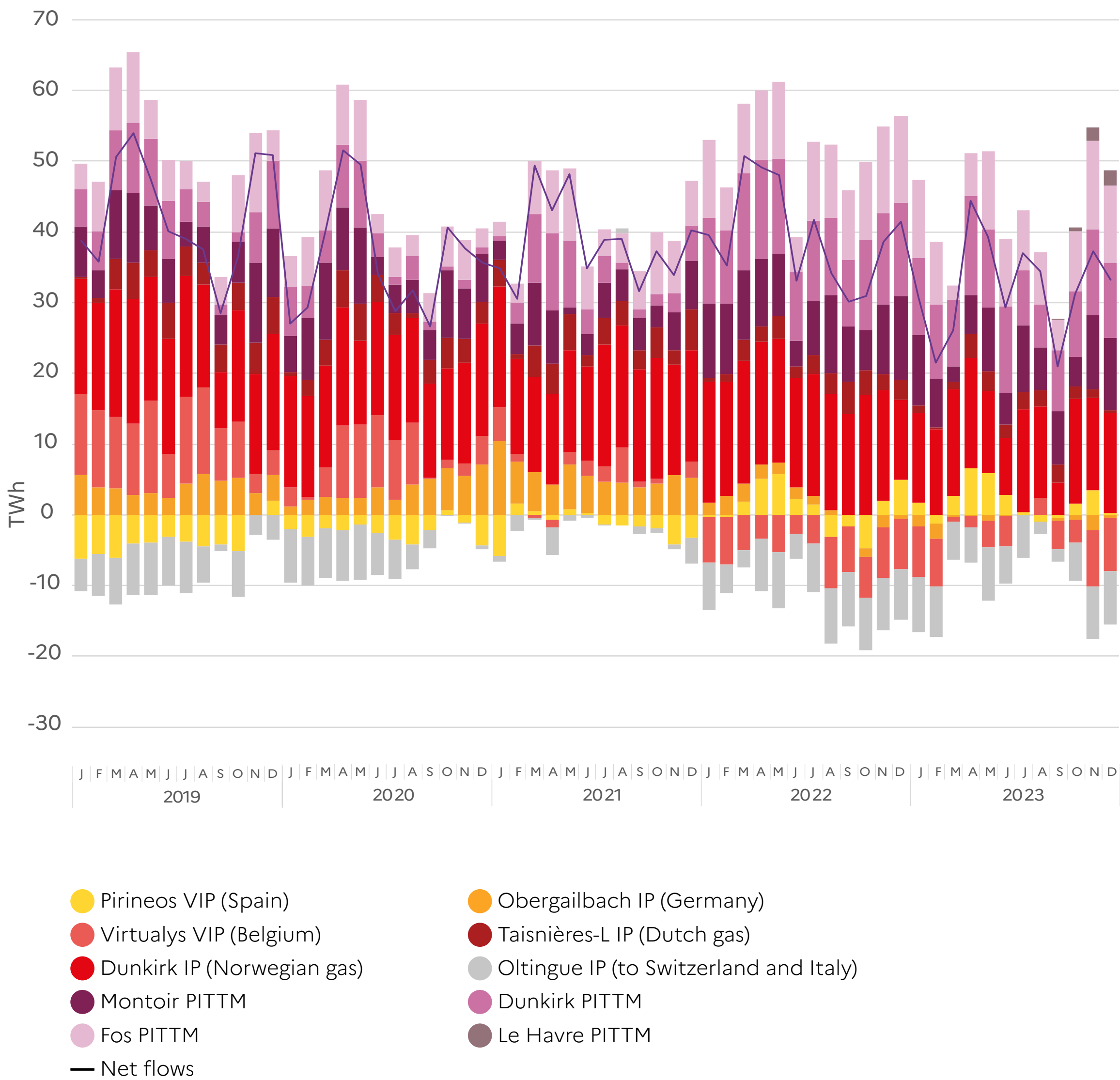
Source: GRTgaz and Teréga data, CRE analysis

Figure 38 Yearly net physical gas flows at interconnection flows (IPs and PITTM) (2013-2023)



Source: GRTgaz and Teréga data, CRE analysis

Figure 39 Monthly net physical gas flows at interconnection flows (IPs and PITTM) (2019-2023)

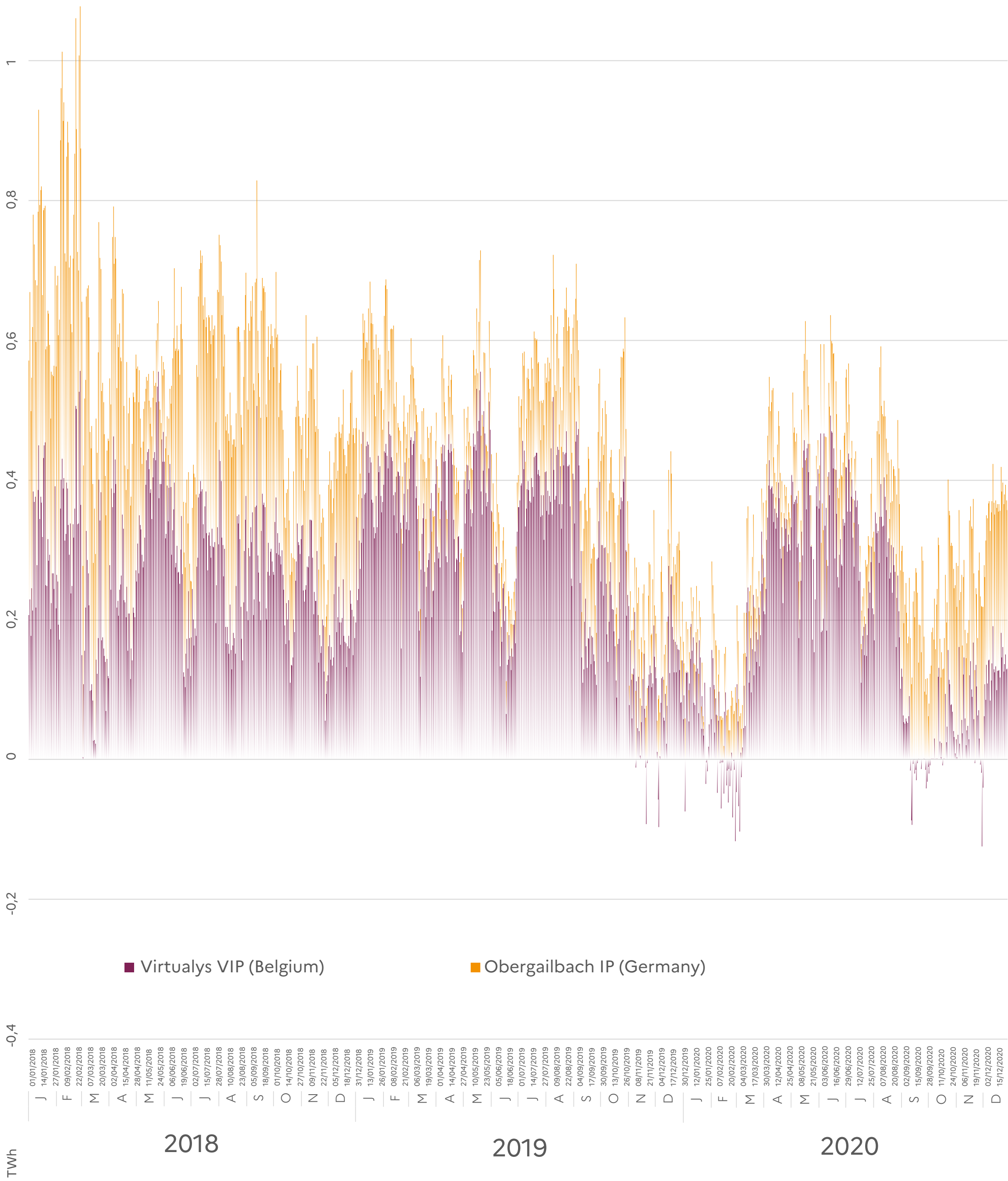


Source: GRTgaz and Teréga data, CRE analysis

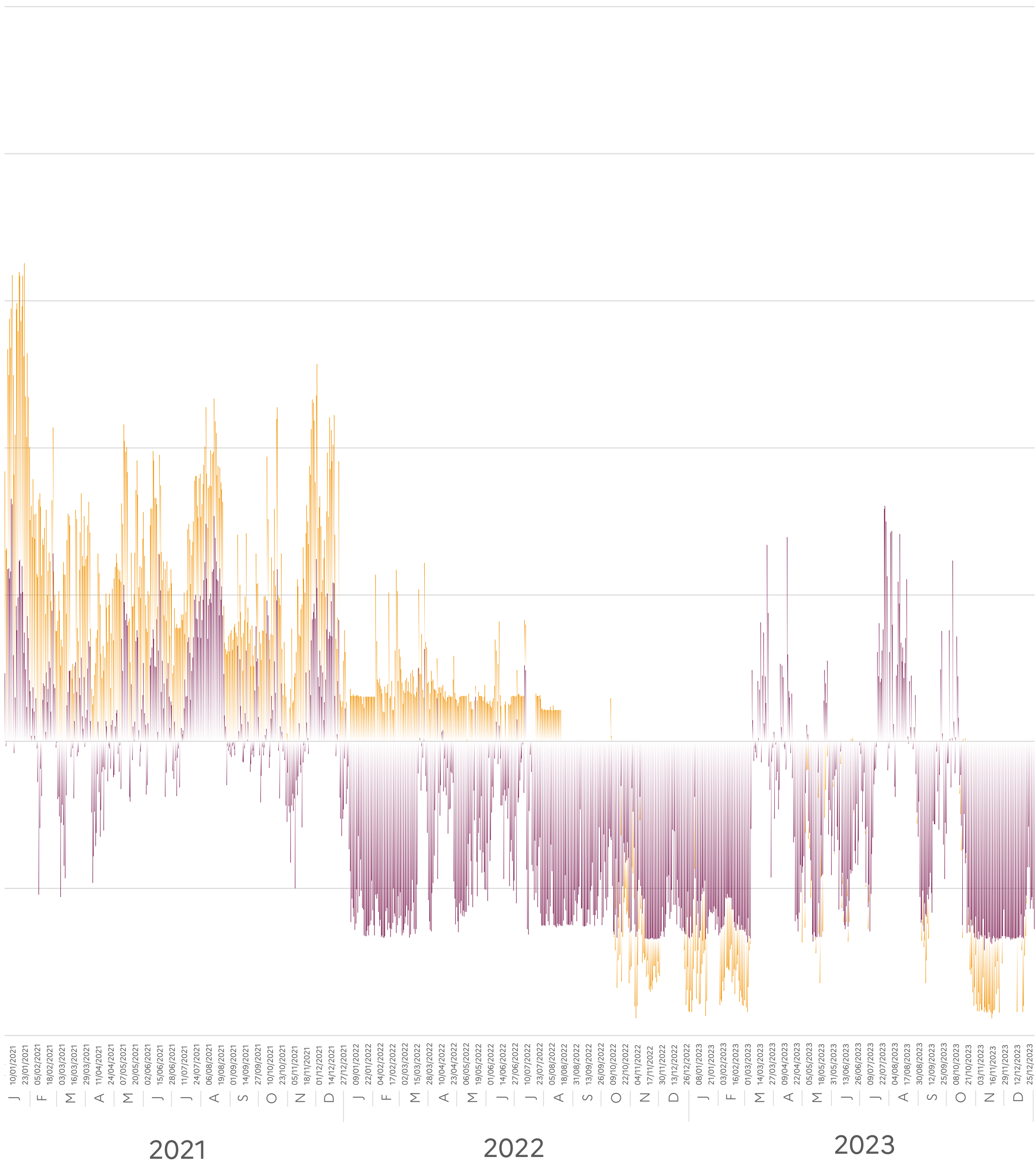
Focus on exports to Germany and Belgium

With the drop in Russian gas deliveries to Europe, import flows at the Obergailbach and Virtualys interconnection points with Germany and Belgium had ceased from December 2021 at Virtualys, and from summer 2022 at Obergailbach.

Figure 40 Physical flows at Virtualys VIP (Belgian border) and Obergailbach IP (German border) (2018-2023)



Source: GRTgaz data, CRE analysis


2021
2022
2023

At the Virtualys interconnection point, flows had already reversed occasionally in 2019 and 2020 (6 days in 2019 and 52 days in 2020), and then more structurally in 2021 (49% of the days during the year). From the end of December 2021 and until the end of the winter of 2022-2023, flows were almost exclusively export-oriented, as French day-ahead prices were almost systematically lower than Belgian prices. As a consequence, France became in 2022 a net exporter for the first time at the Virtualys interconnection point (with 68 TWh exported, compared with only 0.6 TWh imported). These flows were partly destined for Germany and the Netherlands. In 2022, Belgium's net commercial exports to Germany were over 250 TWh (1.6 times Belgian consumption) and around 70 TWh to the Netherlands, while Belgium had historically been a net importer of Dutch gas and its trade with Germany had been close to balance[56].

At the Obergailbach IP, entries fell sharply in the first half of 2022 (-70% versus the first half of 2021), before reaching the minimum technical level required for the operation of the interconnection during the summer (42 GWh/d), as day-ahead price spreads between France and Germany widened. From July to September 2022, German prices were on average €64/MWh higher than French prices. In response to the gas shortage faced by Germany after Russian supplies were cut off via the Nordstream pipeline and Poland (which previously accounted for more than half of its consumption), the Obergailbach IP was adapted to export gas to Germany (see Box n° 7). Exports began on 12 October 2022 and continued mainly over the winter months. In total, France exported 3.7 TWh of gas to Germany between October and December 2022.

From March 2023 onwards, exports to Germany and Belgium were more limited, against a backdrop of a general fall in wholesale prices in Europe and a reduction in price spreads between market areas. Flows at the Virtualys VIP regularly reversed, while exports to Germany ceased in the summer of 2023. At the end of 2023, during the first months of winter, exports to Belgium and Germany resumed at significant levels, in line with the rise in Belgian and German prices relative to French prices. Overall, in 2023, France remained a net exporter to Belgium at the Virtualys VIP and became a net exporter to Germany for the first time (with 9 TWh of exports at Obergailbach).

Episodes of reduced Norwegian gas inflows have accentuated the fall in import flows in the North

The rise in wholesale prices on the European markets from autumn 2021 led Norway to maximise its production at the height of the crisis. However, after a period of very high use of the Dunkirk interconnection point, between mid-2021 and November 2022, several episodes of sharp reduction in Norwegian gas flows to France were observed during the winter of 2022-2023 and in 2023.

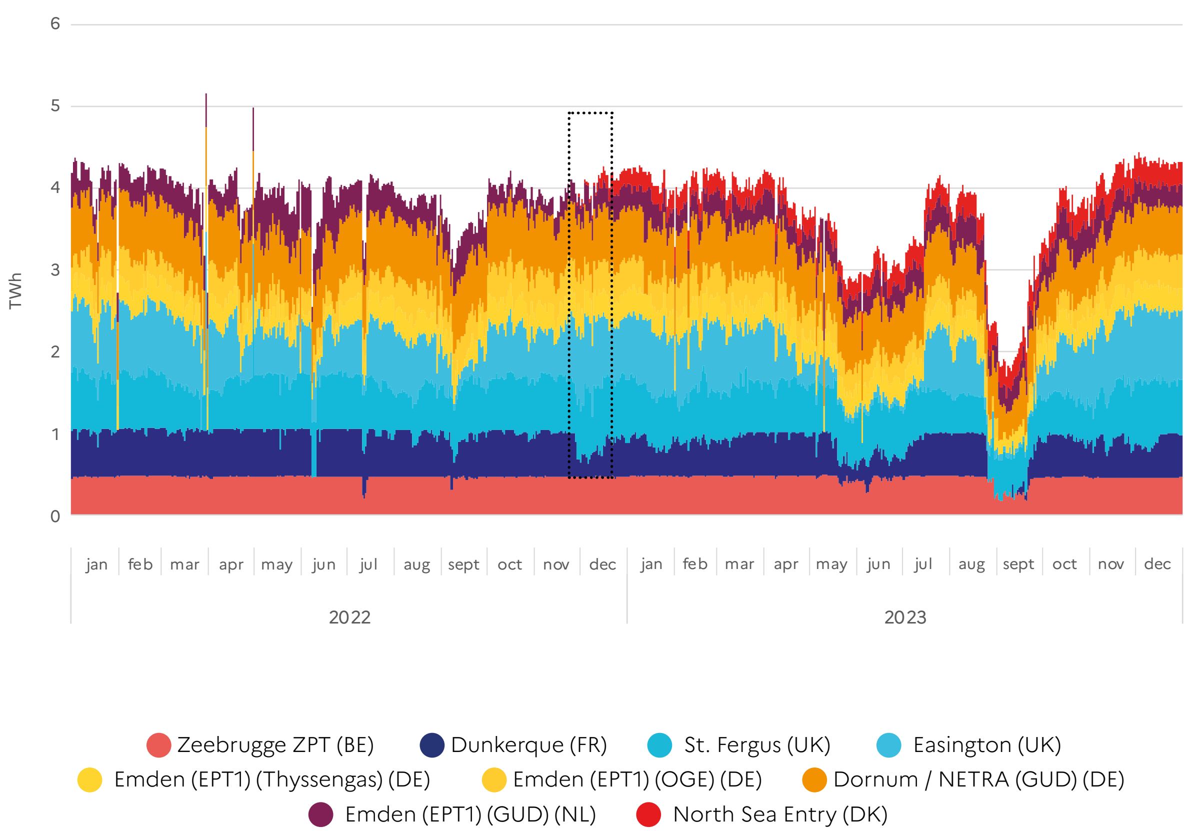
From the end of November to mid-December 2022, arrivals at the Dunkirk IP were reduced to less than 290 GWh/d (i.e. around 50% of firm capacity at this period) compared with more than 500 GWh/d the weeks before, as shown in Figure 41. This can be explained by competition with other European markets connected to Norwegian fields[57] that experienced higher wholesale prices, mainly Great Britain, but also

56. CREG annual report 2022
57. Norway's gas fields are directly connected by pipeline to France, Great Britain, Belgium, Germany and the Netherlands, and since November 2022 to Denmark with the commissioning of the Baltic Pipe, which crosses Denmark before crossing the Baltic Sea to Poland.

Denmark since the commissioning of the Baltic Pipe in November.

In 2023, major maintenance works on natural gas production facilities in Norway in May and June and at the end of the summer led to a reduction in Norwegian gas arrivals for all European importing countries. In September 2023, deliveries at the Dunkirk point fell to their lowest level in a decade.

Figure 41 Norwegian gas flows to EU countries and the UK (2022-2023)



Source: ENTSOG Transparency Platform data, CRE analysis

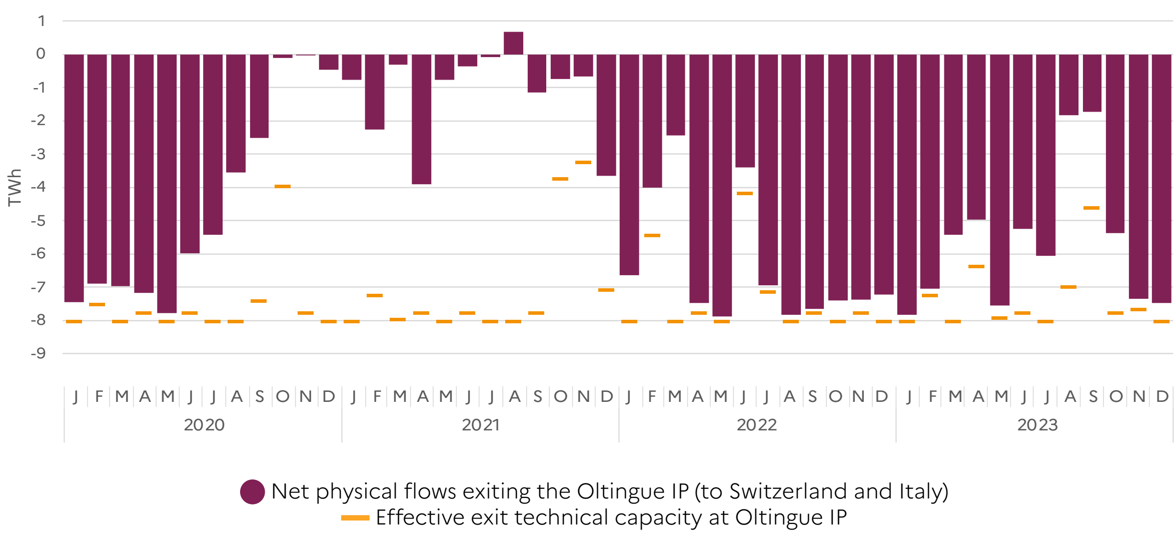
Sustained exports to Switzerland and Italy

After a year 2021 marked by a very low level of utilisation of the Oltingue IP (22% on average), due to an increase in volumes imported into Italy from other sources (from Azerbaijan *via* the Trans-Adriatic Pipeline and from Algeria *via* the Transmed pipeline), the gas crisis gave a strong boost to the use of this point from December 2021 (see Figure 42).

In 2022 and 2023, the IP was very often used to its maximum export capacity, particularly between July 2022 and the end of February 2023, when it was almost systematically saturated. Over this period, Italian day-ahead prices were on average €33/MWh higher than French prices. The price spreads widened particularly between July and the end of September 2022, when it averaged more than €60/MWh. In 2022 and 2023, exports at Oltingue reached levels twice as high as the historical average (72 TWh of net annual physical flows on average, compared with 36 TWh over the period 2016-2020).

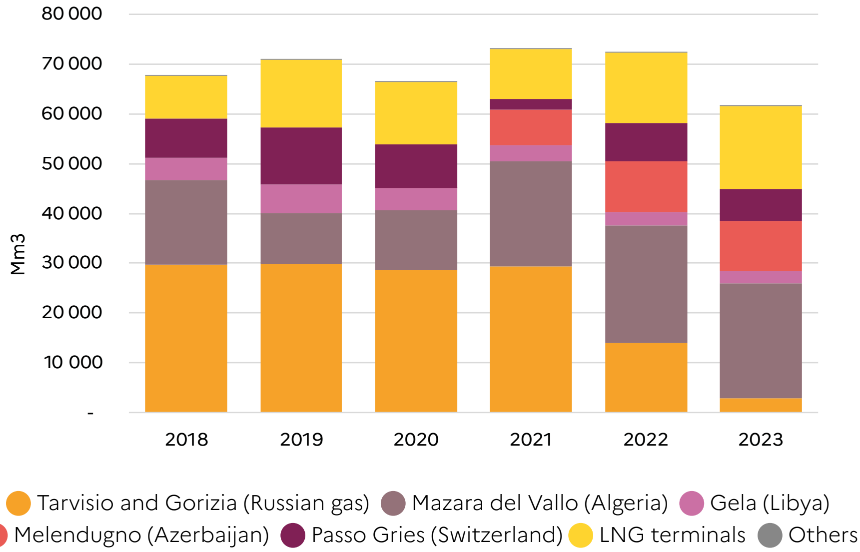
The main reason for using this IP at full capacity was Italy's need to compensate for the fall in Russian gas imports *via* the TAP pipeline, which accounted for 40% of Italy's supplies before the crisis. By 2023, imports from Russia accounted for only 5% of Italian supplies (Figure 43). Italy also increased its LNG imports, but to a lesser extent than France or Spain, due to more limited regasification capacity. The commissioning of a new floating terminal in the summer of 2023 and the high utilisation rate of Italian terminals led to an increase in the share of LNG in Italian supplies, rising from 13% to 27% between 2021 and 2023.

Figure 42 Net physical flows and effective technical capacity at Oltingue IP (Switzerland) (2020-2023)



Source: GRTgaz data, CRE analysis

Figure 43 Italy's yearly gas imports per interconnection point (2018-2023)



Source: Italian Ministry of Environment and Energy security data, CRE analysis

France became a net importer of gas from Spain in 2022 and 2023

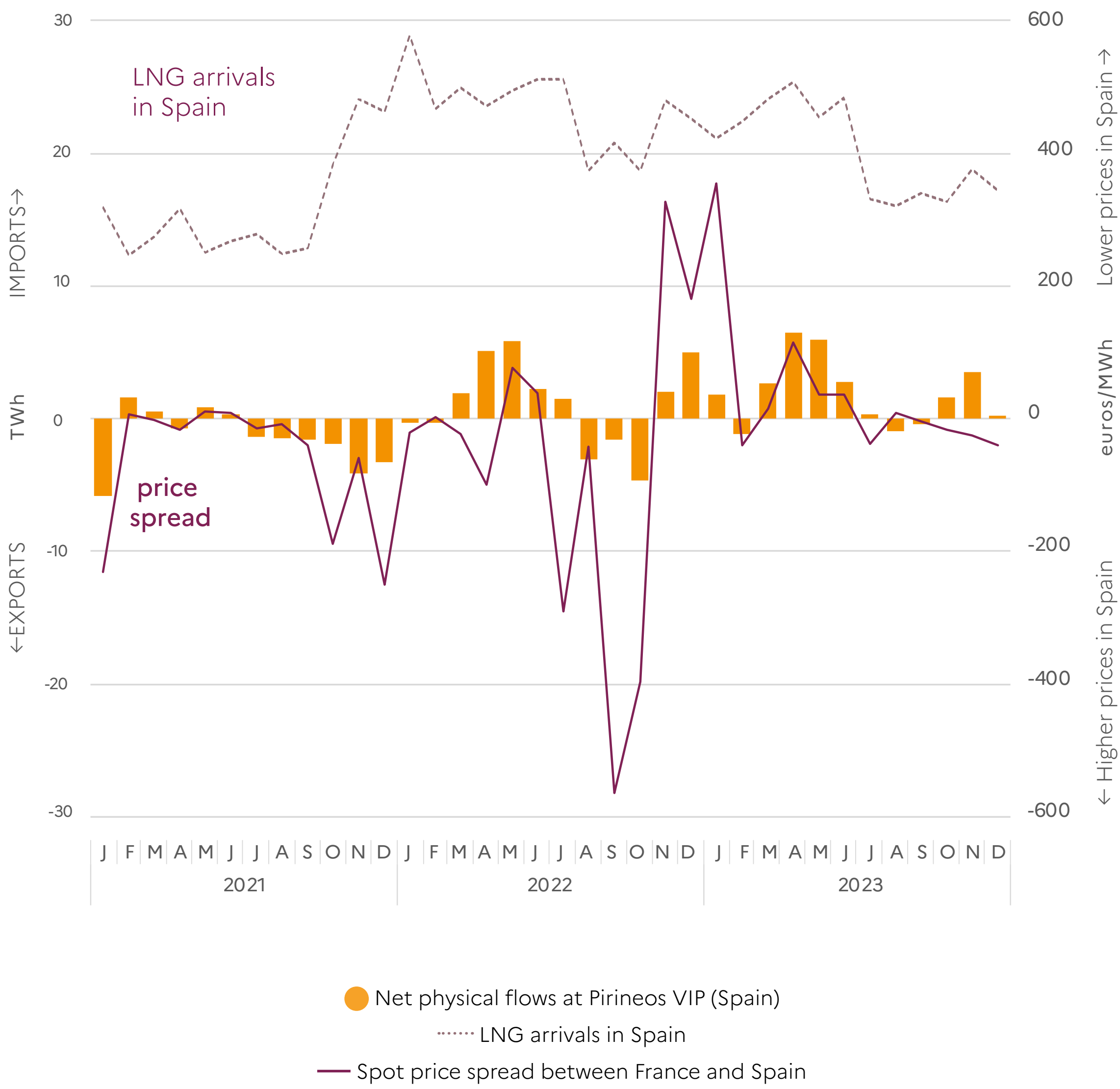
At the interconnection point with Spain, where flows have historically been export-oriented, occasional episodes of imports had already been observed in 2019 and 2020, particularly when wholesale gas prices in Spain were lower than French prices, due to high LNG imports and mild weather conditions.

As from the start of the crisis, Spanish wholesale gas prices were more frequently lower than French prices. This was the case 40% of the time in 2021-2022 and 53% of the time in 2023, compared with 20% of the time in 2020. As a result, France became a net importer from Spain for the first time in 2022 and 2023. Volumes imported reached 26 TWh and 30 TWh in 2022 and 2023 respectively, five times higher than in 2021, while volumes exported were reduced to 12 TWh and 7 TWh, compared to 22 TWh in 2021.

The episodes of high imports from Spain mainly observed in the spring of 2022 and 2023 and in November and December 2022 were directly linked to periods of massive LNG arrivals in Spain, as shown in Figure 44. In 2022, LNG arrivals in Spain were 50% higher than in 2021.

The direction of flows is highly dependent on price spreads, which are driven by economic trends on either side of the border. For example, at the end of the summer of 2022, north-south flows once again became dominant, as Spanish prices rose sharply due to high gas consumption for electricity production (low wind output) and maintenance work at several LNG terminals. Since the crisis, the Pirineos interconnection point has therefore become a point of arbitrage between the two market areas.

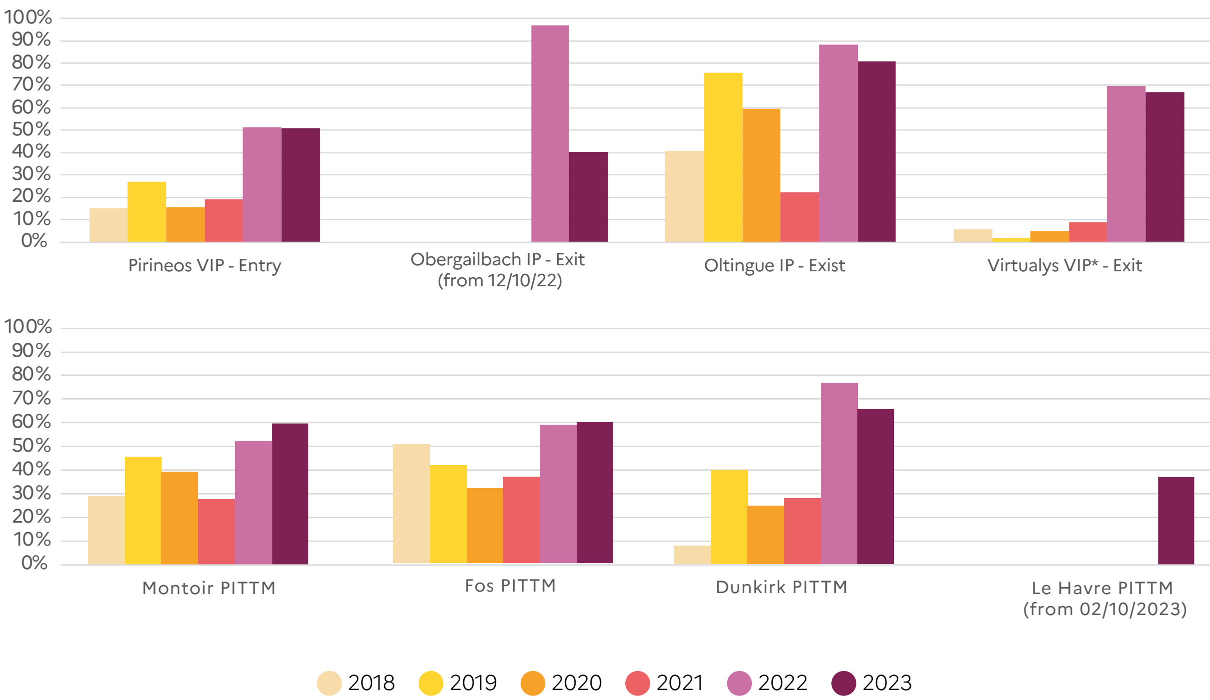
Figure 44 Net physical flows with Spain at Pirineos VIP, evolution of price spreads PVB-PEG and LNG arrivals in Spain (2021-2023)



Source: GRTgaz, GIE and EEX data, CRE analysis

2.1.4. An intensive use of interconnection points during the crisis

Figure 45 Yearly average utilisation rate of land interconnections (PIR) and with LNG terminals (PITTM) (2018-2023)



Source: GRTgaz and Teréga data, CRE analysis

NOTE: Utilisation rates are the ratio of physical flows to effective technical capacity. At the Virtualys PIV, physical export flows are deducted from the gas transit volumes available to Belgium from the Dunkirk terminal directly to the Belgian market, and effective technical capacity is deducted from the capacity reserved by Belgium.

Changes in gas exchanges had an impact on infrastructure utilisation rates. In the North, interconnection points have frequently been saturated for exports, such as at Oltingue, which was used at an average of 88% and 81% of its technical capacity in 2022 and 2023, compared with an average of less than 50% over the 2018-2021 period. Export capacity to Germany at Obergailbach was almost systematically used at maximum capacity since the introduction of the reverse capacity (with an average utilisation rate of 96% from October 2022 to the end of January 2023). After a sharp fall in the utilisation rate, transit to Germany was frequently saturated in November 2023. At the Virtualys exit point to Belgium, the export utilisation rate reached 70% and 67% on average in 2022 and 2023, and remained at levels close to 100% during the winter of 2022-2023, and again at the start of the winter of 2023-2024.

On the import side, the utilisation rates of the interconnections with the LNG terminals and the interconnection with Spain reached record levels. The average utilisation rate of the Pirineos VIP at the Spanish border reached 51% in 2022 and 2023 for imports, compared with an average of 19% in 2018-2021. Utilisation was particularly intensive in April and May 2022 and 2023. The use of LNG terminals reached an exceptionally high level in 2022 and 2023: in 2022, they were all used on average at 95% of their regasification capacity, and these rates were maintained at high levels in 2023 (95% at Fos Tonkin, 81% at Dunkirk, 64% at Fos Cavaou and 72% at Montoir). This intensive use of LNG imports has resulted in a sharp increase in the utilisation rates of entry points from LNG terminals to the gas transmission networks (PITTM), as shown in Figure 45. Utilisation rates at the PITTMs reached 65% and 62% on average in 2022 and 2023 (excluding the terminal of Le Havre), compared with 33% over the 2018-2021 period. The Dunkirk PITTM saw the highest utilisation (76% on average in 2022 and 65% in 2023). The commercial capacity available for Belgium was used at higher levels than the capacity dedicated to the French market in 2022 and 2023. At the Montoir and Fos terminals, the average utilisation rates of entry capacity into the transmission networks reached almost 60% in 2022 and 2023, again a sharp increase compared with previous years. The terminal in Le Havre only came into service at the end of 2023, with an average utilisation rate of 37% over its first three months of operation, then 70% over the second half of December.

The high gas storage filling levels reached in France has helped boosting gas export capacity to the rest of Europe.

The increase of France exports to Northern Europe since Russia's invasion of Ukraine was also supported by a high filling level of storage capacities, even at the height of the gas crisis. With 132 TWh of underground storage capacity (i.e. around 30% of French annual gas consumption), France was the fourth-largest country in the European Union in terms of storage capacity in 2021. The French regulatory framework proved particularly resilient and effective during the crisis (see Box n° 8), making French storages a key asset for the European security of supply, for example by enabling exports to Germany from October 2022, at the heat of the supply crisis.

BOX N° 8

A French gas storage regulatory framework adapted to market needs

Following the law n°2017-1839 of 30 December 2017, the French gas underground storage operators Storengy, Teréga and Géométhane entered the regulated regime in 2018. Since then, the costs incurred for the operation of the storage capacities listed in the Multi-annual Energy Plan (*Programmation Pluriannuelle de l'Energie* or PPE) are covered by the authorised revenue of each operator, which is determined by CRE.

Storage capacities are marketed via auctions according to the terms and conditions defined by CRE. In particular, capacities for the coming gas year are auctioned at a zero reserve price, so that storage capacity can be subscribed on the basis of the forward price spread between summer and winter. The difference (positive or negative) between the auction revenues collected and the operators' authorised income is compensated for by a dedicated tariff term included in the natural gas transmission tariff (ATRT) and paid by consumers located on the national territory. The regulatory framework therefore makes it possible both to cover the costs of storage operators and to maintain in operation capacities that are essential to security of supply.

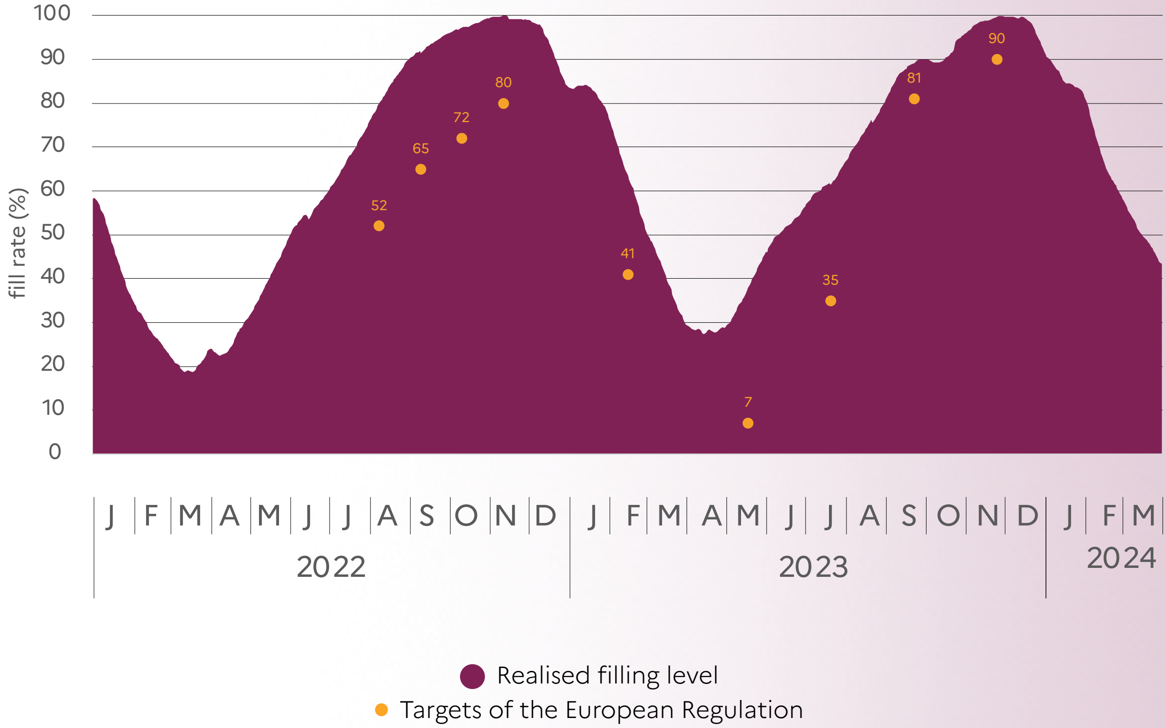
In addition to this mechanism, the regulatory framework ensures that a sufficient level of storage filling is reached at the start of the winter season. The Energy Code requires storage capacity holders to fill 85% of their subscribed capacity by 1st November each year. In the event of difficulties, the Ministry may require market players and/or storage operators to subscribe additional capacity if there is a risk that security of supply will not be guaranteed (this is known as the "safety net" system). Failure to comply with these obligations is punishable by a non-dischargeable fine of up to twice the value of the missing gas volume.

Regulation (EU) 2022/1032 of 29 June 2022, adopted as an emergency measure to deal with the crisis, set filling targets for all Member States on 1st November each year (80% for year 2022 and 90% for years 2023 to 2025), supplemented by intermediate targets during the year, while leaving it up to each Member State to decide on the measures to implement to achieve them. In application of this Regulation, the French government adopted an additional regulatory tool (known as "security stocks"[58]) which enables it to order storage operators to build up the stocks needed to meet the minimum filling target set by the trajectory. In this case, the net costs incurred by the regulated operators to build up these gas stocks are compensated for by the State and charged to the CSPE tax[59].

Neither the safety net mechanism nor the safety stock mechanism had to be activated by the government to date, including during the winter of 2022-2023. The effectiveness of the French regulatory framework ensured that storage facilities were completely filled during the crisis.

58. Introduced in law n° 2022-1158 of 16 August 2022 on emergency measures to protect purchasing power
59. The CSPE (*Contribution au service public de l'électricité*) is a French energy tax used to compensate for the various costs of the public electricity service.

Figure 46 Evolution of French gas storages' filling rate since 2022, and EU Regulation targets



Source: GIE AGSI Platform, CRE analysis

2.1.5. Price spreads with neighbouring countries widened

After years of strong price convergence between European gas hubs, reflecting the high degree of market integration achieved through the use of interconnections, unprecedented price spreads emerged between European markets, especially from spring 2022 onwards, and widened over the course of the year. They reached their highest level in the summer of 2022, when Russian pipeline gas arrivals in Europe plummeted[60].

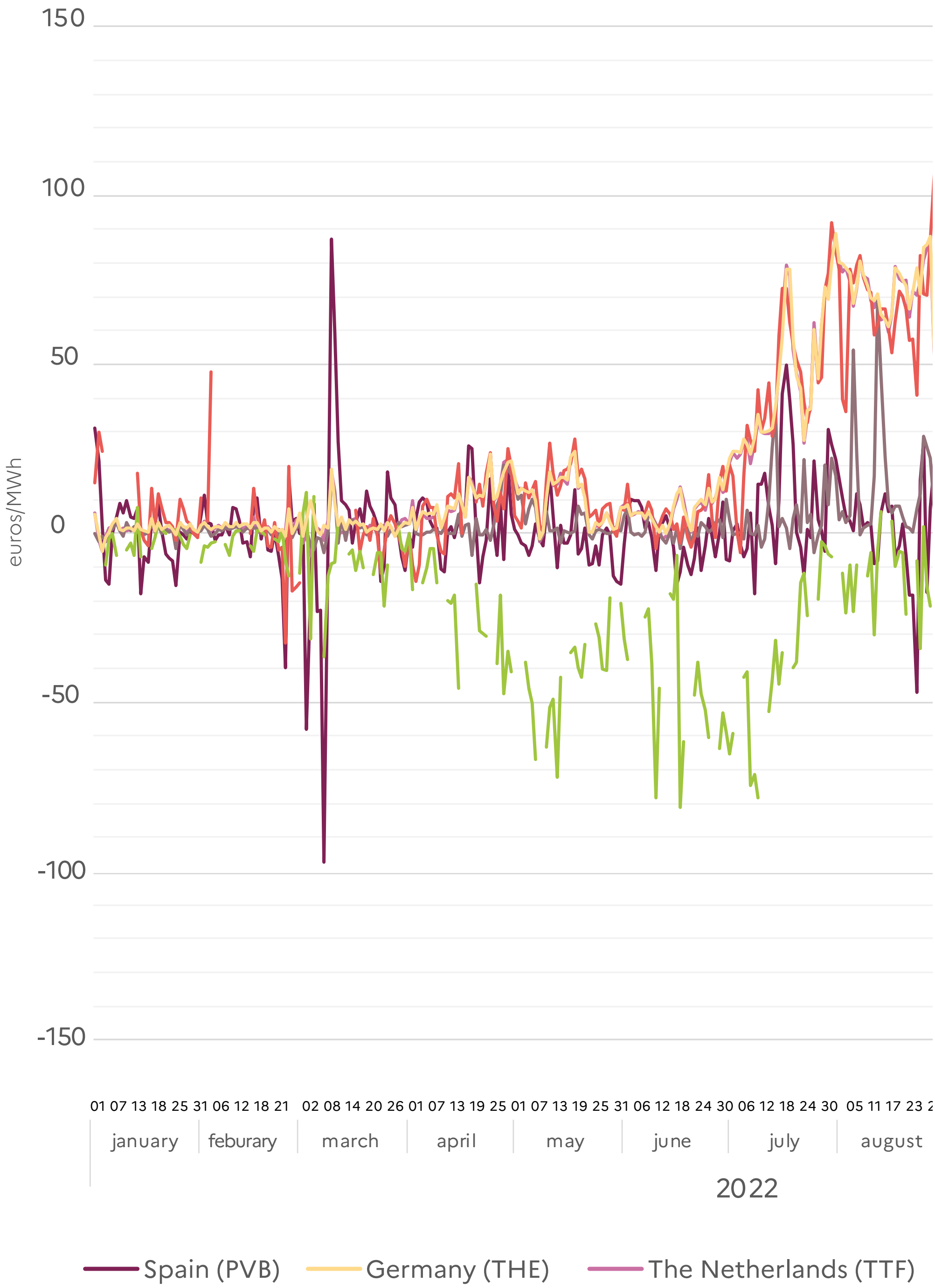
Throughout 2022, day-ahead wholesale prices in Germany, the Netherlands and Italy remained well above French prices, due to their greater dependence on Russian gas imports and their lower LNG import capacity. French day-ahead prices in 2022 were on average €23/MWh lower than Dutch prices, and €24/MWh lower than German and Italian prices. Price spreads with these countries widened sharply over the summer months, reaching an average of €70/MWh in September with Italy and €75/MWh with Germany and the Netherlands. France also benefited from prices that were mostly lower than those in Belgium in 2022, although with more limited price spreads (€6/MWh difference on average in 2022).

The same effects were seen on the monthly and quarterly forward prices on which a large proportion of gas consumption in France is indexed. As a result, gas prices paid by French consumers were significantly lower than in other EU countries (with the exception of the Iberian Peninsula), and France's gas bill was lower than that of its neighbours, even though it has risen sharply.

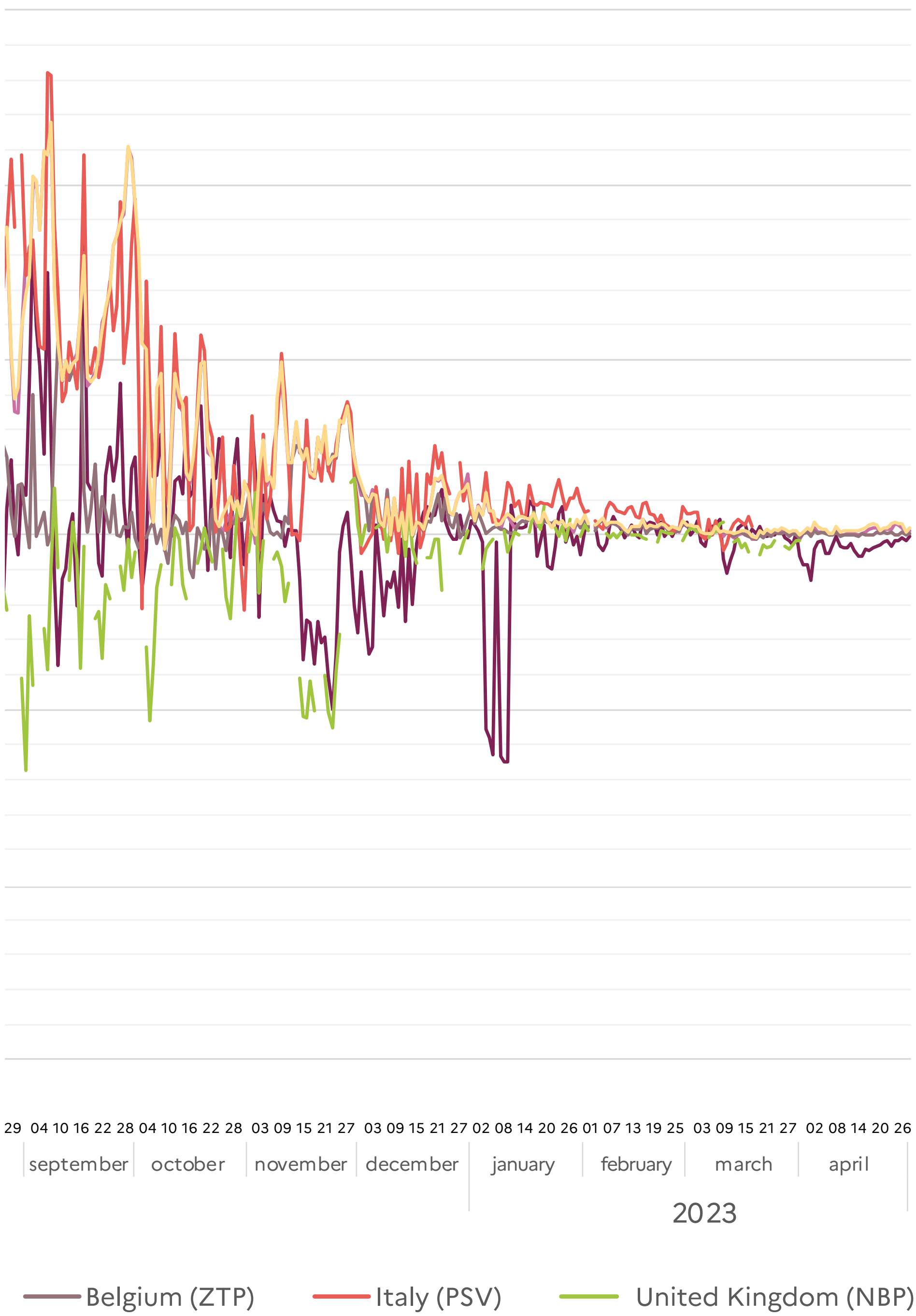
Spanish prices were closer to French prices on average in 2022 (€2/MWh price spread, as in 2021). However, the price spread at this border remained highly volatile during the crisis, reversing very regularly. For example, while in September 2022 gas was traded on the French day-ahead market at a discount of €19/MWh on average compared with Spain, it was traded at a premium of €11/MWh in October 2022. The UK benefited from prices well below those of other European hubs (around €17/MWh below French prices in 2022). The difference was particularly marked between April and July 2022, and in November 2022, in connection with an increase in LNG imports to UK terminals and gas imports from the North Sea.

60. Russian gas flows via the Nord Stream 1 pipeline were sharply reduced from 14 June 2022, before being completely halted on 11 July 2022. On 26 September 2022, an explosion damaged the Nord Stream 1 and Nord Stream 2 pipelines, bringing flows through these interconnections to a complete halt.

Figure 47 Evolution of day-ahead price spreads between France (PEG) and Spain (PVB), Belgium (ZTP), Italy (PSV), the United-Kingdom (NBP), Germany (THE) and the Netherlands (TTF) (October 2021-March 2023)



Source: ICIS Heren and EEX data, CRE analysis


29 04 10 16 22 28 04 10 16 22 28 03 09 15 21 27 03 09 15 21 27 02 08 14 20 26 01 07 13 19 25 03 09 15 21 27 02 08 14 20 26
september
october
november
december
january
february
march
april
2023
Belgium (ZTP)
Italy (PSV)
United Kingdom (NBP)

2.2. Evolution of gas interconnections' operating rules

2.2.1. Operating rules at gas interconnections

The rules holding sway over the use of interconnections within the European Union have been established as part of the implementation of the third European legislative package, which came into force in 2009. They are highly harmonised, reflecting a model that aims to concentrate transactions on marketplaces in order to promote the liquidity of wholesale markets and guide flows between countries on the basis of price spreads. A total of four network codes and guidelines determine the use of gas transmission networks, covering capacity allocation, tariff structures, balancing, network interoperability and congestion management.

Guidelines on congestion management procedures ("CMP")

The purpose of the European Commission's Decision 2012/490/EU of 24 August 2012[61] is to prevent or manage situations of contractual congestion at interconnection points, namely cases where requests for capacity exceed the capacity available for sale (the capacity that may be physically available). It provides for 4 mechanisms: use-it-or-lose-it (UIOLI) of long-term capacity, overbooking, capacity surrender and use-it-or-lose-it (UIOLI) of daily capacity.

Network code on interconnection capacity allocation rules ("CAM")

Regulation (EU) 2017/459 of 16 March 2017[62] (known as the "CAM" code), repealing Regulation (EU) 984/2013 of 14 October 2013, governs capacity allocation at interconnections between market areas. It has harmonised, at all interconnection points within the EU, capacity products and allocation rules, based on auctions organised according to an identical timetable at all interconnection points.

61. Commission Decision of 24 August 2012 on amending Annex I to Regulation (EC) No 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks
62. Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013

Network code on gas transmission network balancing rules ("BAL")

Regulation (EU) 312/2014 of 26 March 2014[63] (known as the "BAL" code) establishes a market-based balancing system harmonised at European level. For both market players and network operators, this system consists in using the wholesale markets to manage the balance between gas injections into the networks, on the one hand, and gas consumption by end customers, on the other.

Network code on interoperability and data exchanges ("INT")

Established by Regulation (EU) 2015/703 of 30 April 2015[64] (known as the "INT" code), its aim is to eliminate obstacles to gas exchanges due to incompatibilities of a technical nature. It relates in particular to interconnection agreements or the odourisation of gas.

Network code on the harmonisation of gas transmission tariff structures ("TAR")

Established by Regulation (EU) 2017/460 of 16 March 2017[65] (known as the "TAR" code), it concerns the harmonisation of tariff structures for gas transmission and aims at improving the transparency of gas transmission tariffs within the European Union and, above all, to avoid discrimination between domestic transmission and cross-border flows.

63. Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a network code on gas balancing of transmission networks
64. Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules
65. Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas

2.2.1.1 Capacity allocation at interconnections

Transmission capacity at interconnection points within the European Union is marketed on different maturities, from several years in advance to the day the gas is delivered. At present, the various products (yearly, quarterly, monthly, daily and intraday) are marketed at auctions held at the same time at all borders. Capacity at French borders is offered for sale on the PRISMA platform.

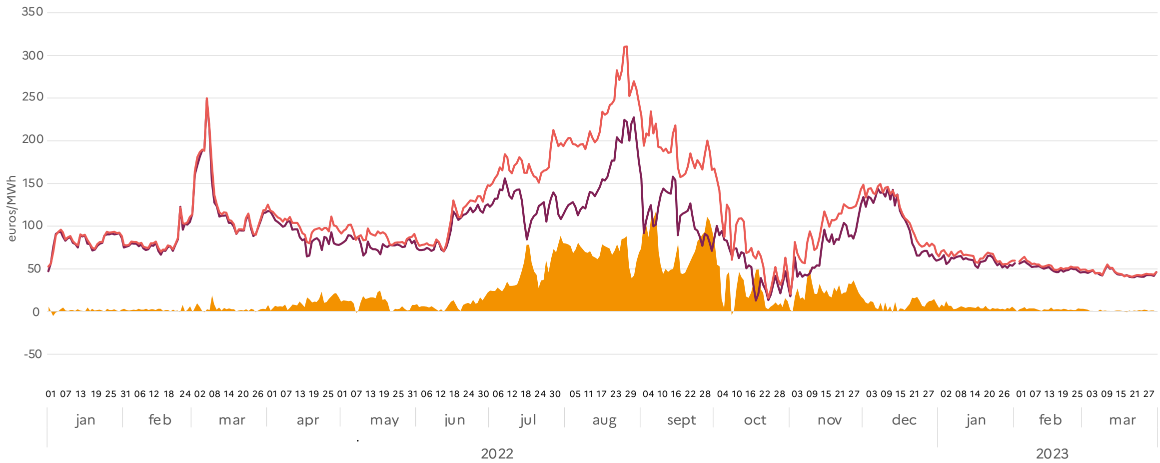
The auctions held in 2020 and 2021 showed that the needs expressed by market players could be met by the capacities available at European interconnection points, resulting in a very high level of price convergence between national marketplaces. In their market monitoring report published in July 2022[66], ACER and CEER noted that price convergence had remained strong despite the imbalances that affected the European market over this period (drop in gas demand due to the COVID-19 pandemic, excess LNG supplies, economic recovery in 2021), which demonstrates a high level of integration. Over 2021 as a whole, the degree of price correlation and convergence was very high in North-Western Europe, where price spreads remained well below €1/MWh, i.e. below the cost of transport between marketplaces. It should be noted that, despite the very sharp increase in prices in 2021, spreads between marketplaces remained fairly stable in the second half of 2021.

However, this was no longer the case for 2022, which saw record price spreads between marketplaces, reaching more than €150/MWh at the height of the crisis in the summer of 2022 (see Figure 48 illustrating the evolution of the price spread between the French and German markets). Among the key factors are the decline in pipeline supplies from Russia offset by increased LNG imports, the capacity constraints for transporting gas from west to east and the limited LNG regasification capacity in Northern Europe. These new congestions led to a very sharp rise in prices for subscribing interconnection capacity at certain borders, particularly from the Netherlands to Germany. The strong price spreads on wholesale markets observed in 2022 pushed up the value of capacity. Strong demand sometimes led to the failure of auction procedures that follow a price increment process until demand is equal or lower than offer ("ascending clock"). The price increments between each auction round were then too small to close the auction in the allotted time. It therefore happened that capacity could not be allocated even though demand was very high. The TSOs often anticipated this problem by modifying the price increments shortly before the start of the auction (flexibility granted by the auction platforms) according to the price spreads observed between marketplaces.

At the beginning of 2023, price spreads returned to levels close to those prevailing before the crisis (i.e. €1 to €3/MWh), due to a reduction in gas demand, an increased availability of LNG import capacity and the rapid development of LNG import capacities in countries where it had lacked.

66. ACER/CEER Gas Wholesale Market Monitoring Report, July 2022

Figure 48 Evolution of the day-ahead price spread between France and Germany from January 2022 to March 2023



Source : ICIS Heren and EEX data, CRE analysis

While the capacity allocation processes governed by the CAM network code were generally resilient during the gas crisis, there is still room for improvement. Back in 2020, the European Federation of Energy Traders (EFET) made proposals to offer more auction windows and greater flexibility in the auction rules (see Box n° 9 below).

BOX N° 9

The revision of the CAM network code should introduce more flexible allocation rules

The CAM network code was designed more than a decade ago, at a time when contractual congestion was frequent at many interconnection points in Europe and when the need for harmonisation was dominant. The code provides for the auctioning of capacity products according to a common calendar at all interconnection points within the European Union. Each product (yearly, quarterly, monthly, etc.) is sold on a single date[67], simultaneously throughout Europe. Since it came into force, contractual congestion has been reduced, the liquidity of European hubs has improved and price convergence has been strengthened (apart from the supply crisis period of 2022).

Despite this positive assessment, some players have called for a review of the CAM code rules to bring them more in line with the current needs of market players. In particular, at the beginning of 2020, the European Federation of Energy Traders (EFET) submitted a proposal[68] to ACER and ENTSOG to increase the number of capacity auctions, in order to increase arbitrage opportunities for market players.

EFET and its members consider the current timetable is too restrictive as it does not allow capacity to be purchased when market conditions are favourable. EFET proposes to keep the auction calendar for yearly, quarterly and monthly products provided for in the CAM code (with the ascending clock algorithm) and to complement it with uniform price algorithm auctions on days when no auction is organised for these products.

EFET's proposals were studied by the regulators and ENTSOG, which conducted a public consultation in early 2021 to gather stakeholders' views on these proposals and, more generally, on the degree of satisfaction with the CAM rules (auction parameters, capacity products, etc.). ENTSOG then formulated alternative proposals[69] for consultation during the summer of 2022. On the basis of feedback from market players, ACER and ENTSOG published their proposals in May 2023, which include the introduction of additional auction dates for yearly, quarterly and monthly products, the possibility for market players to acquire monthly products up to 3 months in advance within the same quarter, and the possibility of acquiring a greater variety of capacity products. These were presented to market players at the 37th European Gas Regulation Forum organised by the European Commission in Madrid on 11 and 12 May 2023. The Forum's conclusions identified the CAM rules as a priority area for revision.

67. With the exception of quarterly products, which are offered several times a year.
68. https://www.gasncfunc.eu/gas-func/issues/01/2020/view
69. Discussed on 27 June 2022 at an online public workshop

CRE has played an active role in this work from the outset: introducing further flexibility is an important issue, particularly in order to adapt the rules more closely to market conditions. In addition to increasing the number of auction windows for standard products, the aim is also to be more agile so as to avoid having to follow the procedure for amending the code for any change, however minor. Indeed, any amendment to the provisions of a network code must be submitted by ACER to the European Commission and must ultimately be adopted by the Council of the EU and the European Parliament (the so-called «comitology» process).

2.2.1.2 Contractual congestion management at interconnection points

For market players, holding capacity grants the right, but not the obligation, to use that capacity ("nomination" process). To avoid abusive withholding of capacity (e.g. where players reserve volumes in excess of their needs), contractual congestion management mechanisms consist in making available to other users those volumes of non-nominated capacity, or to discourage excessive subscriptions by providing for the possibility of restricting rights in the event of recurrent underutilisation. This is typically the case when network users are unable to obtain transmission capacity, despite its physical availability, which constitutes contractual congestion. The European Union adopted guidelines on this subject in 2012. The emergency Regulation adopted in 2022 to deal with the crisis has strengthened some of these provisions in order to facilitate the flows of gas between Member States.

The contractual congestion management mechanisms applied in France

In the European Union, congestion management at onshore interconnection points is governed by the Guidelines on Congestion Management Procedures (CMP)[70], adopted in 2012. According to these guidelines, TSOs must implement mechanisms to prevent contractual congestion situations or resolve them when they arise. The aim of the mechanisms provided for is to return unused capacity so that it can be offered for sale as part of the usual capacity allocation processes, in particular by auction under the conditions laid down in the CAM network code.

The Guidelines provide for four contractual congestion management mechanisms. The first (binding) mechanism consists in withdrawing subscribed capacity from users in the event of recurrent under-utilisation. This is known as long-term use-it-or-lose-it (LT UIOLI). A restitution procedure allows players to return, on their own initiative, some of the capacity they have subscribed, which is then offered again at CAM auctions (surrender). For short-term maturities, Member States can choose between two procedures: (i) oversubscription and buy-back (OS-BB), which consists in TSOs selling more capacity than the interconnection physically allows and buying back the surplus in the event of physical congestion (nominations exceeding technical capacity), and (ii) firm day-ahead use-it-or-lose-it (FDA UIOLI), which makes it possible to offer daily capacity by restricting shippers' renomination rights.

70. 2012/490/EU: Commission Decision of 24 August 2012 on amending Annex I to Regulation (EC) No 715/2009 of the European Parliament and of the Council on conditions for access to the natural gas transmission networks

BOX N° 10

The four contractual congestion management mechanisms in the EU

1.

The long-term use-it-or lose-it (LT UIOLI) allows TSOs to systematically withdraw all or part of booked capacities that are underused by network users at a given interconnection point, when this user has neither sold or offered these capacities on the secondary market at reasonable conditions, while other network users request for firm capacity.

2.

The surrender mechanism consists in TSOs to accept any firm capacity restitution booked by a network user at a given interconnection point, with the exception of daily and within-day capacity products. The surrendered capacity will be re-offered during the standard allocation process and will only be allocated once all available capacity has been sold out. The network user keeps its rights and duties under the capacity contract as long as the capacity has not been reallocated by the TSO.

3.

The oversubscription and buy-back (OS-BB) mechanism allows TSOs to offer firm capacity in excess of technical capacity at interconnection points. If nominations are above the technical capacity, the TSOs must buy back the excess capacity from the shippers. The calculation of capacity offered in addition to technical capacity is therefore based on statistical scenarios of capacity use and a risk analysis in order to avoid excessive buy-back obligations. Additional capacity is only allocated if all other capacity, including capacity resulting from the application of other congestion management procedures, has been allocated.

4.

The firm day-ahead use-it-or-lose-it mechanism (FDA UIOLI) allows the TSO to «requisition» any capacity not nominated by its holder and to offer it for sale again.

At the French interconnection points, the long-term UIOLI, OSBB and capacity surrender mechanisms are implemented. It has also been decided to apply an additional mechanism based on the same principle as the FDA-UIOLI, the only difference being that it preserves the re-nomination rights of holders of firm capacity. This mechanism, known as use-it-and-buy-it (UBI), allows shippers to over-nominate over a daily or within-day horizon capacity that has already been subscribed but not nominated. Capacity is then allocated on an interruptible basis, leaving the primary holders of firm capacity the right to nominate their subscribed capacity, even if it has been reallocated. This system, which is highly effective for reallocating daily capacity that has not been nominated, had been applied for several years only in the main flow direction, before being extended to both directions at all French interconnection points from 2021[71].

The EU "Gas Solidarity" emergency Regulation has reinforced congestion management in Europe

During the supply crisis, the European Union wished to provide Member States with additional tools to maximise the use of interconnection capacity in the face of the consequences of the disruption in Russian gas supplies and major changes to supply patterns. The emergency Regulation known as "Gas Solidarity"[72], which came into force in December 2022 for a period of one year, notably provides for reinforcing the application of the contractual congestion management procedures set out in the European guidelines and supplementing them with several additional tools.

From 1st April 2023, this Regulation provided for the application, at all physical or virtual interconnection points in the EU, of a use-it-or-lose-it procedure applied on a monthly basis. The aim was to enable TSOs to identify unused capacity from one month to the next in order to make more volumes of unused capacity available to the market more quickly than had been possible under the European long-term UIOLI rules.

The national regulatory authorities had the option to derogate from the application of this measure by implementing either a firm day-ahead UIOLI mechanism, or an OSBB enabling at least 5% additional capacity to be offered, or to offer, on an interruptible basis, non-nominated firm daily capacity. This latter system meets the characteristics of the UBI mechanism that had been generalised to French interconnection points in 2021. For this reason, CRE chose to derogate from the application of the monthly UIOLI, after consulting neighbouring regulators[73].

All European regulators have preferred to apply one of the three derogation mechanisms provided for rather than the monthly UIOLI mechanism newly introduced by the European Commission.

All in all, the congestion management measures implemented in France have proved to be very effective and have enabled to make maximum use of all interconnection capacities that are physically available.

71. In application of the provisions of CRE deliberation n° 2021-274 of 16 September 2021 relating to the operation of the single gas market area in France.
72. Council Regulation (EU) 2022/2576 of 19 December 2022 enhancing solidarity through better coordination of gas purchases, reliable price benchmarks and exchanges of gas across borders
73. CRE deliberation of 30 March 2023 deciding on the implementation of the provisions of Article 14 of Council Regulation (EU) 2022/2576 of 19 December 2022

BOX N° 11

The "congested tariff" system amended in 2021 to prevent situations of artificial contractual congestion

Each year, CRE determines the level of the regulated tariff for access to gas transmission capacity at interconnections, which constitutes the reserve price (i.e. the floor price) for the yearly capacity auctions. This tariff is used as the basis for calculating the level of tariffs for shorter-term capacity products (quarterly, monthly, daily and intraday) by applying a temporal factor and a tariff multiplier: the more capacity is reserved over the short term, the more expensive it is, in order to encourage players to reserve capacity over the long term.

The level of these tariff multipliers is governed by the European network code on the harmonisation of tariff structures. This network code stipulates that the level of multipliers should be set between 1 and 1.5 for quarterly and monthly capacity products, and between 1 and 3 for daily and intraday capacity products (except in duly justified cases).

In France, when a point is considered congested (i.e. when firm annual products are allocated with a premium on top of the regulated tariff), these tariff multipliers do not apply anymore (for quarterly, monthly and daily products). When annual capacity is unavailable, it is indeed considered desirable for shippers to be able to access capacity for less than one year at no extra cost. This is known as the "congested tariff" system.

However, the fact that the selling price of the capacity is higher than the reserve price does not necessarily mean that the point is commercially congested, as the volume of allocated capacity may ultimately be lower than the volume of capacity that was marketed. There have in fact been cases of manipulation of the auction rules, apparently aimed at triggering the congested tariff. This was observed during the annual auctions in July 2018, 2019 and 2020 at the Pirineos interconnection point between France and Spain. CRE and Teréga were able to establish that this was a coordinated strategy by a limited number of market players aimed at generating an auction premium while allocating only small volumes of capacity.

Wishing to preserve the principle of the "congestion tariff" while eliminating any windfall effect, CRE decided in its deliberation n°2021-15 of 21 January 2021[74] that the congestion tariff would henceforth only be triggered if the capacity subscription rate at the yearly capacity auction reaches a 98% threshold. The congestion tariff was later abolished in the ATRT8 tariff, which applies from April 2024.

74. CRE deliberation of 21 January 2021 deciding on update of the tariff for use of GRTgaz's and Teréga's natural gas transmission networks as from 1 April 2021

BOX N° 12

A new regulated tariff for gas transmission for 2024-2027

In January 2024, CRE adopted a new tariff for the use of GRTgaz's and Teréga's natural gas transmission networks (known as "ATRT8"), which has been applied since 1st April 2024 for a period of 4 years.

A tariff structure compliant with the Tariff network code's principles

In accordance with the provisions of the Tariff network code, CRE submitted its proposed methodology for public consultation between 26 July and 9 October 2023, which was forwarded to ACER.

To establish the ATRT8 tariff structure, CRE used the same methodology as for the previous tariff ("ATRT7"), which was considered by ACER to be compliant with the principles of the TAR code. However, the flow scenarios used to calculate the reference transmission distances were adapted to take account of the end of long-term contracts, the reorganisation of supplies in Europe and the decline in gas consumption. The structure of the ATRT8 tariff has been set to reflect the costs incurred by users in order to avoid cross-subsidies between categories of users: the unit costs of cross-border flows and of supplying domestic consumers are aligned.

An amended regulatory framework to anticipate the decrease in gas consumption

In its study on the future of gas infrastructures (see Box n° 13), CRE noted that the existing gas transmission network will still be needed in 2050 (less than 10% of infrastructures could be decommissioned or converted to hydrogen), even in scenarios where consumption falls significantly.

These findings led CRE to reexamine the adequacy of the regulatory framework and the determination of operators' authorised revenues with the medium- and long-term challenges identified in the study, with a view to guaranteeing the economic sustainability of the gas system. CRE organised a public consultation during the summer of 2023 to gather stakeholders' views on ways to avoid making future users bear the fixed costs incurred by the current use of infrastructure. The ideas put forward included changing the method for depreciating the assets that make up operators' regulated asset bases (RAB) and no longer indexing the asset base to inflation, by moving from a real remuneration model to a nominal model. These two guidelines have been adopted in the tariff decision for new assets: assets included in the RAB from 2024 onwards will not be revalued for inflation and a nominal rate of return will be applied, and the depreciation period for long-life assets has been reduced (from 50 to 30 years for pipelines, for example). The regulatory framework for assets that entered the RAB before 2024 remains unchanged.

2.2.2. Capacity subscriptions at interconnections

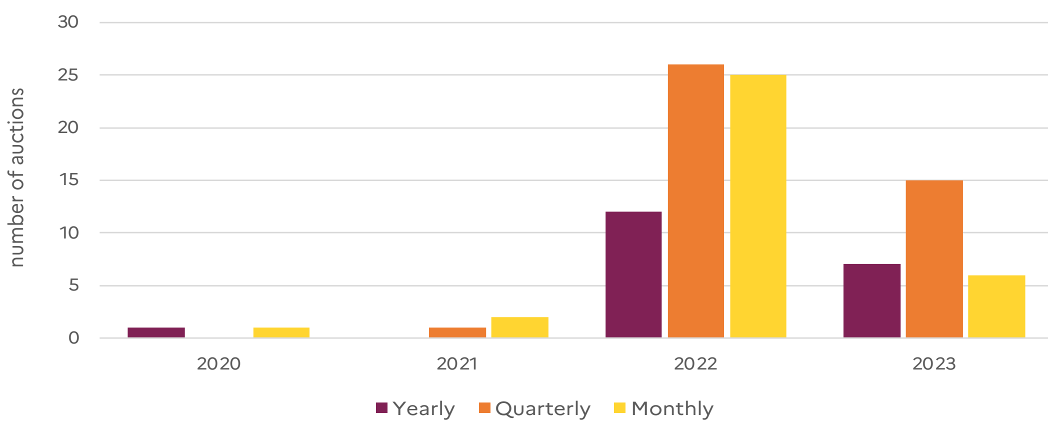
Transmission capacity at interconnections is allocated *via* auctions, whose characteristics and timetable are defined by the European network code on capacity allocation mechanisms (CAM code). These auctions are carried out with a reserve price corresponding to the regulated tariff for third-party access to the transmission network (ATRT) in application of the European network code on the harmonisation of tariff structures.

2.2.2.1 Overview of capacity auctions

From 2020 to 2022, the demand for capacity at French interconnection points expressed in the auctions was lower the longer the maturity of the products. As a result, most auctions for long-term products (1 year or more) resulted in very low allocations. This situation was not unique to France, as at the European borders auction premia were only recorded on 18 occasions in 2020 and 14 in 2021 (less than 0.5% of the auctions), including 2 in 2020 and 4 in 2021 at French interconnection points.

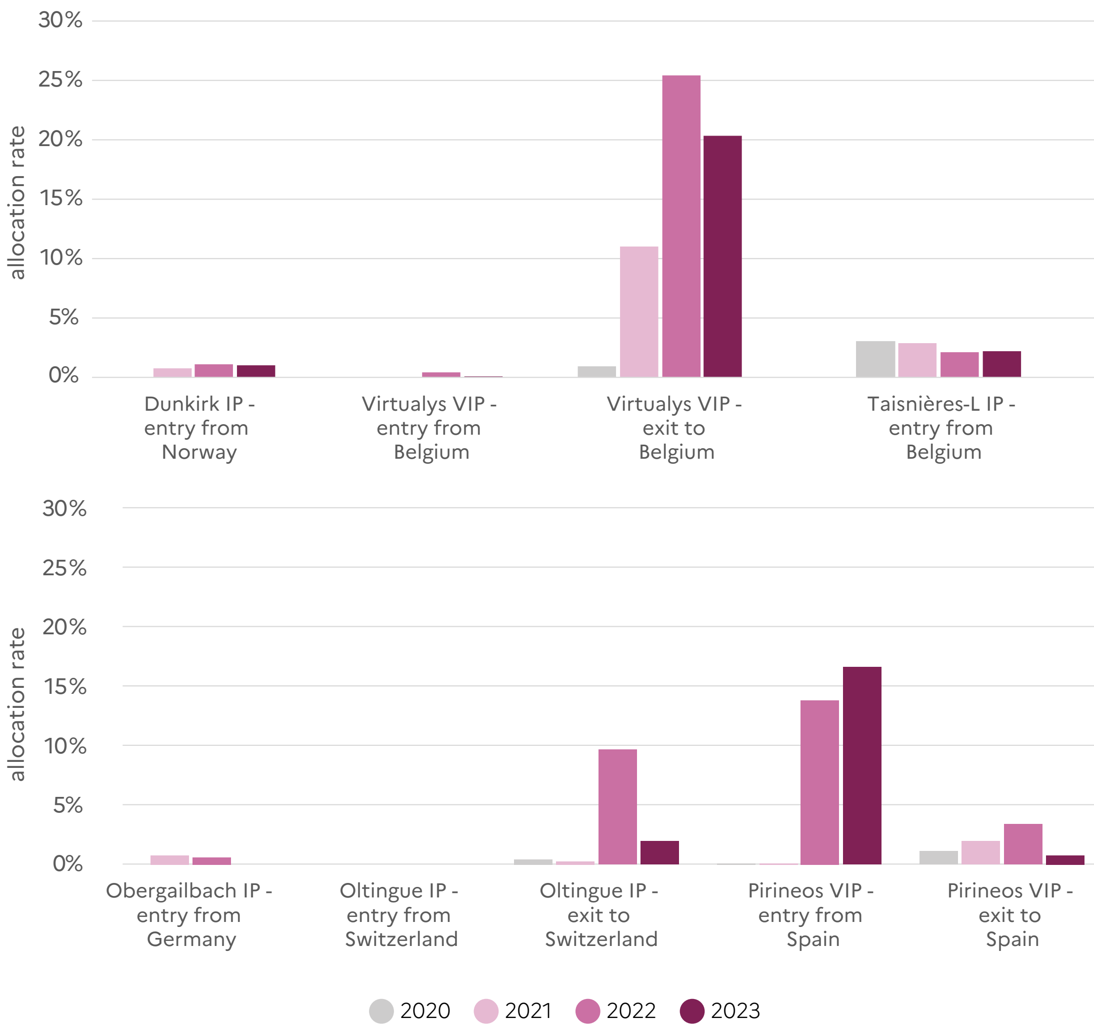
The gas supply crisis radically changed the situation. Strong demand for capacity led to major contractual bottlenecks at certain interconnection points, mainly in north-western Europe. As a result, 246 auctions on the Prisma platform for annual, quarterly or monthly capacity ended above the reserve price in 2022 (i.e. 7% of the auctions), including around sixty at French interconnection points. The situation eased in 2023 compared to 2022, with auction premia recorded on only 69 occasions, including 28 at French borders.

Figure 49 Number of auction premia per capacity product type at French IPs, excluding daily capacities (2020-2023)



Source: PRISMA data, CRE analysis

Figure 50 Capacity allocation rates at French IPs auctioned on the PRISMA platform, excluding daily capacities (2020-2023)



Source: PRISMA data, CRE analysis

At the French borders, the crisis led to a significant increase in allocation rates for annual, quarterly and monthly products, particularly for outflows to Belgium (25% and 20% allocations in 2022 and 2023), outflows to Switzerland (almost 10% allocations in 2022) and inflows from Spain (almost 14% and over 16% in 2022 and 2023). These allocations are in addition to long-term bookings, which account for the majority of subscriptions.

These subscriptions have been combined with high auction revenues at borders where significant price spreads existed. The capacity auctions held in 2022 and 2023 led the French TSOs, GRTgaz and Teréga, to record congestion income (auction premia) of €441 million in 2022 and €15 million in 2023. These surplus amounts are intended to be paid back to network users in accordance with the rules set out in the ATRT gas transmission tariff.

2.2.2.2 Subscription rates at interconnection points and exit points from LNG terminals

Interconnection points

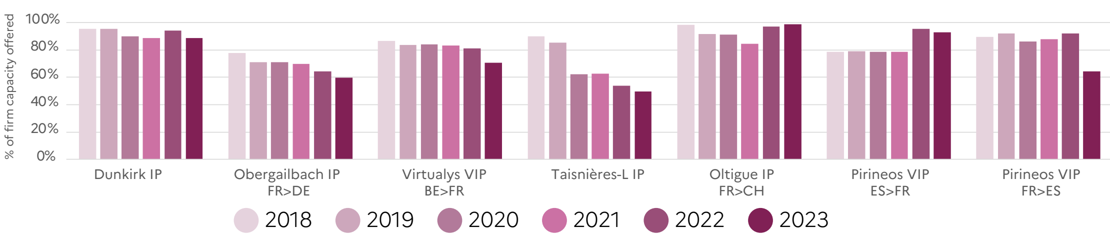
Long-term subscriptions at French interconnection points were very high during the crisis (between 60% and 99% in 2023), as these interconnections were built in return for import contracts or long-term subscriptions when investments were decided following calls for tenders ("open seasons").

Oltingue was the most subscribed interconnection point, with a level of 99% in 2023 in the France to Switzerland direction. Dunkerque was also highly subscribed (94% in 2022 and 89% in 2023). The Virtualys point had high import subscription rates, at 81% and 74% in 2022 and 2023 respectively. Before the crisis, Pirineos was subscribed at higher levels in the France to Spain direction than in the opposite direction, before a reversal was observed from 2022 onwards. Subscriptions at this interconnection point rose significantly in the direction of imports to France from 2022 (exceeding 90% in 2022 and 2023), while they fell considerably in the direction of exports in 2023 due to the end of several long-term subscriptions, to 64%.

Over the last years, Obergailbach and Taisnières L were the least subscribed points. After a sharp fall in subscriptions in recent years, they were subscribed at 60% and 50%, respectively, in 2023. Despite the decision by the Netherlands to cease gas production, subscriptions at Taisnières L were not reduced to zero because of the commitment by the Netherlands to honour signed contracts until the end of the French conversion plan in 2029.

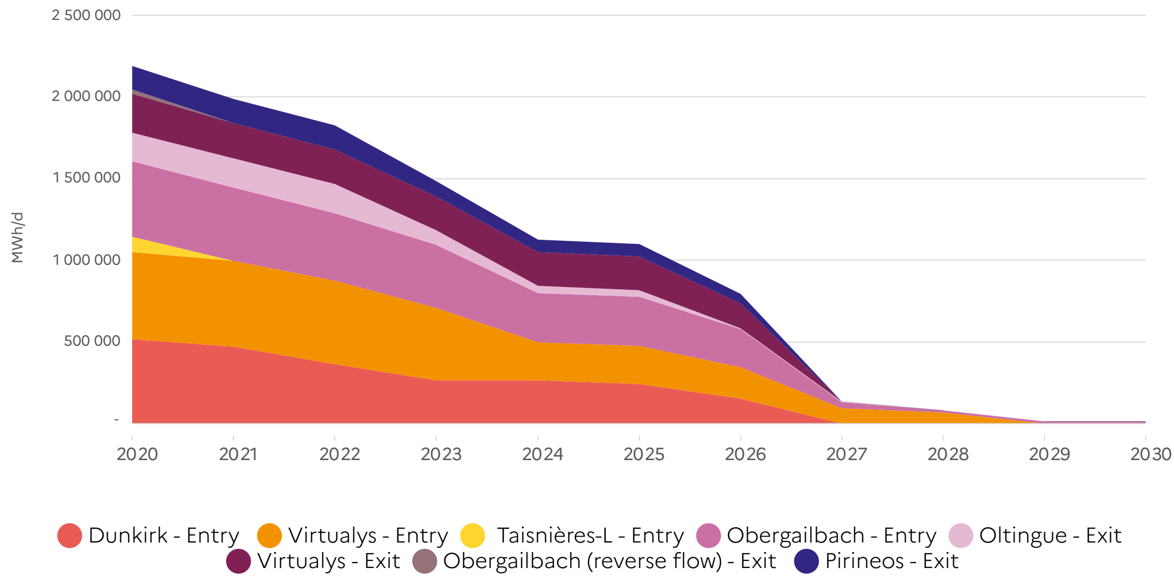
Long-term contracts have long been favoured to secure supply routes, thus bringing a degree of stability to the European gas system. However, in recent years, changes in the way markets operate have gradually led players to adopt supply strategies that are more focused on wholesale markets and short-term maturities. The low level of long-term capacity subscriptions on the PRISMA platform illustrates this trend, which is becoming more pronounced as long-term subscriptions at the French borders expire (see Figure 52 below).

Figure 51 Yearly average subscription rates of firm capacities at French interconnection points (2018-2023)



Source: GRTgaz and Teréga data, CRE analysis

Figure 52 Evolution of long-term subscription rates of capacities at French interconnection points (2020-2030)



Source: GRTgaz and Teréga data, CRE analysis

Entry points from LNG terminals

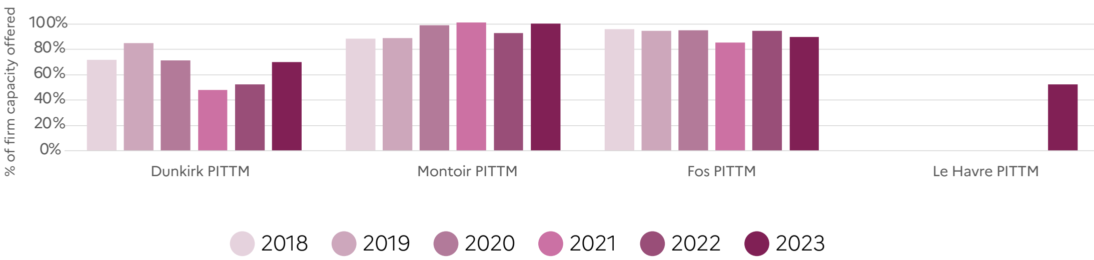
Subscription rates for network entry capacity from LNG terminals (PITTM) were also high (see Figure 53), in line with the existence of long-term LNG import contracts which lead market players to subscribe multiannual capacity at LNG terminals. Over the period 2020-2023, entry capacity into the network from the Montoir terminal was almost entirely subscribed (98% on average) and capacity from the Fos terminals was subscribed by more than 90% on average. The fall in volumes subscribed at the Fos PITTM in 2021 was linked to the fall in capacity at the terminal. The Dunkirk terminal had a lower subscription rate, at 60% on average since 2020. In addition, in response to the gas supply crisis, adjustments have been made at the LNG terminals to maximise the number of unloading slots to support the European gas system.

In agreement with CRE, Elengy's terminals have adjusted and improved the methods used to sell their capacity and have carried out operations to optimise the available capacity. In particular, CRE authorised Elengy to implement new arrangements for selling additional capacity from 1st July 2022. These new arrangements, based on an auction system, make it possible to allocate terminal capacity at market value and reduce the risk of capacity being subscribed solely for speculative purposes to the detriment of security of supply.

These arrangements enabled to value the new capacity made available at the Fos Cavaou and Fos Tonkin terminals. At the Fos Cavaou terminal, technical debottlenecking operations[75] enabled regasification capacity to be increased by 11 TWh in 2022, and by a further 2 TWh in 2023 (bringing the terminal's capacity from 100 TWh at the beginning of 2022 to 113 TWh at the end of 2023), which could be marketed under these new terms and conditions. An additional 2 TWh was made available at the Fos Tonkin terminal.

TotalEnergies reserved 50% of the annual capacity of the new terminal at Le Havre, in accordance with the terms of the exemption from third-party access granted to it.

Figure 53 Evolution of the average subscription rate of capacities at interconnection points between LNG terminals and transmission networks (2020-2023)



Source: GRTgaz data, CRE analysis

With 398 LNG tankers arriving in France in 2022 and 360 in 2023, and the terminals operating at 95% of their import capacity in 2022 and 80% in 2023, French LNG terminals experienced record activity. In addition, new tenders were launched, leading to subscriptions for new long-term capacity.

At the Dunkirk terminal, a market call was launched in February 2022 for 3.5 Gm^3/year of capacity for the 2023-2036 period. All the capacity offered was subscribed until 2026.

At the Fos-Tonkin terminal, the extension of the terminal's activity beyond 2020, until at least 2028, was validated by a call for subscriptions conducted by Elengy in February 2019.

At the Montoir terminal, all of the 3.5 Gm^3/year of capacity offered to the market by Elengy for the 2021-2035 period was subscribed in July 2019 and no additional capacity has been offered to the market since then, as all capacity has been subscribed.

75. A technical debottlenecking consists of removing constraints in the supply chain of an industrial plant in order to increase its capacity.

2.3. The future of gas interconnections

2.3.1. Decreasing gas consumption puts gas interconnections to the test

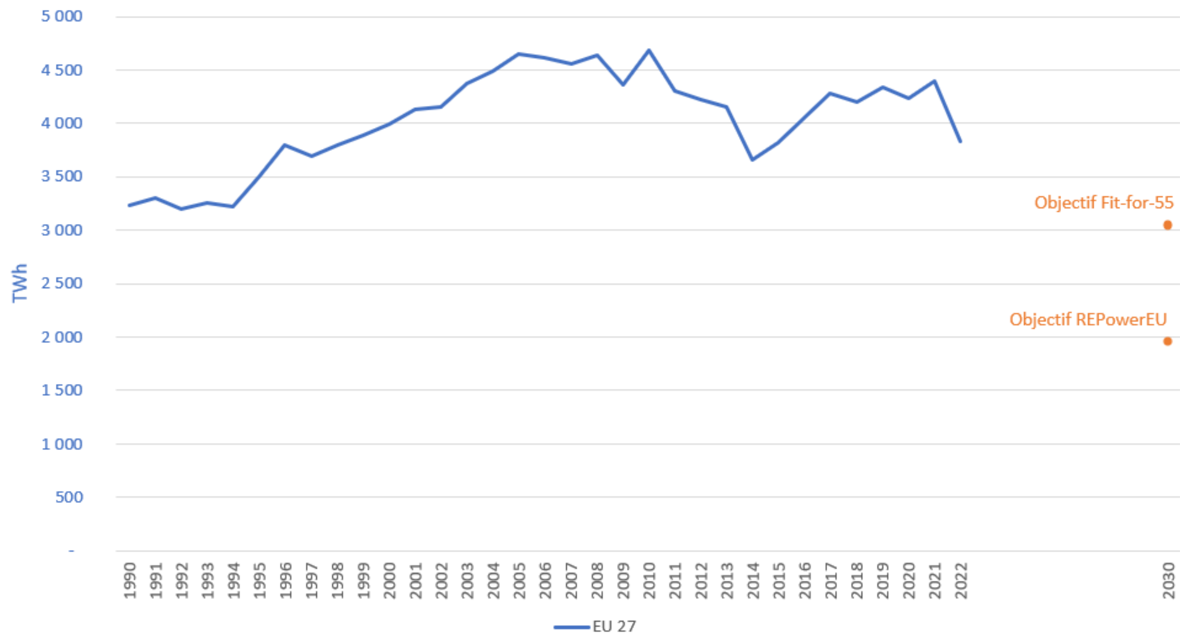
After peaking in the 2000s, the European gas consumption fell sharply in the wake of the 2008 financial crisis and the economic crises that followed, reaching a particularly low level in 2014 due to a combination of weak economic growth and historically high temperatures in Europe. It returned to growth from 2014, then stabilised before the start of the energy crisis in 2022. However, trends vary from one Member State to another. For example, before the energy crisis of 2022, gas consumption in Spain and Portugal had risen by 93% and 144% respectively between 2000 and 2021, while France's consumption had risen slightly by 4% and Denmark's and the Netherlands' had fallen by 46% and 13% respectively.

In recent years, the Green Deal and, later, the "Fit-for-55" legislative package have recognised the need to reduce fossil-gas consumption in the EU. Natural gas is set to be replaced by gases from renewable sources (biogas and synthetic gas), but the volumes involved will not be comparable to those currently being consumed. To meet Europe's climate objectives, the Fit-for-55 package sets a target of reducing the EU's natural gas consumption by 30% by 2030 compared with 2019 (i.e. a reduction in annual consumption of 116 Gm^3). Following Russia's invasion of Ukraine, this target was raised in the REPowerEU plan, which calls for a further reduction of around 100 Gm^3 by 2030 compared with the Fit-for-55 targets (i.e. a reduction of around 55% compared with 2019).

In France, after significant growth in the 1990s, natural gas consumption has stabilised since the early 2000s at around 500 TWh (HCV). Affected by the Covid-19 crisis in 2020 and 2021, then by the consequences of rising energy prices in 2022, French gas consumption fell by 10% between 2019 and 2022. This decrease became even more marked in 2023, with consumption 20% lower than in 2019.

Adopted in 2020, the 2019-2028 Multiannual Energy Plan (PPE) and the National Low Carbon Strategy (SNBC) provide for a significant reduction in French natural gas consumption. The PPE anticipates a 22% reduction in 2028 compared with 2012, which should be accompanied by an increase in the share of renewable gas to 7-10% of consumption by 2030. In the long term, the SNBC foresees a reduction of 40% to 60% between 2020 and 2050, depending on the scenario. By that date, all gas consumption will have to be met by renewable gas.

Figure 54 Evolution of natural gas consumption in the EU since 1990 and EU objectives to 2030



Source: Eurostat data, CRE analysis & editing

Generally speaking, the fall in gas consumption raises the question of the future use of gas infrastructures and the sustainability of their access tariffs, including for cross-border exchanges. Infrastructure costs will have to be spread over a consumption base that could fall faster than these costs, which increases the risk of stranded costs (i.e. infrastructure that becomes useless before it has been amortised).

In this context, decisions to invest in new gas import assets or to maintain existing interconnection capacity in service must be subject to in-depth analysis to ensure that they are in the interests of the gas system and that the current framework is capable of financing them.

When approving operators' investments, CRE's objective is to limit the risk of stranded costs, bearing in mind that national decisions can have an impact on neighbouring countries as national networks are interdependent. The regulators therefore recommend that the ten-year infrastructure development plans also include forecasts for the withdrawal or conversion of assets, to transport hydrogen or CO_2 for example.

The study carried out by the CRE (see Box n° 13 below) assessed in particular the need to maintain cross-border capacity in France, with respect to French consumers' needs in 2030 and 2050 but also from the point of view of neighbouring countries.

BOX N° 13

CRE's report on the future of French gas infrastructures towards 2030 and 2050

In 2023, CRE published a study on the future of gas infrastructures in France in the context of achieving carbon neutrality by 2050[76]. It aimed at assessing the impact of falling gas consumption on transmission and distribution networks, storage infrastructures and LNG terminals.

Three production and consumption scenarios looking ahead to 2030 and 2050 were studied, based on already-existing scenarios (developed by the French Environment and Energy management Agency, ADEME, and by gas network operators). Each scenario represents a specific development in line with the objective of carbon neutrality. They project gas consumption to be between 165 TWh and 320 TWh in 2050. CRE also set itself the target of studying scenarios in which gas entries and exits are balanced in France on a yearly basis, with annual production of green gas meeting domestic consumption. This enables to phase out fossil-gas consumption by 2050, while ensuring France's energy sovereignty. However, cross-border exchanges would still be possible, to supply neighbouring countries, to ensure the balancing of the French network occasionally, and to guarantee security of supply in the event of a contingency.

These scenarios have two opposing effects on gas infrastructures, which CRE sought to model: on the one hand, the adaptation of networks to accommodate local production of green gas distributed throughout the country and, on the other hand, the changing needs for the delivery of this gas to consumers.

All the scenarios assume that imports of fossil gas for domestic consumption will cease by 2050, although fossil gas may still enter the country for transit to other countries. Given the projected fall in fossil gas consumption in neighbouring countries (in line with their National Energy and Climate Plans), the study assumes a significant fall in exports to Spain in all scenarios (between -40% and -95% in 2050 compared with the 2015-2020 period) and to Italy in two scenarios (-38% and -64% in 2050). Transit to Germany is assumed to be zero on a yearly basis by 2050, due to the fall in German fossil-gas consumption and the development of LNG import capacity in Germany. On the basis of the transit flows modelled by the TSOs, CRE considered lower interconnection capacities than today at entry points from Norway, Belgium, Germany and from LNG terminals, and at exit points to Belgium, Spain and Italy.

76. CRE report on the future of gas infrastructures in 2030 and 2050, in a context of achieving carbon neutrality, April 2023

Three main lessons can be drawn from this study with regards gas interconnections in France:

— The current gas transmission network remains largely necessary even in the event of a sharp fall in consumption, to compensate for the geographical and temporal differences between consumption and production. The «releasable» assets are concentrated on the main transmission network. These are twinned pipelines, which will account for 3% to 5% of the kilometres of transmission pipelines by 2050, as well as at least 7 compressor stations.

— France will continue to play an important role in the European gas system, according to an analysis of the climate and energy plans of the countries to which France is interconnected. As a result, transit flows to its European neighbours will require France to maintain a network that is oversized compared to national needs alone. By 2050, transit needs will require maintaining 2% to 3% of the pipelines and close to a quarter of the compressor stations on the main network (these network elements could otherwise be decommissioned).

— Large LNG terminals should continue to be necessary for France's security of supply in the event of contingencies and for European solidarity in the medium to long term. These terminals currently benefit from long-term subscriptions. It is important to avoid taking measures that undermine the current subscription commitments that enable terminals financing, and to adapt the conditions of their regulation to provide them with more agility in a context of international competition.

CRE will continue to analyse the economic consequences of the various infrastructure configurations envisaged for both operators and consumers, as part of the processes of approving operators' investment programmes and developing infrastructures access tariffs.

2.3.2. The development of new LNG import capacity in Northern Europe

LNG is the main alternative to pipeline gas imports from Russia, but the majority of LNG terminals in operation at the start of the gas crisis were located in the South and West of Europe, far from the areas most affected by the drop in Russian gas flows.

The European Commission's REPowerEU plan set out that the EU's annual LNG imports should increase by 50 Gm^3 by 2030 compared with 2021 to replace Russian gas imports (among other measures). Half of the EU's gas demand would then be met by LNG (compared with 20% in 2021).

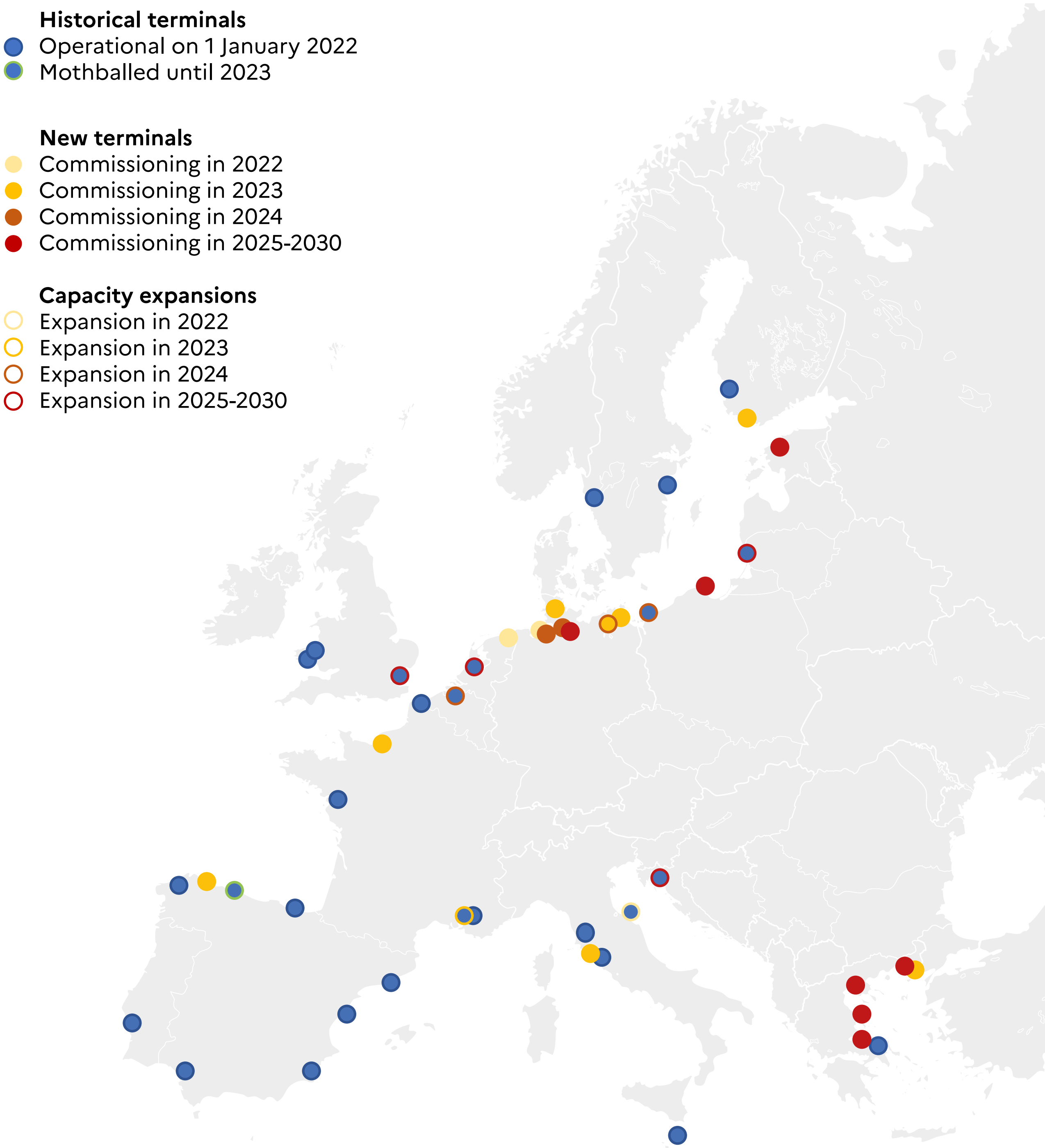
As part of this plan, the European Commission commissioned ENTSOG to assess the additional gas infrastructure and interconnection needs in order to eliminate gas transport bottlenecks in Europe and to make the most of the EU's LNG import capacity against a backdrop of a halt to Russian gas imports. Most of the projects identified were intended to secure supplies to the countries of Central and Eastern Europe and Germany.

REPowerEU thus proposed the creation of six terminals by the end of 2023 (in Germany, the Netherlands, Cyprus, Greece, Estonia and Finland), with two additional projects by 2030 (in Poland and Croatia), bringing the total EU import capacity to around 200 Gm^3/year. The plan also identified projects to strengthen interconnections and storage sites so that the additional LNG imports can be transported to the consumers for whom they are intended, for example with the development of export capacity from France to Germany (see Box n° 7 : Implementation of physical export capacities to Germany at the Obergailbach interconnection point), and the increase in exit capacity from Belgium to Germany.

The new LNG terminals commissioned across the EU as an immediate response to the fall in Russian gas supplies have exceeded the REPowerEU targets: 10 new LNG terminals came into service in 2022 and 2023 (mainly in the form of floating terminals, which are quicker to deploy than onshore terminals and are movable), mostly in Northern Europe, and 9 additional terminals are expected to be commissioned by 2030. At the end of 2023, the EU already had just over 200 Gm^3/year of regasification capacity (+28% versus end of 2021), and current projects should lead to 260 Gm^3/year by the end of 2025.

These current and future developments should lead to a reorganisation of gas flows on the continent, including at the French borders. Germany, a former transit country for gas from Russia, could become a major gateway for LNG in Europe, re-exporting gas delivered in liquid form to the rest of Europe. In 2023, it became the 6th largest importer of LNG in Europe, with 70 TWh (6.8 Gm^3) of LNG arrivals over the year. By the end of 2024, Germany is expected to have the 3rd largest LNG import capacity in the EU, behind Spain and France. The Netherlands are also playing a growing role in the European LNG market following the commissioning of a new terminal in September 2022 (Eemshaven FSRU). By 2023, the Netherlands will have become the second largest LNG importer in the EU, behind France and ahead of Spain. Italy has increased its LNG import capacity by 40% since the commissioning of a 20-year floating terminal in July 2023.

Figure 55 New LNG terminals commissioned in 2022 and 2023, and projects by 2030



Source: GIE data, ACER and CEER, CRE analysis

2.3.3. A new European legislative package for renewable and low-carbon gases

When the Clean Energy Package was adopted in 2019, the European Commission announced the preparation of a complementary legislative package aimed at decarbonising the gas sector. The work had been launched before the outbreak of the crisis linked to Russia's invasion of Ukraine, then suspended in 2022. Negotiations were concluded at the end of 2023 and the legislative proposal for the "Hydrogen and Decarbonised Gases" package (or revised Gas Package) was definitively adopted on 21 May 2024[77].

In its legislative proposal published in December 2021, the European Commission proposed to revise the rules of the European gas market to accelerate the development of renewable and low-carbon gases, in particular biomethane and hydrogen, and to facilitate their access to European networks and markets. CRE responded to the public consultation launched by the European Commission in spring 2022. In its response[78], it argued in favour of a flexible approach allowing to adapt regulation according to market developments and the practices of industrial players.

To ensure that these renewable and low-carbon gases are properly integrated into the networks and that decentralised production has efficient access to the wholesale market, the new legislative package provides for a greater cooperation between TSOs and DSOs on network access, very similar to the model that has been introduced in France since 2018 around the "right to injection" (see Box n° 14 below), as well as several support schemes for renewable and low-carbon gases.

In particular, in order to encourage the development of renewable and low-carbon gases, the revised gas package provides for the possibility of granting them discounts on network access tariffs and on tariffs for access to storage facilities, as well as total exemption from tariffs at interconnection points. While the European Commission had proposed that these rebates should be systematic, they were finally made optional so that national regulators could modulate them according to the degree of development of national sectors and the existence of alternative support and subsidy mechanisms. This last point was one of the most controversial and CRE, just like other European regulators, expressed the view that such discounts would be unnecessarily complex and ill-suited to the needs of the industry. It is considered preferable to guarantee the competitiveness of low-carbon gases when injected into the system, to ensure that they replace fossil gas.

77. Regulation of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen,amending Regulations (EU) No 1227/2011, (EU) 2017/1938, (EU) 2019/942 and (EU) 2022/869 and Decision (EU) 2017/684 and repealing Regulation (EC) No 715/2009 (recast) and Directive of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen, amending Directive (EU) 2023/1791 and repealing Directive 2009/73/EC (recast)
78. CRE response to the European Commission's legislative proposal on gas decarbonisation, April 2022

The texts adopted also provide for the possibility of modifying the perimeter of entry-exit zones, in order to include gas distribution networks. While the Commission had proposed making this extension of the perimeter of the entry-exit zones compulsory, the final texts make this extension optional, which CRE had requested from the start of the legislative work. This optionality will make it possible to maintain the existing tariff and commercial framework in France, which already provides a guaranteed commercial outlet for biomethane producers.

The revised Gas Package also introduced specific provisions to support the development of the renewable and low-carbon hydrogen market (see section 2.3.4).

BOX N° 14 :

The French "right to injection": a reference for the development of biomethane in the European Union?

The French model has proved its worth and is now a reference in Europe. The principles underpinning France's biomethane "right to injection" framework were taken up by the European Commission in 2021 in its legislative proposal on the Gas Package, and the provisions adopted in 2024 include measures to facilitate access to networks for production facilities that are very similar to those in force in France: cooperation between network operators to develop connection plans and schemes, firm network access subject to operational limitations, and the principle of economic efficiency of connections, and investment in reinforcements.

Although authorised in France since 2011, the injection of biogas into natural gas networks remained in its infancy until the "EGalim" law of 30 October 2018[79] which introduced the principle of a "right to injection" for biogas producers wishing to market their production by injection into gas transmission and distribution networks. The law entrusted CRE with the role of defining and implementing the rules governing the right to injection and supporting the development of the sector, in particular by validating the network connection schemes and zoning proposed by operators, and by defining the rules for covering costs.

Once the biogas has been purified, the injection of this "biomethane" represents an opportunity for the gas system, enabling to decarbonise a sector that is still largely fossil-based. However, it represents both a technical and a financial challenge, and entails a major change in the French gas network's design.

In France, a decentralised production spread across the national territory has been developing over the last decade, which requires increasing network capacity to receive this production. This decentralised injection raises challenges for the gas system, which was designed and built to supply domestic consumption points from a limited number of gas extraction and import points.

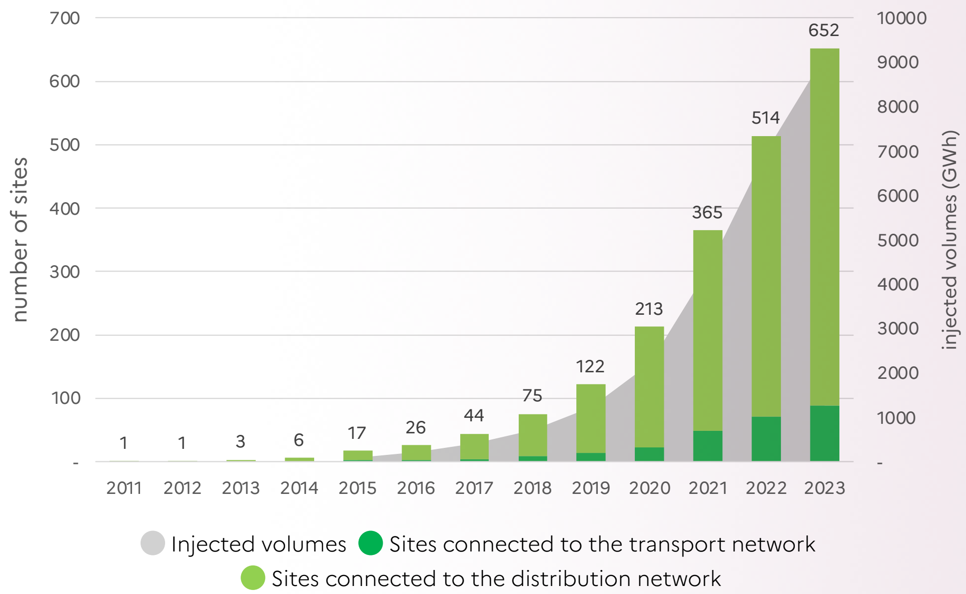
Until the implementation of the right to injection, the cost of network reinforcements was borne entirely by producers, as and when they were connected. Facilities connected at a later stage could therefore benefit free of charge from reinforcements financed by facilities already connected. Since 2018, when a biogas production facility is located close to a natural gas network, the network operators must carry out the necessary reinforcements to enable the biomethane produced to be injected (subject to compliance with the principle of economic efficiency), and producers only have to pay a portion of the connection and reinforcement costs (thanks to the tariff rebate and cost sharing).

79. Law n° 2018-938 of 30 October 2018 for balanced trade relations in the agricultural and food sector and healthy, sustainable food accessible to all

The French framework implemented since 2018 has led to an acceleration in the number of sites connected to the gas networks, and thus in installed production capacity and volumes injected into the networks.

Since the first site was connected in 2011, the number of facilities connected to the networks has reached 652 by the end of 2023, most of them connected to the distribution networks (563).

Figure 56 Evolution of the number of production sites connected to networks and of volumes injected since 2011



Source: Open Data Réseaux Énergies platform (ODRÉ), CRE analysis : https://opendata.reseaux-energies.fr/

In 2023, 2.35 TWh of annual production capacity was commissioned (including 1.8 TWh at the distribution level), which brought the total installed capacity to 11.8 TWh/year (including 9 TWh/year at the distribution level). The capacity installed in 2023 alone is comparable to the cumulative volume of capacity connected to the networks between 2011 and 2019.

The volumes of biomethane injected into the networks in 2023 reached 9.1 TWh, or around 2.4% of French gas consumption. Production was more than four times higher than in 2020 (2.2 TWh, or 0.5% of French consumption), well exceeding the target of 6 TWh set in the Multiannual Energy Programme (PPE) for 2023.

The PPE for 2019-2028 sets a target of 14 to 22 TWh of injected production by 2028. At the end of 2023, the cumulative production capacity of the production sites in the capacity register waiting list (i.e. capacity awaiting connection to the grid) stood at 14.8 TWh/year. At European level, the REPowerEU plan has set a biomethane production target of around 360 TWh/year by 2030.

2.3.4. The search for a European model for hydrogen

The European Commission's 2020 Hydrogen Strategy[80] called for a gradual development of renewable and low-carbon hydrogen, starting with local ecosystems before connecting national markets through more extensive infrastructures. In contrast, the approach set out in the so-called "EU hydrogen and gas decarbonisation" package adopted in 2024 gives a central role to interconnections from the outset. Infrastructures are seen as a key driver for the emergence of a competitive internal hydrogen market. The legislative package aims to create a European market, based on key principles directly inspired by the natural gas market, for example with regard to the regulation of hydrogen pipeline transport, storage and import terminals. These provisions complement the regulation on trans-European energy networks, which, since its revision in 2022, includes hydrogen infrastructure among the projects eligible for the status of project of common European interest. The infrastructure development doctrine places particular emphasis on the conversion of natural gas pipelines for the transport of hydrogen as a means of reducing transportation costs while using assets that would otherwise be decommissioned.

Converting gas infrastructures for the transport of hydrogen

Europe's ambitions for the development of hydrogen require the creation of infrastructures to organise exchanges between Member States with high production potential and consumer countries, and to import hydrogen from third countries. With the REPowerEU plan, the European Commission has set an ambitious renewable hydrogen consumption target of 20 million tonnes in 2030 (half produced in the EU and half imported from third countries)[81], with the aim of phasing out Russian fossil fuel imports.

The conversion of gas assets is one of the options favoured by gas transmission system operators. In their study *European Hydrogen Backbone*[82] published in November 2023, they proposed setting up a "European hydrogen backbone"[83] by identifying sections of the European gas transmission networks potentially available for conversion.

Among the advantages mentioned, the conversion of gas infrastructures for the transport of hydrogen would enable to use existing and socially accepted infrastructures, to deploy an infrastructure at a lower cost than a new construction (between 20 and 30% less than a new hydrogen pipeline) at a gradual pace.

80. Communication COM(2020) 301 final of 8 July 2020, "A hydrogen strategy for a climate-neutral Europe".
81. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions of 8 July 2020: A hydrogen strategy for a climate-neutral Europe
82. European Hydrogen Backbone: Implementation roadmap – cross-border projects and cost update, November 2023
83. The European Hydrogen Backbone (EHB) initiative | EHB European Hydrogen Backbone

The European TSOs propose to ultimately establish a complete European network (31,500 km in 2040), to be developed gradually starting with Belgium, the Netherlands and North-West Germany, which together would represent 1/5 of the reference network in 2040. The estimated total investment is in the range of €27-64 billion, based on the use of 75% of converted natural gas pipelines and 25% of new dedicated hydrogen pipelines.

Figure 57 European Hydrogen Backbone map

Source: European Hydrogen Backbone Maps from the European Hydrogen Backbone (EHB) initiative

There are still many technical uncertainties about the feasibility of converting gas networks to hydrogen, in particular because of its physical and chemical properties. The Commission foresaw that the development of hydrogen could be encouraged by blending it with natural gas into natural gas networks. Some provisions envisaged that TSOs would have to accept up to 5% of hydrogen at interconnection points. This threshold was finally lowered to 2% for reasons of network interoperability, to avoid restricting cross-border trade and to comply with consumers' technical specifications.

In general, conversion will have to be consistent with the need for continuity of supply for natural gas consumers. Uncertainty as to the pace of development of the renewable and low-carbon hydrogen sector argues for an approach based on market commitments, both on the supply and demand side, which will enable medium- and long-term financing of investments to be at least partially secured from an economic point of view.

A governance and planning framework of European hydrogen networks under construction

The European target market model for renewable and low-carbon hydrogen is based on regulated third-party access to the network and strict separation of network management from hydrogen marketing activities. However, existing hydrogen networks may benefit from exemptions and derogations from these principles.

Future hydrogen network operators will eventually be subject to ownership unbundling rules. In the initial phase of infrastructure development, the rules will be subject to greater flexibility so as not to unnecessarily restrict the development of the hydrogen sector. While the model of vertical ownership unbundling between production and transmission remains the reference, the model of a TSO independent from its parent company (known as an "independent transmission operator") remains possible. As regards horizontal ownership unbundling, gas network operators will also be allowed to be active in hydrogen transport or distribution, provided that accounting separation and cost allocation are ensured, as the gas sector is not intended to subsidise the development of the hydrogen sector.

CRE considers that the establishment of a target model is useful to provide visibility to investors, but that exemptions from ownership unbundling enable to take into account the uncertainties that still surround the long-term business model for hydrogen. CRE's work is based on the deployment prospects set out in the national strategy for the development of decarbonised hydrogen in France, presented in December 2023. A regular market analysis carried out by national regulators would give the hydrogen sector the flexibility needed to operate and structure the sector.

A European Network of Network Operators for Hydrogen (ENNOH), separate and independent from the association of gas operators (ENTSOG), is to be set up to promote a dedicated hydrogen infrastructure, cross-border coordination and the construction of interconnections. It will also be responsible for drawing up specific technical rules. A transitional phase has been introduced, until 1st January 2027, during which ENTSOG will be responsible for developing cross-border projects of common interest for hydrogen, involving the hydrogen TSOs and ENNOH when it is established.

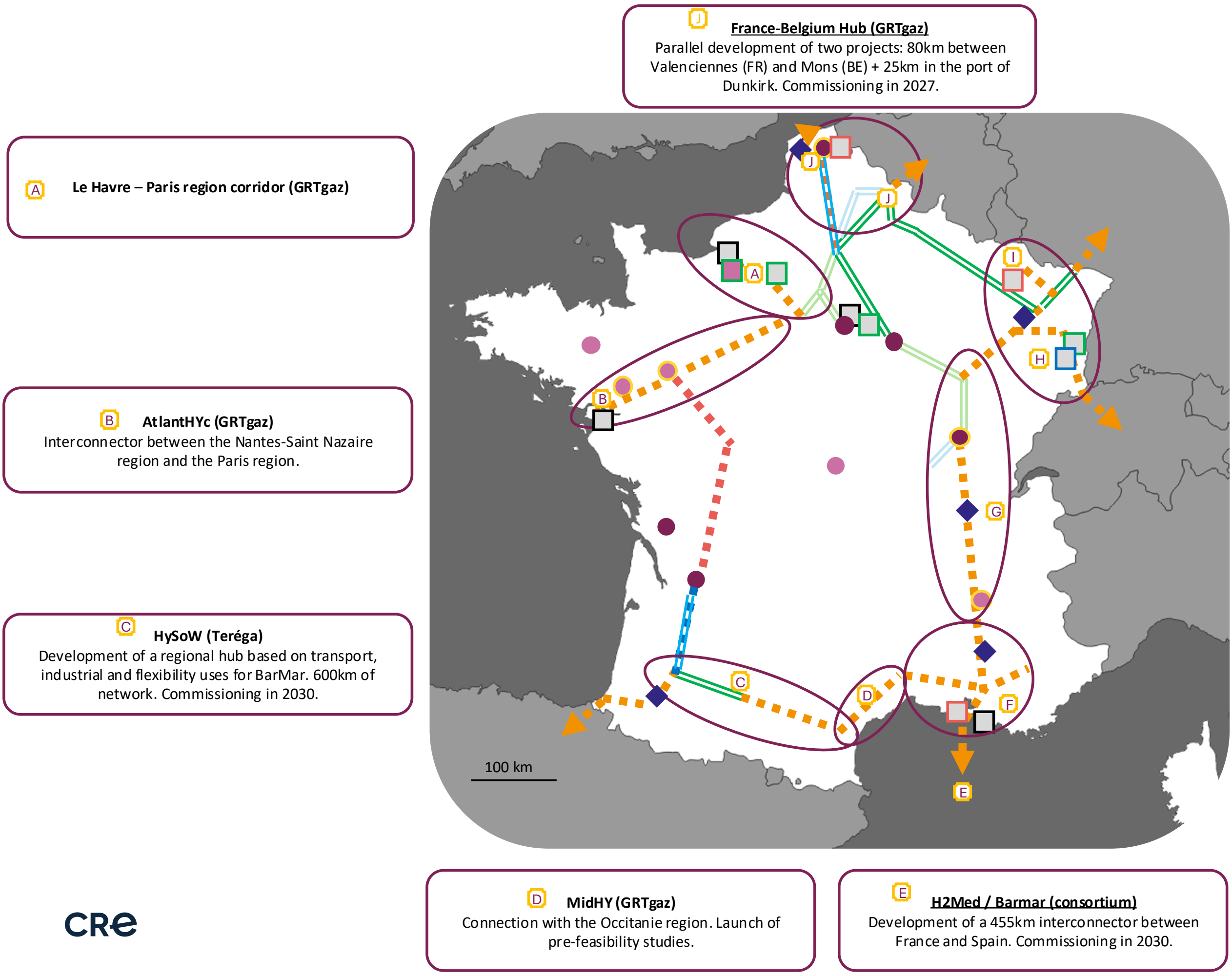
Cross-border hydrogen transport and storage projects now have a dedicated European framework

The prospects that have been expressed for hydrogen production could justify the creation of dedicated transport and storage infrastructures, facilitated by the revision of Regulation (EU) 2022/962 on trans-European energy infrastructures TEN-E in 2022 (see Box n° 5 in chapter 1), which allows cross-border hydrogen infrastructures to be labelled as projects of common interest (PCIs) and projects of mutual interest (PIMs). These labels enable the projects to benefit from faster administrative procedures and to be eligible for European subsidies. Scenarios and methods for the technical and economic evaluation of projects will need to be developed as part of the future European hydrogen ten-year network development plans (TYNDPs), which will include new investments such as the conversion of gas infrastructures.

The European strategy must promote the economic self-sufficiency of the hydrogen sector, which presupposes the gradual construction of a demand reflected by firm commitments from consumers, potentially within the framework of specific models associating producers, transport operators and consumers.

The map below shows the hydrogen transport infrastructure projects in France, including the PCI projects.

Figure 58 Map of hydrogen transmission infrastructure project in France



Source : CRE

Storage

Hydrogen storage project

Transmission

2030

Non-essential reverse-flow capacity (all scenarios)
Non-essential reverse-flow capacity (low scenario)
Non-essential potentially convertible pipeline (all scenarios)
Non-essential potentially convertible pipeline (low scenario)
Hydrogen transport project

2050

Non-essential reverse-flow capacity (all scenarios)
Non-essential reverse-flow capacity (low scenario)
Non-essential potentially convertible pipeline (all scenarios)
Non-essential potentially convertible pipeline (low scenario)
Hydrogen transport project

Consumption

Refineries
Ammonia
Steel
HMD

I **MosaHYc (GRTgaz)**
Development of a 100km cross-border regional hydrogen hub (including 80km of converted pipelines). Commissioning in 2027.

H **RHYn (GRTgaz)**
Development of a local industrial network in 3 phases: 1) Chalampé (chemicals); 2) Basel-Mulhouse airport and industries; 3) Germany. Commissioning from 2029.

G **HY-FEN (GRTgaz)**
Development of a 1200km network connecting BarMar to Germany (H2ercules) and the French hydrogen valleys. Commissioning in 2030.

F **HYnframed (GRTgaz)**
Industrial network at Fos-sur-Mer, then connection to Manosque (**GeoH2**), BarMar and HY-FEN. Commissioning in 2028.

Projects

RHYn (GRTgaz) Project included in the list of PCI/PMI projects in EU Regulation 2022/869

GLOSSARY

20% minRAM: (minimum remaining available margin) – minimum level of capacity (20% of thermal capacity of the considered network element) that TSOs must provide to cross-border electricity trade within a region, introduced in the CWE region since April 2018 and extended to the Core region since June 2022.

ACER: (Agency for the Cooperation of Energy Regulators) – The Agency for the Cooperation of Energy Regulators is a European agency endowed with legal personality, instituted by Regulation (EC) no. 713/2009 and created in 2010. ACER is operational since the 3rd March 2011. Its headquarters are located in Ljubljana, Slovenia. The objective of ACER is to help the national regulatory authorities in exercising and coordinating their regulatory tasks at the European level, and, if necessary, to complement their activities. It plays a key role in the integration of the electricity and gas markets.

ADEME: the French Environment and Energy Management Agency

aFRR: (Automatic Frequency Restoration Feserve) – load reserve activated automatically by a signal from the TSO.

ATRT: (*Accès des tiers aux réseaux de transport*) – the tariff for transporting gas on the transmission system, determined by CRE and applied by the French gas TSOs.

BAL (network code) : Commission regulation (EU) no. 312/2014 establishing a Network Code on Gas Balancing of Transmission Networks.

Bidding zone: in electricity, a market area within which and between which market participants can trade electricity, either anonymously on power exchanges or bilaterally (over the counter) at different timeframes, from very short-term to long-term (up to several years in advance in case of forward transactions).

Bilan prévisionnel: in electricity, the French prospective resource adequacy assessment carried out by RTE to determine the margins or deficits of the French electricity system in order to verify compliance with the reliability standard set by the French public authorities. It takes into account the contribution of each interconnection to the French security of supply.

BNetzA: (*Bundesnetzagentur* für *Elektrizität, Gas, Telekommunikation, Post und Eisenbahnen*) – the Federal Network Agency, the German regulatory authority for electricity, gas, telecommunications, post and railway activities

CACM (guideline): (Capacity Allocation and Congestion Management) – Commission regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management.

CAM (network code): Commission regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems.

Calorific value: measures the amount of energy contained in the gas, usually expressed in megajoules per cubic metre (MJ/ m^3) and constantly measured by gas transporters.

Capacity mechanism: mechanism aimed at guaranteeing the security of supply of the power system by remunerating the capacity of generation units during periods of tension for the system, within the limit of the reliability standard. The principle of the French capacity mechanism is based on the obligation for each electricity supplier to cover, through capacity guarantees, the consumption of its customers during peaks in electricity consumption.

CBCA: (Cross-border Cost Allocation) – cross-border sharing of the costs of a Project of Common Interest (PCI) or a Project of Mutual Interest (PMI).

CCR: (Capacity calculation region) – in electricity, geographical area in which a coordinated capacity calculation is carried out. Pursuant to ACER Decision No 06/2016 of 17 November 2016 and its successive amendments, France is part of three capacity calculation regions: the Core region, the Italy North region, and the South-Western Europe region. In the past, France has been part of the Channel region and the Central Western Europe region.

CEER : (Council of European Energy Regulators) – is an association created in 2000 at the initiative of the national energy regulators of the EU and EEA member states. The CEER organisation structure is composed of a general assembly, sole decision-maker, a Board, working groups specialised in various domains (electricity, gas, consumers, international relations, etc.) and a secretariat that is based in Brussels. A work program is published every year. In conformity with the statutes, decisions are based on consensus and, failing that, by qualified majority voting.

CEF: (Connecting Europe Facility) – is a financing mechanism implemented by the EU for transport, energy and digital projects of common interest (PCI) and projects of mutual interest (PMI).

Central-Western Europe (CWE region): electricity capacity calculation region covering Austria, Belgium, France, Germany, Luxembourg and the Netherlands.

Channel region: former electricity capacity calculation including Belgium, France, the Netherlands and the United Kingdom, abolished following the United Kingdom's withdrawal from the European Union on 1st January 2021.

"Clean energy for all Europeans" package: also known as the "Clean Energy Package" (CEP), is made of eight legislative acts framing the EU energy policy. In particular, Regulation (EU) 2019/943 of the Parliament and of the Council of 5 June 2019 on the internal electricity market lays down the rules for the organisation of the European electricity markets.

CMP: congestion management procedures in the event of gas transmission capacity contractual congestion.

Congestion income: revenues created by the allocation of interconnection capacities at the various timeframes.

Continuous allocation: allocation method for which orders are executed directly when being placed on the order book (competing orders are executed in an order depending on their price and then their entry time).

Contractual congestion: situation in which the users of a gas interconnection cannot contractually obtain transmission capacity, even though it is physically available.

Core region: electricity capacity calculation region including Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia and Slovenia.

Countertrading: remedial actions through which two TSOs conclude a cross-zonal electricity exchange in the direction contrary to the congestion observed.

CSPE: (*Contribution au service public de l'électricité*) – energy public service charges, mainly linked to the support of renewable energies and tariff equalisation, which include additional costs and charges borne by various operators and assessed and compensated annually by CRE.

Decarbonisation: refers to all the measures and techniques aimed at reducing the carbon content of energy. In the case of gas, this involves the promotion and use of so-called "green" gasses alternative to methane that emit little or no greenhouse gasses.

DSO: Distribution System Operator.

EB (guideline): (Electricity Balancing Guideline) – Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing.

Elengy: owns and operates the French LNG terminals of Montoir-de-Bretagne and Fos-Tonkin, and operates the Fos-Cavaou terminal, owned by Fosmax LNG.

Entry-exit zone: System of access to the gas transmission networks that allows the shippers to subscribe separately entry and exit capacities. It opposes the point-to-point system in which entry and exit capacity are booked jointly.

ENTSO-E: (European Network of Transmission System Operators for Electricity) – the TSOs cooperate at the EU level through the ENTSOs to promote the implementation and the functioning of the internal natural gas, electricity and hydrogen markets and cross-border exchanges, and to ensure an optimal utilisation, a coordinated exploitation and a robust technical evolution of the natural gas, electricity and hydrogen transmission systems. In this context, the ENTSOs elaborate the European network codes on the basis of the guidelines established by the ACER and in close cooperation with the Agency.

ENTSOG: European Network of Transmission System Operators for Gas, see ENTSO-E.

ENNOH: European Network of Network Operators for Hydrogen, see ENTSO-E.

ERAA: (European Resource Adequacy Assessment) – in electricity, study carried out by ENTOE-E to assess the power system resource adequacy of up to 10 years ahead to meet electricity demand at European level, in accordance with Article 23 of Regulation (EU) No 2019/943. It serves as a reference for the implementation of national capacity mechanisms in the EU, provided that it is approved by ACER.

ERSE: *(Entidade Reguladora dos Serviços Energéticos)* is the regulator for the gas and electricity markets in Portugal.

EU ETS: (European Union Emissions Trading System) – the EU's emissions trading scheme, created in 2005 to impose an emissions cap on the EU's high emitting sectors.

Explicit/implicit allocation: see market coupling.

FCA (guideline): (Forward Capacity Allocation) – Commission Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation.

FCR: (Frequency Containment Reserve) – primary load reserve activated automatically according to the frequency measured on the network in order to stabilize the frequency.

Firm capacity: interconnection capacity which utilisation is contractually guaranteed.

"Fit for 55" package: set of proposals to revise and update EU legislation and to put in place new initiatives with the aim of ensuring that EU policies are in line with the EU climate target of reducing net greenhouse gas emissions by at least 55% by 2030 compared with 1990 levels.

Flow-based: in electricity, an approach for the interconnection capacity calculation and allocation in which commercial interconnection capacity is determined dynamically by making explicit certain network constraints and giving priority to the borders on which commercial trades have the highest value. The flow-based approach consists of calculating a domain of possible trades within a region that includes several borders (as opposed to the NTC approach). It is the target model prescribed by the CACM Regulation for day-ahead and intraday timeframes.

Fluxys: the Belgian gas transmission system operator, also operating LNG terminal and underground gas storage facilities in Belgium.

FSRU: floating storage and regasification unit for LNG.

FTR: (Financial Transmission Rights) – long-term transmission rights that do not allow to nominate energy but guarantee their holders to receive the price spread of the concerned bidding zones.

Green Deal: set of policy initiatives initiated by the European Commission chaired by Ursula von der Leyen with the overarching aim of making Europe climate neutral by 2050, providing a roadmap with actions to promote resource efficiency by moving towards a clean and circular economy and to halt climate change, biodiversity loss and pollution.

GRTgaz: one of the two operators of the French natural gas transmission system, operating over most of the country, with the exception of the South-Western region (where Teréga operates).

Guideline: formerly known as "administrative directives", the guidelines are an administrative act by which the European institutions aim at better coordinating the application of the European legislation or the national administrative practices in a non-binding manner, i.e. without legal obligations for the addressees, except for guidelines adopted in the form of a European Regulation as part of the implementation of the Third European legislative package.

HAR: (Harmonised Allocation Rules) – harmonised allocation rules for long-term transmission rights.

Hub: the central point of a network which ensures, by its concentration, a maximum number of connections. In gas, the term "hub" refers to the most significant marketplaces in a given geographical area.

Hydrogen and gas decarbonisation package: set of European legislative texts, composed of the gas Regulation and gas Directive, whose revision was proposed in December 2021 by the European Commission and which were adopted in May 2024 by the European Parliament and the Council; the revised texts introduce measures to facilitate the development of renewable and low-carbon gas and to prepare for the emergence of a European low-carbon hydrogen market.

Incremental capacity: a possible future increase in technical capacity via market-based procedures or possible new capacity created where none currently exists that may be offered based on investment in physical infrastructure or long-term capacity optimisation and subsequently allocated subject to the positive outcome of an economic test.

INT (network code): Commission Regulation (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules.

Interruptible capacity: interconnection capacity which utilisation is not contractually guaranteed.

Italy North region: electricity capacity calculation region including Austria, France, Italy and Slovenia.

JAO: (Joint Allocation Office) – European platform in charge of explicit capacity auctions, among others in the long-term timeframe, collectively owned by European TSOs.

L-gas / H-gas: L-gas refers to natural gas with a lower calorific value (quantity of heat released by combustion) than H-gas (high calorific value), due to its higher nitrogen content.

LNG: (Liquefied natural gas) – natural gas converted into liquid form by cooling to -160°C, for ease of storage or transport through LNG vessels.

Market coupling: refers to the joint processing of the order books of power exchanges in several markets, irrespective of the market where they were placed, but taking into account cross-border interconnection capacity. In other words, within the limits of available interconnection capacity, the counterparty to a transaction on an electricity exchange may come from a foreign exchange without the participants having to explicitly purchase the corresponding capacity at the border concerned. This is an 'implicit' allocation of capacity, as opposed to 'explicit' allocations, in which players engaged in cross-border energy exchanges must buy the corresponding interconnection capacity separately from energy purchases/sales.

Coupling can be carried out in the form of auctions, where buy and sell orders are matched simultaneously, or on a continuous basis, where orders are processed as they arrive, on a first-come-first-served basis.

The target model for the day-ahead timeframe is an auction-based coupling, while the target model for the intraday timeframe is a continuous coupling.

mFRR: (Manual Frequency Restoration Reserve) – load reserve activated manually by the TSO, with an activation time of less than 15 minutes.

National Grid: the British electricity and natural gas transmission system operator.

NEMO: (Nominated Electricity Market Operator) – market coupling operator.

Network code: refers to common European rules on cross-border operation of electricity and gas interconnections and systems of the Member States.

NTC: (Net Transfer Capacity) – in electricity, commercial interconnection capacity. This term also refers to one of the two main capacity calculation approaches, within which the commercial interconnection capacity is determined on a per-border basis. This capacity is fixed during the capacity calculation and is not dependent on exchanges at other borders (as opposed to the flow-based approach, in which capacities per borders are not fixed before the capacity allocation phase).

Odourisation: operation consisting of providing an odour to natural gas, which is odourless, for safety reasons. In France, odourisation is carried out by injecting Tetrahydrothiophene (THT) into the natural gas transported on the networks, in a centralized manner, i.e. at the entry points into the gas transport networks. In other countries, this operation is carried out in a decentralised manner, upstream of the distribution networks.

Ofgem: (Office of Gas and Electricity Markets) – the regulator for electricity and gas market in the United Kingdom.

ONDP: Offshore network development plans developed by ENTSO-E in application of the TEN-E Regulation.

Open season: procedure used to dimension a new infrastructure based on the market needs, and to allocate the corresponding capacities in a non-discriminatory manner.

PCI: (Project of common interest) – key cross border infrastructure projects that link the energy systems of EU countries which are intended to help the EU achieve its energy policy and climate objectives.

PEG: (P*oint d'échange de gaz)* – wholesale market for the trade of gas in France.

Physical congestion: state of saturation of the network when an electricity line or a gas pipeline does not allow the transport or distribution of all the quantities injected or withdrawn, taking into account the characteristics and performance of the network equipment.

PITS: (*Point d'interface transport stockage*) – physical or notional interconnection point be-tween a gas transmission network and one or several underground storage sites.

PITTM: (*Point d'interface transport terminal méthanier*) – physical or notional interconnec-tion point between a gas transmission network and one or several LNG terminals.

PMI: (Project of mutual interest) – cross-border infrastructure projects between EU Member States and third countries that contribute to the Union's energy and climate policy objectives. PMIs are a new category of project that will be eligible for support following the revision of the Trans-European Networks for Energy (TEN-E) Regulation in 2022.

PPE: (*Programmation pluriannuelle de l'énergie*) – energy policy management plan developed by the French government for mainland France and co-developed with local authorities for non-interconnected areas.

Price spread: difference between the prices of two bidding zones (see bidding zone).

PRISMA: booking platform for gas transmission capacity.

PTR: (Physical Transmission Rights) – long-term transmission rights that give a physical access to cross-border capacity, by allowing their holders to nominate energy exchanges between the concerned zones.

Redispatching: remedial actions through which a TSO changes the dispatch of a generation unit or the consumption program of a withdrawal site in order to address a localised congestion.

REE: (*Red Eléctrica de España)* – is the Spanish electricity transmission system operator.

REPowerEU: European Union plan launched in May 2022, proposed by the European Commission following Russia's invasion of Ukraine, aimed at reducing Member States' dependence on fossil fuels imported from Russia.

Reserve price: eligible floor price in an auction.

Reverse-flow capacity: entry or exit capacity at a gas network interconnection point in the opposite direction to the main physical direction of flows at the point (reverse capacity is available if the overall flow remains in the main physical direction of flows).

RR : (Replacement Reserve) – load reserve manually activated by the TSO, with an activation time of more than 15 minutes.

RTE : (*Réseau de transport d'électricité*) – the French electricity transmission system operator.

SDDR: (*Schéma décennal de développement des réseaux*) – RTE's ten-year network development plan, which presents proposals for the development of the transport grid in order to support the transformation of the energy system and the implementation of public policies. It is examined by CRE to ensure that investment needs are covered and that it is consistent with the TYNDP (see TYNDP).

SNBC: (*Stratégie nationale bas carbone*) – a climate policy planning document developed by the French government with the aim of reducing France's greenhouse gas emissions until 2050 and achieving carbon neutrality by 2050.

South-Western Europe region (SWE): electricity capacity calculation region including Spain, France and Portugal.

Storengy: the main underground gas storage facility operator in France (together with Teréga and Géométhane).

TAR (network code) : Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.

TEN-E Regulation : Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, repealing Regulation (EU) No 347/2013. This European Regulation defines the criteria and procedures for selecting projects of common interest and of mutual interest, the methods for allocating their costs and the possible granting of EU financial support.

Teréga : one of the two operators of the French natural gas transmission system, which operates in the South-West of the country.

Terna : Italian electricity transmission system operator.

TSO: Transmission System Operator.

TTF : (Title Transfer Facility) – market zone for the trade of gas in the Netherlands.

TURPE: (*Tarif d'utilisation du réseau public de transport d'électricité*) – French tariff for the use of public transmission electricity grids of RTE.

TYNDP: (Ten Year Network Development Plan) – Union-wide plan developed by ENTSO-E and ENTSO-G, which includes the modelling of the integrated network, scenario development and an assessment of the resilience of the system. It is drawn up pursuant to Article 48 of Regulation (EU) no 2019/943 and serves as a basis for the assessment of cross-border investments in networks.

VIP: (Virtual Interconnection Point) – grouping of two or more interconnection points which connect the same two adjacent entry-exit systems, for the purposes of providing a single capacity service.

XBID: project of implicit cross-border capacity allocation at the intraday timeframe, in force at all French borders since 2021, allowing market participants to trade energy from the day before the delivery until one hour before the delivery, provided there is available capacity at the interconnections.

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