HEC PARIS – MASTER THESIS

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How to extract value from battery storage, as an investor and as an operator?

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Introduction

Today, the concentration of greenhouse gases (GHGs) in the atmosphere is higher than at any point in time during the last 450,000 years.[1] This increase has been determined as the major cause of global warming, which could have disastrous consequences in the short to long-term with increased climate hazards and risks to ecosystems and humans. People will be affected globally by global warming, whether they are located in rural or urban settings, with significant impacts on health (through climate-related diseases, decreased mental health, etc.), well-being (with damages on infrastructure, land reduction, etc.) and economic situations (lower agricultural productivity, etc.). [2]

Global greenhouse gases emissions have climbed to 60 Gt CO_2 eq. in 2018, compared to 38 Gt CO_2 eq. in 1990, which represents a 58% increase. The main contributor to GHGs emissions during the period has been the use of energy systems, among which electricity and heat production represent about two-thirds of emissions. Generation of electricity through polluting sources such as coal have played a major role in this trend.

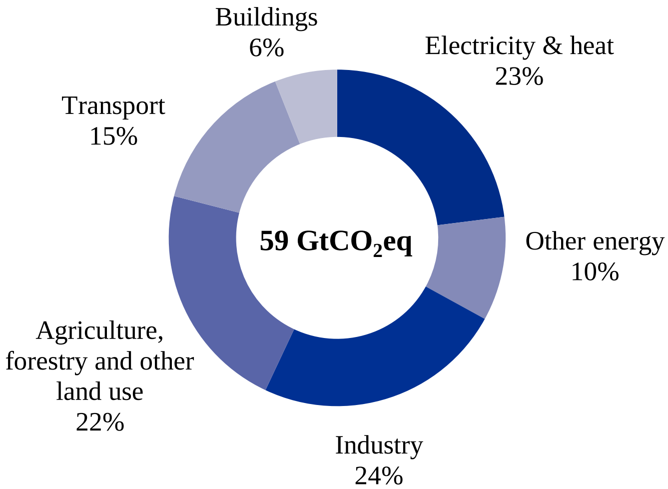


Figure 1: Direct GHG emissions by economic sector in 2019[3]

Therefore, it has become excessively urgent in major economies and developing countries to shift electricity production away from polluting sources towards more renewable sources, thereby reducing the carbon intensity of energy systems (e.g., -1.5% in Europe for CO_2-related emissions between 2010 and 2019). Renewable energy sources, such as solar photovoltaics and windmills have benefitted from generous supporting schemes in developed economies as they

[1] Arnaud Brohé et al., 2009, *Carbon Markets: An International Business Guide*
[2] IPCC, 2021, *IPCC Assessment Report VI, Working Group II, Impacts, Adaptation and Vulnerability*
[3] IPCC, 2021, *IPCC Assessment Report VI, Working Group III, Chapter 2: Emissions Trends and Drivers*

allow a "green" production of energy, with a lower carbon intensity than other means of generation, which could be considered as "brown" (e.g., gas-fired plants).

Although some renewable energy sources can be stable and predictable in their electricity generation capacity, such as hydropower, most of public and political focus nowadays is on intermittent renewable energy sources (photovoltaics and wind), whose production profile is by nature variable and unpredictable because of weather conditions.

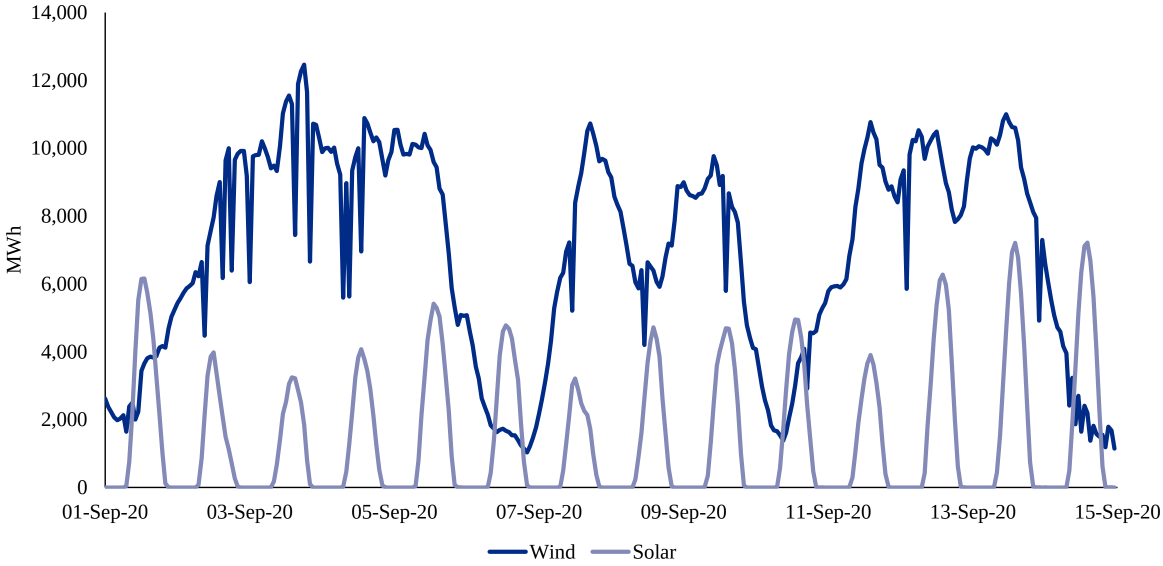


Figure 2: Electricity generation from wind and solar sources in the United Kingdom, between September 1, 2020 and September 15, 2020[4]

Technologies such as energy storage, and especially battery storage, have attracted a lot of public attention and are somehow expected to help support the system by limiting this intermittency. The smoothing of generation would actually happen through the purchase or removal of energy when production is higher than consumption, which would be then sold or given back to the system after having been stored for hours or days.

Although decades-old solutions of energy storage solutions such as hydropower generators (e.g., dams) have proven their efficiency at preserving and returning energy in a cost-effective manner, can batteries, which are still an emerging technology, achieve the same status? Is there any room for a profitable business model for investors, which could spur active investments from private investors in the sector? If yes, **how can investors or operators extract value from battery storage?**

This Master Thesis will first give an overview of the current electricity and energy storage markets before deep-diving in the battery storage market, with its functioning, its main players, and its outlook. Then, we discuss the structure through which investors and operators can extract value from battery through trading operations *via* arbitrating day-ahead electricity prices.

[4] ENTSO-e Transparency Platform, visited in April 2022

I. Overview of the energy storage market

A. Focus on the European electricity market structure

i. A centralised, national, and vertically integrated model which remains the backbone of the system…

Although each European country's electricity market has its specificities, the overall structure is quite similar from one country to another: it works on a centralised, national and vertically integrated model, supervised by the State and public authorities. The energy market is very different from other industrial sectors as it has some unique characteristics. Electricity represents a product that cannot be differentiated in terms of quality, it is difficult to store and its cost depends mostly on the way it is produced. Also, the demand of electricity is highly inelastic and as it has no substitutes, the supplier must be sure he can deliver as much electricity as it is required at any given moment.

The value chain, from the production of electricity to the retail distribution, is composed of various stakeholders:

- Producers of electricity
- Transmission System Operators (TSO)
- Distribution system Operators (DSO)
- Providers
- Consumers

Each stakeholder has specific roles and duties and is in charge of one stage of procurement.

1. Producers of electricity[5]

Producers of electricity are companies producing electricity using facilities they own (plants, wind turbine centres, solar panels…). They undertake to inject the quantity of energy purchased by the customer into the network.

Since the opening of the electricity market to competition (more details about the liberalisation process are provided in the following section), there are many electricity producing companies in Europe, which can range from small producers producing a few megawatts from a hydropower unit to industry giants with multiple power plants, like EDF, RWE, Vattenfall, E.ON or Enel. An electricity producer can also be a company or an individual who consumes the electricity it produces on site and transfers part of it to the transport or distribution network.

[5] Eurostat, visited in April 2022, Electricity production, consumption and market overview

Total net electricity generation in the EU was 2,664 Terawatt hours (TWh) in 2020, which was almost similar to the year before (the total amount of electricity produced is referred to as gross electricity production. However, power plants consume some electricity for their own use and net electricity production is obtained by deducting this amount from gross production). Germany had the highest level of net electricity generation in 2019 among the EU Member States, accounting for 20.5 % of the EU total, just ahead of France (19.1 %); Italy (10.2 %) was the only other Member State with a double-digit share.

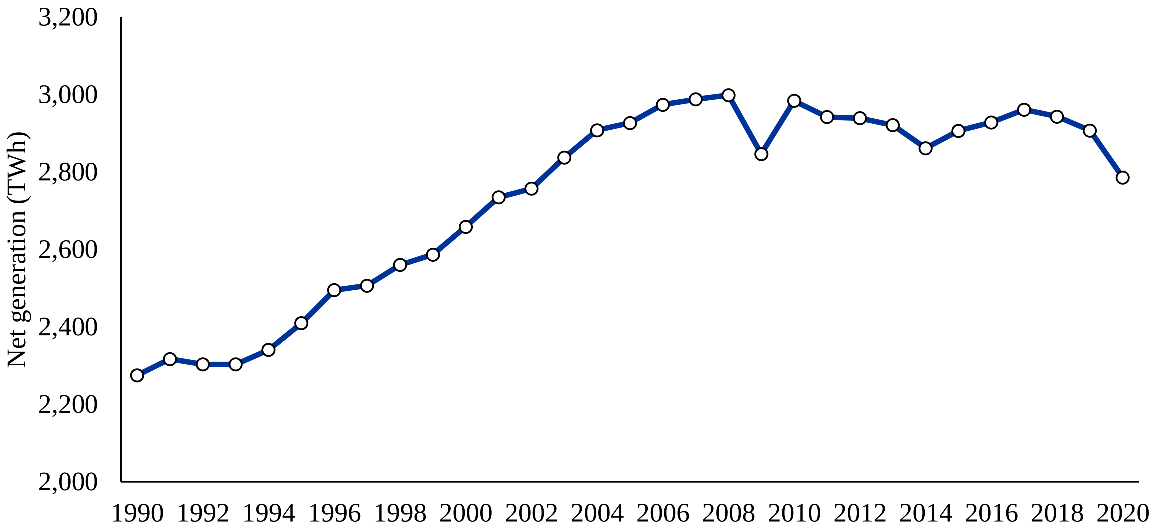


Figure 3: Net electricity generation in the EU between 1990 and 2020 (TWh)[6]

More than half (58.7 %) of the net electricity generated in the EU in 2020 came from non-combustible primary sources. Less than half (41.3 %) came from combustible fuels (such as natural gas, coal and oil). A quarter (24.3 %) came from nuclear power stations. Among the renewable energy sources shown in Figure 3, the highest share of net electricity generation in 2019 was from wind turbines (14.7 %), followed by hydropower plants (13.8 %) and solar power (5.3 %).

[6] Eurostat, visited in April 2022, *Electricity production, consumption, and market overview*

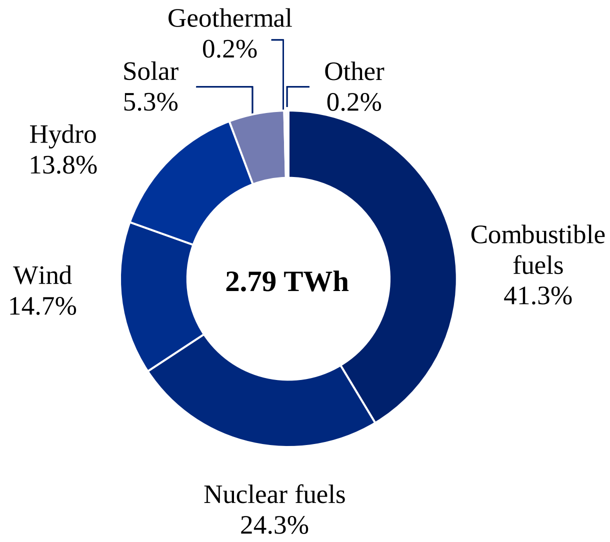


Figure 4: Net electricity generation in the EU in 2020 (%, based on GWh)[7]

The sources of electricity production vary among the Member States: around 90% of electricity production came from fossil fuels in Cyprus and Malta, while almost three quarters (70%) of electricity production came from nuclear power plants in France, followed by 54% in Slovakia. In Denmark over half of electricity production (57%) came from wind energy, while around 63% of electricity production in Austria came from hydro power plants.

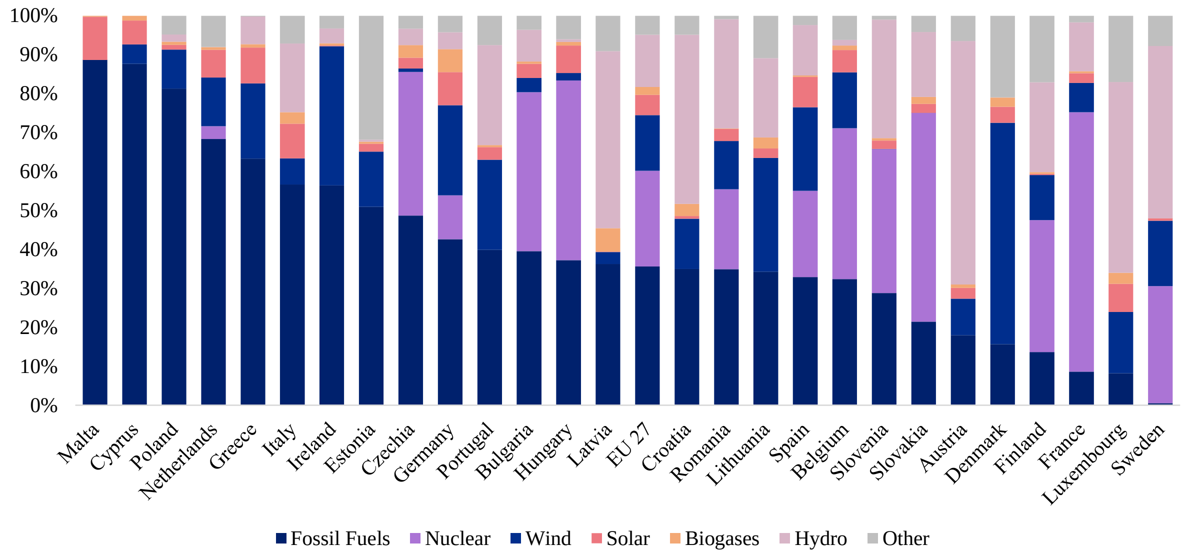


Figure 5: EU production of electricity by source, 2020 (%)[8]

[7] Eurostat, visited in April 2022, *Electricity production, consumption and market overview*
[8] Eurostat, visited in April 2022, *Electricity production, consumption and market overview*

2. Transmission System Operators (TSO)

The carrier is the operator of the high-voltage electricity network, used for the interregional and international transmission of electricity. Indeed, high voltage is required to reduce the amount of energy lost over long distance: extra high voltage lines are used to connect countries and regions (from 300kV up to about 800kV) and high voltage lines are used for transmission on a regional or local scale (between 100 and 300kV).

Due to the notion of natural monopoly, there is generally only one carrier per country, such as RTE in France, Elia in Belgium, Energinet in Denmark or Creos in Luxemburg. In this way, the technical, legal and financial conditions relating to the access and use of these networks are regulated. In order to avoid a drift in tariffs against network users and to ensure access to networks on an objective, transparent and non-discriminatory basis, the authorized revenues of network operators, as well as the way in which these revenues are collected from each category of users, are determined by an independent regulatory authority.

At European level, these are organised in a common organization, the European Network of Transmission System Operators (ENTSO-e). The members are the 41 electricity network operators from the 27 countries of the European Union, plus the UK, Norway, Switzerland, Iceland, Serbia, Bosnia-Herzegovina, Montenegro, North Macedonia. This set supplies a population of 532 million inhabitants. Electrical interconnections make it possible to secure the European electricity network because they provide the possibility of mutual aid between countries, in the event of a shortage in one of them, by injecting electricity into its network, in order to avoid a “blackout”.

3. Distribution System Operators (DSO)

The distributor is the operator of the electrical network to which most end customers are physically connected. They use medium voltage lines to deliver electricity to small industries and SMEs (between 1kV and 100kV) and low voltage lines for individuals (less than 1kV). Like in the case of TSOs, DSOs operate in a market which is considered as a natural monopoly. In France, medium and low voltage lines are largely managed by ENEDIS (subsidiary of EDF): Enedis manages 95% of the French electricity distribution network; local distribution companies manage the remaining 5%. The situation is similar in most European countries with companies like Alliander in the Netherlands or Netz in Germany.

Main European DSOs are gathered into a common organization, E.DSO (European Distribution System Operators), which gathers 39 leading DSOs in 24 countries. It focuses on guiding EU research, innovation and regulation on electricity distribution networks.

4. Providers

They buy electricity from producers and sell it to consumers. Sometimes a single company operate as a producer and a provider at the same time, like EDF, Engie, ENI, Vattenfall etc.

Before the 1990's, providers were in a situation of monopoly in most European countries, just like TSOs and DSOs (more details about liberalization are provided in the following section). Today, the market is open to competition and multiple players are present. However, companies which were in a monopoly situation before liberalization remain the main provider in many countries (EDF in France still owns about 70% of the market).

5. Consumers

The final electricity consumed by individuals, companies and other consumers as administrations, reached 2,664 TWh in 2020 in the European Union. With a population of the EU-27 reaching 447.0 million inhabitants on 1st January 2021, its average electricity consumption was 5,960 kWh per capita.[9] The highest per capita consumption (Iceland, Norway, Sweden, Finland, Luxembourg) is explained by the presence of electro-intensive factories such as aluminium refineries or paper mills, attracted by very low electricity prices (hydroelectric or nuclear power stations).

ii. …But increasingly complex due to the liberalisation an emergence of new players

1. The liberalisation process in Europe

The objective of this subsection is to present how electricity markets in the European union went from siloed markets controlled by state-owned monopolies, to liberalised, coupled markets open to competition.

Before the liberalisation process started in Europe, electricity markets were organised as national or regional monopolies of state-owned companies. The public involvement was mainly justified by four arguments[10]:

- The need to provide a constant and safe supply of electricity while maintaining politically and socially acceptable prices.
- It was assumed that the electricity supply chain, from the production to the consumer, was a natural monopoly with economies of scales to be gained by vertically integrating the value chain.

9 Eurostat, visited in April 2022, *Population and population change statistics* and *Electricity production, consumption and market overview*

10 Arentsen and Künneke, 1996, *Economic organization and liberalization of the electricity industry*

- The investment risks and amounts related to the transmission and distribution infrastructure was high.
- Uninterrupted supply was necessary to balance supply and demand at all times. The market was not trusted enough to be delegated this task.

However, technical innovation progressively enabled developed economies to transition to a more liberalised model in which production and other functions could be decentralized and opened to competition, but not necessarily privatized.[11]

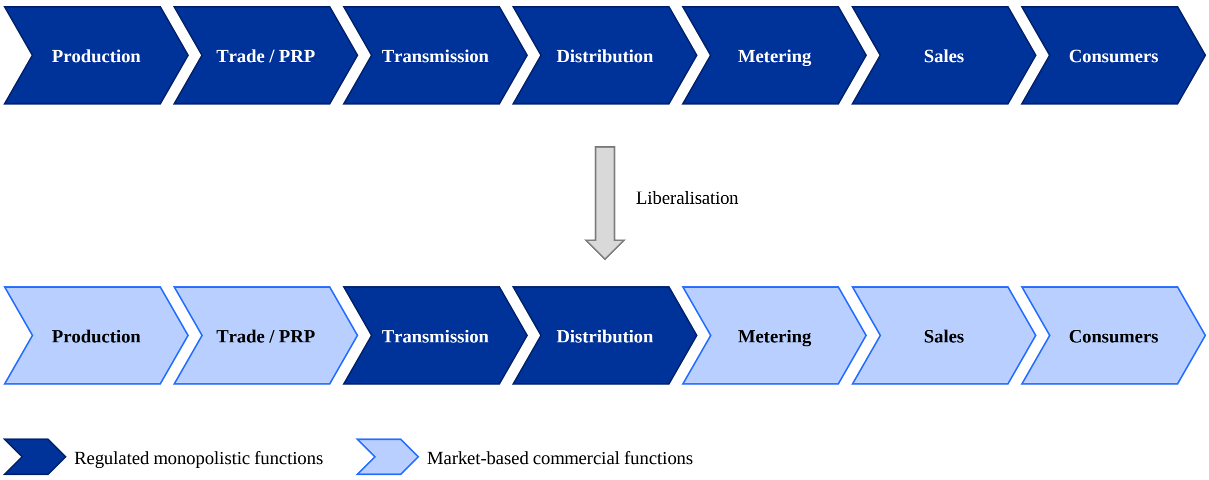


Figure 6: Electricity value chain before and after the liberalisation[12]

The liberalisation of the electricity market in the European Union took place through the implementation of a package of three directives, each one replacing and completing the previous one.

Directive 1996/92/EC was the first comprehensive legislative package on electricity market liberalisation, with the creation of a competitive international market in the European Union. The purpose of the legislation was to create common rules for each Member State of the European Union for the generation, transmission, and distribution of electricity.[13] The main articles were:

- **Article 4**, which allowed Member States to go through either an authorization procedure or a tendering process, both needing to be based on transparent and objective criteria, to increase generation capacities.
- **Article 7**, which mandated Member States to designate an independent Transmission System Operator (TSO) who would be responsible for operating, maintaining and developing the interconnections with other systems.
- **Article 10**, gave Member States the possibility to require Distribution System Operators (DSOs) to give priority to renewable energy sources (RES).

[11] Künneke, 1999, Electricity networks: how “natural” is the monopoly?
[12] Künneke, 2008, Institutional reform and technological practice: the case of electricity
[13] EUR-Lex, 1996, Directive 96/92/EC

- **Article 14.3**, which introduced the unbundling of accounts for Vertically Integrated Utilities (VIUs), to avoid market distortions.

Seven years later, Directive 2003/54/EC was implemented to address shortcomings that were identified following the implementation of Directive 1996/92/EC, as it did not directly curb market dominance and predatory behaviour. It became legally binding to designate and unbundle TSOs (Article 10.1) and DSOs (Article 15) activities from other operations (especially when integrated within a VIU). Access to networks became more transparent for market participants with the obligation for TSOs and DSOs to apply public tariffs without discrimination.[14]

Lastly, Directive 2009/72/EC was the last implemented package of regulations for liberalisation of the European electricity market. It mainly required all Member States to designate an independent regulatory authority at the national level (e.g., la *Commission de Régulation de l'Energie*, CRE in France) with Article 33.4 and Article 35.1.

In addition to the directives that were implemented successively for 13 years, the general EU competition law principles also apply to the electricity markets, which means that[15]:

- Agreements distorting competition between and within Member States are prohibited (Article 101 TFEU).
- Undertakings of a dominant position within the internal market are prohibited (Article 102 TFEU).
- State aid is strongly regulated and prohibited when it distorts unfairly competition between Member States (Articles 107 and 108 TFEU).

As a consequence of these regulations, electricity markets were opened to more competition from the private sector.

Moreover, the implementation of common rules for the electricity markets progressively enabled Member States to target the creation of a common electricity market. This "coupling" is an undergoing process at the level of the European union for the intraday and day-ahead electricity markets. It relates to the possibility for Member States' TSOs to exchange electricity between bidding zones through physically interconnected grids. This initiative is especially driven by the private sector (power exchanges such as EPEX Spot, through the Price Coupling of Regions, which corresponds to a single algorithm used to settle transactions on the day-ahead market in different European countries) as it opens new markets, but is also supported by Member States (e.g., with the implementation of a single Target Model for the day-ahead market, the Single Day-Ahead Coupling (SDAC)).[16]

[14] EUR-Lex, 2003, Directive 2003/54/CE
[15] EUR-Lex, 2012, Treaty on the functioning of the European union
[16] EPEX Spot, visited in April 2022, Market coupling

2. Impact of liberalisation on wholesale electricity prices

After presenting the liberalisation process of electricity markets in the European union, it is worth understanding how the introduction of competition for generation has impacted wholesale electricity prices on the back of developing renewables and the pricing mechanism on power exchanges.

First, it is important to understand how electricity prices are determined on electricity markets. Generators submit offer orders with a certain quantity and price at which they are willing to sell electricity based on their marginal cost of producing this quantity of energy. Offers are then accumulated to create an *offer curve*. Similarly, a *demand curve* is created with the bid prices and quantities of consumers. The point at which the curves intersect is considered the settlement price and quantity that will be used for all market participants.

However, given that the submission of bids is based on the marginal cost of production and not on the average cost of production, renewable electricity producers are largely favoured relative to other producers such as gas-fired and coal-fired plants. Indeed, RES generators have a close to zero marginal cost of production, and thus crowd out other generators from the offer curve. In addition, the priority dispatch granted during a certain period to renewable energy sources and feed-in-tariffs (FIT) and feed-in-premiums (FIP) lowered the costs associated with the construction and operation of renewable energy infrastructure.[17]

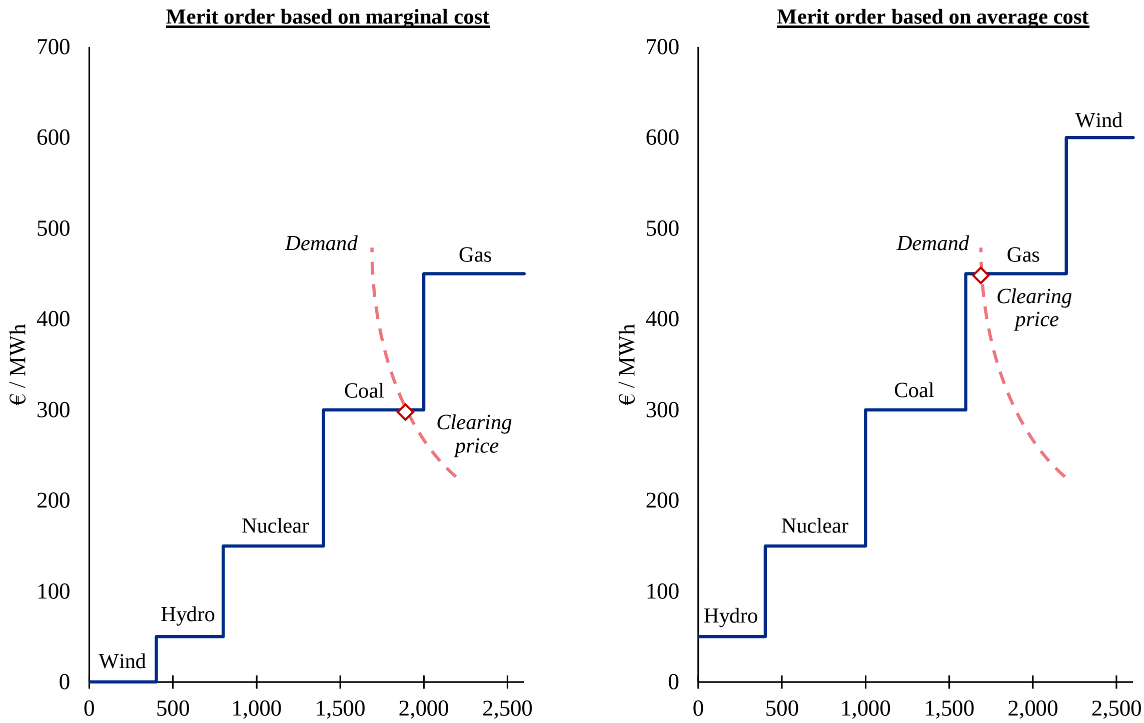


Figure 7: Illustrative supply stack models, based on marginal and average costs[18]

[17] François Benhmad and Jacques Percebois, 2018, *Econometric analysis of the merit order effect in electricity spot price: the Germany case*
[18] Ibid

This resulted in a downwards pressure on electricity prices which is referred to as the *merit order effect*. Gas-fired and coal-fired plants are progressively crowded out of the electricity market in some countries, and usually cannot operate on a profitable basis because the peak prices are lower than their marginal costs of operations. This is illustrated by the charts above, showing how the merit order pricing based on marginal costs allows wind generators to sell their electricity despite an overall unprofitable model.

The lack of publicly available model on supply stacks limits the possibility of analysing how this phenomenon has played out in the European Union since the 2000's. However, studies have estimated that increasing renewable penetration has contributed to a 9.6% decrease in electricity base prices between 2007 and 2013 in Germany, although the decrease related to higher emission prices is estimated to be about 21.5%.[19]

iii. Innovation is likely to drive change in the sector in the near future

Current electric grids were built more than a hundred years ago, when electricity needs were different and smaller. Today, consumption is changing, and electricity generation needs to adapt to this evolution. That's why the concept of Smart Grid emerged in the 2000's – some people prefer to speak about power grid modernization.

In classical electricity networks, there is only one-way interaction: flow of electricity goes from producers to consumers, producers don't receive any information about the needs of consumers. A Smart Grid is an electricity network based on digital technology that is used to supply electricity to consumers *via* two-way flow of electricity and data. Smart Grids coordinate the needs and capabilities of all generators, grid operators, end users and electricity market stakeholders, minimising costs and environmental impacts while maximising system reliability, resilience and stability. In practice, it consists in adding sensors and software to the existing grid that will give utilities and individuals new information that will help them understand and react to changes quickly. Thus Smart Grids enable electricity customers to become active participants.

Here are some advantages of Smart Grids compared to classical ones:

- **Smart grids have "self-healing" capabilities.** Instead of physically rerouting power with the current grid system, in case of issue, which is time-consuming, smart grids, through the use of sensors and software, would detect and immediately route the power around the problem, limiting the issue to fewer homes.
- **Deferring electricity usage away from peak hours**. Smart Meters, often considered as the first step of implementing Smart Grids, are devices that record information such as consumption of electric energy, voltage levels and power factor. Smart Meters communicate the information to the consumer for greater clarity of consumption behaviour, and electricity suppliers for system monitoring and customer billing. This

[19] Kallabis et al., 2016, *The plunge in German electricity futures prices – Analysis using a parsimonious fundamental model*

system contains benefits for all the players of the market: first for the customer himself, as it enables him to lower his electricity bill. It also helps to homogenize demand during the day and prevent peaks in demand, that can lead to blackouts. It also represents cost savings for utilities: to keep up with constantly changing energy demands, utilities must turn power plants on and off depending on the amount of power needed at certain times of the day; the cost of power depends on the time of the day it is used. Electricity is more costly to deliver at peak times because additional often less efficient power plants must be run to meet the higher demand. In Smart Grids, cooperation of customers helps to lower consumption at these times.

- **Smart Grids are a means to better integrate sustainable energy sources to the grid**. To accommodate a higher percentage of renewable energy, large quantities of conventional back up power and huge energy storage are needed. These would be necessary to compensate for natural variations in the amount of power generated depending on the time of day, season and other factors such as the amount of sunlight or wind at any given time. Since today's electricity grid cannot handle this variability, the cost of adopting the renewable energy sources is currently very expensive. By better forecasting the needs of customers and by incorporating electricity storage devices into the network.

Another structure which is part of the Smart Grids environment is the notion of Microgrids. The traditional centralized utility grid is a big, interconnected network: it takes energy from large far away energy generation plants and transmits it over long distances to consumers.

Businesses and communities can choose to supply their own energy locally by building their own Microgrid. A Microgrid is a group of interconnected energy users and distributed energy resources. These are energy systems that can include solar panels, batteries, wind turbines, etc. Energy is generated closer to where it's needed. The Microgrid can be connected to the larger central grid and be used as a complement and a substitute: in case of an outage, the Microgrid can continue to supply power to homes and businesses for a while. And if the Microgrid generates more electricity than the neighbourhood needs, the surplus can be thrown into the centrale grid. A Microgrid can also operate independently from the national grid.

The concept of a Smart Grid began to emerge in the early 2000's. Each country has their own unique definition of a Smart Grid based on their own policies and objectives. Development of smart grid technologies is part of the European Technology Platform (ETP) initiative and is called the SmartGrids Technology Platform. The SmartGrids European Technology Platform for Electricity Networks of the Future began its work in 2005. Its aim is to formulate and promote a vision for the development of European electricity networks.

A historic milestone has been reached in the European energy sector in 2021 as the penetration of smart electricity metering has passed the 50% mark. At the end 2020, the EU27+3 region was home to nearly 150 million smart electricity meters, corresponding to a penetration rate of 49%. The installed base is expected to exceed 227 million units in 2026.[20]

[20] Report realized by Berg Insight, 2021, *Smart metering in Europe*

Although European electricity structure is evolving rapidly, we are still lagging some countries which managed to modernize their grid in a more efficient way, like Singapore or Israel. In 2009, Singapore's Energy Market Authority (EMA) embraced smart grid technology by launching their pilot smart grid test program, the Intelligent Energy System (IES). Through this program, they have turned their country's energy infrastructure into a hotbed of experimental technological ingenuity. Monitoring stations are aided by Supervisory Control and Data Acquisition (SCADA) systems, which automatically detect disruptions at all levels of electricity transmission and distribution on the grid. Two-way metering is also utilized in Israel. It allows consumers to choose services based on their needs, creating a more flexible market and reducing energy loss.

B. Focus on energy storage

i. Energy storage technologies and installations

Due to growing concerns about the environmental impacts of fossil fuels and the capacity and resilience of energy grids around the world, engineers and policymakers are increasingly turning their attention to energy storage solutions. Indeed, energy storage can help address the intermittency of solar and wind power; it can also, in many cases, respond rapidly to large fluctuations in demand, making the grid more responsive and reducing the need to build backup power plants. The effectiveness of an energy storage facility is determined by how quickly it can react to changes in demand, the rate of energy lost in the storage process, its overall energy storage capacity, and how quickly it can be recharged.

Energy storage is not new. Batteries have been used since the early 1800s and pumped-storage hydropower has been operating in the United States since the 1920s. But the demand for a more dynamic and cleaner grid has led to a significant increase in the construction of new energy storage projects, and to the development of new or better energy storage solutions.

There are many ways of storing energy, each with their strengths and weaknesses. Here is an overview of the main technologies available today.

1. Pumped storage hydroelectricity

Pumped storage hydroelectricity works on a very simple principle: two reservoirs at different altitudes are required. When the water is released from the upper reservoir, energy is generated by the down flow, which is directed through high-pressure shafts, linked to turbines. In turn, the turbines power the generators to produce electricity. When there is an excess of electricity generation, water is pumped back to the upper reservoir by linking a pump shaft to the turbine shaft, using a motor to drive the pump.

This kind of plant generates energy for peak load, and at off-peak periods water is pumped back for future use. The PHS technology is a suitable option for large-scale applications to cope with intermittency of renewable energies.

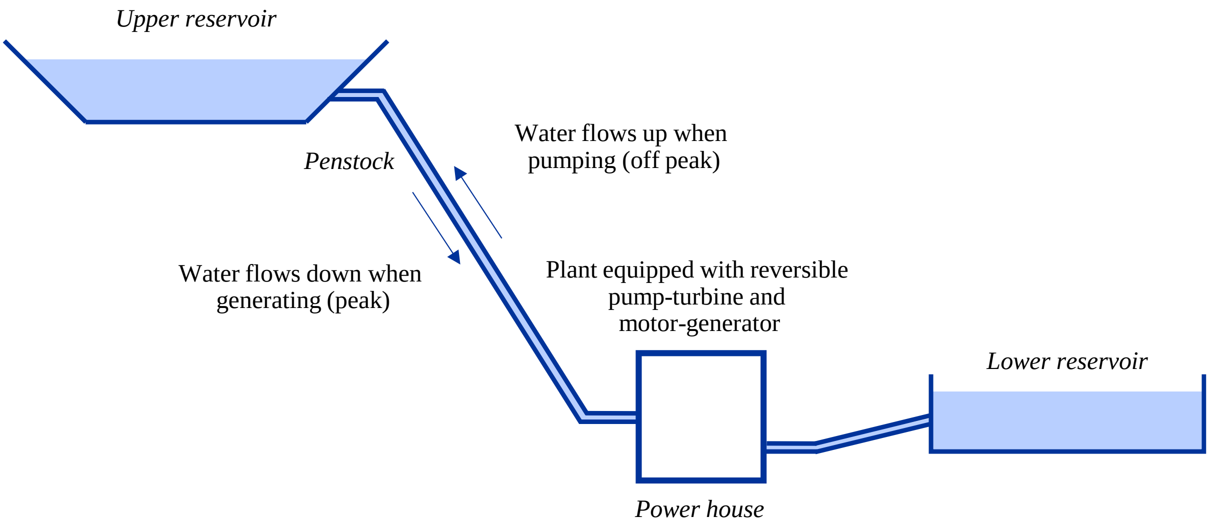


Figure 8: The principle of a pumped storage mechanism[21]

Currently, Pumped Storage has the highest share of grid-scale electricity storage around the world, with 95% of all the worldwide large-scale electric storage capacity provided by this technology. It's a well-tried and researched technology. Pumped-storage hydropower is more than 80% energy efficient through a full cycle, and PSH facilities can typically provide 10 hours of electricity (compared to about 6 hours for lithium-ion batteries).

But the technology also has its limitations:

- The major drawback of PHS lies in the scarcity of available sites for two large reservoirs and one or two dams. The place must also be geographically adapted: in general, in flat places, PHS may be difficult to use or may not be used at all.
- Furthermore, it does take time to pump water from the lower reservoir to the top reservoir, and this can only be done in times of excess renewable energy, so there is not a continuous stream of electricity on tap.
- PSH projects are long-term investments: long lead time (typically 10 years) and high cost (typically hundreds to thousands of million US dollars) for construction.
- Many pumped hydroelectric systems can have negative impacts on land and wildlife: environmental issues (e.g., removing trees and vegetation from the large amounts of land prior to the reservoir being flooded), disruption of fish spawning routes or creation of large reservoirs that fill canyons or gorges are common concerns.

[21] Vahid Vahidinasab, Mahdi Habibi, 2021, *Electric energy storage systems integration in energy markets and balancing services*

Until recently, the largest pumped hydro grid power storage systems in the world was in Bath County, Virginia, USA, with a generating capacity of 3 GW and was known as the « world's biggest battery ». Late 2021, an even larger PHS facility was completed in China's Hebei Province, with a generating capacity of 3.6 GW.

In Europe, the largest facilities are the Grand'Maison Dam in France, with a power capacity of 1.8 GW, and the Dinorwig Power Station in Wales, with a capacity of 1.7 GW. Here are the details of cumulative installed pumped hydropower storage capacity in Europe, by country (in MW):

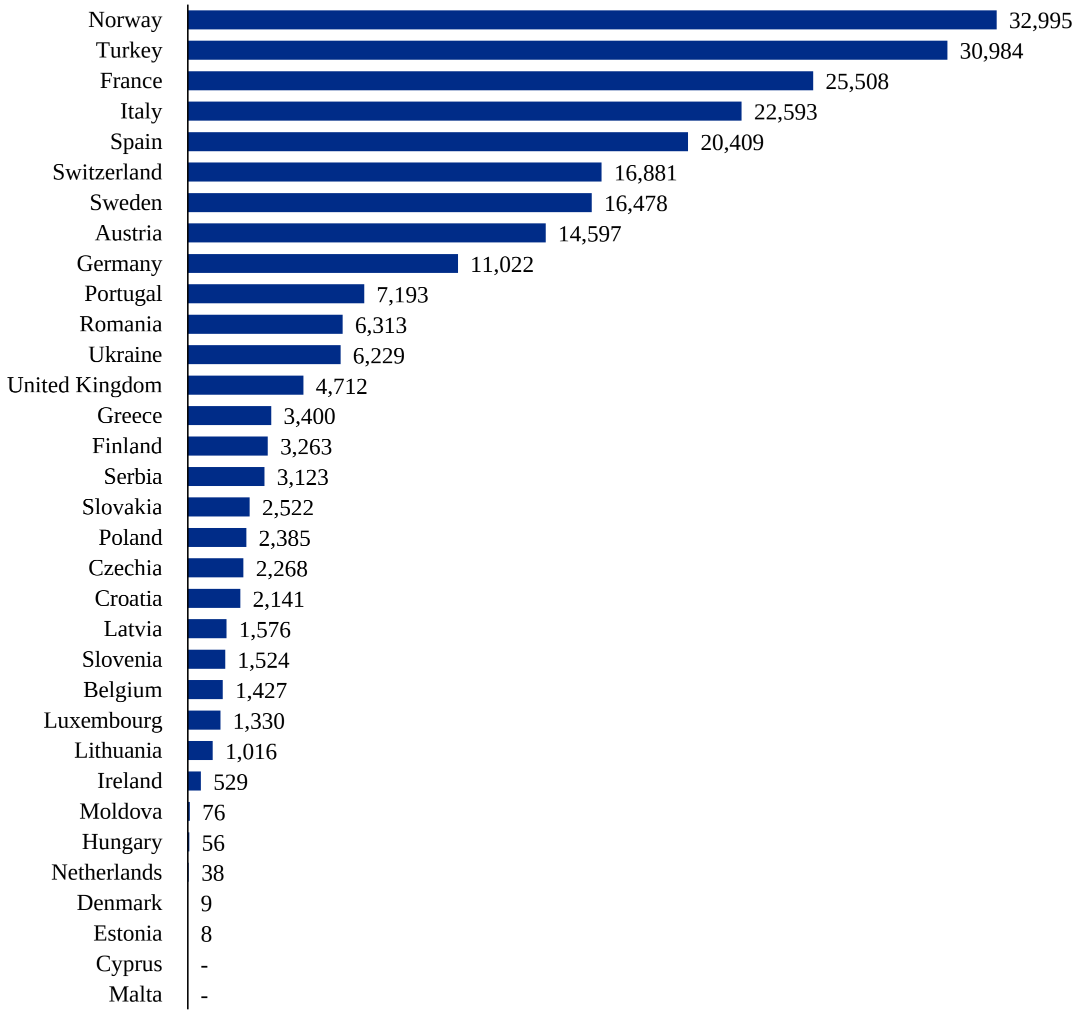


Figure 9: Cumulative installed pumped hydropower storage capacity in Europe in 2020 (in MW)[22]

[22] Hydropower, visited in May 2022, *Cumulative installed pumped hydropower storage capacity in Europe in 2020*

2. Compressed Air Energy Storage (CAES)

CAES is another approach to storing electric energy produced at times of excess supply and making it available again at times of high demand. The process is based around the gas turbine cycle. Surplus power is used to compress air using a rotary compressor and then store it, often in an underground chamber. There are several storage options, but the best option is to store the compressed air in existing geographical formations such as disused salt mines. Salt carverns are usually free of cracks and fissures as any ingress of water through cracks will dissolve salt, which then crystallizes and creates air-tight seals. When the power is required, it is released from the chamber and passed through an air turbine that generates electricity from the flow of high-pressure air. Output from the plant can be boosted by burning natural gas in the high-pressure air before it enters the air turbine, as would happen in a conventional gas turbine. However, this has the penalty of producing carbon dioxide emissions, which the plain storage plant does not. More advanced plants can store heat during air compression and release it during the expansion phase.[23]

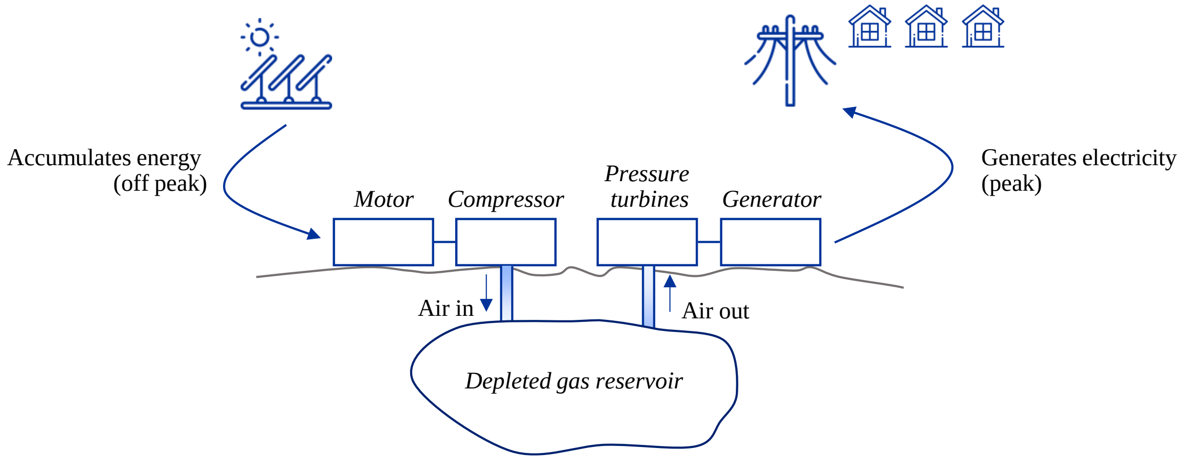


Figure 10: The principle of a Compressed Air Energy Storage mechanism[24]

A CAES system stores air by three possible ways: diabatic, adiabatic and isothermal.

- **Diabatic CAES** is basically the same as a conventional gas turbine except that the compression and expansion stages occur at different time periods. For example, when electricity is in excess, air is compressed and stored in a reservoir, and when electricity is needed, air is heated with natural gas and expanded through a turbine. Worldwide, there are two diabatic CAES plants in operation: the Huntorf plant (290 MW) in Germany and the McIntosh plant (110 MW) in Alabama, USA. The Huntorf plant was commissioned in 1978 to become the world's first CAES plant. The McIntosh plant incorporates a recuperator to reuse the exhaust heat energy. When compared with the Huntorf plant, this recuperator reduces fuel consumption by 22%–25% and improves cycle efficiency by 42%–54%. These two CAES plants have consistently shown good performances with 91.2%–99.5% starting and running reliabilities.

[23] Science Direct, visited in April 2022, *Compressed Air Energy Storage* and *Gas Turbine Cycle*
[24] PG&E website

- **Adiabatic CAES** is a system in which the heat produced due to the compressing of air is captured via a thermal energy storage system. When the electricity is needed, this stored heat is returned to the air before expansion through the turbine. This method does not require the use of premium fuels to heat the compressed air before expansion as the diabatic method, but the process requires advanced thermal storage techniques that are not readily available. The world's first adiabatic CAES system is ADELE at Saxony-Anhalt in Germany, with a storage capacity up to 360 MWh and an electric output of 90 MW, aiming for around 70% cycle efficiency.

- **Isothermal CAES** is an evolving technology that attempts to overcome some of the limitations of conventional CAES: current systems use turbomachinery to compress air to around 70 bars before storage and, in the absence of intercooling, the air heats up to around 900 °K, making it impossible to process and store. Isothermal CAES is technologically challenging since it requires heat to be removed continuously from the air during the compression cycle and added continuously during expansion to maintain an isothermal process. There are currently no isothermal CAES plants available around the world, but several possible solutions have been proposed based on reciprocating machinery with a cycle efficiency of 70%–80%.

CAES is the second biggest form of energy storage currently behind Pumped Storage Hydroelectricity. One advantage CAES has over PHS is that CAES is cheaper to develop. CAES systems also require very little maintenance when compared with other energy production methods.

However, there are several challenges associated with CAES:

- When air is compressed, it heats up. Unfortunately, the warmer the air, the smaller will be the amount of air that can be stored. This problem can be dealt with in three ways: adiabatically, by storing the heat and reusing it when the air is expanded to produce power; isothermally, with the aid of heat exchangers, and diabatically, by dissipating the heat to the atmosphere.[25]

- When releasing the compressed air, the pressure in the cavern is slowly reduced and this affects the amount of electricity produced by the turbine. It can be dealt with by controlling the rate at which the air is discharged and thus creating a constant supply of electricity. Another solution being researched by Seamus Garvey at Nottingham University is to store the air in large energy bags deep in lakes or in the sea..

- Not all geographic locations can be used to build CAES facilities, salt mining caverns being the best way to store compressed air underground. However, recent research has shown that other formations of porous and permeable rock may serve the same purpose. Scientists hope to expand the use of CAES from load-shifting to a more active source of large-scale clean energy production. In addition, engineers are already working on technology to expand the use of CAES for small-scale, off-grid operations.

[25] Science Direct, visited in April 2022, *Heat Exchangers*

3. Flywheel Energy Storage (FES)

Flywheel energy storage is a technology for storing electric energy in the form of kinetic energy by constantly spinning a disk or the rotor of a flywheel. The key components of FES systems are a rotating cylinder, bearings, a generator or motor, and a container to accommodate the flywheel. The charging process requires high acceleration for spinning of the rotor by acquiring the electrical energy given to the motor. This electrical energy is stored in the flywheel by keeping the body rotating at a constant speed. During the discharge process (i.e., when electrical energy is required), the disk rotates the shaft connected to the generator to produce electricity.[26]

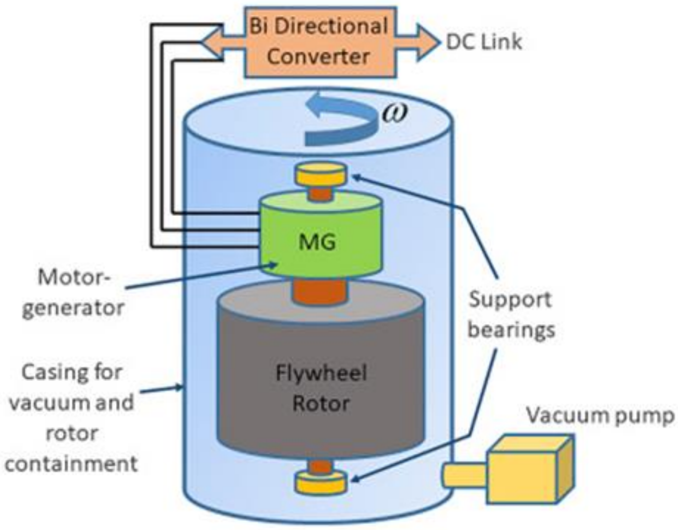


Figure 11: The principle of a Flywheel Energy Storage mechanism[27]

FES systems have several inherent advantages over other energy storage systems:

- They can provide energy quickly without needing time to start up.
- They have an exceptionally long life, in excess of 20 years and can provide hundreds of thousands of discharge cycles, if designed properly.
- They have low maintenance costs.
- They can operate under a wider range of temperatures.
- There is no greenhouse emission or toxic material produced when flywheels are working, so it is very environment friendly.

[26] Science Direct, visited in April 2022, *Flywheel*
[27] Keith R. Pullen, 2019, *The Status and Future of Flywheel Energy Storage*

But the technology also has its drawbacks:

- High losses due to self-discharge: due to the existence of friction, eventually flywheels will lose some energy. Self-discharge rates that can go from 50% up to 100%. In consequence, this technology is more adapted to store energy for short periods of time. However, there are means to minimize friction and improve efficiency. This goal can be realized through two approaches: (i) through the creation of a vacuum environment for the flywheel to spin in, ensuring there will be no air resistance and / or (ii) through the installation of a permanent magnet or electromagnetic bearing to make the spinning rotor float.
- High cost of ensuring the system's security
- Sizeable footprint especially when fabricated out of steel
- High cost of current systems: high capital cost of $1,000–$5,000/kWh

Currently, high-power flywheels are used in many aerospace and UPS applications. For utility-scale storage a ‘flywheel farm’ approach can be used to store megawatts of electricity for applications needing minutes of discharge duration. Today the world’s largest flywheel energy storage system is in Stephentown, New York. The 20-megawatt system marks a milestone in flywheel energy storage technology, as similar systems have only been applied in testing and small-scale applications.

It is still a matter of discussion whether flywheel energy storage will, in the future, become very common. This issue depends on many factors, like the concentrations of effort or the short-term progress in other types of energy storage devices.

4. Power-to-Gas

Power-to-Gas (also known as P2G or PtG) is a technology that uses excess electricity to produce hydrogen via water electrolysis. The hydrogen can then be injected directly into the natural gas network and be used as a fuel (either for transport, displacing oil in light vehicles, railways, and marine applications) or as a feedstock for industry; it can also be converted into synthetic methane through a chemical reaction called methanation, which consists in combining hydrogen with CO2.

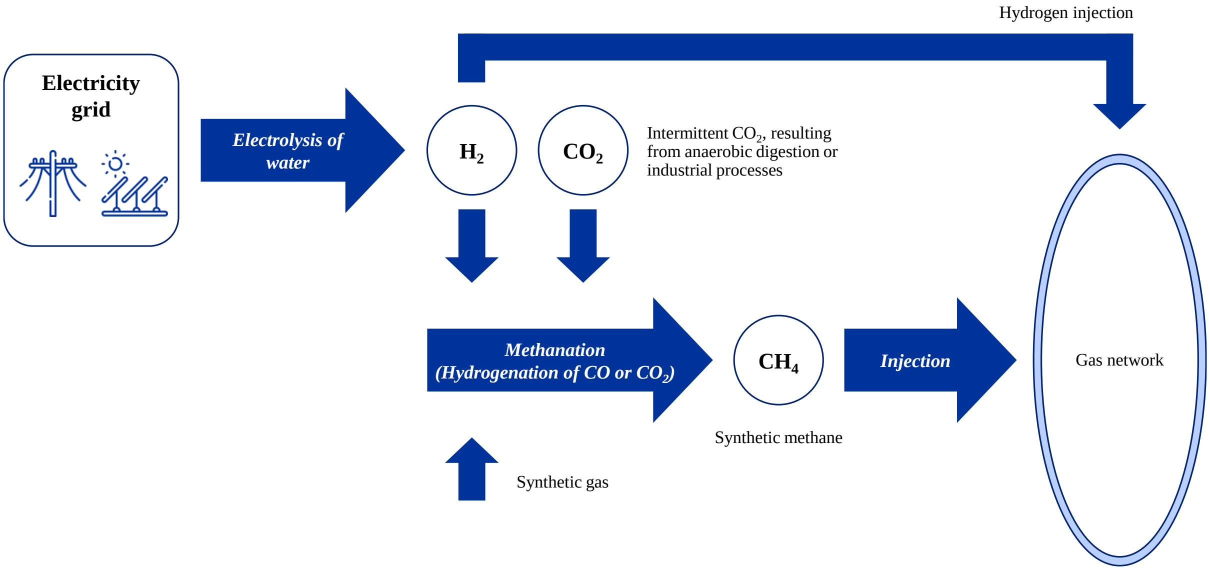


Figure 12: The principle of a Power-to-Gas mechanism[28]

The storing capacity of this technology is huge, both hydrogen and methane being much easier to store than electricity. Indeed, gas can be stored for days, weeks and even months. It can also be easily transported geographically for use elsewhere, through gas pipelines. Another advantage of this method is that the methanation process allow to reuse CO_2 rejected by industrial processes: not only methane is a highly efficient gaseous fuel and is carbon neutral when generated via PtG, but it also captures carbon during the process.

But the technology has also its limits:

- As we mentioned, hydrogen can be injected directly into the gas grid, but this can raise technical and safety issues if its concentration becomes too high. The maximum concentration allowed varies from a country to another: the UK, for example, only allows injection of 0.1% hydrogen by volume, while in parts of the Netherlands the limit is 12%. However, advancements to loosen these constraints are underway.

- Another limit of Power-to-Gas today is its cost: neither electrolysis nor methanation are yet close to be cost-competitive when compared to other energy storage processes. These conversion processes are especially difficult and costly to run in an intermittent mode. They have low "round-trip efficiency" of storing and then re-generating electricity: an estimated 34-44% for the hydrogen pathway and 30-38% for the methane pathway. Research, development, and pilot deployment of these technologies is needed to drive down costs, supported by carbon pricing that adequately values the climate benefits of power-to-gas.

[28] Gaz Réseau Distribution France website

While still in its infancy, Power-to-Gas provides a promising approach to convert renewable power into “green” hydrogen and methane: 56 hydrogen and 38 methanation projects were active in 2019. While the existing fleet mostly comprises pilot or demonstration projects under 1 MW, nearly 45% of these projects fed or planned to feed gas into the grid or reconvert it into power or heat. Most advanced European country in the domain are Germany, followed by Denmark, the UK, France, Switzerland and Spain. One of the largest existing P2G projects in the world is the 6-MW PEM electrolysis Energiepark Mainz project in Germany, which began operation in May 2014. The system uses a first-generation Siemens Silyzer 200 electrolyzer to convert surplus power from wind farms. The hydrogen is then fed into the local grid, delivered to surrounding industrial companies, or provided to regional filling stations.

Major projects are also being developed outside of Europe, especially in Canada and the US. In 2018, hydrogen generation and fuel cell firm Hydrogenics and Enbridge Gas Distribution began operating the 2.5-MW Markham Energy Storage Facility in Ontario, Canada, to provide regulation services to the regional Independent Electricity System Operator. In 2019, Southern California Gas Co. and Danish P2G technology provider Electrochaea commissioned the first “scalable” biomethanation reactor system in the U.S. at the National Renewable Energy Laboratory (NREL) Energy System Integration Facility in Golden, Colorado. The plant contains a 25-foot-tall bioreactor system, which uses a thermophilic microorganism that feeds on hydrogen produced via and wind and solar–fuelled 250-kW electrolyzer and carbon dioxide to produce pipeline-quality methane.

5. Thermal energy storage (TES)

Thermal energy storage means heating or cooling a medium to use the energy when needed later. In its simplest form, this could mean using a water tank for heat storage, where the water is heated at times when there is a lot of energy, with the energy being stored in the water. The basic principle is the same in all TES applications.

What mainly varies is the scale of the storage and the storage method used. Many different technologies can be used to achieve thermal energy storage and depending on which technology is used, thermal energy storage systems can store excess thermal energy for hours, days or months.

TES systems are divided in three types: sensible, latent and chemical storage. The differences between these methods are the material, the temperature of operation and a few other parameters.

- **Sensible heat storage** (SHS) is the most straightforward method. It simply means the temperature of some medium is either increased or decreased. This type of storage is the most commercially available out of the three, as the others are still being researched and developed. One of the cheapest, most used options is a water tank, but materials such as molten salts or metals can be heated to higher temperatures and therefore offer a higher storage capacity.

- **Latent heat storage systems** store energy without the medium changing in temperature but rather depends on the changing state of a medium. So called 'phase change materials' have been developed, which can store heat in their mass as latent heat. These materials are commonly used in solar applications and building materials, where they absorb and store excess building heat.

- **Thermochemical heat storage systems** use thermo-reversible chemical reactions. The storage system is charged by an endothermic reaction, absorbing the resulting enthalpy. This is then discharged by an exothermic reaction.

The most used and promising TES technology is the one using molten salt. The salts are heated and stored in an insulating container during off-peak hours. When energy is needed, the salt is pumped into a steam generator that boils water, spins a turbine, and generates electricity.

Molten salts used for TES applications are in solid state at room temperature and liquid state at the higher operation temperatures. High-temperature properties such as the volumetric storage density, viscosity and transparency are similar to water at room temperature. The primary drawback with water as a heat transfer fluid is the limited range of temperature over which it can be used. The theoretical liquid range of water is between 0 and 100 °C, but the practical temperature range for water used as heat transfer fluid is much less than 100 °C because of the high vapor pressure near the boiling point. Also, high pressure is needed to keep water at a liquid state when the temperature is over 100 °C, which results in high costs due to the related pressure vessels and pipes. Accordingly, high temperature water (over 100 °C) is unsuitable as a heat transfer fluid or thermal energy storage medium for solar energy power plants. Thermal oils can maintain their liquid phase up to about 300 °C and can be used as thermal storage media and heat transfer fluids, but their applications are limited by several intrinsic disadvantages such as low decomposition temperature, low density, flammability, high vapor pressure, fuming tendency, and low chemical stability.

From the entire gamut of materials researched for various properties, molten salts are a very specific group that have immense potential as thermal energy storage and heat transfer media for solar energy applications. Molten salts have been proposed as heat transfer fluids for high temperatures from 250 to 1000 °C. Low melting point (LMP) molten salts are a group of salts which remain liquid over a wide temperature range. Other important properties of LMP salts includes good heat and electrical conductivity, high thermal and chemical stability, low viscosity, and environmental friendliness. The liquid range for an individual molten salt could be from 150 to 600 °C. By a combination of different LMP salts and the optimization of composition, the liquid temperature range is expected to increase significantly. Due to these properties, LMP molten salts could be excellent thermal storage media and heat transfer liquids in solar power plant systems.

At the end of 2019 the worldwide power generation capacity from molten salt storage in concentrating solar power (CSP) plants was 21 GWh. The global molten salt thermal energy storage market was valued at 1.4 billion U.S. dollars in 2020 and is expected to grow at a compounded annual growth rate (CAGR) of 25.1% from 2021 to 2031. Europe accounted for 78.2% share of the total value of molten salt thermal energy storage units in 2020.[29] This can be ascribed to the region's early adoption of molten salt thermal energy storage, which was prompted by rigorous rules governing emission standards and renewable energy consumption.

6. Batteries

Batteries are another main energy storage technology, already used for years and still under improvement. They will be described in detail in the next section.

ii. Business model of energy storage in today's market

This subsection focuses on the different business models that can be put in place for energy storage and the different reasons that may support the choice of one model over another. We first discuss the revenue streams that can be expected from operating an energy storage installation and present what role can investors expect to have in the whole value chain when operating energy storage installations.

The use of energy storage can prove useful at different stages of the value chain, either through *ancillary services* or *load shifting*.

- **Ancillary services** refer to the functions that support the grid reliability. These services consist in grid stabilisation (frequency containment, voltage control, etc.) or provision of electricity (black start energy, etc.) to ensure its availability at all times.
- **Load shifting** refers to the ability of batteries to charge and discharge at will, which can help market participants increase or decrease the supply or demand of electricity when it is advantageous to do so (e.g., helping a Business Responsible Party (BRP) meeting its buying/selling forecasts to achieve a balanced portfolio).[30]

[29] Data by Transparency Market Research, a global market intelligence company providing global business information reports and services

[30] Baumgarte et al., 2020, *Business Models and Profitability of Energy Storage*

Ancillary services and load shifting can be directly remunerated on ancillary services markets, on which the TSO is usually the sole purchaser of products.[31] However, these services can be performed or useful to different electricity market participants, such as investors (who perform trading by buying and selling electricity), producers (who produce electricity), transmission and distribution system operators (T&D) (who are responsible for the transportation of electricity and the stability of the grid) and consumers (who purchase and consume electricity).[32]

Three revenue streams could create value for these market participants:

- **Price arbitrage**, which refers to the utilisation of different prices of electricity across markets, either at one time or across time within a single market
- **Cost avoidance**, which refers to the savings that can be done through the use of energy storage (e.g., penalties for unbalanced portfolios for BRPs, etc.)
- **Investment deferral**, which refers to the savings resulting from not investing in certain infrastructure (e.g., not increasing grid capacity, etc.)

Figure 13 summarises the services, market participants and revenue streams of battery storage.

[31] EASY-RES, 2018, *Report Reviewing the Current Market Regulatory Framework*
[32] Baumgarte et al., 2020, *Business Models and Profitability of Energy Storage*

	Cost avoidance	Investment deferral	Price arbitrage
Trading			
	Frequency containment *Provide frequency containment* *Avoid cost of ramping portfolio*		**Price arbitrage** *Buy at low / sell at high prices* *Exploit volatility in electricity market prices*
	Short-term frequency restoration *Provide short-term frequency restoration* *Avoid cost of ramping portfolio*		
	Long-term frequency restoration *Provide long-term frequency restoration* *Avoid cost of ramping portfolio*		
	Trading forecast *Meet buying / selling forecast* *Avoid penalties for deviations*		
Production			
	Frequency containment *Provide frequency containment* *Avoid cost of ramping production*	**Voltage control** *Provide voltage control* *Save investment in voltage regulators*	
	Short-term frequency restoration *Provide short-term frequency restoration* *Avoid cost of ramping production*	**Black start energy** *Provide black start energy* *Save investment in black start generator*	
	Long-term frequency restoration *Provide long-term frequency restoration* *Avoid cost of ramping production*	**Backup energy** *Provide backup energy* *Save investment in backup generator*	
	Schedule flexibility *Meet selling forecast* *Avoid cost for ramping up*	**Peak shaving** *Shave demand peaks* *Save investment in capacity expansion*	
	Production forecast *Meet selling forecast* *Avoid penalties for deviations*		
Transmission & Distribution			
	Frequency containment *Provide frequency containment* *Avoid cost of control services*	**Voltage control** *Provide voltage control* *Save investment in voltage regulators*	
	Short-term frequency restoration *Provide short-term frequency restoration* *Avoid cost of restoration services*	**Peak shaving** *Shave supply / demand peaks* *Save investment in capacity expansion*	
	Long-term frequency restoration *Provide long-term frequency restoration* *Avoid cost of restoration services*		
	Black start energy *Provide black start energy* *Avoid cost of black start service*		
Consumption			
	Frequency containment *Provide frequency containment* *Avoid cost of ramping consumption*	**Voltage control** *Provide voltage control* *Save investment in voltage regulators*	**Consumption arbitrage** *Buy at low prices* *Exploit volatility in consumer prices*
	Short-term frequency restoration *Provide short-term frequency restoration* *Avoid cost of ramping consumption*	**Backup energy** *Provide backup energy* *Save investment in backup generator*	**Self-sufficiency** *Buy at low prices* *Exploit gap in buying and selling prices*
	Long-term frequency restoration *Provide long-term frequency restoration* *Avoid cost of ramping consumption*		
	Peak shaving *Shave demand peaks* *Avoid demand charges*		**Business model** *Application* *Revenue stream*

Figure 13: Business models for energy storage[33]

[33] Baumgarte et al., 2020, *Business Models and Profitability of Energy Storage*

Although academic analysis has found battery storage business models to be largely unprofitable, deployment of capacity is on the rise on a global scale. Subsidies and the intention of gaining an "unfair advantage" in this market may be driving these investments, and there may simply be a lag between market developments (diversifying sources of revenue and costs decreases) and academic studies.

Overall, four main business cases have been identified so far for the use of battery storage[34]:

- **Front-of-the-Meter** (FTM) **grid services**, which is based on frequency containment, intraday-market participation, and revenues from long-term capacity contracts. The main purpose of these projects is to generate revenues in the FCR and FRR markets (which requires a liberalized ancillary services market) and to generate additional revenues through long-term capacity contracts when available.

- **FTM renewables integration**, which is based on the integration of energy storage solutions with large-scale renewable energy sources (RES) in remote locations. This solution enables RES operators to shift production injection in the grid, correct forecast errors and maintain a constant output. This can significantly increase revenue for RES operators.

- **Behind-the-Meter** (BTM) **Commercial & Industrial**, which provides commercial and industrial consumers with energy in times of high demand to reduce or avoid power charges. It can also be coupled with distributed energy resources (DER) to perform arbitrage through an aggregation program. The main requirements of this business case are a volatile consumption and high peak load prices.

- **Off-grid micro and mini-grids**, which are based on the replacement of expensive and polluting diesel generators used in remote locations with batteries to provide a constant energy output, when coupled with DER.

The European Union is overall an attractive region for energy (and more specifically battery) storage with the liberalisation process and coupling of the markets. However, some solutions are more relevant in some countries that others (e.g., renewable integration is most relevant in France, by microgrids have more appeal in Greece). The map below summarizes the potential of each solution (based on the lithium-ion technology) in European countries.

[34] Killer et al., 2019, *Implementation of large-scale Li-ion battery energy storage systems within the EMEA region*

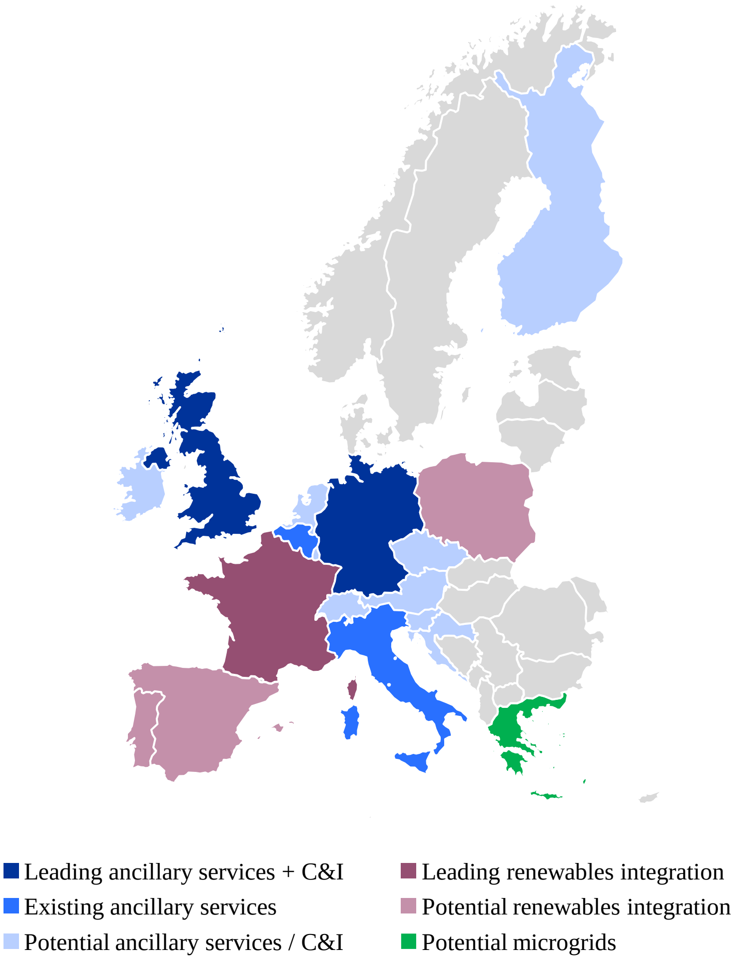


Figure 14: Li-ion BESS market overview in Europe with main existing (or potential) use-cases per country, given market regulations[35]

When a market and sources of revenues have been identified, different structures of ownership and roles in the operation of the energy (especially battery) storage system can be considered. These considerations are dependent on the level of risk that operators are willing to take in the context of a project. When commercial operations and market risks are high, services agreements covering certain functions of the battery and shared ownership structures may be used to outsource some of the risk (and therefore expected returns) to third-parties.[36]

There are five main possible business models for an energy storage installation that we identified, through discussions with Mirova's Mr. Romano and based on Baringa and UK Power Networks, 2013, *Smarter Network Storage – business model consultation*:

[35] Killer et al., 2019, *Implementation of large-scale Li-ion battery energy storage systems within the EMEA region*
[36] Baringa and UK Power Networks, 2013, *Smarter Network Storage – business model consultation*

- **Merchant model**, in which the operator has the full ownership and operating role of the asset and is entirely responsible for monetising the value that can be extracted from the wholesale and ancillary services markets.

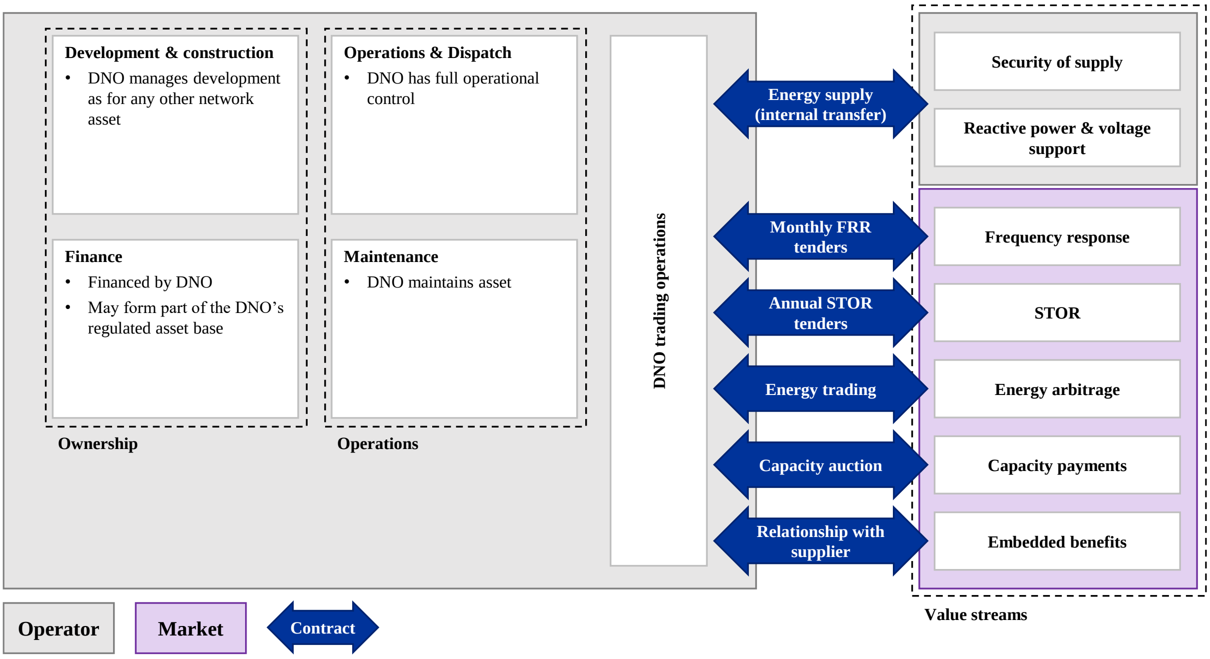


Figure 15: Overview of the merchant model[37]

[37] Baringa and UK Power Networks, 2013, *Smarter Network Storage – business model consultation*

- **Distribution system operator** (DSO) **model** is relatively similar to the Merchant model, in which the operator owns, operates, and maintains the asset, but includes an obligation to support the broader network system on a local or regional scale. The energy storage operator has a role similar to a TSO on a more local scale (by providing balancing and other ancillary services such as peak shaving and frequency containment) and is incentivized through a regulatory incentive scheme and retains both risks (with respect to financing, control, and commercialization) and returns related with the operations of the assets, with no third-party involvement.

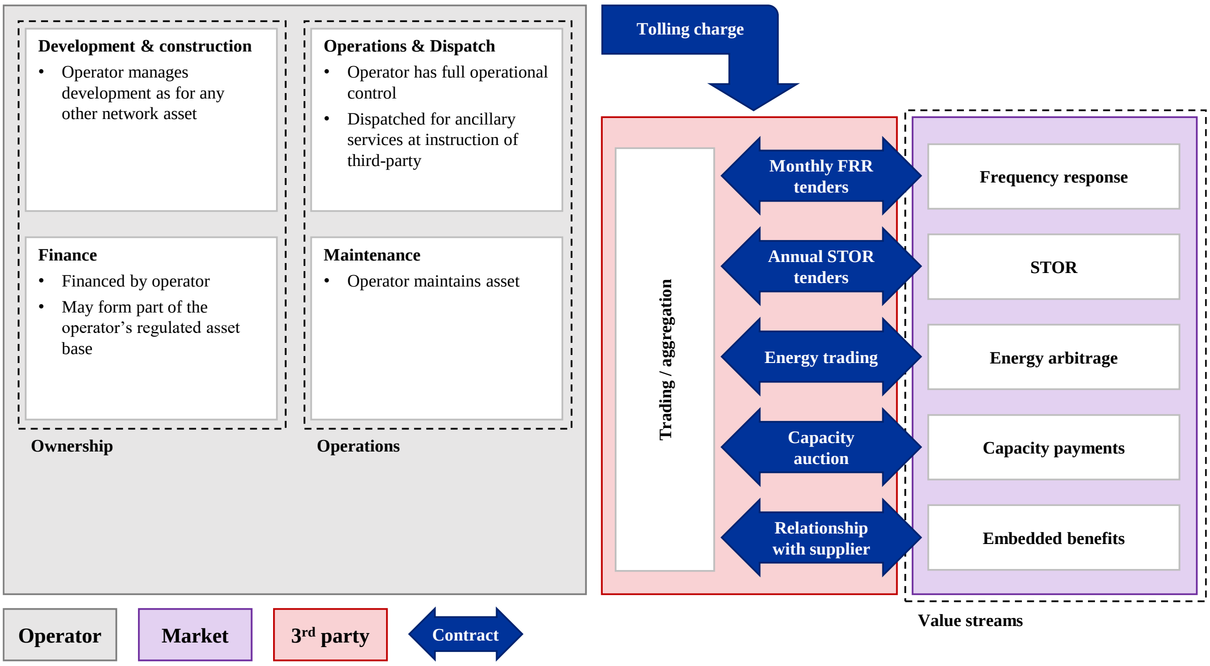


Figure 16: Overview of the Distribution System Operator model[38]

[38] Baringa and UK Power Networks, 2013, *Smarter Network Storage – business model consultation*

- **Brownfield model**, which is best suited for financial investors which are unwilling to bear development and / or construction risks (e.g., Gore Street Energy Storage Fund, etc.). These investors acquire the asset when it has been developed (regulatory authorizations have been obtained) or when the asset is under construction or operational. With the Brownfield model, investors are still responsible for the operations, maintenance and trading operations of the asset.

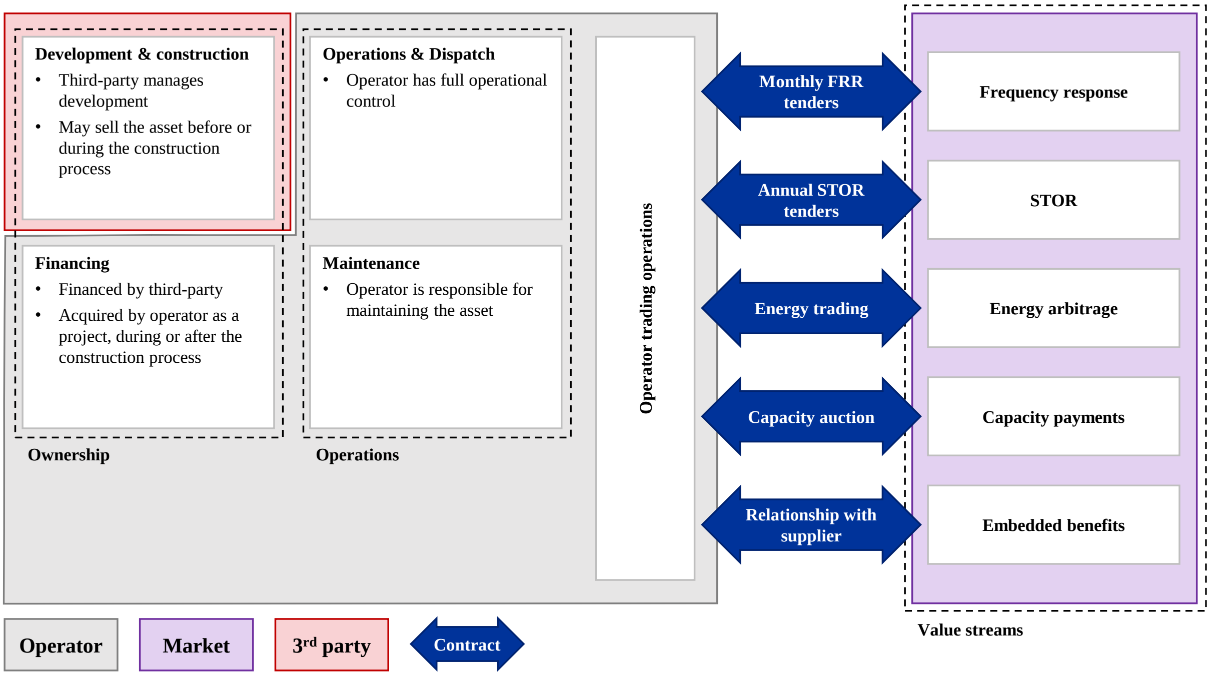


Figure 17: Overview of the brownfield model

- **Capital recycling model**, which is usually used by companies with a certain experience in the sector (e.g., ENGIE). It can be considered as the complement of the Brownfield model as the developer is willing to bear the development and potentially the construction risks but offloads the operational and commercial risks to another investor. It usually allows developers to benefit from an attractive valuation and to leverage their experience.

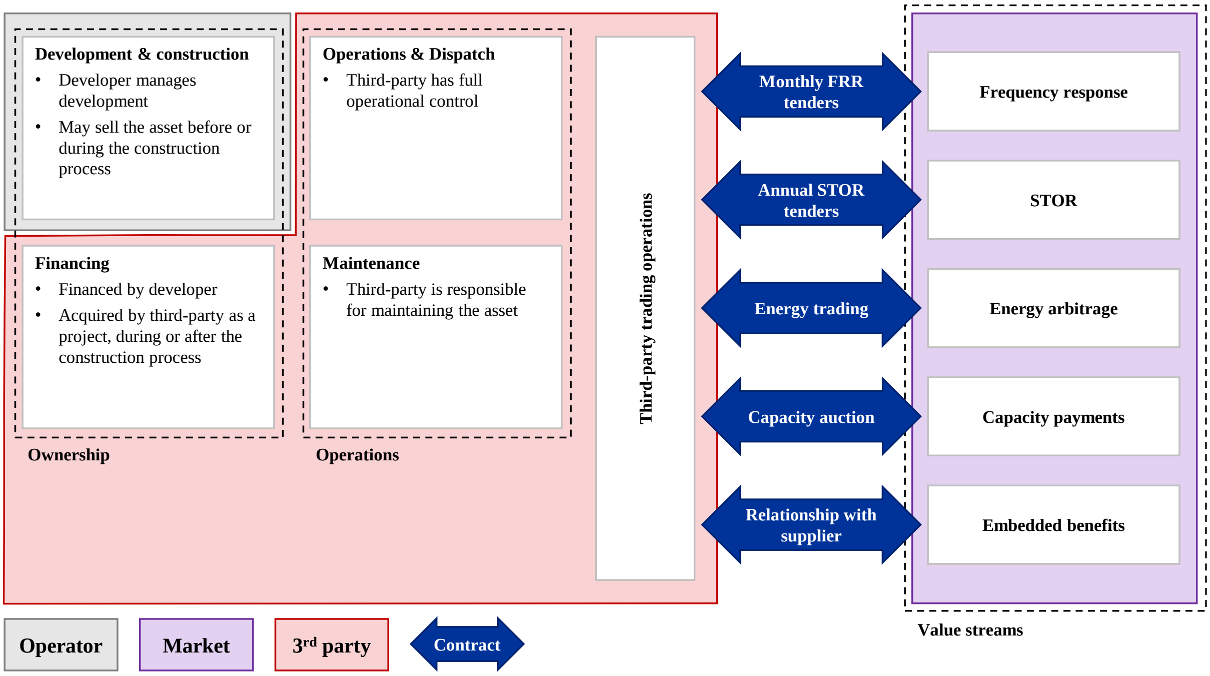


Figure 18: Overview of the capital recycling model

- **Stewardship model**, in which financial investors invest a majority or minority equity ticket in the project, alongside a developer that has experience in the sector and is willing to bear or share the development and construction risks and share the operational risks. A maintenance contract is usually signed with the developer to maintain the asset. This model is mainly used by developers to create liquidity early in the life of the project.

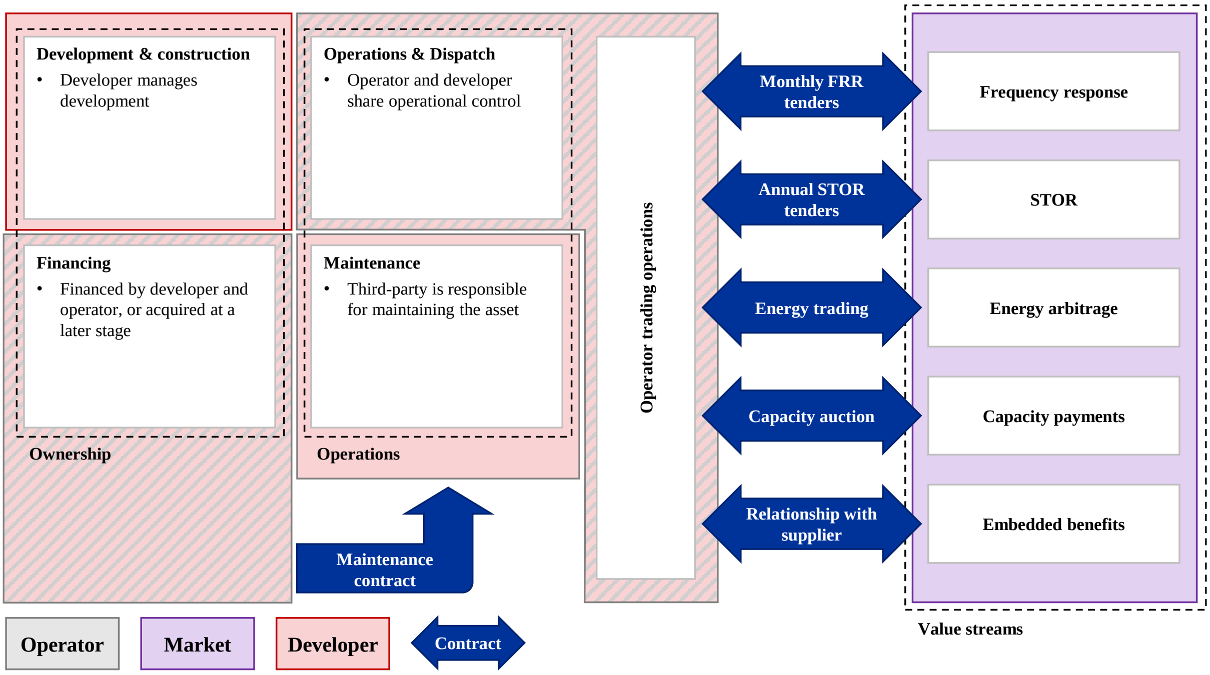
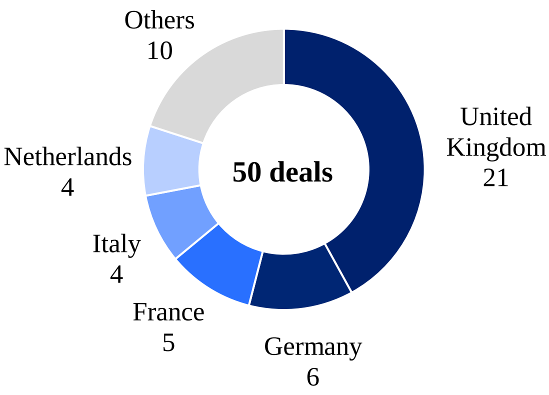


Figure 19: Overview of the stewardship model

iii. Analysing investors' approach

Following this analysis of business models that can be implemented in the context of an investment in battery storage systems, we present what have been the approaches used by investors over the last few years in the industry.

We analysed 50 deals from 14 different countries, although most of them happened in the United Kingdom (21), Germany (6) and France (5). This difference in terms of location may be explained by (i) the structure of the markets, which may be more liberalized in the United Kingdom, despite a relatively equal-sized market in terms of electricity consumption, when compared with Germany and France. The oldest deal we analysed occurred in May 2018 and the most recent one occurred in May 2022.



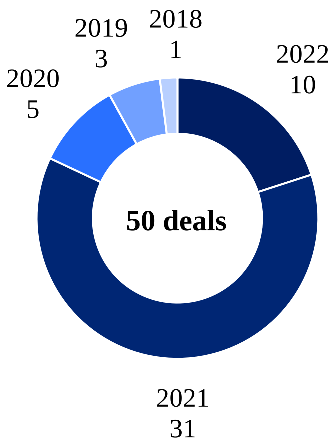


Figure 20: Breakdown of deals analysed by target's country of incorporation and date of occurrence

The first result of the analysis is that most deals were done by financial investors, which is most likely explainable by (i) the ability of strategic investors to develop these deals in-house (i.e., as greenfield projects), without the need to invest in a project or a developer and (ii) by the greater access to capital of financial investors, which have been particularly high given the low-interest rates environment during the 2010's.

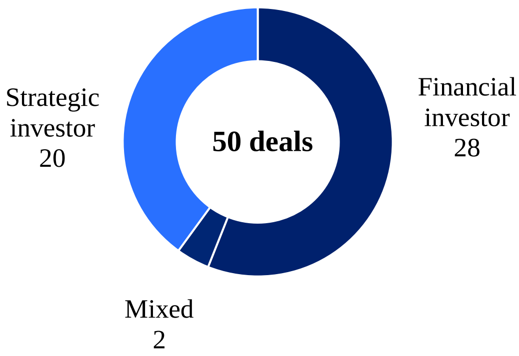


Figure 21: Breakdown of deals analysed by type of investors

Overall, investments in developers (i.e., in companies developing a technology or already developing or managing infrastructure) has been dominant. This model of investment has been preferred by strategic investors (10 out of their 20 deals). Investments in projects (only with authorisations or in development) and operational projects has been massively favoured by financial investors, which most likely see these models of investments as a mean of benefiting from projects without having to provide technical knowledge (which would correspond to the stewardship or capital recycling models).

Based on a discussion with Mirova's Impact Private Equity Fund manager Marc Romano, it became clear that investments in standalone projects did not make financial and operational sense. Given the high capital expenditures expected to build such infrastructure, the most likely model for battery storage investors is integrating the operations of a battery with the production of a variable renewable energy (VRE) source, such as wind or solar.

Integration with VRE is particularly useful for renewable energy companies such as Neoen and Iberdrola, which respectively owned an installed and under-development capacity of 642 MW and 193 MW at the end of 2021.[39] As presented during the discussion with Mr. Romano, this allows these green electricity producers to shift the sale of electricity from one timeframe to another, when the selling price is higher. This strategy enables them to generate higher revenues, thus potentially benefiting from the developing technology of battery storage.

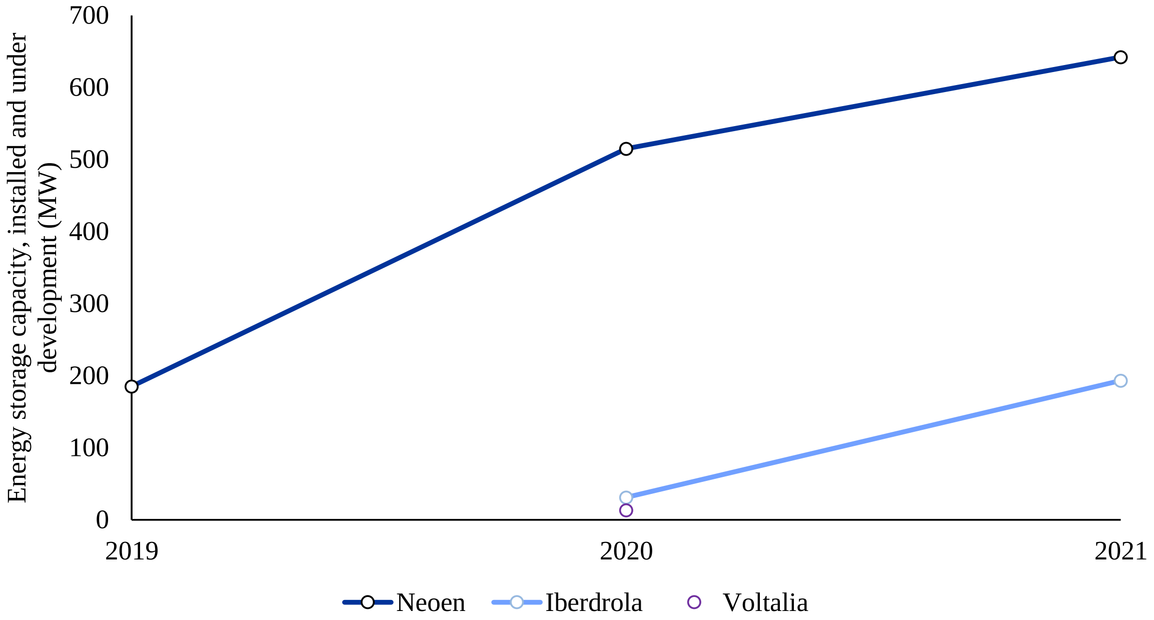


Figure 22: Evolution of selected renewable energy producers' energy storage capacity, installed and under development (MW, 2019-2021)[36]

iv. An alternative to handle energy production volatility: Demand Response

Demand response (DR) is an alternative to handle energy production volatility, alongside energy storage. It allows to better manage electricity production and distribution by adjusting demand rather than offer. By participating in DR programs and pilots, customers shift or reduce their electricity usage at certain times of the day, generally when a utility's electric demand is peaking. Participation in demand response programs and pilots are triggered by economic incentives, price signals, direct communications, or other conditions. Effective demand response programs provide various economic and environmental benefits, including:

[39] Neoen and Iberdrola, 2022, *2021 Annual Reports*

- Avoiding construction of new power plants
- Avoiding purchases of high-priced energy
- Enhancing grid reliability, which helps prevent blackouts
- Reducing power use from fossil fuels used to meet peak demand

Methods of engaging customers in demand response efforts include offering time-based rates such as time-of-use pricing, critical peak pricing, variable peak pricing, real time pricing, and critical peak rebates. It also includes direct load control programs which provide the ability for power companies to cycle air conditioners and water heaters on and off during periods of peak demand in exchange for a financial incentive and lower electric bills.

The electric power industry considers demand response programs as an increasingly valuable resource option, whose capabilities and potential impacts are expanded by grid modernization efforts. For example, sensors can perceive peak load problems and utilize automatic switching to divert or reduce power in strategic places, removing the chance of overload and the resulting power failure. Advanced metering infrastructure expands the range of time-based rate programs that can be offered to consumers. Smart customer systems such as in-home displays or home-area-networks can make it easier for consumers to changes their behavior and reduce peak period consumption from information on their power consumption and costs.

Demand Response programs have been even more closely looked at since the beginning of the war between Ukraine and Russia. Russia's invasion of Ukraine has roiled the markets and geopolitics of energy, driving oil and gas prices to their highest levels in nearly a decade and forcing many countries to reconsider their energy supplies. According to the International Energy Agency, Russia is the world's largest oil exporter to global markets, and its natural gas fuels the European economy: the EU imported around 40% of its natural gas, more than one-quarter of its oil and about half of its coal from Russia in 2019.[40]

[40] Nature, 2022, *Global research community condemns Russian invasion of Ukraine*

II. Deep dive on battery storage

A. What is battery storage

i. Functioning

Batteries are made of stacked cells where-in chemical energy is converted to electrical energy and vice versa. The desired battery voltage as well as current levels are obtained by electrically connecting the cells in series and parallel.

Cells are composed of two half-cell reactions (oxidation-reduction) linked together via a semipermeable membrane (generally a salt bath) and a wire. Each side of the cell contains a metal that acts as an electrode. One of the electrodes is termed the cathode, and the other is termed the anode. During charging, the side of the cell containing the cathode is reduced, meaning it gains electrons and acts as the oxidizing agent for the anode. The side of the cell containing the anode is where oxidation occurs, meaning it loses electrons and acts as the reducing agent for the cathode. During discharge, the process is the reverse. The two electrodes are each submerged in an electrolyte, a compound that consists of ions. This electrolyte acts as a concentration gradient for both sides of the half reaction, facilitating the process of the electron transfer through the wire. This movement of electrons is what produces energy and is used to power the battery.

The cell is separated into two compartments because the chemical reaction is spontaneous. If the reaction was to occur without this separation, energy in the form of heat would be released and the battery would not be effective.

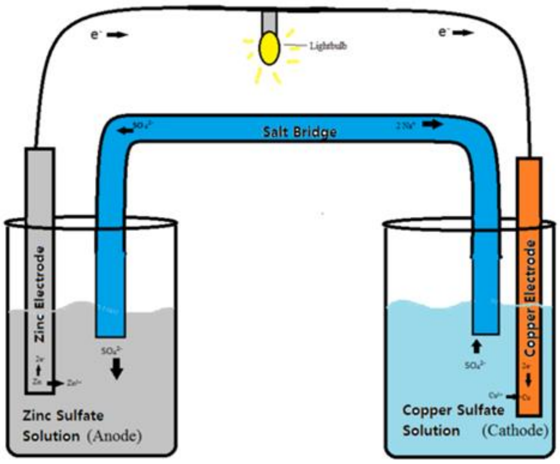


Figure 23: A typical cell used in batteries

The batteries are rated in terms of their energy and power capacities. For most of the battery types, the power and energy capacities are not independent and are fixed during the battery design. Some of the other important features of a battery are efficiency, life span (stated in terms of number of cycles), operating temperature, depth of discharge (batteries are generally not discharged completely and depth of discharge refers to the extent to which they are discharged), self-discharge (some batteries cannot retain their electrical capacity when stored in a shelf and self-discharge represents the rate of discharge) and energy density.

ii. Technologies and applications (existing and under development)

Batteries features vary depending on the electrochemistry technology they use. Here is an overview of the main BESS battery types and opportunities they offer for battery storage solutions.

1. Lithium-ion (Li-ion) batteries

The cathode in these batteries is a lithiated metal oxide and the anode is made of graphitic carbon with a layer structure. The electrolyte is made up of lithium salts dissolved in organic carbonates. When the battery is being charged, the lithium atoms in the cathode become ions and migrate through the electrolyte toward the carbon anode where the combine with external electrons and are deposited between carbon layers as lithium atoms. This process is reversed during discharge.

Li-ion batteries are the most widely used batteries worldwide: according to the 2020 report prepared by the US Energy Information Administration (EIA), over 90% of large-scale battery energy storage systems in the USA were powered by lithium-ion batteries. The global statistics are pretty much the same. This type of rechargeable battery is widely popular in electric vehicles, consumer electronics, and portables, such as smartphones, laptops, tablets, and cameras. The advantages of a Li-ion battery make it one of the leading technologies facilitating the storage of energy. It’s light and compact, has high capacity and energy density, low maintenance, and a long lifetime. In addition, lithium-ion batteries are easily and quickly charged and have a low self-discharge rate. The weak points of this battery technology include high cost, flammability, and intolerance to extreme temperatures, overcharge, and overdischarge.

2. Lead acid (PbA) batteries

Each cell of a lead-acid battery comprises a positive electrode of lead dioxide and a negative electrode of sponge lead, separated by a micro-porous material and immersed in an aqueous sulfuric acid electrolyte (contained in a plastic case).

A lead-acid battery is the oldest battery technology and is also one of the cheapest and most available solutions that find use in automotive and industrial applications as well as power storage systems. These batteries can operate effectively at both high and low temperatures and have a well-established recycling system. According to the Energy Storage Association, lead-acid batteries are extremely eco-friendly; more than 90% of their material is recovered and the average lead battery is made-up of more than 80% recycled materials. Slow charging, heavyweight, and low energy density are among the major drawbacks of this battery technology. They also have a shorter lifespan than other battery options but are the least expensive.

3. Nickel-Cadmium (Ni-Cd) batteries

This battery type prevailed in the market of wearable electronics until Li-ion batteries entered the game. Ni-Cd batteries have many configurations, they are inexpensive, easy to ship and store, and highly resistant to low temperatures. The technology is behind its competitors in energy density, self-discharge rate, and recycling. Nickel-metal hydride (Ni-MH) batteries use the same component as Ni-Cd technology—nickel oxide hydroxide ($NiO(OH)$). However, the Ni-MH battery chemistry provides better characteristics, such as higher capacity and energy density.

4. Sodium-sulphur (NaS)

A NaS battery consists of molten sulfur at the positive electrode and molten sodium at the negative electrode separated by a solid beta alumina ceramic electrolyte. The electrolyte allows only the positive sodium ions to go through it and combine with the sulfur to form sodium polysulfides. During discharge, positive sodium ions flow through the electrolyte and electrons flow in the external circuit of the battery producing about 2 V. The battery is kept at about 300°C to allow this process.

The advantages of NaS batteries involve high energy and power density, a long lifetime, and stable operation under extreme ambient conditions. Nevertheless, this battery technology has a limited application area because of high operating temperatures (not less than 300°C) and sensitivity to corrosion. In addition, sodium is a hazardous component that is highly flammable and explosive. Sodium-sulfur batteries are well-suited for standalone energy storage applications integrated with renewable power sources.

An advantage of Na-ion batteries compared to Li-ion batteries is that they are significantly cheaper due to the fact that sodium is much more easily harvestable than lithium and is available in much higher quantities on Earth. Sodium can easily be extracted from salt, which itself is found in extremely high quantities in ocean and seawater and can produce clean drinking water as a result as well. Additionally, unlike Li-ion batteries that need the presence of the highly expensive cobalt, Na-ion batteries use iron and manganese, which are much cheaper in comparison. The production of Na-ion also avoids the ethical implication of using cobalt, which is mostly mined in the Democratic Republic of Congo and is linked to various cases of human rights abuses.

5. Flow batteries

This type of battery consists of two electrolyte reservoirs from which the electrolytes are circulated (by pumps) through an electrochemical cell comprising a cathode, an anode and a membrane separator. The chemical energy is converted to electricity in the electrochemical cell, when the two electrolytes flow through. Both the electrolytes are stored separately in large storage tanks outside the electrochemical cell. The size of the tanks and the number of electrolytes determines the energy density of these batteries. However, the power density in flow-batteries depends on the rates of the electrode reactions occurring at the anode and cathode. Flow batteries are often called redox flow batteries, based on the redox (reduction–oxidation) reaction between the two electrolytes in the system.

The most common flow battery type is the vanadium redox battery (VRB). The other types consist of zinc-bromine, zinc-iron, and iron-chromium chemistries. Despite their low energy capacity and low charge/discharge rate, flow batteries have several important advantages, allowing them to hold a large market share in on-grid and off-grid energy storage systems, including large-scale applications. These benefits involve an extremely long lifespan (up to 30 years), high scalability, fast response time, and a low risk of fires because flow batteries contain non-inflammable electrolytes.

iii. Functioning of a BESS

A BESS (Battery Energy Storage System) captures energy from different sources, accumulates this energy, and stores it in rechargeable batteries for later use. It is a compound system comprising hardware components along with low-level and high-level software. The main BESS parts include:

- A battery system. It contains individual battery cells that convert chemical energy into electrical energy. The cells are arranged in modules that, in their turn, form battery packs.
- A battery management system (BMS). A BMS ensures the safety of the battery system. It monitors the condition of battery cells, measures their parameters and states, such as state-of-charge (SOC) and state-of-health (SOH), and protects batteries from fires and other hazards.
- An inverter or a power conversion system (PCS). This converts direct current (DC) produced by batteries into alternating current (AC) supplied to facilities. Battery energy storage systems have bi-directional inverters that allow for both charging and discharging.
- An energy management system (EMS). This is responsible for monitoring and control of the energy flow within a battery storage system. An EMS coordinates the work of a

BMS, a PCS, and other components of a BESS. By collecting and analysing energy data, an EMS can efficiently manage the power resources of the system.

Depending on its functionality and operating conditions, a BESS can also include a range of safety systems, such as a fire control system, a smoke detector, a temperature control system, cooling, heating, ventilation, and air conditioning systems. The safety systems have their own monitoring and control units that provide conditions necessary for the safe operation of a BESS by monitoring its parameters and responding to emergencies.

Apart from electronics, complex BESSs rely on robust software solutions. For example, state-of-the-art systems use machine learning algorithms to optimize energy management. Estimating battery states and characteristics with high accuracy requires reliable algorithms and mathematical models built within BMS software development.

B. Presentation of the value chain

BESS are not all created equal: services, functionalities, and pricing structures can vary from project to project. However, certain components remain consistent.

i. Upstream portion of the value chain

The upstream components of the BESS include the following:

- **Storage Technology:** it includes the battery cells that convert chemical energy into electrical energy (see previous section for more details). Li-ion batteries currently dominate the market, but a diverse blend of battery technologies is beginning to be deployed.
- **Power Conversion:** Power conversion technologies primarily include bidirectional inverters (hardware) and some software within the inverter. Inverters are relatively technology-agnostic, meaning the inverter market will grow with the overall energy storage market.
- **Thermal Management:** Thermal management technologies maintain the desired temperature range within a system and are critical for optimizing storage capacity, lifespan, performance, and safety. High-temperature storage technologies such as sodium-sulphur batteries use vendor-specific custom systems, while other technologies such as flow batteries tolerate a wider range of temperatures without heating, ventilation, and air conditioning.
- **Software & Controls:** Software and controls technology is required for all aspects of system operation and performance. Three sub-components make up the software and controls component of an energy storage system:
    - Advanced sensors and system management devices monitor performance, manage health, and set dispatch / cycle frequency limitations of systems.

- Controls manage the charge and discharge rate, optimize economic dispatch, balance competing applications and obligations, and control aggregated distributed systems.
- Communications technologies send and receive data and control signals, and support software and firmware upgrades.

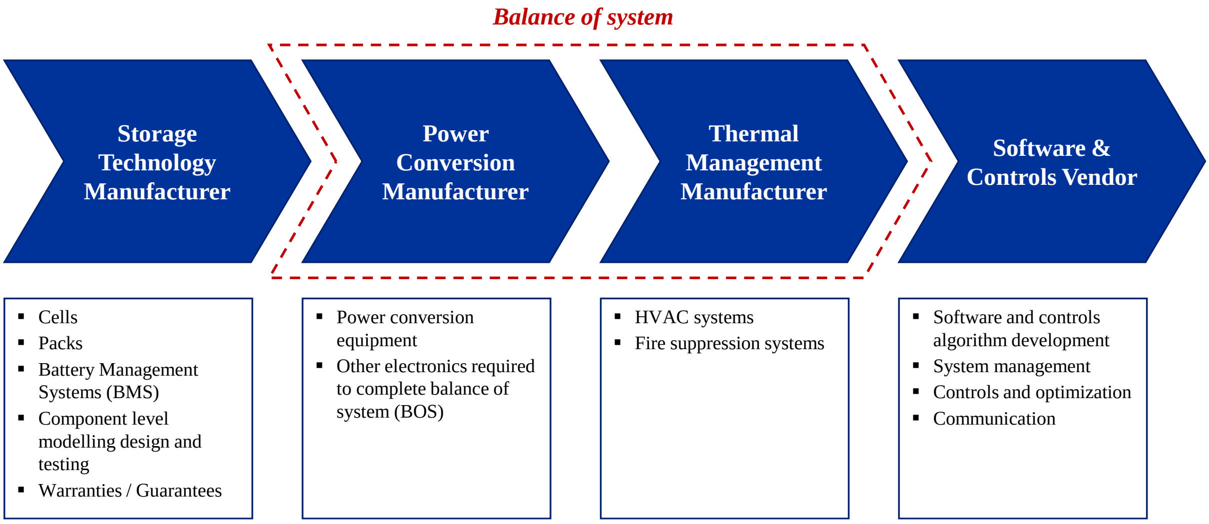


Figure 24: Upstream portion of the value chain

ii. Energy storage integrators

As the market matures, the role of integrators has become key in the value chain for ensuring that projects are successfully built and that they become profitable. A system integrator is a company that specialises in combining component subsystems and ensuring that these subsystems function together as a whole. It is usually responsible for procuring individual components, primarily the battery modules, power conversion system (PCS) and other balance of plant; assembling the system; providing a wrap on warranties; integrating the controls and energy management system (EMS); often providing project design and engineering expertise; and providing operation, monitoring and maintenance services.

The global energy storage industry continues to rapidly expand, creating opportunities for new entrants and incumbents alike. As the market grows, many system integrators are evolving their business model to create a stronger competitive footing. New market entrants are also joining, often from the solar inverter or battery cell manufacturer space. Globally, Fluence, Tesla Energy and NEC Energy Solutions (before its exit from the market) have historically been the leading system integrators. In the future, the system integrator landscape will further diversify, primarily driven by energy storage inverter manufacturers expanding their presence, targeting solar-plus-storage applications and existing players such as Wartsila and Powin Energy targeting strategic opportunities to drive expansion. At the same time, there will also be consolidation - as illustrated by the recent market exit by NEC Energy Solutions - particularly challenging smaller, regional players. Major system integrators are globalising and can offer more cost-effective solutions based on the scale of their operations.

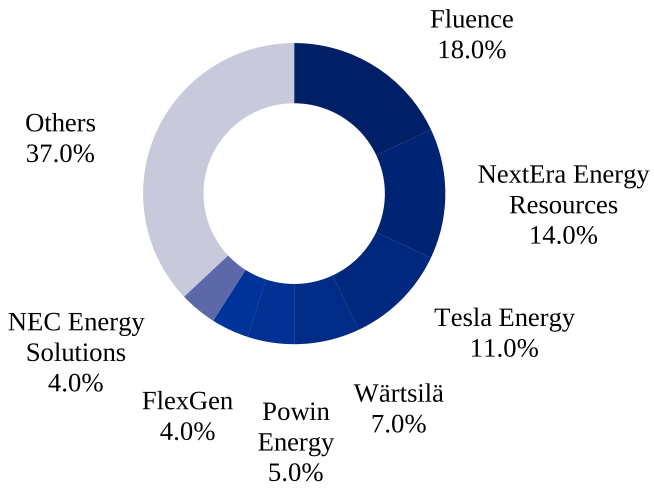


Figure 25: Top energy storage system integrators in 2021[41]

iii. Energy storage owners and operators

BESS owners in Europe and around the world are numerous and diversified: anyone can invest in a BESS and sell the stored electricity to the grid. BESS owners are mainly companies which are part of the electricity value chain, like TSO (Transmission System Operator) companies or electricity producers. For example, in France, the biggest BESS in operation is operated by the national transmission system operator RTE. Total was contracted by RTE for the project, which has 25MWac rated output and 25MWh of storage capacity. It has been built at the site of a former oil refinery operated and owned by Total in Dunkirk, in northern France. Moreover, RTE also awarded Total with 130MW of energy storage contracts and the Dunkirk project will be followed by four more projects.

However, BESS development is still at a relatively early stage in France compared to other countries in the world and even in Europe. According to the report published in 2020 by the European Commission « Study on energy storage: contribution to the security of the electricity supply in Europe », although the dominating energy storage reservoir in Europe is still pumped hydro storage, new batteries projects are being developed rapidly especially in Germany and the UK. The report states that the Lithium-ion batteries represent most of BESS projects. *Figure 26* presents the cu+

Current installed capacity for BESS systems in different European countries. Meanwhile, in terms of future projection, the UK presents the most important power capacity, followed by Ireland and Germany. Up to the publication of the report, the total power capacity of authorized projects with electrochemical storage is 5,499 MW in the UK, almost 10 times higher than the current operating capacity.

[41] HIS Market, 2022

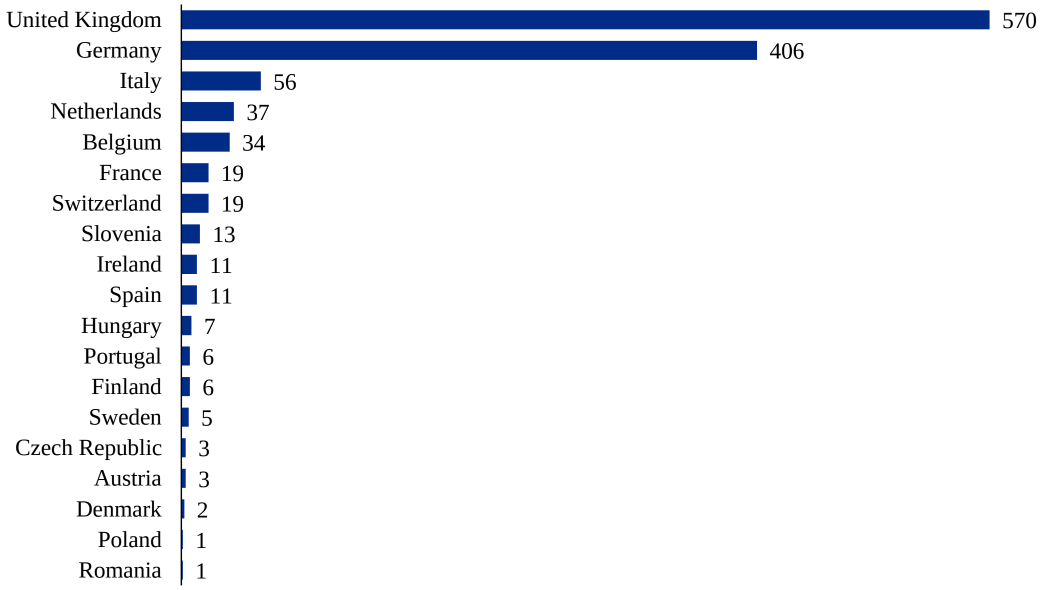


Figure 26: Total installed power capacity (in MW) of operated BESS in European countries[42]

iv. New entrants redefining the value chain

Global energy markets are facing major changes. We move from a model with centralized electricity generation in power plants operated by large utilities towards a mix of decentralized and often renewable energy production in small facilities. Those small-scale plants are typically owned by small companies or households, who become ‘prosumers’: consumer and producer at the same time. Business models are being reinvented and our grids redesigned.

1. Virtual Power Plants (VPP)

A VPP broadly refers to an aggregation of resources (photovoltaics, battery storage, and controllable loads) coordinated to deliver services for power system operations and electricity markets. In practice, a VPP can be made up of multiple units of a single type of asset, such as a battery or a device in a demand response program, or a heterogeneous mix of assets.

These units are dispatched through the central control room of the virtual power plant but nonetheless remain independent in their operation and ownership. When integrated into a Virtual Power Plant, the power and flexibility of the aggregated assets can be traded collectively. Thus, even small units get access to the lucrative markets (like the market for balancing reserve) that they would not be able to enter individually. Any decentralized unit that consumes, stores, or produces electricity can become a part of a Virtual Power Plant.

[42] Report by the European Commission, 2020, *Study on energy storage: contribution to the security of the electricity supply in Europe*

Additionally, to operating every individual asset in the Virtual Power Plant, the central control system uses a special algorithm to adjust to balancing reserve commands from transmission system operators and to grid conditions – just as a larger, conventional power plant does. Furthermore, the Virtual Power Plant can react quickly and efficiently when it comes to trading electricity, thus adjusting plant operations according to price signals from the power exchanges.

VPPs are often compared to microgrids. Though microgrids and VPPs share some critical features, there are major differences between them. Microgrids can be both grid-connected or off-grid systems, they can 'isolate' themselves, allowing them to function independently from the grid. VPP are always grid connected systems. Other differences between the two are microgrids being dependent upon hardware innovations like inverters and smart switches, while VPPs are heavily reliant upon smart meters and IT. It is also stated that storage units are mostly needed in microgrids while they may not feature in VPPs.

The biggest VPP in the world is Tesla's VPP in Australia. With the support of the South Australian Government, Tesla developed a network of 50,000 solar and Tesla Powerwall home battery systems across South Australia. And the project continues to grow, Tesla having announced its intention to launch a new phase and add another 3,000 batteries to the network. In Europe, the Norwegian hydro giant Statkraft is the main actor in the VPP field. The firm plans to build 2 GW of VPP capacity in the U.K., and 12 GW in Germany. They have 10+ GW of existing installed capacity that is equivalent to 10 thermal power plants with the ability to power a major city. Their VPP strategy also includes buying hydro projects in France and Turkey.

2. Vehicle-to-Grid (V2G)

According to a study by the U.S. Department of Energy (DOE), the growing demand from plug-in electric vehicles and many other technologies that require electricity could increase the load on our power grids by up to 38% by 2050. Power companies and government agencies are working hard to meet this demand, but it's a challenging task. The idea behind vehicle-to-grid technology, is that electric vehicles can be part of the solution to this problem.

The vehicle-to-grid (V2G) concept aims to optimise the way we transport, use and produce electricity by turning electric cars into 'Virtual Power Plants'. Under this relatively new concept, electric cars would store and dispatch electrical energy stored in networked vehicle batteries which together act as one collective battery fleet for 'peak shaving' (sending power back to the grid when demand is high) and 'valley filling' (charging at night when demand is low). V2G would allow consumers to charge electric vehicles and monitor their energy costs, using mobile devices. This information helps utilities to better manage grid loads during peak times.

Although the basic concept of V2G charging sounds simple enough, implementing it requires a complex suite of smart technology. Charging stations must be equipped with software that communicates with the central grid to assess overall system demand at any given time.

3. Domestic batteries

Storage batteries are not necessarily large-scale infrastructures powering large areas. They can also be designed at the scale of a single house, they are then called domestic batteries (or home batteries). A domestic battery is an in-home energy storage unit that has the ability to store energy either straight from the power grid, or power generated from renewable energy resources like wind and solar. Households can install single batteries, or couple them together for even more storage capacity.

The first company to launch mass production of domestic batteries was Tesla with the Tesla Powerwall. It is a rechargeable lithium-ion battery which allows individuals to store electricity for solar self-consumption, time of use load shifting, and backup power. The Powerwall was introduced in 2015 with limited production. Mass production started in early 2017 at Tesla's Giga Nevada factory. The original Powerwall (retroactively referred to as the Powerwall 1) had a 6.4 kWh capacity and was capable of delivering 3.3 kW of power. Tesla introduced an improved Powerwall 2 in October 2016 with a 13.5 kWh capacity and capable of delivering 5 kW of power continuously and up to 7 kW of peak power in short bursts (up to 10 seconds). Later versions of the Powerwall 2, shipped after November 2020, had the same capacity, but can deliver 5.8 kW of power continuously and up to 10 kW of peak power. The Powerwall+, introduced in April 2021, combines the functions of a Powerwall 2, a Backup Gateway and a solar inverter. As of May 2021, Tesla has installed 200,000 Powerwalls.

Since Tesla introduced the Powerwall, many other companies have started offering home battery backup products, especially companies that compete with Tesla Energy to sell photovoltaic solar energy generation systems. Three companies dominate the battery energy storage market: Enphase Energy, LG Chem and Tesla. Together, these three brands accounted for about 85% of the sales in 2021. The Tesla Powerwall costs $8,500 before installation and between $12,000 and $16,500 for a full system installation. The Enphase battery is currently the most expensive home battery product, at roughly 50% more than Tesla’s Powerwall. Despite the large price difference, in 2021, Enphase surpassed Tesla as the largest supplier of home energy storage systems.

III. How to extract value from battery storage as an investor and as an operator?

A. Overview of current electricity trading mechanisms

i. OTC contracts and electricity markets

As explained previously, the electricity sector was organized as a regularized monopoly up to three decades ago. Vertically integrated companies, such as Electricité de France (EDF) in France were responsible for generation, transmission, and distribution of electricity.[43] Through several legislative packages in 1996, 2003 and 2009, the sector was gradually opened to competition in the European Union. Unbundling became the norm, although transmission and distribution remained strongly regulated monopolies, and electricity generators and suppliers (for the wholesale and retail electricity markets respectively) started operating in a liberalized market environment.[44]

The objective of this section (i) is to give a brief overview of the current market design of the electricity markets in Europe and the trading mechanisms that have been developed to ensure an efficient functioning of liberalised electricity flows in each country.

1. Wholesale markets

The wholesale electricity market correspond to the market on which electricity is traded, before being delivered to consumers *via* the grid. This latter part corresponds to the retail electricity market.[45] This section will focus on the wholesale market and, more precisely, on the energy-only markets (i.e., markets in which generators are remunerated for the electricity they have generated), and not on capacity markets (i.e., markets in which generators would be remunerated for their available capacity).[44 above]

When electricity generators and suppliers, traders and demand side management operators decide to trade electricity, 3 types of transaction are possible between bilateral parties:

- In **power exchanges**: participants can submit generation and demand bids, which are then cleared on a regular basis and result in a single price.
- In **organized (or cleared) OTC (Over-the-Counter) transactions**: participants can submit generation and demand bids, and can also accept offers from other participants, which results in different prices for each trade.
- In **bilateral (or non-cleared) OTC transactions**: participants agree bilaterally on each trade.

OTC contracts are still the most traded contracts in the European Union, with about 70% of forward volumes in 2020.

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[43] Richard Green, 2004, *Electricity liberalisation in Europe–how competitive will it be?*
[44] KU Leuven Energy Institute, 2015, *The current electricity market design in Europe*
[45] Commission de Régulation de l'Energie, 2021, *Wholesale electricity market*

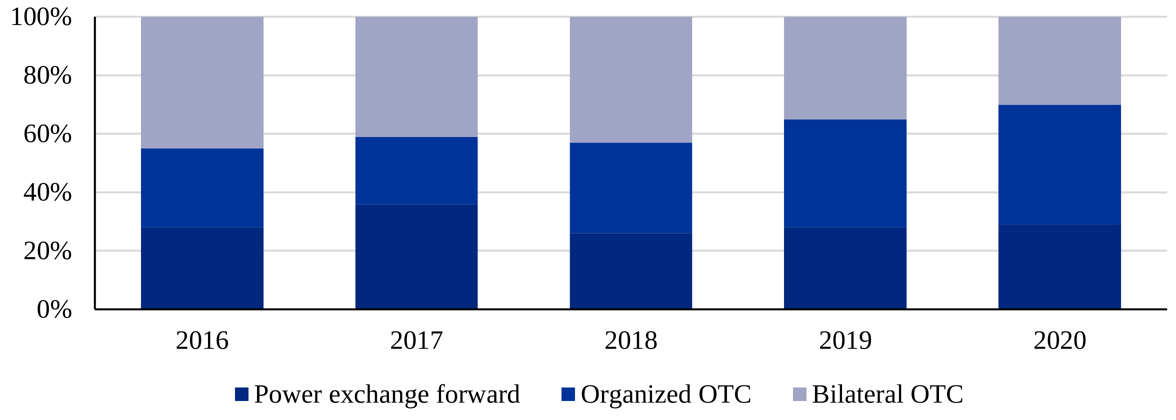


Figure 27: Share of yearly traded volumes of selected European forward markets by product type, 2016-2020[46]

It is often the case that trading is more important than physical consumption, with forward contracts being exchanged between market participants several times. The churn factor, which can be defined as the overall volume traded through exchanges and brokers, divided by the actual consumption of electricity, gives an idea of the importance of trading in this sector. It is the most important in more developed countries of the European Union (including Germany, France, and the United Kingdom).

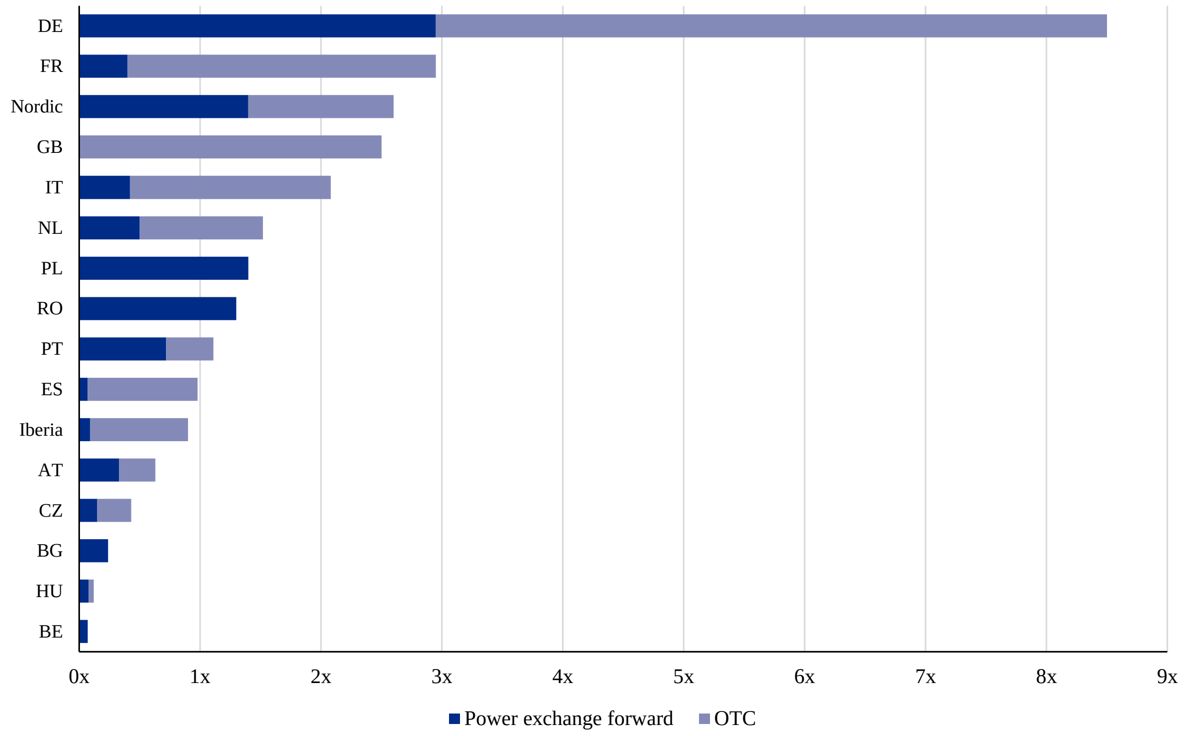


Figure 28: Forward markets churn factor per type of trade in the largest European forward markets, 2020[47]

[46] ACER, 2022, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020*
[47] Ibid

In addition to the forward markets, which allow the trading of power contracts in advance of the actual delivery of electricity, other markets have been created to ensure the constant balance of consumption and grid losses with the generation of electricity at any given point in time. All power markets, such as the intra-day market and balancing market, have been designed to be organized in sequential order.

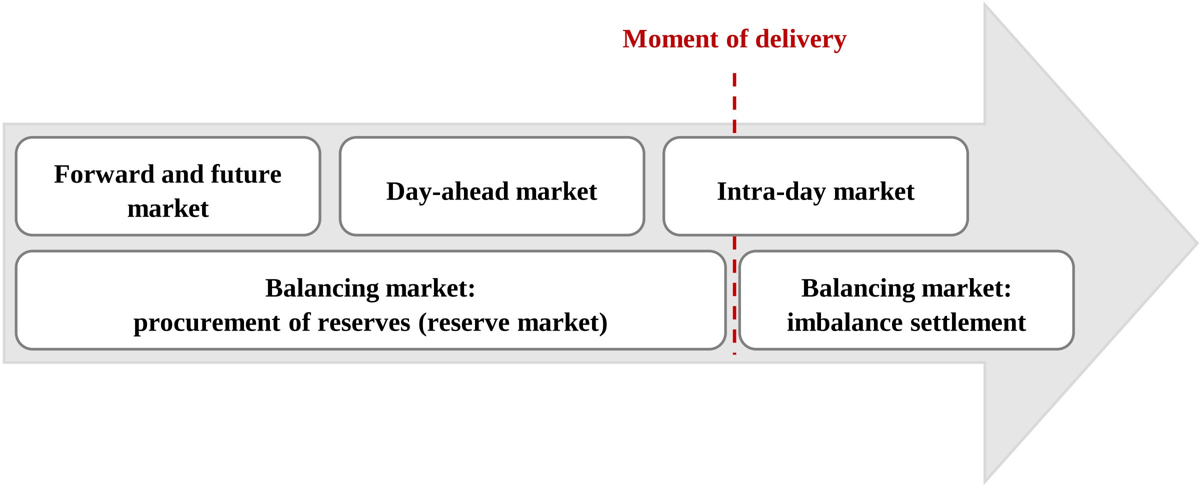


Figure 29: Sequential order of power markets in the European Union[48]

The following subsections will present the different power markets' objective(s), their participants and the type of contracts that can be traded.

a. Forward, futures and options markets

In chronological order, the first market on which power contracts can be traded is the forward and futures market. A forward contract is an OTC (hence customizable) contract between bilateral parties, whereas futures are standardized and then exchanged on power exchanges. These contracts extend between years before up to the day before delivery of electricity and specify amounts that must be delivered / consumed at a certain time for a price agreed upon. Options are financial products whose value is based on an underlying product and gives their holder a certain right, often regarding this underlying. Options can be traded either Over-the-Counter or on exchanges.

In the European Union, futures can be traded on power exchanges and forwards can be traded through brokers (which can also be markets when trading organized OTC contracts). International trading platforms from outside the European Union also having a role. Below are the different brokers that are present in France and Spain to trade forwards.

[48] KU Leuven Energy Institute, 2015, *The current electricity market design in Europe*

Figure 30: Brokers in France and Spain offering power forwards trading[49]

Different players are active on the forward and future market:

- **Power exchanges** for futures and options trading.
- **Brokers** for forwards trading.
- **Electricity generators** to sell electricity and reduce their vulnerability to electricity price decreases.
- **Consumers** such as large industrials to secure their consumption at an upfront cost.
- **Hedge funds** to arbitrage and speculate on power prices at different maturities (e.g., Odey Asset Management, Auspice Capital, Andurand Capital Management and Centaurus Energy).

Given the coupling of European power markets, it has become possible to trade power forwards and futures between different bidding zones. A bidding zone usually corresponds to a Member State, but there can be exceptions such as Austria and Germany, that once were part of the same bidding zone, and Denmark, which is split between two bidding zones (DK1 and DK2).[50]

The allocation of the transmission capacity, which represents the limited volume of electricity conforming to the system security criteria can be transmitted in a power grid, is done explicitly for yearly and monthly allocation. The cross-border transmission capacity rights are purchased independently from the forward or future contracts, through an auctioning organized by the Joint Allocation Office (JAO) in Central and Western Europe. This gives the right to buy or sell electricity in another zone.[51] There are two main types of long-term transmission rights:

- **Long-term physical transmission rights** (PTR): gives a right to physically transfer a given volume of electricity across two bidding zones during a specified period. Financial compensation can be received if the right is not exercised.
- **Long-term financial transmission rights** (FTR): does not give a right for a physical transfer of electricity, only for a financial compensation (as in the case of a PTR).

[49] Refinitiv, visited on April 2022
[50] Joint Allocation Office (JAO), 2022, *List of Bidding Zone borders*
[51] Elia, visited in April 2022, Electricity Market Facilitation – *Capacity allocation*

The explicit cross-border allocation is opposed to the implicit cross-border allocation: the BRP does not need to nominate its exports or imports of electricity and has automatically access to cross-border transmission capacity rights by submitting an order on a power exchange. This mechanism is used on the daily and intraday capacity allocation markets.

For the remaining part of this subsection, we will focus on publicly traded products (i.e., futures and options). When a market participant decides to submit a buy or sell order on a power exchange, he can decide to trade:

- Futures and futures spreads
- Options

It is important to understand the difference between baseload and peakload contracts, as they are priced differently.

- **Base load** is the minimum amount of electrical demand over a 24-hour period. It is usually well-forecasted and is supplied by stable load plants (e.g., nuclear, hydroelectric and geothermal plants).
- **Peak load**: is the amount of electricity that must be delivered to the electric grid to meet the maximum demand during a given period.
- **Off-peak** (or intermediate) **load**: is the amount of electrical demand higher than the baseload, but lower than the peakload demand. It is usually covered by electricity generators having moderate fixed and variable costs.[52]

Graphically, the load curve from a given year can be sorted into a load duration curve, which enables readers to immediately identify base, intermediate and peak loads.

[52] Thomson Reuters Practical Law, visited in April 2022, *Intermediate Load*

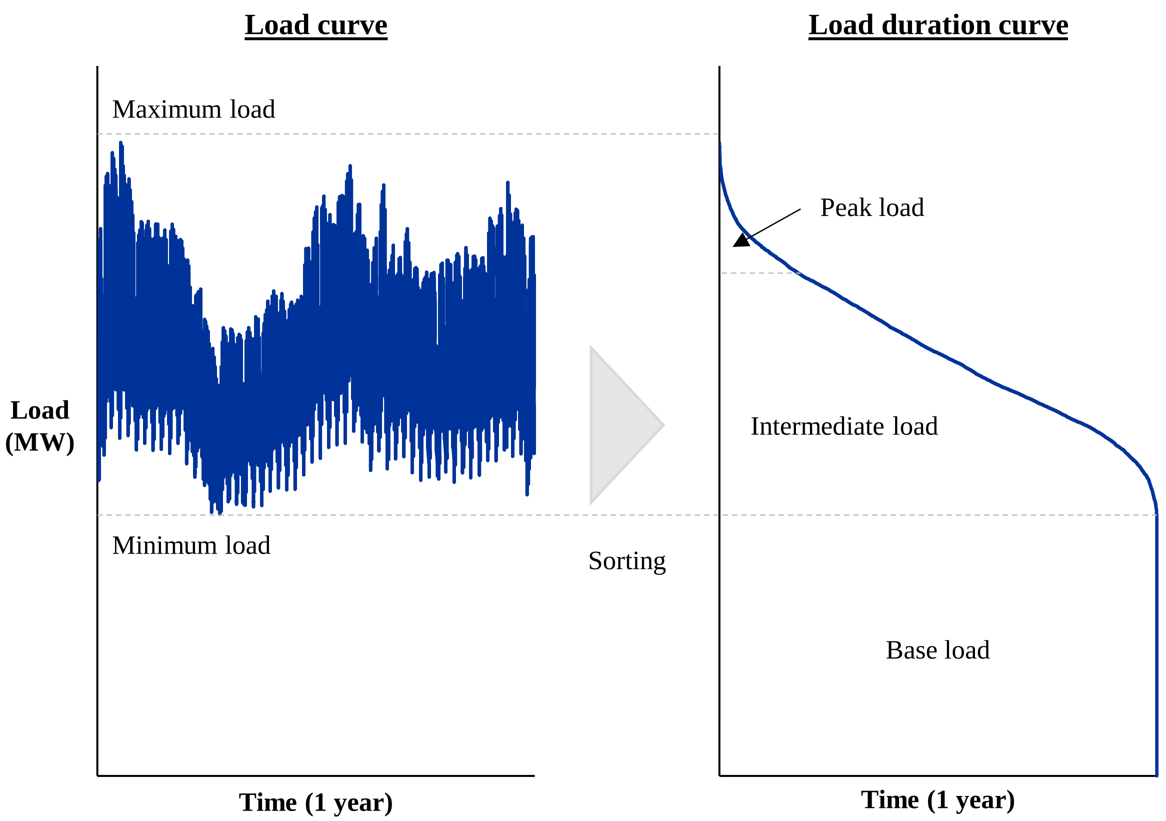


Figure 31: Load and load duration curves for Germany in 2020[53]

These three loads are usually defined in terms of hour ranges in futures contracts. For example, on EEX, base load refers to load delivered anytime in the day, peak load refers to load delivered between 8 a.m. to 8 p.m. on any business day and off-peak refer to load delivered between 8 p.m. and 8 a.m. of the following day.[54]

Each future (or forward) is characterised by a set of features, the main important ones being:

- The contract unit (in MWh).
- The price quotation (*currency* per MWh).
- The minimum price fluctuation (which can be decomposed between the delivery rate (in MW), the tick size (in *currency*/MWh) and the duration (in h).
- The settlement method (physical or financial).
- The maturity or eligible contracts (i.e., all the maturities for which the contract is available, mostly relevant for futures whose maturity is standardised, which is not the case for forwards).

A simplified futures contract example if given below for a German peak load contract with monthly maturities.

[53] Refinitiv, visited in April 2022
[54] Powernext, 2020, *Contract Specifications*

CONTRACT UNIT	1 MW x 12 hours = 12 MWh Clears in multiples of the number of weekdays in the contract month
PRICE	Euro per MWh
TRADING HOURS	Sunday - Friday 6:00 p.m. - 5:00 p.m. (5:00 p.m. - 4:00 p.m. CT) with a 60-minute break each day beginning at 5:00 p.m. (4:00 p.m. CT)
MINIMUM PRICE FLUCTUATION	€0.01 x 1 MW x 12 peak hours x # of weekdays / month
PRODUCT CODE	CME Globex: DEP CME ClearPort: DEP Clearing: DEP
LISTED CONTRACTS	Monthly contracts listed for the current year and the next 2 calendar years. list monthly contracts for a new calendar year following the termination of trading in the December contract of the current year.
SETTLEMENT METHOD	Financially Settled
TERMINATION OF TRADING	Trading terminates at 12:00 Noon German local time on the business day prior to the last weekday of the contract month.
DAYS OR HOURS	Peakload refers to all full hours in the weekdays of a calendar month from 8am to 8pm Germany Local Time (12 hours per day) The range is 240 to 276 MWh.

Figure 32: Simplified specifications of a German power peak load calendar month futures trading on CME Group[55]

The main options traded on power markets are *calls* and *puts*. A call option gives its holder the right to purchase a given amount of electricity at a predetermined strike price, whereas a put option gives its holder the right to sell a given amount of electricity at a predetermined strike price. Buying an option has an additional price, the option price (or premium), which has to be paid even if the option is not exercised.[56]

Options' margins can be structured either as:

- **Equity-style options**: the premium of the option is paid upfront and the margin requirement is determined on a daily basis based on the underlying product price.
- **Futures-style options**: the trade of the option does not result in any cash movement and the position is marked-to-market on a daily basis. The total premium is then calculated and paid when the position is removed.[57]

[55] CME Group, visited in April 2022, *German Power Peakload Calendar Month Futures - Contract Specs*
[56] Salvador Pineda and Antonio J. Conejo, 2013, *Using electricity options to hedge against financial risks of power producers*
[57] CME Group, 2017, *A Primer on Margining Styles for Options*

b. Day-ahead market

In sequential order, after the forward and futures market is the day-ahead market. On this market, electricity is traded one day before the actual delivery. Given that each bidding zone must ensure the balance between consumption and grid losses on one side with generation on the other, day-ahead market is particularly important.

To ensure the efficient implementation of the Single Day-Ahead Coupling (SDAC) and of the Single Intraday Coupling (SIDC) initiatives, competent authorities can designate Nominated Electricity Market Operators (NEMOs) which are the only operators allowed to perform tasks related to day-ahead and intraday power markets, in cooperation with TSOs. The main tasks of NEMOs are to collect bids and offers from market participants, clear the transactions and work jointly with TSOs to ensure efficient operations.[58]

Among the 16 NEMOs currently existing in the European Union, several cover different geographies.

Figure 33: Geographical coverage of 3 NEMOs in the European Union as of 2022[59]

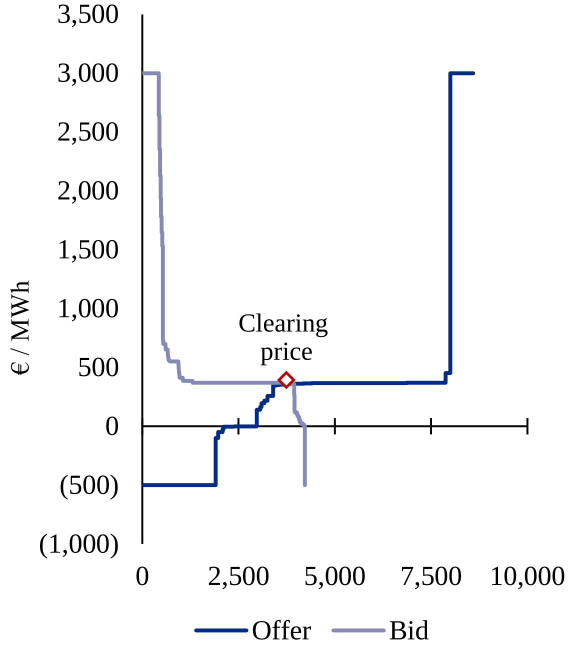
Although electricity can be traded through Over-the-Counter contracts, market participants can also trade electricity through power exchanges such as Nord Pool, Epex Spot and Belpex.[60] The main characteristics of those day-ahead contracts include:

- The possibility of trading 24 hourly contracts, for the following day.
- Order books closing at 12:00 p.m. CET (9:20 a.m. GMT for Great Britain, 11:00 a.m. CET for Switzerland) in D-1.
- Preliminary results published until 12:45 p.m. CET and final results published until 12:57 p.m. CET (9:30 GMT for Great Britain, 11:10 CET for Switzerland) in D-1.

[58] All NEMO Committee, visited in April 2022, *About the All NEMO Committee*
[59] ACER, 2021, *List of 2022 NEMOs on the Day-Ahead and Intraday markets*
[60] Epex Spot, visited in April 2022, *Trading Products*

Additional half-hour D-1 auctions are also available in Great Britain, giving members the opportunity to balance their physical portfolios and generators to further optimize their generation portfolio.

Prices are then determined by crossing the supply and demand curves for each hourly contract. Below are examples for the 4:00 a.m. and 7:00 p.m. contracts on April 17, 2022 in Greece.



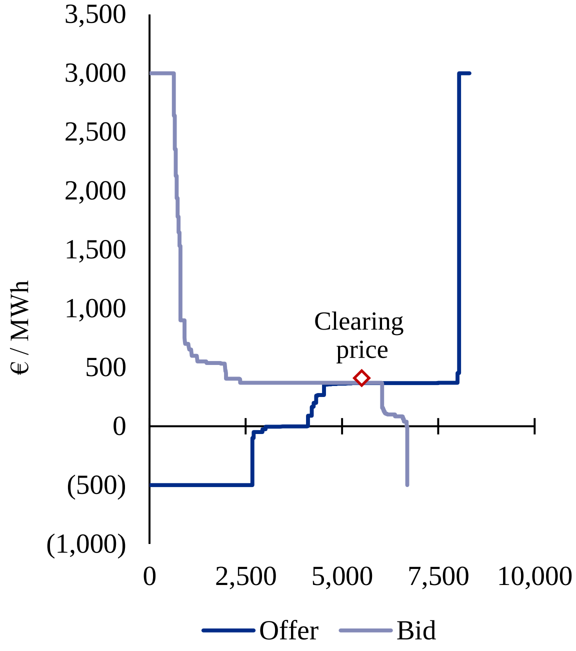


Figure 34: Day-ahead market aggregated bid/offer curves for 4:00 a.m. and 7:00 p.m. contracts on April 17, 2022[61]

Different types of orders can be submitted on the day-ahead market, such as single hourly orders or block orders, which consist in an order of a specified volume and price for a given number of consecutive hours within the same day.[62] Each exchange has then its own definition of the various block orders that are available on its platform, but the main important ones are:

- **Curtailable blocks**: set of blocks which are executed or rejected altogether (*All-or-None principle*)
- **Linked blocks**: set of blocks whose execution is dependent on the execution of a mother (linked) block

When the day-ahead market for a given day closes, each Balance Responsible Party (BRP) submits a balanced portfolio to the TSO in charge of the bidding zone. These "nominations" give an overview of the planned generation and / or consumption for each unit of the BRP.

[61] Energy Exchange Group, visited in April 2022, *Day-Ahead Market Publications*
[62] Nord Pool, visited in April 2022, *Day-Ahead Trading – Block order*

c. Intraday market

On the intraday electricity market, power is traded on the day of delivery day itself, giving the possibility to market participants to correct changes in their day-ahead submissions to TSOs (nominations), due to unexpected changes in their forecasts (better wind forecasts, plan outages, etc.).[63]

Contracts can have different mechanism of settlement (auction or continuous) and different lengths of settlement (either 15, 30 or 60 minutes).[64]

As mentioned previously for the forward and futures market, bidding zones can be coupled together, either implicitly or explicitly. As such, Belpex Continuous Intraday Market (Belpex CIM) has put in place a joint mechanism for the allocation of intra-day capacity, and an implicit allocation mechanism using the Elbas trading system with the Netherlands.[65]

Over the last years, cross-border volumes of electricity have significantly increased, representing about one-third of all intraday volumes in 2020.

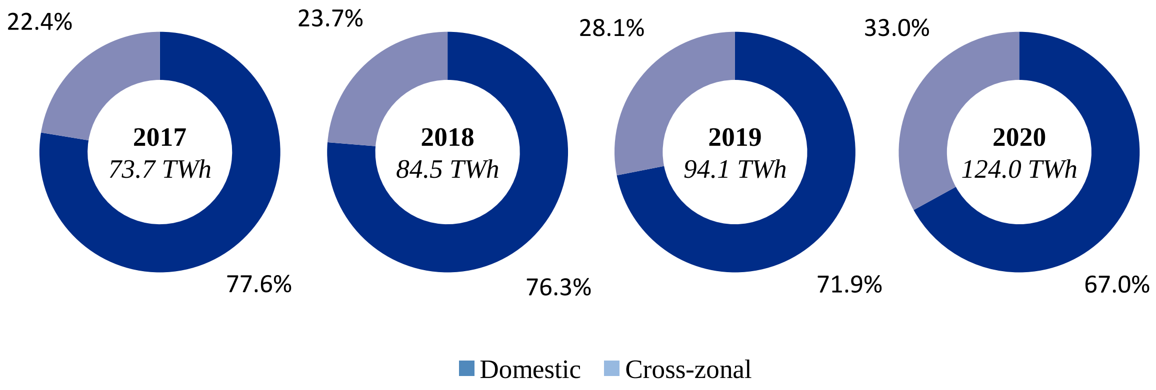


Figure 35: Share of ID-traded continuous volumes according to intra-zonal vs. cross-zonal nature of trades in Europe and yearly continuous ID-traded volumes[66]

After clearing the intraday market, each BRP can submit intraday nominations to the TSOs, which are added to its day-ahead nominations. Contrary to the nominations for the day-ahead market, these intraday nominations can be imbalanced and are later dealt with in the balancing market.[67]

[63] KU Leuven Energy Institute, 2015, *The current electricity market design in Europe*
[64] ACER, 2022, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020*
[65] European Commission, 2016, *METIS Technical Note T4 – Overview of European Electricity Markets*
[66] ACER, 2022, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020*
[67] KU Leuven Energy Institute, 2015, *The current electricity market design in Europe*

d. Balancing market

A BRP may suffer from a real-time imbalance, i.e., a difference between the level of its injections and offtakes from the grid on a quarterly-hour basis. In this situation, the TSO's role will be to maintain the balance of the system by activating reserves (also called the Net Regulation Volume, or NRV).

- A positive NRV corresponds to an upward regulation, i.e., an increase in grid injections or decrease in grid off-takes
- A negative NRV corresponds to a downward regulation, i.e., a decrease in grid injections or increase in grid off-takes

There are two sides to balancing markets: (a) the procurement and activation of reserves by the TSO (i.e., the physical settlement of imbalances) and (b) the financial settlement of imbalances.

a) Procurement and activation of reserves

The procurement and activation of reserves can be referred as the reserve market. Its role is to generate electricity when necessary (energy service), and to maintain a constant minimum level of capacity to generate electricity if needed (capacity service).

There are different types of reserves that can be activated in sequential order:

- **Frequency containment reserves** (FCR, or "*primary reserves*") which can stabilize the frequency within seconds through automatically controlled and local reserves of energy. Cooperation on FCR involving 11 TSOs in the European Union is underway, with daily auctions between TSOs for four-hour products. Balancing Service Providers (BSPs) relationship with TSOs' (including delivery) are then handled on a national basis.[68]
- **Frequency restoration reserves** (FRR, or "*secondary reserves*" and "*tertiary reserves*") progressively replace FCR after 30 seconds to 15 minutes to restore the system balance, either through an automatic activation (aFRR) or a (semi-)manual activation after aFRR activation (mFRR)
- **Replacement reserves** (RR) progressively replace FRR after 12.5 minutes to ensure the system balance if FRR fails to do so.

[68] ENTSO-e, visited in April 2022, *Frequency Containment Reserves (FCR)*

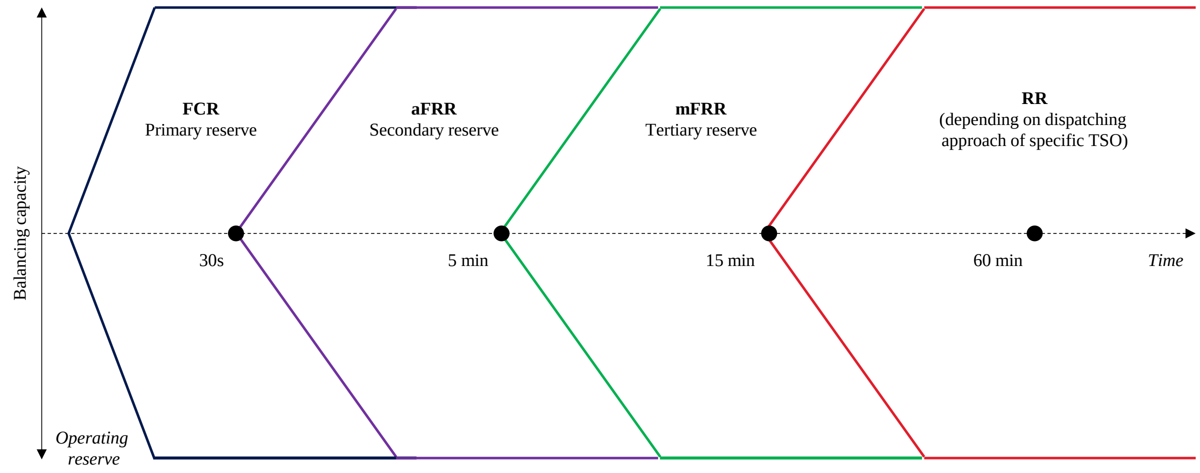


Figure 36: Balancing market processes for frequency restoration in the European Union[69]

This market is rapidly evolving through European cooperation. New players have entered the market (aggregators, energy storage and demand response operators), further increasing the possibilities for private players to improve the system.

b) Settlement of imbalances

Imbalances are then financially settled with TSOs imposing a tariff on imbalanced BRPs. The imbalance pricing is done within a specific time frame called the Imbalance Settlement Period (ISP). It is currently mandated that ISPs should be of 15 minutes in all European countries by 2025.

For each ISP is determined a certain price that BRPs will either pay or receive if their portfolio is not balanced. This price is based on:

- The **Marginal Incremental Price** (MIP), which corresponds to the highest price paid by the TSO for upward regulation during an ISP.
- The **Marginal Decremental Price** (MDP), which corresponds to the lowest price received by the TSO for downward regulation during an ISP.

Other calculation mechanisms can be used to compute the imbalance settlement price, such as the volume weighted average price of balancing energies, used by RTE in France.[70]

The table below summarizes the payment flows in case of procurement reserves utilisation, in case the MIP and MDP are used.

[69] ENTSO-e, 2018, *Electricity balancing in Europe*
[70] RTE, visited in April 2022, *Imbalance settlement price*

		Net Regulation Volume (NRV)	
		Negative / downward regulation	***Positive*** / upward regulation
BRP imbalance	***Positive*** (higher generation or lower consumption)	**MDP – α_1** *TSO pays BRP*	**MIP** *TSO pays BRP*
	Negative (lower generation or higher consumption)	**MDP** *BRP pays TSO*	**MIP + α_2** *BRP pays TSO*
Financial flow for TSO		α_1	α_2

Figure 37: Overview of imbalance settlements[71]

It is usual to include an additional term to ensure that financial flows to TSOs are always equal or above 0. For imbalance settlement in France, for example, a "*(1+k)*" or '*(1-k)*" factor will adjust the payment received or paid by BRPs. This is an additional mechanism with the use of marginal prices to incentivize BRPs to have a balanced portfolio.

e. After-market

Lastly, although limited in terms of size and geographical coverage, it is possible for BRPs to reduce the cost related to their imbalanced on the after-market available on Epex Spot. This market is accessible in Belgium and in the Netherlands and enables participants to adjust their physical position ex-post, ahead of the imbalance settlement.[72]

2. Retail markets

When it comes to the possibility of extracting value from electricity markets, retail markets are less of interest given their organization: mainly focused on consumers and industrial consumers. Although this will be less important in the other sections of this Master Thesis, we wish to offer a comprehensive view (although simplified) on electricity markets.

The most important players in this market are the suppliers (which can have a nationwide geographical coverage), who offer contracts to households and / or non-household customers. For example, the main suppliers in France are EDF, Engie, Total Energies and other foreign competitors such as Eni, Vatenfall, and Iberdrola.

A good indication of favourable or unfavourable barriers-to-entry (and hence of the state of the competition of retail electricity supply) is the number of suppliers that are owned by DSOs, and not the number of suppliers itself.

[71] KU Leuven Energy Institute, 2015, *The current electricity market design in Europe*
[72] Epex Spot, visited in April 2022, *Trading Products*

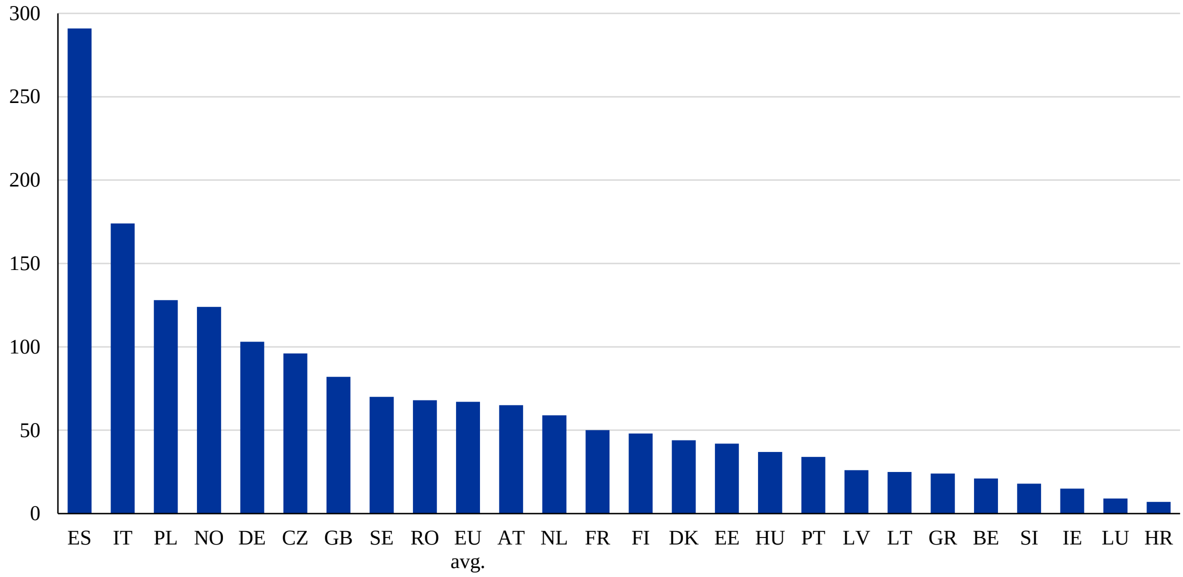


Figure 38: Total number of active nationwide electricity suppliers in the European Union, in 2020[73]

Retail markets can be considered as "rigid" from private players' point of view given the important number of public price intervention. These can take the form of price regulations, price caps, price approvals or social tariffs. Just for the household market in the European Union, about half (15 out of 28 countries) have adopted such schemes.

[73] ACER / CEER, 2021, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 - Energy Retail Markets and Consumer Protection Volume*

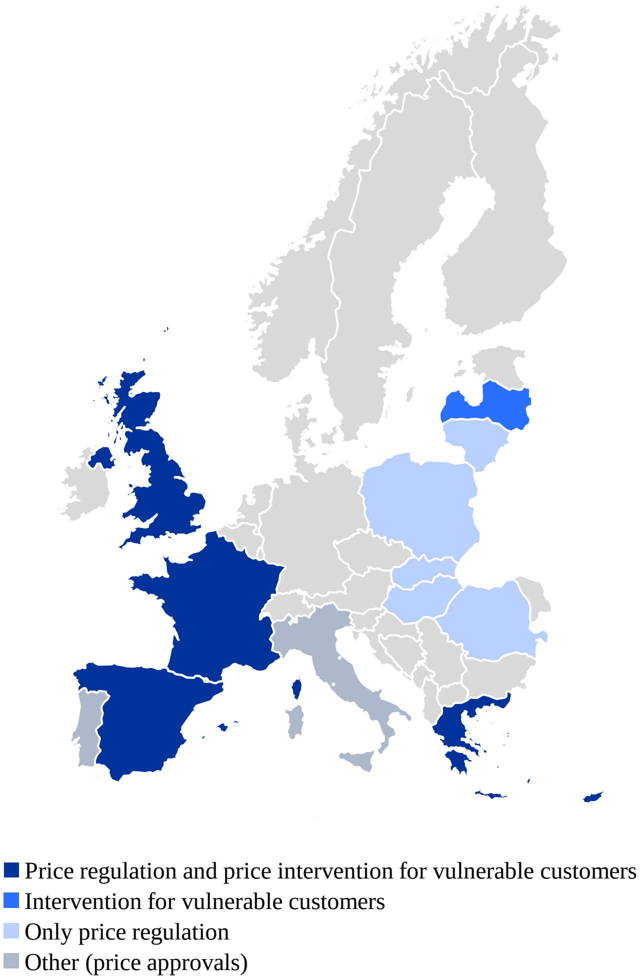


Figure 39: Existence of price intervention in the electricity household market in 2020[74]

The main reason of European countries to implement a public price intervention is the protection of household customers against price increases. These measures can cater to all or only vulnerable households (e.g., Belgium and Latvia). Other supporting measures include reductions or bonuses which do not directly impact the electricity price. Social tariffs are another form of intervention to help targeted groups of consumers. For example, in Spain, a social electricity bonus is offered as a discount on the electricity bill for the standard price offer.

In the non-household market, price intervention is less frequent, with only 9 member states countries were relying on such schemes.

[74] ACER / CEER, 2021, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 - Energy Retail Markets and Consumer Protection Volume*

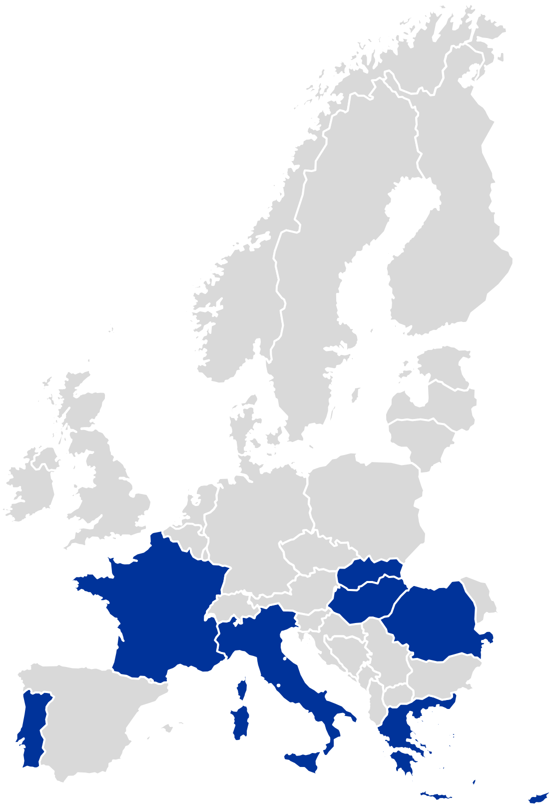


Figure 40: Existence of price intervention in the electricity non-household market in 2020[75]

In these countries, public price intervention takes the form of price regulation for small businesses. The main reason underlying this price intervention is the support of small companies with affordable prices.

Given the limited competitive environment in these retail markets, we decide to focus on wholesale markets for the rest of the analysis of this section.

ii. Trading access and operations regulation on the wholesale market

This subsection will analyse how difficult it is for new entrants to enter the electricity wholesale market through the analysis of barriers to entry and efficient price formation and regulations from the states and trading platforms.

Regulation is sometimes a barrier for new players to enter markets and to an efficient price formation. The main limits to the free formation of prices in the European Union are:

[75] ACER, 2021, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020 - Energy Retail Markets and Consumer Protection Volume*

- **Prices restrictions**, either with price caps or floors, limiting the free fluctuations of prices. This may eventually prevent the prices from reflecting the value of scarcity (in times of low supply or high demand) and of abundance (in times of high supply or low demand). For example, in the day-ahead and intraday markets in Portugal and Spain, limits 0 and 180 €/MWh remained active.
- **Pricing model**, with either a single or a dual pricing. A single pricing model refers to a situation in which BRPs are charged or paid the same price and are thus incentivized to reduce the imbalance of the system. In a dual pricing model, the price for deficit and surplus differ, are usually caped or linked to other market timeframes. In this situation, BRPs are not incentivized to reduce the system's imbalance, and larger players are favoured as they can aggregate their positions across their portfolios to reduce their imbalance.
- **Treatment of final positions**, which can be done either through a single position (the schedules for production and consumption are settled jointly) or through a dual position (the schedules for production and consumption are settled independently). With a dual position treatment of final positions, players are incentivized to balance their own schedule, without favouring the balance of the system as a whole. It is also more complicated for smaller players to manage different portfolios at once.

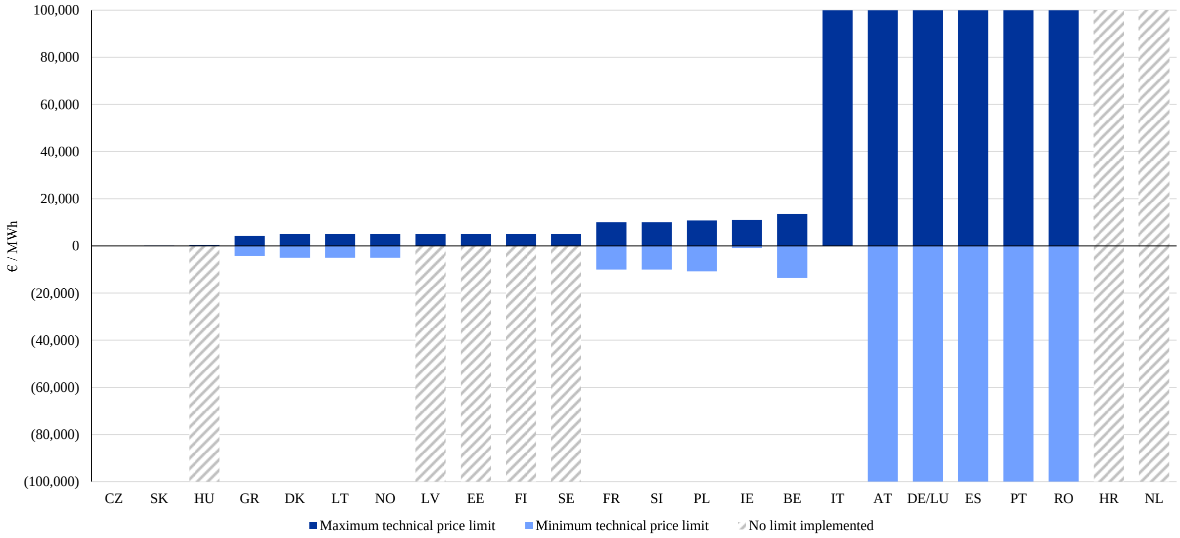


Figure 41: Maximum and minimum technical price limits for balancing energy products in the European Union in 2020[76]

In addition to restrictions regarding the efficient price formation, rules have also been implemented in the European Union's Member States to require market participants to meet certain requirements for participating in the balancing markets. These requirements may relate to delivery time, the minimum capacity required in the prequalification process, the minimum bid size, etc.

[76] ACER, 2022, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2020*

- **Duration of the delivery period**, which is defined as the period during which the BSP delivers the full requested charge of power. Currently, some qualification processes require this period to be up to more than 4 hours. Too long delivery periods can be direct barriers to small or new entrants for the balancing markets.

- **Minimum capacity required in the prequalification process and minimum bid size**, with the European target model setting the minimum quantity of the energy bid volume and granularity at 1 MW. This favours the entry of small entrants, especially RES generators and demand side response operators. Some specific barriers exist in some countries, such as a minimum bid size of 10 MW for mFRR in France for example.

- **Validity period of the balancing energy bids**, which corresponds to the minimum resolution period for a product in the market. In the European Union, it usually ranges from 15 minutes up to 4 hours. Longer validity periods limit the ability of new entrants to bid.

There are also restrictions imposed by platforms to be granted access to their trading capabilities. We focus below on some of the conditions imposed by Nord Pool and EEX to become a market participant on their platform.

On Nord Pool, entities wanting to perform trading on a physical market must enter in a Participant Agreement with Nord Pool and must be eligible as counterparty under the Clearing Rules determined by Nord Pool.[77]

Clearing members must enter into a Balance Responsible Party Agreement (BRPA) with a relevant TSO (or its agent). In addition, each clearing member must notably:

- Appoint a contact person for clearing.

- Establish one or more clearing accounts with Nord Pool and nominate cash settlement accounts.

- Provide initial collateral and meet its collateral calls.

It is worth noting that Nord Pool retains a discretionary power regarding the admission of members on its platform, based on its own assessment of their ability to trade.

Entities wishing to trade on an EEX platform must be first admitted by EEX for specific products or group of products, in accordance with Commission Regulation (EU) No 1031/2010. Participants must possess sufficient technical knowledge, which is determined with an exam, whose result is then examined by the Management Board, who keeps a discretionary power on the acceptance or rejection of a new participant on the platform.[78]

Only the following companies may fill an application for admission to the exchange trading:

[77] Nord Pool, 2021, *General Terms*
[78] EEX, 2021, *Rules and Regulation*

- Companies trading for their own account.
- Companies trading in their name for a third-party account.
- Companies acting as intermediaries (brokers).
- Indirect trading participants.

The market participant must also take part in clearing on European Commodity Clearing (ECC). The following lists the most important requirements necessary for admission by ECC[79]:

- Completion of a Know-Your-Customer (KYC) questionnaire and possible additional assessments if requested by ECC and passing of the ECC KYC assessment or other applicable access policies of ECC.
- The conclusion of a BRPA with the relevant TSO in case of physical delivery.
- Equity of at least €50k.
- Contributions to the Clearing fund.

Therefore, regulation can be quite cumbersome for new entrants, whether it is related to barriers to entry or efficient price formation, or to get a proper registration on a trading platform to trade power contracts. The legal process can take time and must be prepared in advance.

iii. Emerging market design: Peer-to-Peer trading

New models have emerged with recent technological developments (especially with the cost reduction of photovoltaics). The birth and rise of prosumers, which are both producers and consumers, has fostered the creation of more decentralized and local energy markets through peer-to-peer (P2P) power trading. In these markets, consumers and prosumers can trade electricity on an online trading platform (e.g., Vandebron in the Netherlands or sonnenCommunity in Germany), which circumvents traditional State-sponsored Power Purchase Agreements (PPA) and provides a community with local and often green energy when produced with renewable energy sources.[80]

Peer-to-peer power trading is a business model in which consumers and prosumers are connected to an online marketplace on which electricity can be directly traded, without an intermediary. In this way, prosumers producing energy through Distributer Energy Resources (DER) such as photovoltaics, are encouraged to share their excess production on the P2P market, instead of selling them back to electricity suppliers at the “buy-back rate” (i.e., the tariff at which can be sold to utility on the grid, usually lower that consumers’ tariffs). Similarly, consumers can achieve lower prices by purchasing electricity directly from prosumers instead of purchasing it from the grid.[81]

[79] ECC, visited in April 2022, *DCP Clearing Members*
[80] Junlakarn et al., 2022, *Drivers and Challenges of Peer-to-Peer Energy Trading Development in Thailand*
[81] IRENA, 2020, *Peer-to-peer electricity trading – Innovation landscape brief*

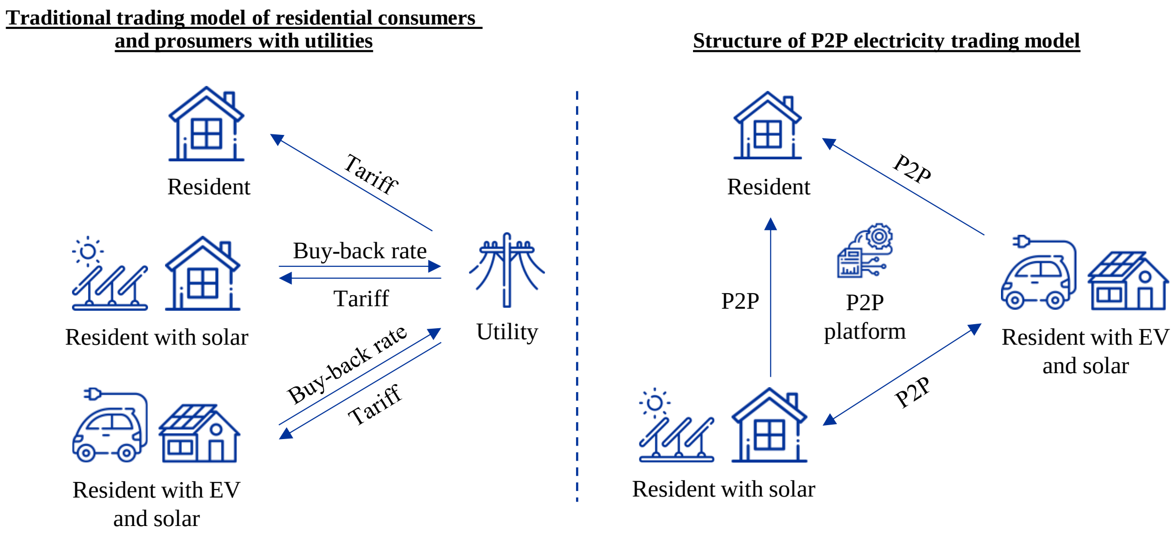


Figure 42: Illustrative models of traditional and P2P trading model[82]

A peer-to-peer trading model can be established in different contexts. Local and broader communities, individual neighbours and isolated mini or micro-grids can be viable hosts to this solution, as long as prosumers and consumers are willing to trade with one another.

To facilitate transactions within peer-to-peer networks, P2P operators have developed different technologies to allow more efficient trading. The use of platforms through software allows participants to determine prices at which they are willing to sell / purchase electricity. This virtual layer completes the physical layer installed to determine the production and consumption of market participants (smart metering, etc.). Ledger technologies, especially Blockchain, can improve the trading mechanisms by providing tracing and verification of energy exchanges on the platform.

Overall, P2P electricity trading could increase renewable energy deployment and flexibility given the ability of market participants to take advantage of dynamic pricing of energy, thus reducing the congestion and improving the balance of energy networks. In addition, as it can play a role of a Virtual Power Plant (VPP), investments required by suppliers and generators in electricity generation and grid reinforcements are lower. In the long-term, P2P trading could provide an efficient way to make electricity consumption greener and more cost efficient, as savings in electricity are assumed to be roughly 10% per year.

One of the main barriers to the development of this technology remains regulation, as the market must be relatively liberalised to allow consumers and prosumers to trade between each other. For instance, prosumers are not defined in the Netherlands, so they need to apply for supplier licenses to sell electricity. However, it is possible for prosumers with no capability to apply for a license to act as a reseller through a cooperation agreement with other market participants who have supplier licenses. On the other hand, the regulation in the United Kingdom and in the United States does not allow the implementation of peer-to-peer electricity trading.

[82] IRENA, 2020, *Peer-to-peer electricity trading – Innovation landscape brief*

Given the regulatory constraints and small-scale imposed on peer-to-peer electricity trading, we will not focus on this aspect of the market in our trading model. Nonetheless, it is obvious that a model could be developed to optimise utility for all stakeholders (utility, consumers and prosumers).

B. Building an electricity trading model

The objective of this subsection is to develop a simplified version of an electricity trading model for the day-ahead market that could be used in the context of utility-scale battery storage. Although we ignore some constraints imposed by the market design in some European countries and do not account the possibility of trading on the balancing market, the merit of this algorithm is to provide an easy-to-understand view on the functioning of day-ahead trading, that can be used in different countries with sufficient data and working on forecasts.

We first discuss the sources of inspiration of this model before presenting the approach we decided to adopt, and we conclude this section by illustrating the ex-post and ex-ante performance of the model in some European countries.

i. Sources of inspiration for building our trading model

In this subsection, we give an overview of some existing models designed to simulate power trading using battery storage. Different approaches have been adopted in the studied scientific papers, with varying scopes, from the day-ahead market only to broader models integrating trading on the day-ahead market and the balancing market as well.

In *Optimal Daily Trading of Battery Operations Using Arbitrage Spreads*, Abramova and Bunn consider arbitraging hourly price spreads in the day-ahead auction as the main revenue stream for battery storage. Intraday hourly spreads are estimated as densities based on a flexible four-parameter distribution, most importantly wind, solar and the day-ahead demand forecasts. These forecasts support the optimal daily scheduling of a storage facility, operating on single and multiple cycles per day.[83]

The objective of the analysis is to use these estimates to maximize the following function:

$$Maximize_{b_i s_j} \sum_{i=0}^{N-1} \sum_{j=0}^{N-1} \left[\frac{\eta}{2} \Upsilon^{(i,j)} \left(bs_{ij} - 1\right)\left(b_i + s_j\right)\right] - n \cdot c$$

Where:

- i and j are the hourly indices, both numerated from 0 to 23.
- N is the number of hours in a day available for the battery to trade ($N = 24$).

[83] Ekaterina Abramova and Derek Bunn, 2021, *Optimal Daily Trading of Battery Operations Using Arbitrage Spreads*

- n is the number of spread trades per day.
- η is the battery efficiency for roundtrip spread trade.
- c is the transaction costs for a roundtrip spread trade.
- b_i (resp. s_j) is the amount of energy (non-negative) to be bought (resp. sold) by the battery at hour i (long position) (resp. j (short position)).
- bs_{ij} is the element of an indicator matrix which tracks the timing of spread trades (at row i, col j).

Some conditions are imposed on the maximization function, which eventually lead to the maximization of the value which can be extracted from trading on spreads of the day-ahead market.

In *Maximising the value of electricity storage*, Staffella and Rustomjib implement a more complex model that accounts for the arbitrage of day-ahead market prices, in addition to receiving revenue for ancillary services such as availability and utilisation on the reserve markets.[84] They compute the profits generated by 3 methods:

- Arbitrage only ($ArbOnly$ scenario)
- Arbitrage with revenue from availability on the balancing market, but no revenue from utilisation ($ArbAv$ scenario)
- Arbitrage with revenue from availability and utilisation of stored energy on the balancing market ($ArbAvUt$ scenario)

$$Profit_{arb} = \sum_{\substack{All\ periods \\ outside \\ av.\ windows}} Q_{out} \cdot (P_{util} - MC_{out}) \cdot \eta_{out} \cdot TS - \frac{Q_{in} \cdot (P + MC_{in}) \cdot TS}{\eta_{in}}$$

$$Profit_{av} = \sum_{\substack{All\ periods \\ within \\ av.\ windows}} P_{availability} \cdot Q$$

$$Profit_{ut} = \sum_{\substack{All\ periods \\ within \\ av.\ windows}} Q_{out} \cdot (P_{util} - MC_{out}) \cdot \eta_{out} \cdot TS$$

Where:

- Q_{in} and Q_{out} are the input and output power capacity (in MW).
- η_{in} and η_{out} are the charging and discharging efficiencies (between 0 and 1).
- MC_{in} and MC_{out} are the marginal cost of charging and discharging (in £/MWh).

[84] Iain Staffell and Mazda Rustomji, 2016, *Maximizing the value of electricity storage*

- P is the spot price (in £/MWh)
- Q is the installed capacity
- TS is used to convert MW for each half-hour settlement period to MWh ($TS = 0.5$)

Profits are then used to compute the Rate of Return (ROR) of each technology. The time value of money is ignored.

$$ROR = \frac{Profit[£/kW/yr] - Opex[£/kW/yr]}{Capex[£/kW/yr]}$$

The maximisation of the profit yielded by the algorithm is subject to some constraints.

This paper is interesting in the sense that it introduces the possibility for battery storage operators to analyse the possibility of trading on different markets and how this decision may be influenced by the size of the battery storage. In fact, the model gives the possibility to the battery to decide when it would be more profitable to become "available" (with or without "utilisation") on the balancing market, rather than carrying out arbitrage on the day-ahead market only. Consequently, there can be alternations between availability periods (with or without "utilisation" depending on the scenario) and arbitraging periods.

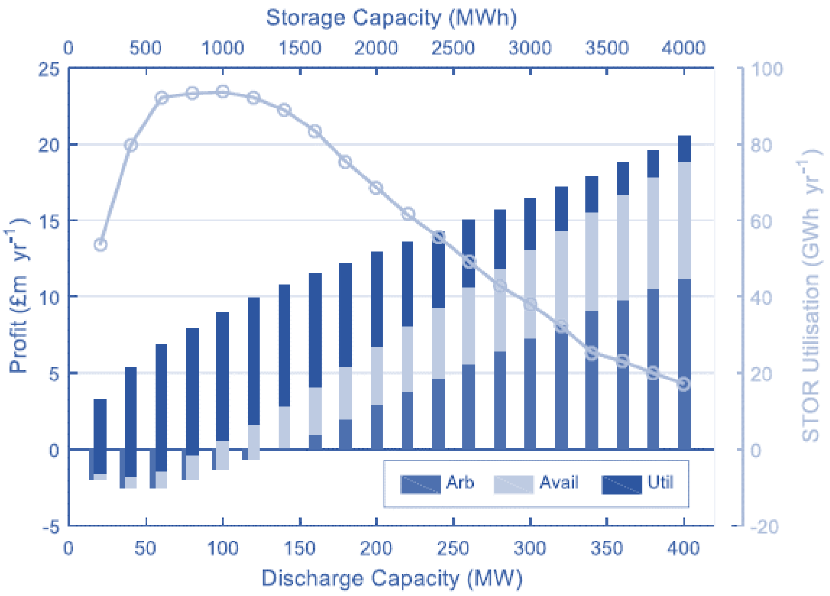


Figure 43: Variation of total profit with fixed discharge capacity from Staffell and Rustomji[85]

Their main conclusions are that:

- There is a threshold of 72% for battery efficiency under which it is more profitable to only offer reserve services, even with no utilisation revenue, than to purely perform arbitrage.

[85] Iain Staffell and Mazda Rustomji, 2016, *Maximizing the value of electricity storage*

- Profit is independent of discharge capacity in the ArbOnly and ArbAv scenarios, but affect the ArbAvUt scenario, via interaction with the usage of short-term operating reserve (STOR): smaller discharge capacities can be utilised more often.

- The highest profits do not result in the highest rates of return and for a given capacity, it is likely that there is an optimal discharge time (c-rate) to maximise the ROR.

Although they provide a framework to maximise the ROR by trading on the day-ahead and balancing market, the level of ROR is not viable given the current battery lifetimes and electricity prices. Additional sources of revenue must be considered to increase the viability of battery storage according to them.

Lastly, in *Optimal Battery Storage Participation in European Energy and Reserves Markets*, Pandžić et al. develop a bilevel model for optimal battery storage participation in day-ahead energy market as a price taker, and reserve capacity and activation market as a price maker.[86]

This paper is interesting in the way that it introduces the notion that battery storage impacts dynamically reserve market prices, depending on the quantity of energy sold or purchased. The objective is to maximize a profit function subject to certain constraints:

$$Maximize_{\Xi^{UL}} \sum_{t \in \Omega} [\lambda_t^{da}\left(q_t^{dis} - q_t^{ch}\right) + \left(\lambda_t^{cap\uparrow} \cdot q_t^{cap\uparrow} + \lambda_t^{cap\downarrow} \cdot q_t^{cap\downarrow}\right) + \left(\lambda_{t,s}^{a\uparrow} \cdot q_{t,s}^{a\uparrow} + \lambda_{t,s}^{a\downarrow} \cdot q_{t,s}^{a\downarrow}\right)]$$

Where:

- λ_t^{da} is the day-ahead market price (in €/MW)
- q_t^{dis} and q_t^{ch} are the battery storage discharging and charging quantities (in MW)
- $\lambda_t^{cap\uparrow}$ and $\lambda_t^{cap\downarrow}$ are the up and down reserve capacity clearing price (in €/MW)
- $q_t^{cap\uparrow}$ and $q_t^{cap\downarrow}$ are the battery storage up and down reserved capacity (in MW)
- $\lambda_{t,s}^{a\uparrow}$ and $\lambda_{t,s}^{a\downarrow}$ are the up and down reserve activation clearing price in scenario s (in €/MWh)
- $q_{t,s}^{a\uparrow}$ and $q_{t,s}^{a\downarrow}$ are the battery storage activated up and down reserve quantities in scenario s (in MWh)

Consequently, there are three revenue streams in this paper, (i) from the day-ahead market arbitrage, (ii) from the capacity reservation market as a price maker, i.e., $\lambda_t^{cap\uparrow}$ and $\lambda_t^{cap\downarrow}$ are themselves variables whose value depends on the battery's bids and lastly (iii) from the reserve activation.

This model uses data on reserve capacity and activation quantities and costs from the German markets and demonstrate how battery can significantly impact aFRR reserve market prices. This is particularly relevant to understand that, in the long-term, battery storage may have a

[86] Pandžić et al., 2020, *Optimal Battery Storage Participation in European Energy and Reserves Markets*

significant impact on prices and spreads, which may gradually reduce the profitability of such infrastructure.

ii. Presentation of the trading model

Based on the models we described above, we decided to develop a simplified model to arbitrage the day-ahead market prices. We use a linear regression to understand the determining variable of electricity prices, and then used either forecasts or actual prices to maximize the profit that can be extracted from the day-ahead market.

In the following subsections, we first describe the data we have access to and the linear regression we use, then we present the objective function we maximize and other inputs.

1. Available data and linear regression

The first step of the trading model is to perform a regression analysis to estimate the relationship between hourly electricity price (dependent variable) and four exogeneous factors (independent variables). It can then be used to model the relationship between them.

Mathematically, we can model a dependent variable y_t by a linear combination of coefficients $ß_i$ and independent variables x_i. Random shocks (errors or residuals) ε_i that are unobservable and assumed to be independent and identically distributed are added to the mathematical relationship. These random shocks are assumed to follow a Normal Distribution law of parameter $(0,\sigma^2)$.

$$y_t = ß_1 \cdot x_{1,t} + \cdots + ß_N \cdot x_{N,t} + \varepsilon_t, \text{ for } t \in \Omega$$

An objective function is then used to determine the most relevant model to estimate $ß_i$. It is usual to use the sum of squared errors (SSE). Its objective is to find the $ß_i$ such that the sum of squared errors is minimized:

$$SSE = \sum_{i \in \Omega} (y_i - \widehat{y_i})^2 \text{ , where } \widehat{y_i} \text{ the estimated value of } y_i \text{ for given values of } ß_i$$

In practice, when using the SSE objective function, the coefficients of the linear regression can be obtained with the following formula:

$$\widehat{ß} = X(X^T X)^{-1} X^T y$$

Where:

- y is the matrix with the dependent variable data
- X is the matrix such that $y = X \cdot ß + \varepsilon$, with ε the errors matrix

In the context of our trading model, we base the regression on several datasets from Refinitiv and the ENTSO-e Transparency platform. We focus on European countries in which all or almost all data points are available (manual minor corrections are done to ensure there is not missing data points).

The dependent variables $y_{t,h}$ are the hourly electricity prices on the day-ahead market, which are directly exported from Refinitiv. The data used is based on the following exchanges historical prices.

France	Germany & Austria	Belgium	Great Britain	Spain	Nordics	Czech Republic
EPEX Spot	EPEX Phelix	Belpex	Nord Pool	OMIE	Nord Pool	OTE

Figure 44: Exchanges used to export hourly electricity prices on the day-ahead market

It is worth noting that Germany and Austria were part of a single bidding zone until October 2018. Data is available for the common bidding zone after this date, so we decided to (i) keep the common bidding zone pricing and (ii) to sum the different elements of our independent variables to make sure that data is consistent during the regression period.[87]

Electricity prices are also considered from January 1, 2015 to December 31, 2020 to remove the volatility and unprecedented increase in electricity prices that has prevailed since 2021, on the back of gas, coal and European carbon prices increases (themselves driven by a weakened fossil fuel supply chains and higher than expected demand in line with the Covid-19 pandemic recovery).[88]

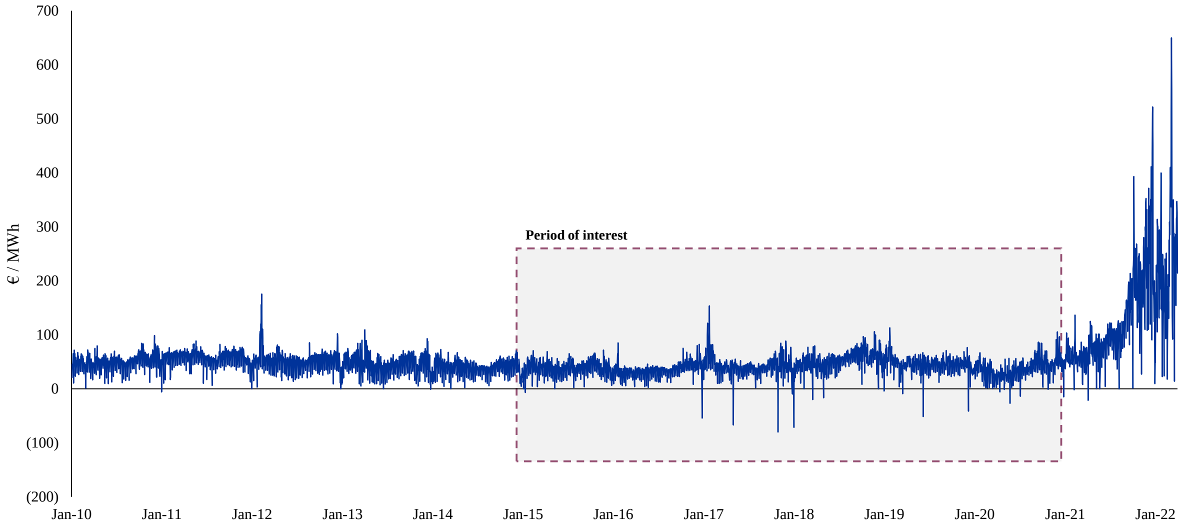


Figure 45: Electricity prices on the German-Austrian market for 9:00 a.m., between January 2010 and March 2022[89]

Based on *Data-driven modelling for long-term electricity price forecasting* of Gabrielli et al.,[90] the independent variables used in our linear regression are the following:

[87] APG, 2017, *End of the German-Austrian electricity price zone – what does this mean?*
[88] IEA, 2021, *What is behind soaring energy prices and what happens next?*
[89] Refinitiv
[90] Gabrielli et al., 2022, *Data-driven modelling for long-term electricity price forecasting*

- The **forecast load** for each country, which is provided by the ENTSO-e Transparency platform – and extracted through FileZilla – on an hourly basis (at most). The data is then manually converted in daily load data points.
- The **solar** and **wind actual production** for each country, which are also provided by the ENTSO-e Transparency platform – and extracted through FileZilla – on an hourly basis (at most). The data is manually summed and converted into the average share of variable renewable energy sources (RES) production.
- The **natural gas** and **crude oil prices**, which are provided by Refinitiv on a daily basis. We use *ICE NBP Natural Gas Electronic Monthly Energy Future* contracts (in £) for the natural gas prices and *ICE Europe Brent Crude Electronic Energy Future* contracts (in $) for the oil prices. We use the same data points for all countries and adjust for daily currency exchange rates.

For the regression to be consistent, we match the prices of electricity on day D with:

- Forecast load from day $D-1$ for day D
- Average variable RES share in last week (relative to day D)'s production
- Natural and crude oil last trading prices from day $D-2$ because when bidding on day $D-1$ for electricity prices on day D, bidders only have access to the close price of day $D-2$

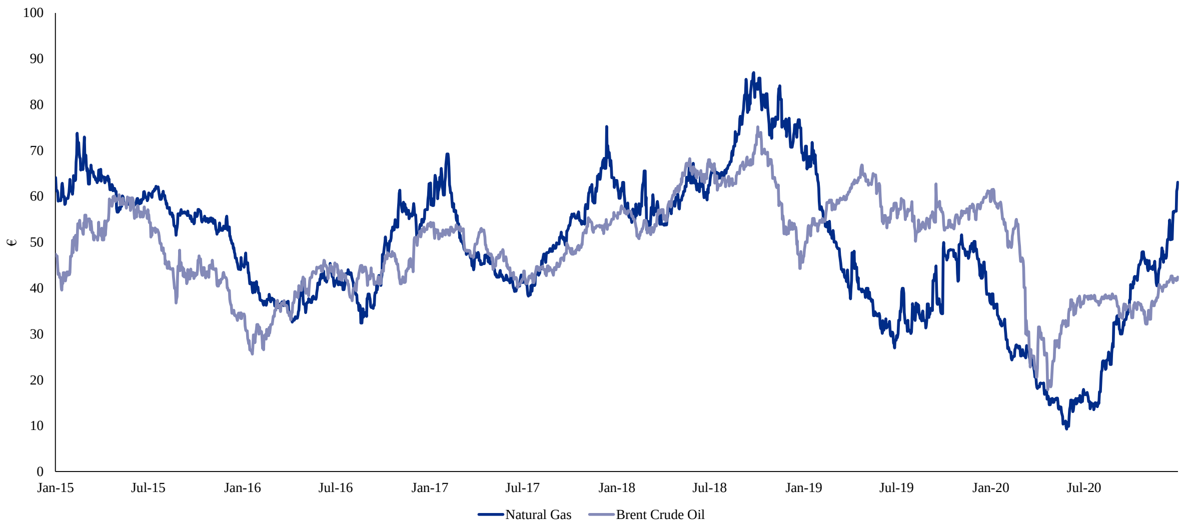


Figure 46: Evolution of natural gas and brent crude oil prices, exchange rate-ajusted, from January 2015 to December 2020[91]

Load and solar generation are relatively seasonal. However, wind generation is quite volatile although there is an underlying seasonal trend. As a result, the average weekly RES share in the total load is unstable. [92]

[91] Refinitiv
[92] ENTSO-e Transparency platform, visited in March 2022

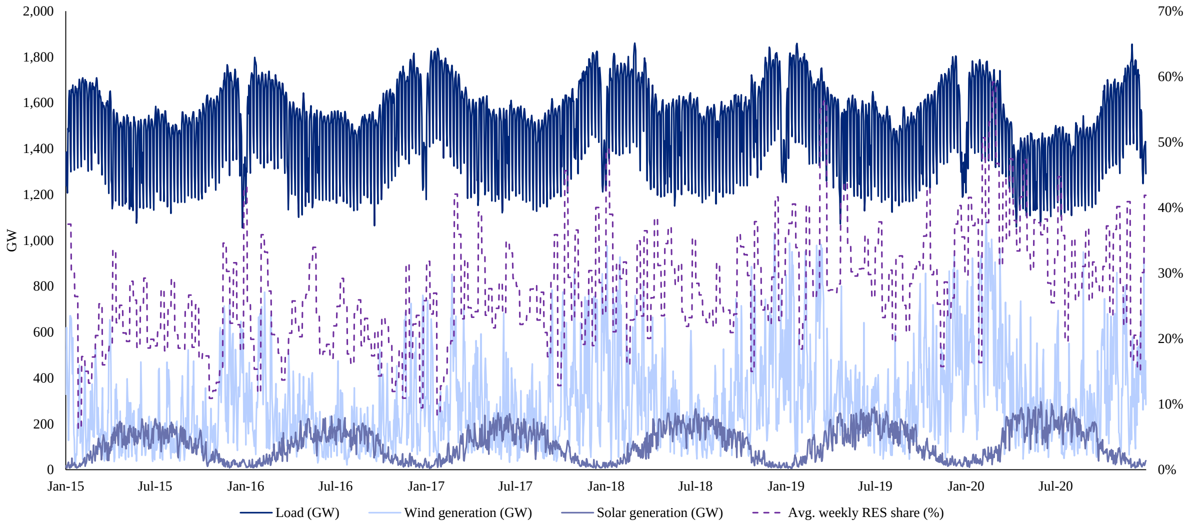


Figure 47: Evolution of electricity load, solar and wind generation (in GW) and average weekly RES share (in %)[93]

The result of the linear regression can be summarized by the following relationship:

$$y_{h,d} = ß_0 + ß_1 \cdot [Load\ Forecast, in\ GWh]_d + ß_2 \cdot [Avg.\ last\ week\ RES\ share]_d + ß_3 \cdot P_{Natural\ Gas,d-1} + ß_4 \cdot P_{Brent\ oil,d-1}$$

After running the regression, we compute the adjusted coefficient of determination (adjusted R²) for each of the 24 regressions of each country. It indicates the level of linear association between the set of independent variables and the dependent variables.

$$Adjusted\ R^2 = 1 - \frac{T-1}{T-K} \cdot \frac{\sum_{t=1}^{T} \varepsilon_t^2}{\sum_{t=1}^{T} (y_t - \bar{y})^2}$$

The adjusted R² gives a better measure of the relevance of the model given that it penalizes the addition of extraneous predictors to the model (by dividing by $T - K$). Consequently, it is necessarily smaller than R².

Lastly, we compute the statistical relevance of each parameter by determining its t-statistics by testing if it is significantly different from 0. In this regard, we compute the covariance matrix of the regression:

$$\hat{V} = \left(\frac{1}{T-K} \sum_{t=1}^{T} \varepsilon_t^2\right) (X^T X)^{-1}$$

And then calculate the t-statistics:

$$T - statistics_{\widehat{ß}_i} = \frac{\widehat{ß}_i}{\sqrt{\hat{V}_{i,i}}}, \text{ with } \frac{\widehat{ß}_i}{\sqrt{\hat{V}_{i,i}}} \sim t_{T-K}$$

Where t_{T-K} is a Student's t-distribution with T-K degrees of freedom, given that $T \approx 2{,}192$. We retain -1.96 and 1.96 as threshold for the relevance of the parameters at a 95% confidence level.

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93 ENTSO-e Transparency platform, visited in March 2022

Below are the results of the 24 regressions for France. We note that RES share coefficients are mostly insignificant, which may relate to the important volatility in values.

Variable	OLS regressions											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Intercept	**(5.19)**	**(8.39)**	**(10.48)**	**(10.78)**	**(11.56)**	**(15.41)**	**(22.10)**	**(32.31)**	**(34.90)**	**(31.83)**	**(29.43)**	**(25.12)**
	(3.07)	(5.21)	(6.58)	(6.50)	(6.86)	(9.24)	(11.13)	(12.79)	(12.96)	(13.01)	(12.93)	(11.53)
Load Forecast	**12.27**	**13.40**	**14.29**	**13.54**	**13.73**	**16.86**	**23.76**	**33.98**	**36.99**	**34.53**	**32.94**	**29.87**
	14.10	16.15	17.43	15.84	15.82	19.64	23.24	26.11	26.68	27.40	28.10	26.62
RES share	**(16.23)**	**(13.37)**	**(12.56)**	**(12.48)**	**(8.00)**	**0.18**	**15.14**	**21.52**	**24.55**	**21.84**	**10.92**	**5.33**
	(2.03)	(1.75)	(1.67)	(1.59)	(1.00)	0.02	1.61	1.80	1.93	1.89	1.01	0.52
Natural Gas	**0.35**	**0.31**	**0.29**	**0.25**	**0.24**	**0.27**	**0.34**	**0.39**	**0.40**	**0.45**	**0.47**	**0.48**
	17.35	16.25	15.10	12.60	11.95	13.69	14.36	13.16	12.46	15.47	17.23	18.54
Oil	**0.21**	**0.21**	**0.21**	**0.22**	**0.21**	**0.22**	**0.21**	**0.23**	**0.26**	**0.22**	**0.18**	**0.15**
	8.24	8.51	8.63	8.48	8.12	8.42	6.84	5.90	6.26	5.79	5.15	4.55
Number of observations	2188	2188	2188	2188	2188	2188	2188	2188	2188	2188	2188	2188
Adjusted R²	0.43	0.43	0.43	0.37	0.35	0.41	0.43	0.44	0.44	0.48	0.51	0.51

Variable	OLS regressions											
	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
Intercept	**(21.33)**	**(23.93)**	**(27.65)**	**(30.80)**	**(32.22)**	**(35.74)**	**(34.75)**	**(22.35)**	**(10.15)**	**(1.99)**	**0.28**	**(2.42)**
	(10.49)	(11.41)	(12.44)	(13.45)	(14.05)	(14.34)	(5.85)	(7.31)	(4.71)	(1.08)	0.17	(1.56)
Load Forecast	**26.83**	**27.82**	**29.42**	**30.16**	**31.13**	**35.94**	**45.47**	**31.54**	**19.44**	**11.68**	**10.05**	**11.99**
	25.62	25.75	25.69	25.56	26.35	27.99	14.86	20.02	17.53	12.35	12.03	15.02
RES share	**6.13**	**3.98**	**4.34**	**17.20**	**30.67**	**43.47**	**5.44**	**36.31**	**20.25**	**1.44**	**(7.43)**	**(11.22)**
	0.64	0.40	0.41	1.59	2.83	3.69	0.19	2.51	1.99	0.17	(0.97)	(1.53)
Natural Gas	**0.48**	**0.48**	**0.46**	**0.46**	**0.49**	**0.55**	**0.64**	**0.57**	**0.49**	**0.41**	**0.38**	**0.38**
	19.81	19.10	17.46	17.03	17.87	18.69	9.06	15.61	19.29	18.66	19.75	20.37
Oil	**0.13**	**0.12**	**0.12**	**0.13**	**0.10**	**0.06**	**(0.10)**	**0.06**	**0.14**	**0.21**	**0.25**	**0.21**
	4.09	3.61	3.65	3.63	2.90	1.49	(1.06)	1.21	4.28	7.42	10.06	8.66
Number of observations	2188	2188	2188	2188	2188	2188	2188	2188	2188	2188	2188	2188
Adjusted R²	0.52	0.51	0.48	0.47	0.48	0.49	0.20	0.37	0.43	0.42	0.47	0.49

Figure 48: Regressions for hourly electricity prices in France based on data from January 2015 to December 2020[94]

2. Trading model

The trading model objective is to maximize the following objective function:

$$Maximize_{Q_{in,0},Q_{out,0}\ldots Q_{in,23},Q_{out,23}} \sum_{h\in[0,23]} [\frac{Q_{in,h}\cdot P_{in,h}}{\eta_{in}} + Q_{out,h}\cdot P_{out,h}\cdot \eta_{out}]$$

Where:

- Q_{in} and Q_{out} are the energy quantities purchased or sold on the day-ahead market (in MWh) at hour h.
- P_{in} and P_{out} are the electricity prices at time of charge or discharge respectively (in €/MWh) at hour h.
- η_{in} and η_{out} are the charge and discharge efficiency of the battery (between 0 and 1).

Subject to the constraints:

- $\sum_{h\in[0,23]}[Q_{in,h} + Q_{out,h}] = 0$, to force the state-of-energy (soe) to be 0 at the end of a given day.

[94] ENTSO-e Transparency platform and Refinitiv, visited in March 2022

- $0 \leq soe_h \leq soe_{max}, \forall h \in [0{,}23]$, to force the soe of the battery to remain positive, but below or equal to its maximal charge level.
- $0 \leq Q_{out} \leq Power$ and $0 \leq Q_{in} \leq Power$ with power the battery power (in MW), to force the hourly purchases or sales of electricity to remain within the technical capabilities of the battery.

The purpose of this function is to maximize the flows of electricity that are purchased on the day-ahead market at a given hour, before being sold once again on the day-ahead market later in the day. It is imposed that the state-of-energy of the battery should be equal to zero at the end of the day and that the state-of-energy should be always contained within normal bounds (positive and below or equal to the maximum capacity of the battery).

Then, capital expenditures (capex) and operating expenditures (OpEx) are determined. We use the same methodology than Staffell and Rustomji in *Maximising the value of electricity storage*. The calculations of the capital expenditures are based on the DOE/EPRI convention and presenter as a sum of a power (€/kW) and energy (€/kWh) terms. Economies of scale are ignored and the specific cost (per kW or kWh) is constant, regardless of the battery capacity.[95]

$$capex = \frac{power[kW] \cdot cost\ of\ power[€/kW] + capacity[kWh] \cdot cost\ of\ capacity[€/kWh]}{power}$$

We then annualise the capex expenditures by dividing the aforementioned capex by the lifetime of the battery:

$$Annualised\ capex = \frac{capex}{lifetime\ of\ the\ battery}$$

For example, the capital cost of 1 MW, 10 MWh lithium-ion battery whose cost would be of 1,468 €/kW and 367 €/kWh, with a lifetime of 10 years would have an annualized capex of 513.6 € / kW / year:

$$Annualized\ capex = \frac{\frac{1{,}000 \cdot 1{,}468 + 10{,}000 \cdot 367}{1{,}000}}{10} = \frac{5{,}136}{10} = 513.6\ €/kW/year$$

Several literature reviews give an overview of the costs and performance of different energy storage technologies, BESS, and non-BESS. Estimates for the total project costs (i.e., including energy storage system costs, engineering, construction, project development and grid integration) for 2018 and 2020 are summarized in the graphs below.)[96,97]

A battery power of 1 MW and energy-to-power (E/P) ratio of 4h was used as often as possible for those estimates. And values were converted in euros using the currency exchange rate as of December 31, 2018 for 2018 estimates and as of December 31, 2020 for 2020 estimates.

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[95] Iain Staffell and Mazda Rustomji, 2016, *Maximizing the value of electricity storage*
[96] Mongird et al., 2019, *Energy Storage Technology and Cost Characterization Report*
[97] Mongird et al., 2020, *Grid energy Storage Technology Cost and Performance Assessment*

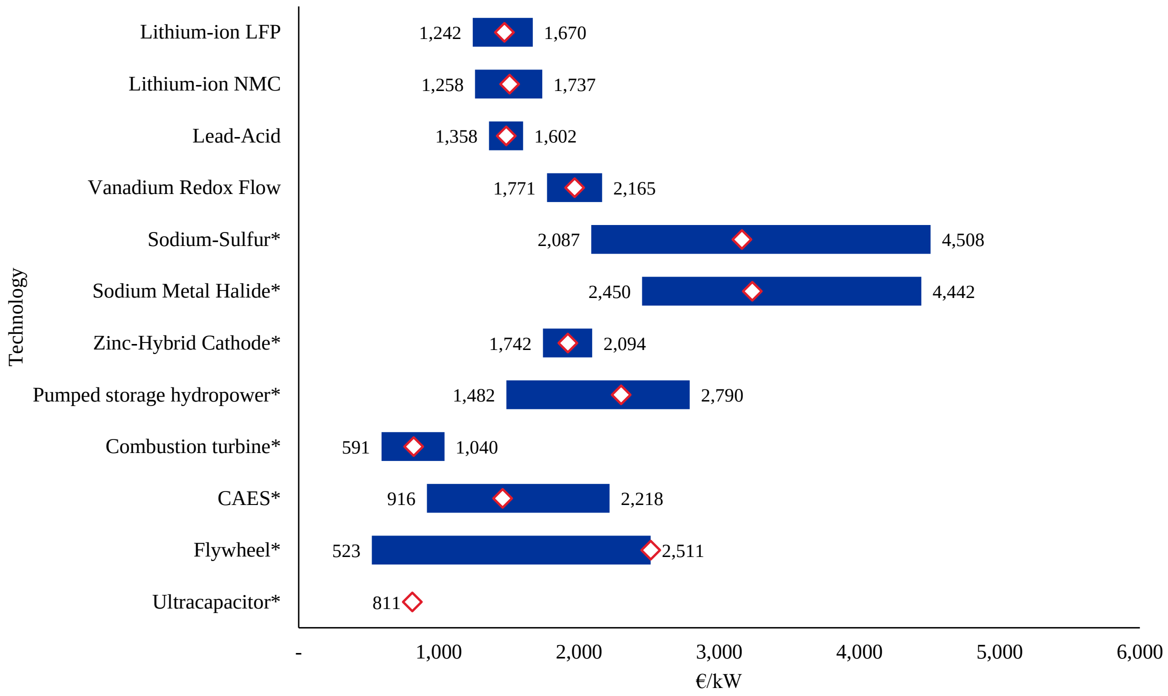

Figure 49: Summary of total project costs (in €/kW), by technology, BESS and non-BESS (indicate 2018 estimates)*[98][99]

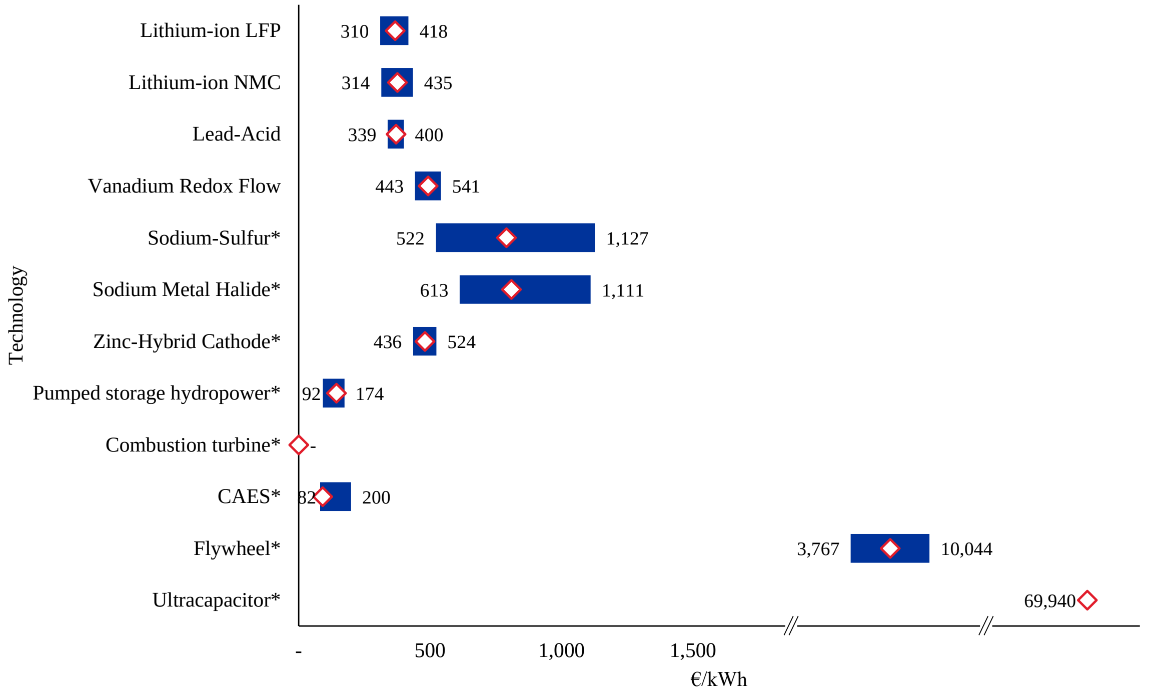

Figure 50: Summary of total project costs (in €/kWh), by technology, BESS and non-BESS (indicate 2018 estimates)*[100][101]

[98] Mongird et al., 2019, *Energy Storage Technology and Cost Characterization Report*
[99] Mongird et al., 2020, *Grid energy Storage Technology Cost and Performance Assessment*
[100] Mongird et al., 2019, *Energy Storage Technology and Cost Characterization Report*
[101] Mongird et al., 2020, *Grid energy Storage Technology Cost and Performance Assessment*

The performance of each type of technology are also compiled in the graph given below. BESS technologies are among the most efficient, with lithium-ion (LFP and NMC) achieving a round-trip efficiency (RTE) of 86%. Nonetheless, the annual degradation of RTE of battery storage is significantly higher than for non-BESS technologies (e.g. 0.5% for lithium-ion batteries and 5.4% for lead-acid batteries, against 0.14% only for flywheel storages, and no degradation for pumped hydro storages).

In addition, non-BESS technologies have a longer lifetime, almost twice as important as BESS technologies, which may also explain their attractiveness in terms of energy storage infrastructure (pumped storage hydropower in particular).

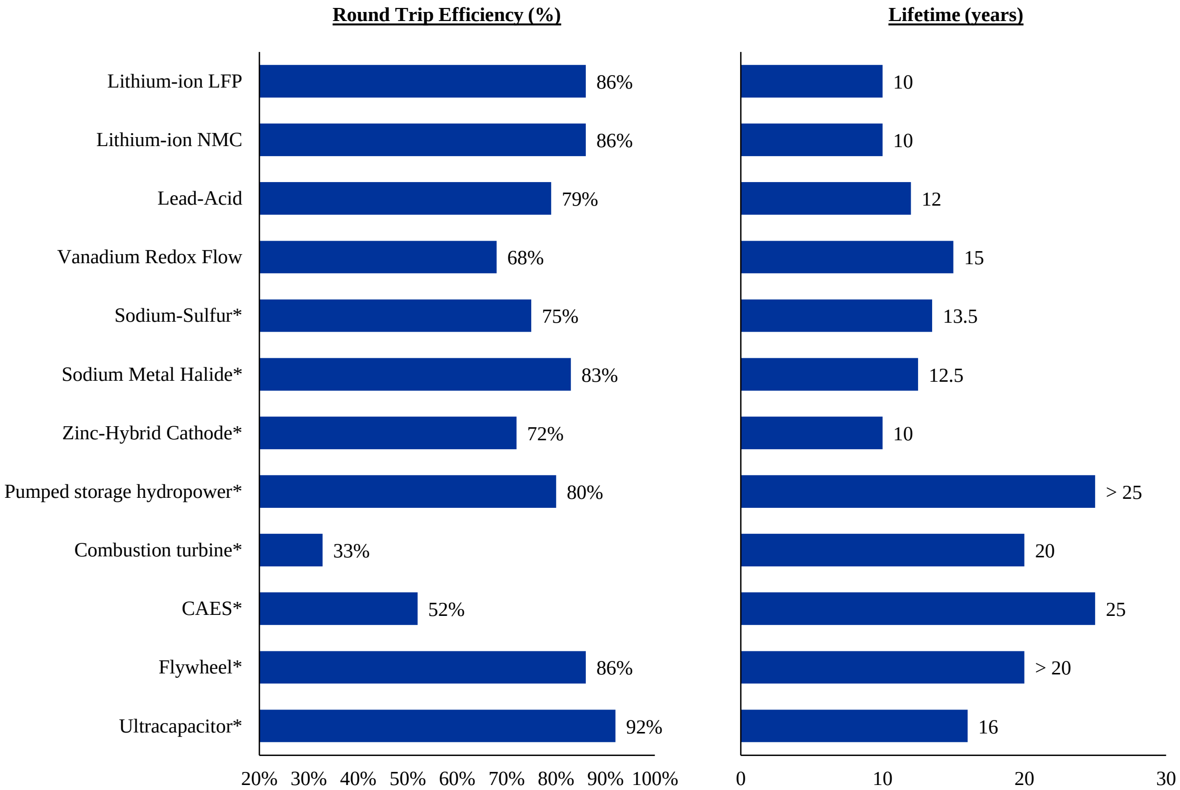

Figure 51: Summary of performance indicators, by technology, BESS and non-BESS (indicate 2018 estimates)* [102,103]

iii. Performance of the trading model on out-of-sample data

In this subsection, we run the trading algorithm to maximize profit from trading operations for one year, from January 1, 2020, to December 31, 2020. We try to see how battery power and capacity and technology can impact profit. We also compare how trading based on perfect foresight (i.e., maximization based on historical prices) compares with trading based on forecast prices.

[102] Mongird et al., 2019, *Energy Storage Technology and Cost Characterization Report*
[103] Mongird et al., 2020, *Grid energy Storage Technology Cost and Performance Assessment*

We represent below the profit generated by maximising the profit generated by arbitraging day-ahead electricity prices using a lithium-ion LFP battery, with different power and capacity, in France, based on 2020 prices. Although profit, defined as revenue generated by the sale of electricity, minus the costs related to the purchase of electricity and the operating costs of the battery, increases relatively linearly, rate of return is higher for smaller batteries (i.e., with smaller power and capacity). This is linked to the fact that capacity costs are not ten times lower than power costs (on a unitary basis), which translates in rising costs for the capacity of batteries.

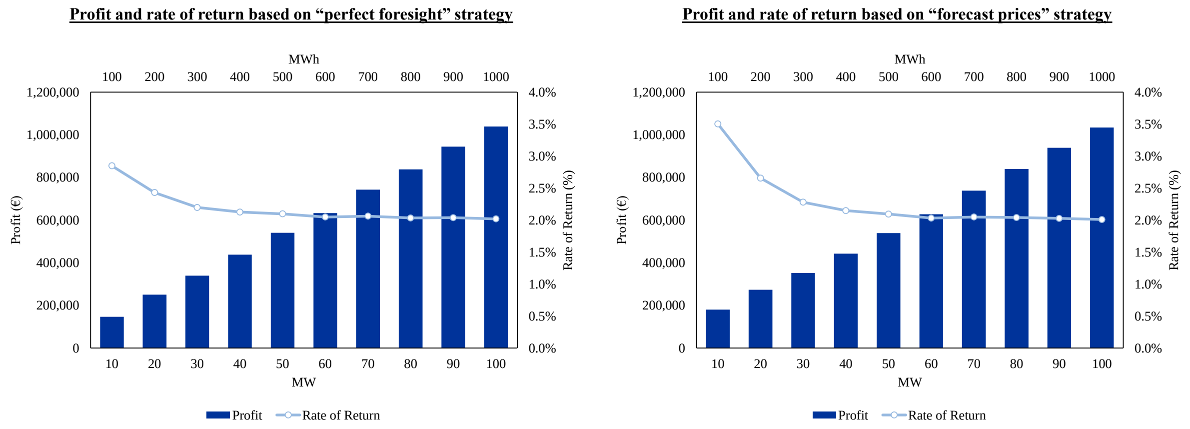

Figure 52: Profit and RoR of Lithium-ion LFP batteries, based on historical and forecast prices, by power and capacity, in France, in 2020

For example, in the case of the 30 MW – 300 MWh battery, in the “forecast prices” scenario (i.e., forecast prices are used to determine the trading pattern before actual historical prices are used to determine the real profit realized with this pattern), December 9, 2020 trading operations were the most profitable, with most purchases occurring in the morning and sales later in the day. This can be explained by prices that were much higher than anticipated during the day, with resulted in higher-than-expected profits starting at 6:00 am. At the end of the day, as imposed in the algorithm, the state-of-energy of the battery is zero.

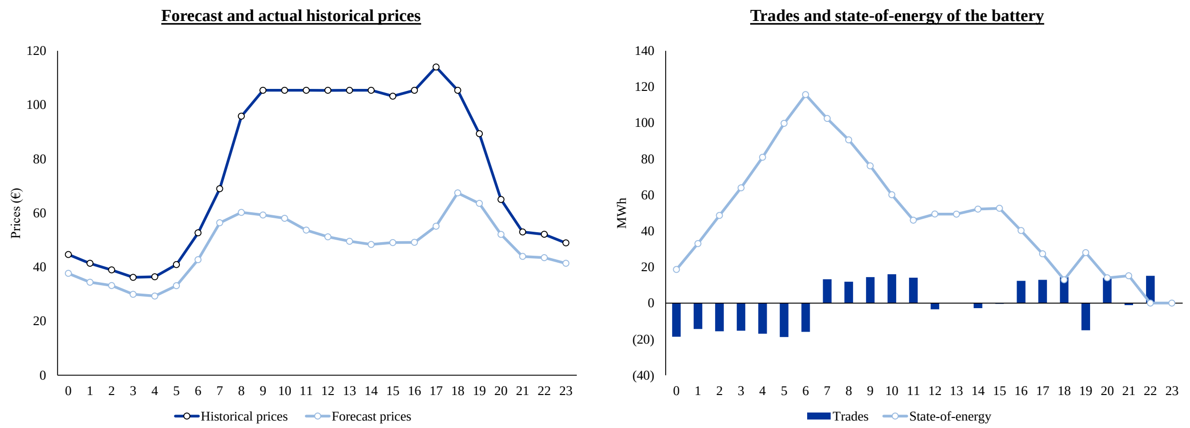

Figure 53: Prices, trades and state-of-energy of the lithium-ion LFP battery on December 9, 2020 (30 MW, 300 MWh)

Similarly, we represent below the profitability and rate of return of different technologies. We mainly note than the lithium-ion technology remains the most profitable one out of all the technologies in terms of rate of return. There are still some inconsistencies due to the low number of iterations in our algorithm, which are caused by the limited computing capacity we have access to. Not accounting directly for variable operating expenses related to electricity flows (in € / kWh / year) may also have an impact on the difference between the two scenarios.

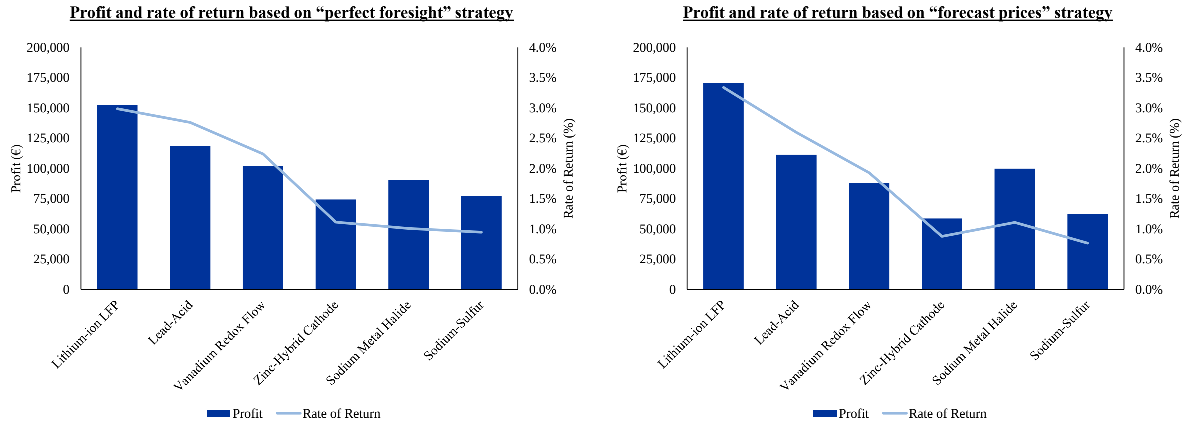

Figure 54: Profit and RoR of different battery technologies, based on historical and forecast prices, in Germany and Austria, in 2020

C. Performance of our electricity trading model using forecasts

The trading model was first used on out-of-sample data from 2020 to determine how well it would perform using forecast prices. It is relatively difficult to develop long-term forecast models of electricity prices given their volatility and the high likelihood of unexpected demand or offer shocks. Even though, we designed a SARIMA model coupled with a Bass diffusion model to describe the evolution of long-term seasonal trends (load and variable RES adoption), which is then used to forecast long-term electricity prices using the relationship resulting from the linear regression on 2015-2020 data.

We first discuss the underlying theory and the implementation of the SARIMA and Bass diffusion models, then we present the performance of the trading model under different scenarios by forecasting operations between 2021 and 2023. Lastly, we provide some insights on how this model could be improved (on the trading and forecasting standpoints).

i. Forecasting multiple variables using a SARIMA and arbitrary decisions

The Autoregressive Integrated Moving Average Model (ARIMA) is a widely used time series analysis model in statistics for short-term predictions. Because this method is relatively systematic and flexible, it is used notably in meteorology, engineering technology and economic statistics.[104]

[104] Chang et al., 2013, *Seasonal Autoregressive Integrated Moving Average Model for Precipitation Time Series*

It is usual to denote an ARIMA model as $ARIMA(p, d, q)$ where p, d and q correspond to the order of the autoregressive, integrated and moving average parts of the model. The periodicity of periodical time series is usually caused by seasonal changes (monthly, quarterly, or yearly for example) or some other natural reasons.

A SARIMA model, which can be denoted $SARIMA(p, d, q)(P, D, Q)s$ is used when the data series are seasonal, which means that there are different cycles with the same repetitive phase. If the period of the time series is equal to 52, it can be denoted $SARIMA(p, d, q)(P, D, Q)52$. This is a convenient model to forecast short-term seasonal data.

A few steps are necessary before running a SARIMA model, including:

- Stabilizing the variance if it increases or decreases over time.
- Identifying the preliminary value of the autoregressive order p, the order of differencing d and the moving average order q with their corresponding parameters P, D and Q using the Autocorrelation Function (ACF) and the Partial Autocorrelation Function (PACF).

Once the model is established, the parameters and corresponding standard errors can be estimated using different statistical techniques, such as the Least Square Estimation. Future values can then be predicted.

For this Master Thesis, we decide to forecast daily data converted into weekly data. Weekly predictions are then converted once again in daily data using the average weekly intra-week variation of load for the load predictions. For the weekly average of variable RES share in the electricity production, we keep the weekly forecasts. The predictions are realised using a $SARIMA(1,0,1)(0,1,1)52$ model.

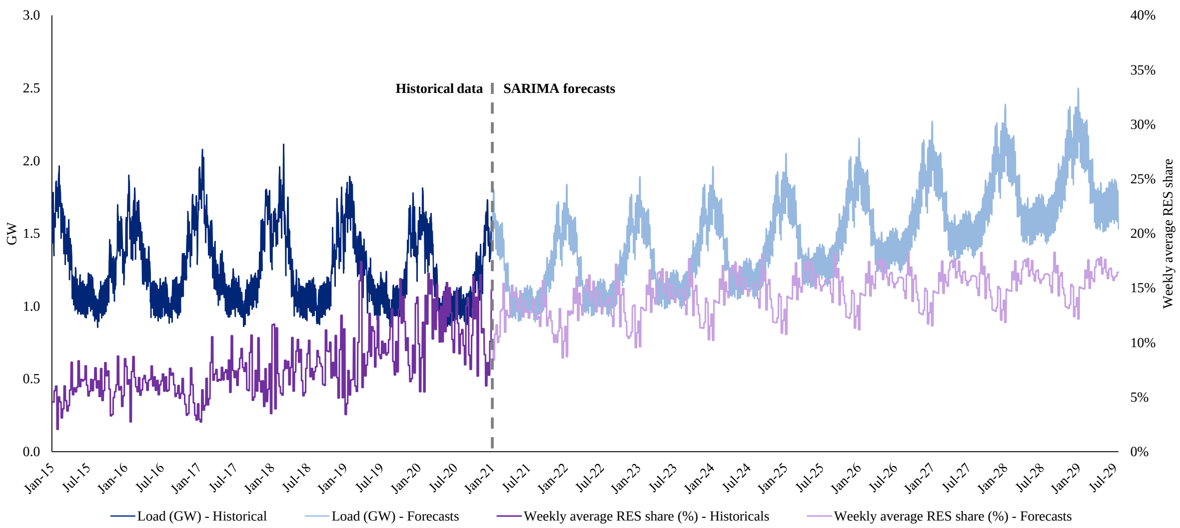

Figure 55: SARIMA(1,0,1)(0,1,1)52 forecasts for load and weekly average RES share in France, between January 2021 and July 2029, based on 2015-2020 data, considering an increase in load and RES share over time[105]

[105] ENTSO-e Transparency Platform, visited in April 2022

However, we believe that the SARIMA model implemented does not reflect the future growth in electricity consumption. Different plans for an increasing electrification of Europe (e.g. the *Fit for 55* package, intended to cut gas emissions by at least 55% by 2030, is expected to increase electricity consumption by 50% by then[106]) should have a significant impact on the consumption and green production of electricity.

Therefore, we added a Bass diffusion model to reflect this faster-than-historical increase. The *forte* of a Bass diffusion model is that it focuses on the growth and spread of new products but can be adapted in other situations. It offers a simple but good baseline model to assess the diffusion of a model through the adoption rate of this product and whose diffusion history is unknown.[107]

The mathematical relationship underlying the pace of adoption is given by:

$$F(t_i) = \frac{1 - e^{-(p+q)t_i}}{1 + \frac{q}{p} e^{-(p+q)t_i}}$$

Where:

- p is the coefficient of innovation, whose average value is 0.03[108]
- q is the coefficient of imitation, whose average value is 0.38

This pace of adoption is then multiplied by the market potential (N), which, in the case of the Master Thesis, corresponds to the total future increase induced by the faster than anticipated electrification of countries.

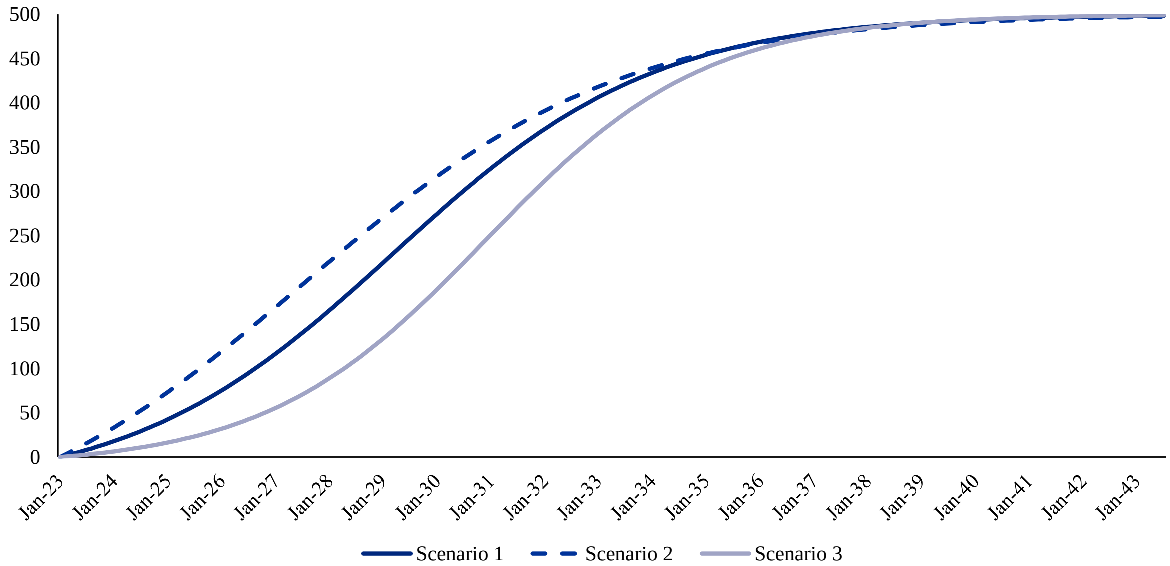

Figure 56: Graphical representation of the Bass diffusion model under different parameters

[106] Goldman Sachs, 2022, *The rise of Power in European Economies*
[107] Frank M. Bass, 1969, *A new product growth for model consumer durables*
[108] University of Washington, visited in April 2022, *Coefficients of Innovation (p), Imitation (q) and Market Potential (N) for Several Products*

In the graph above, we represent 3 scenarios:

- *Scenario 1*, with p = 0.005 (i.e., 0.06 when annualised) and q = 0.0233 (i.e., 0.28 when annualised) and N = 500
- *Scenario 2*, with p = 0.0025 (i.e., 0.03 when annualised) and q = 0.03167 (i.e., 0.38 when annualised) and N = 500
- *Scenario 3*, with p = 0.000833 (i.e., 0.01 when annualised) and q = 0.04 (i.e., 0.48 when annualised) and N = 500

We assume that electricity consumption should increase by 50% by 2030 vs. the average consumption between 2015–2020 (i.e., over a 10-year period), in line with Goldman Sachs' *The rise of Power in European Economies*. [109]

Regarding the variable RES share in the electricity production of each country, the European Union has adopted a 32% renewable energy target by 2030. Therefore, we decide to consider an increase of 50% relative to the 2015-2020 average level..[110]

We also use the average values for the Bass diffusion model, but converted in weekly values, i.e.:

- $p = \frac{0.03}{52} = 0.000577$
- $q = \frac{0.38}{52} = 0.007308$

Natural gas and oil prices are fixed throughout the estimate period at €50 (£50 for Great Britain), close to the 5-year average (2015-2020).

Country	**France**	**Germany & Austria**	**Belgium**	**Great Britain**	**Spain**	**Czech Republic**
Load	Scenario 1: + 20% over 10 years vs. 2015-2020 average Scenario 2: + 50% over 10 years vs. 2015-2020 average					
Avg. RES share	+ 50% over 10 years vs. 2015-2020 average					
Natural gas price	50					
Oil price	50					
(p, q)	(0.000577, 0.007308)					

Figure 57: Overview of forecast model scenarios' parameters

[109] Goldman Sachs, 2022, *The rise of Power in European Economies*
[110] European Commission, 2018, *Directive 2009/28/EC*, revised in 2018

ii. Performance of the trading model under different scenarios

Based on the aforementioned scenarios, the trading model was used to determine the profits and rate-of-returns generated in the different countries analysed. Nordics countries had to be excluded from the sample because of important gaps in data for Sweden.

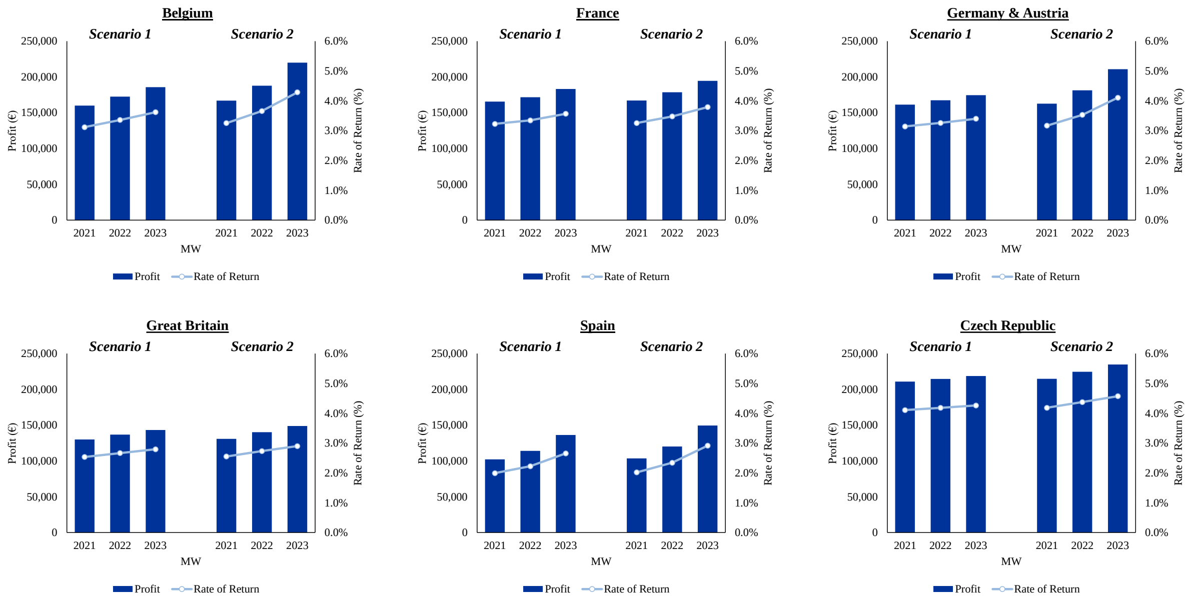

Figure 58: Profit and RoR over 2021-2023 forecasted years in different European countries, in 2 scenarios

The highest rate-of-returns were generated in Czech Republic, Belgium, and Germany & Austria, with annualized rate-of-returns above 4.0% in scenario 2. In a scenario with a significant increase in load (+50% in 10 years in scenario 2 vs. only +20% in 10 years in scenario 1), the rate-of-returns computed by the trading algorithm were strictly higher than in the other scenario. This can be explained by the direct relationship between the load and the price prediction.

Nonetheless, it is still worth noting that the annualized rate-of-return, which is still below 100%, shows how this strategy would be highly unprofitable for investors.

iii. Limits of the model and possible future improvements

The aim of our algorithm is to provide a realistic model that would account for the electricity market structure and the various trading costs and benefits that are associated with it. But the algorithm has its limits and weaknesses, especially when it is used in real settings. This has led us to identify some aspects that could be subject of further developments and could vastly improve the algorithm features and realism.

1. Opening and improving data access

One of the main barriers in the creation of the trading algorithm was the public availability of datasets. Despite the existence of the ENTSO-e Transparency Platform, which has been of tremendous help in building the algorithm, most information is either collected by electricity suppliers or TSOs / DSOs (e.g., RTE) or trading platforms (e.g., Epex Spot) and then monetized, which prevents any non-funded research to have access to these databases.

However, sometimes, this information is crucial to analyse and understand how past prices have been determined and how the different explanatory variables have evolved over time. For example, we did not obtain data on supply stack models and volumes of intraday products. Accessing this data could have helped us understand how the development of renewable energy sources in the European Union, under the current pricing mechanism, have impacted (i) the supply of energy at no marginal cost (i.e., crowded out gas-powered energy) and (ii) fostered the development of shorter contracts to enable a faster response to abrupt changes in electricity production.

The issue is not related only to the monetization of data, but also with the poor public tracking of real assets projects and investments. Because of either poor public management or lack of incentives to force disclosure on the nature and time of investments, it is difficult for researchers to have a clear idea on the state of energy storage systems in Europe (Directorate-General for Energy's database on energy storage appears to miss many projects on energy storage[111]) and sometimes, important gaps in data cannot be explained.

Therefore, it is clear that any research on energy storage or energy trading will face obstacles in building a clear view on past data, unless researchers have enough funding or direct support from companies that can provide them with private databases that are better maintained than the public ones (although the latter remain particularly helpful for production-consumption analysis). Large improvements could be brought to the algorithm by having a broader access to information, which could allow for a more careful and granular selection of relevant explanatory variables.

2. Integrating intraday trading and additional costs and benefits

The major flaw of the trading model that has been developed in this Master Thesis is its sole focus on day-ahead electricity markets. Ignoring intraday / reserve markets is most likely the main reason explaining the poor profitability results we obtained and discussed in the previous section. Prices in these shorter-term markets have been historically more volatile than in the day-ahead markets and much more unpredictable. This structure is much more suited for energy storage systems, which do not require preparation ahead of delivering electricity. However, the main issues with the integration of the intraday market in the trading algorithm would have been:

[111] Directorate-General for Energy, visited in May 2022, *Database of the European energy storage technologies and facilities*

- The complexity associated with the integration was far beyond our knowledge and we did not consider ourselves able to reproduce the model from other research papers such as *Optimal Battery Storage Participation in European Energy and Reserves Markets* of Pandžić et al.[112], although this would have been ideal to obtain a better view on returns that could be expected from electricity trading.

- The impossibility to work on predicted data, which is the objective of the trading algorithm we developed. Given the high volatility of intraday prices, which can vary significantly depending on renewables energy production, predicting future prices would have almost impossible, given we did not have access to complete data with (half-)hourly granularity. Therefore, the maximization of the profitability in the model could have been done only on historical prices, but not on future data.

In addition to lacking access to these intraday prices, the complexity and the scope of analysis would have been vastly reduced.

Nonetheless, there are initiatives that could be studied in a further analysis. For example, it is possible to imagine taking inspiration on asset management's theories, with portfolio parameters optimization. By optimizing parameters on historical data, which could integrate day-ahead and intraday markets data, the algorithm could be fit to trade independently, without having the need to receive further inputs.

The realism could also be improved by modelling the real asset (i.e., the battery in our model) independently from the trading algorithm. This would allow to systematically test for the capacity, efficiency and thus costs that are associated with the use of this asset. This refers notably to the decreasing efficiency of batteries, which can be significant for lead-acid batteries (about 5% p.a.) but limited for lithium-ion batteries (about 0.3% p.a.).[113]

3. Improving the profit optimization mechanism

Another fundamental aspect that prevents the algorithm from being realistic is how heavy calculations are to maximize profits on relatively short timeframes. We have relied on Scipy's *basinhopping* function to iterate results whose starting point was predetermined. The results are often unsatisfactory in terms of (i) profitability results as we are unsure that the most profitable iteration is, at least, actually a local maximum and (ii) computation time required to maximize profitability on given time frames, despite the low number of iterations (c. 20).

As a consequence, we believe vast improvements could be brought to the algorithm by using more complex mathematical methods that we do not master. The Lagrangian method, which enables to mathematically find local extrema under equality constraints, would be particularly relevant in our opinion.[114]

[112] Pandžić et al., 2020, *Optimal Battery Storage Participation in European Energy and Reserves Markets*
[113] Mongird et al., 2020, *Grid energy Storage Technology Cost and Performance Assessment*
[114] David Morin, 2007, *Chapter 6 – The Lagrangian Method*

In addition, should the algorithm future developer decide to maximize prices based on forecast prices instead of a parametrization-based optimization, then it could be also relevant to improve price predictions using more advanced machine learning methods (such as a random forest for example).

4. Modelling in a realistic situation: FTM renewables integration

Lastly, we believe that the trading algorithm could have been vastly improved by virtually positioning the battery storage in the context of an integrated installation with variable renewable energy (VRE) sources, i.e., a FTM renewables integration business model. As mentioned previously, according to our discussion with Marc Romano, battery storage is mainly used by infrastructure developers when developing VRE sources installations and used as a means to shift electricity sale to a different timeframe. This allows developers to increase the profitability of their installation by benefiting from higher selling prices.

As a consequence, it could have been helpful to add another module to the trading algorithm, in which past weather conditions could have been used to either optimize ex-post profits of an integrated battery storage system, or to forecast future weather conditions to maximize the potential profit from the integration.

All in all, the algorithm would become significantly more realistic if it was developed with the support of a public or private company with a real renewable energy infrastructure project, which would allow the algorithm developer to access more information than we did, in a more realistic setting and more focused objective (i.e., an open-source algorithm, capable of trading electricity on the day-ahead and intraday markets, in coordination with renewable energy sources).

Conclusion

The progressive increase in renewable energy sources in the European production mix may have significant consequences on the electricity grid, with intermittency becoming an issue for the network stability. Liberalisation of the European electricity markets and technological innovations have created a sense of hope among investors, politicians, and societies that storage solutions may help smooth this intermittency and deal with the ecological issues of non-renewable energy.

Nevertheless, challenges remain for battery storage solutions, including their ability to be cost-competitive against other existing or emerging technologies that may overshadow battery storage's current development (e.g., hydrogen). Batteries have a huge potential, but in the current state, they may need to be coupled with other solutions and provide additional services to offset their high building and maintenance costs. Recent innovations allowed to drastically decrease the price of batteries, so we can expect this trend to continue in the future and batteries to become more cost-effective in the mid-to-long-term.

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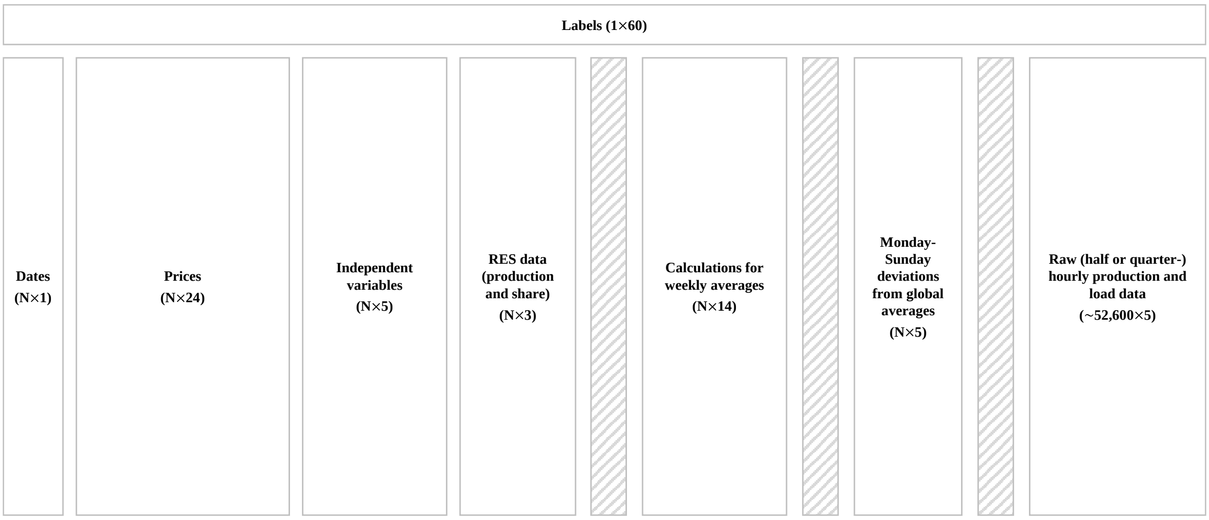
Annex

Trading algorithm

The code of the trading algorithm for arbitrage trading is available for download here. Data can be requested directly by email at arnaud.walter@hec.edu or madina.safaeva@hec.edu.

Structure of the dataset for the trading algorithm



N represents the number of days

Project costs and performance indicators by battery technology

Technology	$/kW (low)	$/kW (mid)	$/kW (high)	$/kWh (low)	$/kWh (mid)	$/kWh (high)	Efficiency	Calendar Life	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Exch. Rate (USD/EUR)
Lithium-ion LFP	1,517	1,793	2,040	379	448	510	86%	10	0.51	4.40	1.221
Lithium-ion NMC	1,537	1,838	2,122	384	459	531	86%	10	0.51	4.51	1.221
Lead-Acid	1,658	1,808	1,956	414	452	489	79%	12	0.51	5.90	1.221
Vanadium Redox Flow	2,163	2,404	2,644	541	601	661	68%	15	0.51	6.79	1.221
Sodium-Sulfur*	2,394	3,626	5,170	599	907	1,293	75%	13.5	0.30	10.00	1.147
Sodium Metal Halide*	2,810	3,710	5,094	703	928	1,274	83%	12.5	0.30	10.00	1.147
Zinc-Hybrid Cathode*	1,998	2,202	2,402	500	551	601	72%	10	0.30	10.00	1.147
Pumped storage hydropower*	1,700	2,638	3,200	106	165	200	80%	> 25	0.00	15.90	1.147
Combustion turbine*	678	940	1,193	0	0	0	33%	20	10.50	13.00	1.147
CAES*	1,050	1,669	2,544	94	105	229	52%	25	2.10	16.70	1.147
Flywheel*	600	2,880	2,880	4,320	11,520	11,520	86%	> 20	0.30	5.60	1.147
Ultracapacitor*	930	930	930	74,480	74,480	74,480	92%	16	0.30	1.00	1.147

*All data from 2020, except technologies noted with a *, indicating data form 2018*

Interview with Marc Romano – Impact Private Equity at Mirova

Do you plan to invest, or have you invested in BESS-type energy storage solutions?

Yes

1. What technology will be favoured?

Lithium, with better consideration of recycling. Or maybe a sodium-based technology, although it is currently not satisfactory because of its low efficiency. However, it is available more easily and does not heat up (which reduces the risk of fire).

2. In which geography are you planning to invest?

We are planning to invest in an area that consist in areas with non-controllable renewables (e.g. wind or PV), i.e., Germany, Nordic countries, Poland, France, Spain and Portugal.

3. What are your expectations regarding the profitability of this investment?

Profitability or break-even can be achieved when the batter storage is integrated with renewable energy sources. As a producer, there is less arbitrage strategy and more thoughts given to the energy sale price. This is a highly developed model in the United States.

   a. In line with conventional infrastructure?

As a standalone investment, no. However, when integrated with VRE sources, the overall profitability of the investment can be improved, which allows to achieve a decent profitability profile. The capex induced by the energy storage must not be too important, hence the challenge of finding the balance between the need and the costs.

   b. Would the project be entirely financed with equity?

There would be a mix of equity and debt, which would fluctuate during the life of the investment. However, given the rising interest rates, it is likely that the share of equity in investments will grow again. The profitability of equity today is about 8% p.a., hence the question of debt levels (even more important given the absence of subsidies nowadays).

4. What do you see as the main sources of market risk for this project?

There is little support today for the installation of giga-storage. The main risk is the fluctuation of electricity prices, the second risk is related to maintenance and obsolescence of batteries (the replacement of batteries leads to pressure on raw materials used for manufacturing). Political risk plays on prices (in a market with a structural energy deficit, price elasticity is less important, poorer arbitrage, weaker spreads). The more we push towards renewable energy, the more we will create local overcapacities. If there is a state system that dictates price peaks, profitability could be ultimately reduced.

5. How do you characterise the competition between strategic and financial investors? Is there a complementarity?

There is more complementary than competition because strategic investors have limited investment capacity (high cost of equity, limited equity investment in a project). The advantage of infrastructure funds is that they promise an 8% return and not 15% (which is the level of a corporate). The corporate will bring its industrial experience that the funds do not have.

Nonetheless, competition may exist on the capture of technology (e.g., acquiring companies, etc.).

6. What form of ownership would be contemplated (e.g., stewardship model)?

Mirova's objective is to invest in companies developing batteries more than investing in companies owning and managing assets. These investments are complementary (complementary capex) because they improve the overall renewables infrastructures' profitability, as it enables to inject energy when prices are financially interesting.

7. What would be the expected investment period? Equal to the life of the batteries?

The investment horizon would be over 5 years as Mirova does not invest in infrastructure (but in the companies developing the technologies), whereas infrastructure funds would invest with a horizon of 10-15 years. The lifespan must be sustainable so that there is something to resell (residual value that will remain in the equity), hence the importance of maintenance. It is necessary to include battery maintenance in the Business Plan.