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D4.1 Flexibility - related European electricity markets: Modus operandi, proposed adaptations and extensions and metrics definition

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Abstract

The scope of this document is to explore the modus operandi of European electricity markets, to assess how the emerging flexible resources are incorporated into them and to propose new market operation approaches that facilitate the participation of variable renewable energy sources and other flexible assets. The deliverable offers a country level analysis of the regulatory provisions that enable the participation of flexibility resources in the market, focusing on the existing mechanisms for mobilizing distributed flexibility, as well as the respective barriers. Business models and interactions among the relevant parties (Operators, Aggregators, Retailers, Consumers, Prosumers, etc.) are mainly analysed in terms of pilot projects and research approaches. Innovative flexibility trading solutions and best practices are explored within and beyond Europe in order to propose specific recommendations for the deployment of flexibility into the electricity markets. Last, flexibility metrics to measure the flexibility available in the system are identified.

Keyword list

flexibility trading, flexibility markets, flexibility metrics, flexibility sources, Distributed Energy Resource flexibility

Executive summary

The scope of this document is to explore the operation principles of European electricity markets, to assess the participation of emerging flexible resources into them and to propose new market operation approaches that facilitate the integration of variable renewable energy sources and other flexible assets.

Towards this scope the deliverable first presents a country level analysis of the current regulatory provisions, business models and barriers for the deployment of flexibility services into the EU electricity markets. Focus is given on the countries involved in the project's consortium, namely the Nordics, Spain, Italy, UK, Belgium, Greece, Cyprus and Germany. It can be seen that the Nordic countries (Denmark, Finland, Norway, Sweden), UK, Belgium and Germany are front-runners in promoting flexibility related services, while important progress is noticed in Spain and Italy. Southern countries like Greece and especially Cyprus are still lagging in allowing flexibility sources into the electricity market.

In the Nordics, UK, Belgium and Germany consumers are eligible to participate (individually or via aggregators) in the wholesale electricity markets (including day-ahead and intra-day) as well as the balancing market. In Spain the demand-side and the storage installations were recently (end of 2019) included in the balancing market. In Italy the market opening to distributed resources was carried out through three pilot projects (named UVAC, UVAP and UVAM). The UVAM project, which is the most recent one, aggregates demand response and non-relevant production in order to participate at ancillary services market. In Greece, demand can contribute to the stability of the system only through interruptible loads. The interruptible load service can be offered by consumers connected to the electricity transmission and MV network of the interconnected system via their participation in auctions. In Cyprus currently the electricity market cannot support neither flexibility services nor aggregation and demand response. Flexibility related mechanisms will be able to participate through a fully functioning competitive electricity market, which is planned to become operational by the end of 2021.

Local flexibility markets are particularly developed in the UK with flexibility projects funded through national funding mechanisms, undertaken by several Distribution Network Operators (DNOs). Since 2018 the DNOs have been tendering and procuring for various flexibility services to help solve congestions in the local electricity grids, so the exploitation of flexibility is now business as usual for the DNOs, with local flexibility markets already established to purchase flexibility through online platforms. In Spain a pilot project on local flexibility markets named IREMEL has started by the Iberian Market Operator, OMIE.

The consumers' participation in the market is facilitated through various mechanisms. The most common include financial incentives like exemptions in payments of network tariffs and taxes for prosumers and certain categories of electricity producers. Such incentives mainly concern the self-consumed electricity and are particularly established in the Nordics and the UK. Excess electricity can be sold under different pricing schemes. In Norway, prosumers can in many cases receive the hourly spot price for their excess electricity under specific contracts.

Another mechanism necessary for the provision of consumer functionalities, such as near real-time feedback on their energy consumption or generation, is the existence of smart meters. In Finland smart electricity meters were effectively installed at all customers already in 2013. Thus the country has been at the forefront of promoting real-time price signals for consumers and all customers have the possibility of choosing an electricity contract with dynamic pricing. Also in Norway the smart meter roll-out has been completed across all costumer types since January 2019. The smart-meters installed provide 15-minute measurements and have allowed the Norwegian tariff design to move towards capacity-based tariffs. This has turned to a more cost reflective tariff structure where customers can valorise their flexibility potential.

Obstacles that hinder the participation of distributed energy resources in the flexibility market differ per country. In Finland and Belgium legal barriers concern mainly the absence of a cohesive regulatory framework among the different municipalities and regions. In addition, the complicated administrative procedures, the frequent changes in support schemes for DERs, the differences in processes and tariffs between the different energy companies and DSOs hinder participation in the market especially to non-professional negotiators and households. These obstacles are particularly met in the Nordics and in Belgium. In regulatory terms the market in Spain, Italy, Greece and Cyprus is not yet open for aggregators. In Belgium, aggregators are blocked from full participation in the balancing and wholesale

markets, due to the fact that they must have the retailer's permission to enter these markets with a given consumer. For UK, the reassessment of actors responsible for balancing costs and delivery/ imbalance risks emerges as a need for enhancing the participation of aggregators in the capacity market. For less mature markets, like for example in Greece and Cyprus, a comprehensive regulatory framework for the integration of storage systems and EVs should be developed. Similarly, demand management and response schemes should be implemented.

In all countries more incentives and subsidy schemes for investments in DERs should be provided. In the UK, volatility of prices, low profit for big size generators, absence of clear price signals for flexibility products for DNOs are the main economic obstacles. In Italy barriers for demand side flexibility are mainly examined within the UVAM project. The main barriers are economic and relate to the high remuneration of capacity in parallel with the high energy price caps for bids which lead to an unbalance between offers for availability and the offers for energy. In Belgium economic barriers concern price caps tailored to specific technologies, not flexible and very high network tariffs and the Belgian scheme that determines transmission and distribution fees based on energy consumption. In Germany the Federal Network Agency is currently speaking out against the introduction of flexible network charges and the determination of regional fees is seen as procedure of high effort.

In Spain and the UK, the high competition already existing in the ancillary services market makes difficult access for new parties. In the technical side most important obstacles are the prequalification requirements for aggregators (as in Belgium and the UK), the highly complex market (e.g in Belgium and especially in the UK), the lack of transparency by the operators (e.g in UK, Belgium) and the delay of smart meters roll out (e.g in UK, Belgium, Greece, Cyprus). In Germany barriers for market participants are the duration of the accounting period and the length of time between the close of trading and the delivery date. In addition, concerns on data protection are prominent in all countries and analysed for Belgium and Greece. In markets like the Greek and the Cyprian, prerequisites in technological infrastructures for launching new electricity markets and coupling them with the other European ones are presented.

New market operation approaches are explored in flexibility research projects and pilots for flexibility market places within and beyond Europe. In Europe, markets and models developed within the Enera, Piclo Flex, NODES market, GOPACS, Flexibility Power market, SmartNet, CoordiNet EU-Sysflex, Dominoes, INTERRFACE, Ecogrid, TDI2 projects are analysed.

The SmartNet, CoordiNet, EU-SysFlex, DOMINOES and INTERFACE projects are all Horizon2020-funded research projects, with most of them introducing flexibility marketplaces with small scale R&D demonstrators. SmartNet, CoordiNet and INTERRFACE focus on TSO-DSO coordination schemes to favour the integration of ancillary services from demand side management and distributed generation and the participation of consumers accordingly. The proposed mechanisms within CoordiNet are tested in Spain, Sweden and Greece, while the pilots of SmartNet run in Italy, Denmark and Spain to monitor transmission's distribution parameters and investigate modalities for the acquisition of ancillary services from specific resources located in distribution systems. INTERFACE examines use cases concerning congestion management, peer to peer local markets, market platforms and local flexibility markets. Different market designs like local markets and bilateral agreements with local markets are defined within the EU-SysFlex project demos and a wide range of flexibility sources is utilized. DOMINOES focuses on the distribution grid and provides different business models for demand response and virtual power plants. A local DSO enabled marketplace will be designed and developed. The validation sites will be a DSO environment and a VPP site in Portugal and a microgrid site in Finland.

Enera, NODES, GOPACS and Piclo Flex are examples of operational flexibility market places, offering more mature flexibility trading solutions compared to the aforementioned Horizon research projects. The goal of ENERA project is to experiment an exchange-based flexibility market for grid congestion management. The project uses flexible resources in order to avoid curtailment, especially coming from renewable resources and is implemented in Germany. Trades are executed by "on demand" local order books. Within the NODES project the objective is to operate a market platform that strives for flexibility valorisation and gives the opportunity to buyer of flexibility to alternate its consumption/production according to a contract. On the NODES platform, local flexibility can be procured in the intraday timeframe. The offered flexibility, which is not needed locally, will be forwarded to other existing market platforms, more specifically the intraday and balancing market. No standard product definitions are set.

Piclo's main innovation is providing an efficient online marketplace for local flexibility by cutting through the complex barriers and the multiple steps required. In doing so, it helps DSOs (commercial agreements with three DSOs are already signed) to tender for local DER capacity while improving coordination and avoiding conflicts with the TSO. The tenders are organised per constraint area, so all flexible resources connected within a predefined geographical area can compete in the tender. For one constraint area, multiple tenders can be held for different services (such as reinforcement deferral, maintenance) and different contract periods. GOPACS is a Grid Operators Platform for Congestion Solutions and acts as an intermediary between the needs of network operators and markets with the aim to mitigate congestion in the grid in an efficient way. GOPACS is integrated into the existing sequence of markets by sourcing flexibility from existing platforms. It is connected to a national intraday platform of Netherlands from which offers can be procured by GOPACS through a locational tag. GOPACS platform defines the Intraday Congestion Spread (IDCONS) product.

Outside the European borders the deliverable focuses on innovative local market projects developed in USA and Australia and presents new paradigms for the deployment of renewable energy sources, as established in countries of Latin America. Examples of local markets and flexibility related initiatives in the USA are the New York Reforming the Energy Vision, the Delaware EV pilot, the LO3Energy/Brooklyn Microgrid, the California Independent System Operator separate flexibility ramping product, the Southern California Edison Company, the Clean Coalition Community Microgrids and an initiative of East Bay Community Energy. The New York Reforming the Energy Vision and LO3Energy/Brooklyn Microgrid initiatives focus on improving the integration of distributed energy resources (DERs) by introducing market places for consumer centred trades. Other initiatives are tailored to specific DER services like the Delaware pilot, which is an EV aggregator acting as an intermediary between the local TSO and flexibility service providing EVs. In addition, the development of innovative solutions for new ancillary services is examined, as the new separate flexibility ramping product implemented by the California Independent System Operator. In contrast to conventional ancillary services, this product focuses on addressing net load changes between time intervals, and not on standby capacity aimed at meeting demand deviations within a time period. In addition, an innovative feature of this proposal is that it is continuously procured and dispatched. In Australia innovative models and proposals for the deployment of DERs are retrieved from the Open Energy Networks project and the Distributed Energy Roadmap of the West Australian Government.

Flexibility metrics identified for the scope of this deliverable are categorized per flexibility category (grid, storage, markets, supply and demand) and are further divided per flexibility domain. For instance, regarding the flexibility markets, flexibility metrics are identified for each of the wholesale, balancing and retail markets. The respective metrics concern the markets' gate closure times and product lengths, the bid size, the level of aggregators' integration, the progress in removal of price caps, the markets' liquidity, the status of market planning in case of the wholesale markets and of sector coupling in retail markets, the spatial resolution in the wholesale market and the applicability of cross – border exchange in the balancing markets.

The recommendations proposed to encourage flexibility concern various fields. As a first recommendation for variable renewable energy and distributed energy resources to be effectively integrated in the wholesale electricity market and ultimately contribute to system flexibility, this deliverable proposes to reinforce the design of short term and balancing markets and long term support mechanisms. Adapting short-term markets requires improving temporal and spatial granularity, increasing the details of bidding formats, and strengthening the link between energy and reserve markets. Adapting balancing markets involves redefining traded products, recognising the contribution of variable renewables to grid stability, and avoiding dual-imbalance pricing. Encouraging long term support mechanisms concerns incentives for renewable participation in generation-adequacy, support and capacity mechanisms. Next the deliverable proposes innovative approaches to planning and operating smarter distribution networks and increasingly engaging network users. Conventional grid access and connection rules and practices should be adapted accordingly and smart-grid technologies deployed. The analysis recommends to shift the focus of regulation when assessing grid operators from investment adequacy to an extended set of indicators to measure operators' performance. It also highlights that distribution revenues should be independent of the volume of energy distributed and emphasizes on the design of cost effective retail tariffs and the roll out of smart metering technologies to promote self-consumption. Other recommendations concern the encouragement of new roles of

DSOs as market facilitators and distribution system operators, interacting more closely with other agents such as suppliers, aggregators and transmission- and independent-system operators. Specific proposals regarding the adaptation of market design for aggregation and demand response and the development of infrastructure for storage and electric vehicles are also presented. A special reference to recommendations for enhancing interactions between the DSO and the TSO is provided. TSO – DSO coordination requires to implement innovative technology solutions that are available but not yet deployed, such as grid monitoring, two-way communications with flexible customers and with the TSO, network quasi real-time simulations, solutions for operational data exchange between TSOs and DSOs and integration of information about current and short-term distribution grid operating conditions.

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1 Introduction

Power systems undergo deep transformation towards decarbonized, clean and more efficient energy generation and consumption mechanisms. This changing environment is particularly characterized by the increasing investments in renewable generation and distributed energy resources, located both at the transmission and distribution grids. Those sources are posing new challenges to the grids operation. At the transmission grid, balancing and frequency regulation are the main issues, and new flexibility markets to guarantee ramping availability are being implemented. At the distribution grid, reverse power flows, new congestion and voltage issues are appearing, and research seeks to provide new flexibility services to DSOs to optimize the distribution grid operation and defer investments. DSO tasks are then evolving from long-term planning to include also short-term grid operation, and coordination of TSOs and DSOs becomes essential for efficient resources usage at both systems [1].

In order to fulfil the task of balancing electrical supply and demand, to date the TSOs procure generation reserves to cover system imbalances, exploiting among others reserve markets [1]. When energy markets were first developed, only traditional flexibility units (centralized generators like thermal and hydro power plants) connected to the transmission network were used to provide power reserves [2]. Accordingly, technical and economic rules have been built into this paradigm. According to the Network Code on Electricity Balancing [3], the different types of Reserve Capacity that shall be secured by the TSO as Balancing Capacity, namely, that shall be procured in the Ancillary Services Market and maintained for real-time activation, are the following:

- Frequency Containment Reserve (FCR),
- Frequency Restoration Reserve with automatic activation (aFRR),
- Frequency Restoration Reserve with manual activation (mFRR), and
- Replacement Reserve (RR).

In the current context where the share of renewable generation and distributed energy resources is increasing in the electricity generation mix, distribution systems are facing new operational challenges due to their intermittency and uncertainty of the resources located in them. Additional flexibility will become an increasingly valuable resource to balance generation and demand in real time. This balance is critical to ensure the stability and security of the electric power system. At the same time, it is clear that solely relying on grid investments to cope with increasing electricity load and the connection of decentralised generation to the distribution grid will be very expensive. To cope with these challenges, DSOs are seeking for products and market tools to enable more active system management and control using flexibility [4].

Flexibility is usually defined as the possibility of modifying generation and/or consumption patterns in reaction to an external signal (price or activation signals) to contribute to the power system stability and security in a cost-effective manner. Flexibility is procured by different market agents (TSOs, DSOs, Balance Responsible Parties or BRPs) and expected to be supplied from different types of agents (supply and consumer side agents), located at the transmission or at distribution grids (with different operation problems). The main stakeholders involved in flexibility markets and their roles are:

- TSO: responsible for the operation of the transmission system and its stability.
- DSO: responsible for the operation of the distribution system and power delivery to customers.
- BRP: market entity (wholesale supplier or retailer, etc.) or its chosen representative responsible for its imbalances. It has to pay penalties for its deviation from its energy schedules [1].
- BSP: market participant providing balancing services (either or both balancing capacity and balancing energy). BSPs commonly comprise of the following categories: generating units; dispatchable RES portfolios; and dispatchable load portfolios. A BSP can be its own BRP, being responsible for its own imbalances [3], [1].

Flexibility products can be offered to the TSO for system flexibility (power balancing and frequency control, and to a lesser extend congestion management), and are usually provided by conventional thermal power plants, hydro power plants (including pump storage units), zonal interconnections (one of the most important balancing resources, limited by the unused lines capacity) or Demand Response (DR) services of large consumers. Flexibility products can also be offered to DSOs for local balancing, voltages or congestion management (network flexibility), or to BRPs for portfolio balancing (market flexibility), by DER providers connected at the distribution grid [1].

In Europe, flexibility markets are recognised as a tool to make better use of the existing distribution grids and thereby also reduce the need for grid investments. Namely, the newly adopted Clean Energy Package [5] for all Europeans states that DSOs shall procure services in a market-based manner from resources such as distributed generation, demand response, or storage when such services are cheaper than grid expansion. Similarly, the Council of European Energy Regulators (CEER) and the respondents to its recent consultation identify market- based procurement as the preferred approach to foster the use of flexibility at the distribution grid [6]. Finally, the European Network for Transmission System Operators for Electricity (ENTSO-E) and the major associations for European DSOs recently published a report in which they emphasize the need for grid flexibility procurement [7]. This report also laid out how TSOs can coordinate with DSOs as flexibility connected to the distribution grid can be used by both network operators to relieve congestion or for other services. At national level however the progress of enabling flexibility services in the distribution grid and the operation of flexibility markets varies significantly among the different Member States. This mainly depends on the national policies and regulatory framework.

Given the diversity of situations, legislation and needs across EU Member States and varying nature of DSOs (e.g. size and location), this deliverable reviews the deployment of flexibility at national level to identify best practices and main barriers. In addition, it analyses innovative business models and interactions among market actors and system operators to facilitate flexibility exploitation.

1.1 Task 4.1

The objective of Task 4.1 “Trading of flexibility in electricity markets” is to study the operation of European electricity markets in order to assess the participation of flexibility resources into them and propose operation mechanisms for facilitating flexibility assets integration into the market, especially as regards distributed flexibility. To achieve the above objective Task 4.1 will investigate flexibility trading business models and best practices in EU and global markets and seek ways of their adaptation in the European electricity market design.

1.2 Objectives of the work reported in this deliverable

The ultimate objective of this deliverable is to inspire the development of flexibility markets within Europe, especially in the distribution level. To do so, a country level analysis is conducted, which at first investigates the regulatory provisions regarding flexibility assets and their participation in the electricity markets, if applicable. Focus is given on the flexibility stemming from Distributed Energy Resources (DERs) and the role of relevant actors (DSO, TSO, MO, Aggregator, Retailer, End User etc.) in the procurement and trade of flexibility services. Barriers for market access of flexibility resources are also identified. Innovative projects and pilots that enable to test new concepts and solutions in a market oriented environment are investigated, to form relevant recommendations applicable in the EU electricity market context.

1.3 Outline of the deliverable

The remainder of the deliverable is structured as follows: Section 2 provides a review of the current status of flexibility trading in European markets, outlining the current regulatory provisions, business models and obstacles hindering the implementation of new flexibility markets. Section 3 presents pioneering projects regarding market approaches for flexibility services within and beyond Europe and seeks ways for their adaptation in the European electricity market. Proposals and recommendations to foster the integration of new flexibility market approaches in Europe, especially in the distribution level, are also introduced. Section 4 focuses on flexibility metrics and some concluding remarks are given in Section 5.

1.4 How to read this document

A pre requirement for reading this document is a good knowledge of the electricity markets design and operations. Previous basic knowledge on electricity flexibility resources and trading concepts will contribute to a better understanding of the report’s content. The document can be read without prior knowledge of any other FEVER-specific documentation or report.

2 Current status of flexibility trading in European electricity markets

2.1 Nordics

In the Nordic countries, there has been a significant increase in the integration of distributed production. This trend has been in line with the overall goals of the European energy policy (consumer centric energy market and increased renewable power production). The integration of distributed production has been accelerated and is projected to be accelerated with the utilization of storage technologies (i.e. batteries) and advancements in the ICT sector (energy management systems, machine learning applications to power systems e. t. c.).

The installed capacity of distributed renewable electricity production for self-consumption in the Nordics was about 2750 MW in 2017. About three quarter of the installed capacity comes from wind power however, the PVs installations show an increase since many of the wind sources are approaching their end of technical lifetime. Most Nordic countries have a regulatory framework that promotes and supports the development and installation of distributed electricity production. The general regulatory framework has many similarities between the countries, although the definitions of prosumers, the specific design of the regulations and the level of support differs from country to country.

In particular, regarding PV for the household sector, currently Sweden has the most supportive regulatory framework for household PV deployments and the same time the most complex since total support is achieved through multiple exemptions, tax incentives and policy instruments. Even though, Denmark historically has had the most generous support system, the country has significantly decreased its support due to very rapid household PV installation. Compared to Sweden, Norway and Finland regulations are less generous, although it is difficult to compare since the regulations and instruments differ between the countries and the level of support could be dependent on the specific actor or instalment. Households and businesses in those countries have the right to sell their production either to the DSO or to a power supplier. In most cases, the prices are equivalent or similar to the relevant Nordpool spot price (hourly Day-ahead prices). Apart from this, all countries have different types of investment support or tax deduction schemes for the installation of PV-systems or other types of distributed electricity production.

The current transition in Nordic countries' energy sector mainly strives towards a green future with a decarbonized energy system that focuses on system integration costs, reliability and sustainability. Authors in [8] state that coherent changes have to made in the market design, regulatory framework conditions and the market coupling of the Nordic countries. Specifically, improvements in several sectors, such as electricity, heat, gas and transport, that are able to provide flexibility must take place along with the growth of distributed energy resources in the electricity supply. This integration should be in a complete coordination in order to avoid barriers that may render the transition to integrated flexible energy systems uncertain

2.1.1 The Nordic electricity market

The Nordic power system is a mixture of generation sources, where hydro, nuclear and wind power are the main sources. The Nordic region has many energy intensive industries and a large share of electricity-heated houses. Therefore, the electricity consumption and the electricity's share of total power use is higher than in the rest of the EU. Development of electricity consumption is highly influenced by the weather during the year, with lower electricity demand in the summer and increased consumption in wintertime. The Nordic countries have a higher share of renewable energy production compared to the rest of EU. Over half of the electricity production is generated from hydropower.

- Finland, Denmark, Norway, Sweden, Estonia, Lithuania and Latvia form an integrated wholesale electricity market, the Nordic-Baltic market. The Nordic-Baltic market has been price linked to the North Western European electricity market since 2013. There is currently one power exchange (Nord Pool AS) active in the Nordic market and another (EPEX SPOT) entering the market. The balancing market is trading in automatic and manual reserves and is operated by the Nordic TSOs (Svenska kraftnät, Statnett, Fingrid and Energinet) in order to maintain power balance during the hour of operation [9]. The National Regulatory Authorities are: The

Danish Energy Regulatory Authority (DERA) in Denmark
- Energiavirasto – The Energy Authority (EV) in Finland
- The Norwegian Energy Regulatory Authority's (NVE-RME) in Norway
- The Energimarknadsinpektionen / Energy Markets Inspectorate (EI) in Sweden

2.1.2 Finland

2.1.2.1 Current regulatory provisions and business models

In Finland, small-scale electricity production is defined in the law as a unit of power plants with a total max power of 2000 kVA [10]. Other relevant limits are 100 kVA (power limit for micro production) and 800000 kWh (energy limit for tax-exempt small-scale production). There have been tests of virtual metering in apartment buildings and discussions of changing legislation to encourage distributed electricity production in energy communities. However, as of 2018 special regulation of self-consumption only applies to individual households or companies and not energy communities. Prosumers can sell excess electricity through the grid. According to the Ministry of Economic Affairs and Employment of Finland, self-consumers have market access to sell excess electricity with the same conditions as other producers.

The price of excess electricity depends on the contract. In June 2017, most electricity retailers have announced offers to buy surplus electricity from micro-PV deployments. In general, the companies pay the Nord Pool Spot Finland area price of the surplus electricity although there are exemptions and companies offering “special deals” (such as for example the opportunity to use excess electricity generation for EV charging). In other cases, excess electricity is sold at a fixed rate. Some companies also charge a fee for the offtake of surplus electricity.

Grid production tariffs are set by the DSOs according to local conditions. The savings of grid production tariff therefore vary but is not higher than 0,87 cents/kWh as is the top limit for the variable feed-in tariff in Finland according to EU-regulation. Some companies do not charge the feed in tariff for the smallest producers as the cost of charging fee will outweigh the income. For instance, a DSO (namely Helen Sähköverkko) neither charges nor pays production tariffs for small-scale production. Other DSOs (for instance Vasa Elnät) charge small-scale producers a production transmission fee. Residential grid consumption tariffs are largely a function of consumed energy (Wh). Prosumers consuming their own electricity production are not always charged extra to finance the transmission and/or distribution grid but may be charged a monthly fee for self-generators depending on the local DSO company. Taxes for small-scale producers with an annual production below 800000 kWh (prosumers) are exempt from paying tax for electricity consumed on their own site. By contrast, large power producers must pay electricity tax for the consumption of self-produced electricity. The tax exemption applies also to the emergency preparedness contribution (0.013 c/kWh). Also, revenues generated through sales of electricity are tax free, when the revenue generated through the off-take agreement is modest. Individuals may get a tax credit for the labour cost component of electricity installations. The sum is 45% of the total labour cost, including taxes. The maximum tax credit for a person is 2400 EUR per year. The Ministry of Economic Affairs and Employment grants investment support/energy aid for the renewable electricity production. This energy support is particularly intended for promoting the introduction and market launch of new energy technologies. So far, the Ministry has granted a 25% investment subsidy of the total costs of grid-connected PV projects. Companies, communities and other organizations are eligible for the support. For the agricultural sector, an investment subsidy is also available for a renewable electricity production from the Agency for Rural Affairs. The subsidy covered 40% of the total investment costs in 2018.

According to the Publication of the Ministry of Economic Affairs and Employment [11], Finland has been at the forefront of promoting real-time price signals for consumers. As required by legislation, smart electricity meters were effectively installed at all customers already in 2013. All customers have the possibility of choosing an electricity contract with dynamic pricing. At the end of 2018, approximately 9% of retail customers had a dynamic electricity price contract. Consumer protection and competitiveness in the retail sector are reflected in measures aimed at curbing hefty single price increases, such as the legislation that lays down restrictions on the annual price increases of electricity transmission charges. Also, other means are currently under consideration by the Ministry of Economic Affairs and Employment. The role of flexibility and demand response was further emphasized in the National Energy and Climate Strategy. Based on the strategy, the Ministry of Economic Affairs and Employment tasked a large working group (Smart Grid Working Group) to find ways to promote further customers' participation in the electricity markets and resource adequacy in 2016. The working group completed its work in October 2018 and gave concrete proposals on how to improve the situation. The Ministry of Economic Affairs and Employment is currently implementing these proposals in parallel with the Clean Energy Package implementation.

Finland does not have quantitative objectives for the protection of energy consumers and to improve the competitiveness of the energy retail market. The requirements related to consumer protection have been included in the Electricity Market Act currently in force. On 1 February 2019, an amendment came into force regarding a centralized information exchange database called Datahub, which will provide each party in the electricity market with all relevant information on electricity trading. Datahub will enable even more efficient and consistent transfer of data, which will be essential in the future electricity retail market. This kind of common platform is also vital to developing other opportunities, such as services for enabling significantly better demand flexibility even at an individual consumer level. The project has already started and is expected to be completed in 2022. In 2018, 72% of the electricity supply in Finland was traded through the Nord Pool day-ahead market. Finland is heavily dependent on integrated European electricity markets as there is a significant deficit in generation capacity compared to peak load. Finland imports over 20% of its annual electricity supply and around 30% of power consumption during winter peaks.

Based on the general trends anticipated in Finland and Europe the following specific long-term objectives of a market design in Finland have been specified with respect to the use of flexibilities:

- The new/expanded markets shall be appropriate to generate maximum value for all types of flexibilities. Focus is put on small-scale flexibilities as they may pose new and expanded requirements. However, the market must provide a level playing field for all types of flexibilities – small-scale and large-scale as well as being technology-neutral.
- The new/expanded markets shall reflect the correct value at different times and at different locations. It shall explicitly provide for mechanisms to reduce transaction costs.
- The scope of the markets shall encompass mechanism to ensure proper system balancing as well as mechanisms to facilitate congestion management. This is important to ensure the flexibilities are made available to the maximum extent possible to ensure safe and secure system and network operations
- Independent of the flexibility mechanism, more decentralized resources create the need for TSO/DSO coordination. Such coordination will allow for a more efficient use of such resources.

These four specific objectives help to achieve the main market design targets, being cost efficiency, sustainability and security of supply. Flexibilities can participate in the current market in the balancing mechanism and explore some of the possible short-term values.

Table 1: Participation of Demand Aggregators in the Finish Balancing Markets [12]

Market open to DA	Min bid size (MW)	Not. time	Max number of activations	Product resolution	Symmetry	Duration of delivery	Tender period	Energy Payment €/MWh	Capacity payment €/MW/h
Finland									
FCR-N	0.1	3 min	Continuous activation	1hour	YES	No stop	Yearly or daily	Yes if yearly reserved	13.5
FCR-D	1	Piece – wise linear regulation or 5s if	Several times per day		NO	Until the freq. has been 49.9 Hz for 3		50 on average	2.4

		f<=49.7 3s if f<=49.6 1s if f<=49.5				minutes			
aFRR	5	30s – 5min (100%)	Depends on the bids, several times per day/per year	1 hour	NO	No stop	Daily	50 on average	0
mFRR	5	15 min	Rarely	1 hour	NO	15 minutes	No later than 45 minutes before the hour of use, or weekly	50 on average	3.3
Strategic reserve (RR)	10	15 min		1 hour	NO	N/A	Every 2-3 years	NO	Pay as bid

However, there are still some obstacles, which have been specified by Fingrid (finish TSO). These involve barriers to participate in Fingrid's balancing market as well as hurdles to support system balancing by "self-balancing" [13]. In addition to the value flexibilities can generate for balancing, flexibilities may also contribute to network operators, namely congestion management. Today, congestion management does not play a significant role in Finland. Actions by the TSO are required only rarely (i.e. less than once a month). TSO's costs for re-dispatch (congestion management within the bidding zone) amounted to only 2.2 million Euro in year 2018. Countertrade costs (between bidding zones) were 1.9 million Euro. Re-dispatch in DSO networks is not current practice. However, congestions may emerge in the future and appropriate solutions are required to making maximum use of all available flexibilities in the system.

2.1.2.2 Existing obstacles

In Finland the requirements in order to apply for a distributed energy resource in a building varies from municipality to municipality. This creates an increased level of complexity and it is time consuming for the people interested in investing in DERs. In addition, a permission is required from the DSO in order to connect a DER to the electricity grid. Nevertheless, there are nearly 80 different DSOs in Finland and consequently a large number of grid connection procedures and guidelines. There are also differences in the contractual conditions between the energy companies with regard to offtake agreements, since some companies charge a fee for the offtake of surplus electricity, while some are willing to purchase the electricity with the spot price. Installations smaller than 100 kVA are not mandated to pay the electricity tax nor the emergency preparedness contribution for the electricity generated for own consumption or for the surplus electricity sold to the grid. Larger installations might perceive this as a barrier. For private individuals, the only financial instrument available to incentivize an investment in e.g. solar panels is the tax credit for household expenses that can be applied for the installation works. Companies, municipalities and other organizations may be eligible to receive support for small-scale electricity investment projects. Therefore, the availability of subsidy schemes for investments is limited.

2.1.3 Denmark

2.1.3.1 Current regulatory provisions and business models

In Denmark, there is no strict definition of distributed energy systems, or prosumers, meaning that variations occur across sectors and institutions [10]. In most parts of regulation, smaller energy producing units (for self-consumption) are described as systems up to nominal values of 50 kW. In most publications from the Danish TSO (Energinet dk) the limit is 1-10 kW. Prosumers may sell excess electricity to the DSO or to any electricity supplier based on independent contracts with the DSO. All grid-connected PV and onshore wind turbines designed within a consumption system (e.g. a household) needs to apply for a permit at the Danish Energy Agency. In the permit the technical guidelines for connection are stipulated as well as the desired production group for the electricity production unit. In Denmark it is mandatory for DSOs to connect electricity generation. The costs for the connection of the production units are forwarded to the owners of the production units. Previously the cost was covered by the grid operator (DSO), but recent changes to the regulation make the local DSO able to forward grid reinforcements and connection costs to the producers. There are differences according to the size and the place where the connection point is, since the necessary reinforcement may differ. As a general rule, under the new scheme, all connection costs are forwarded to the energy producing unit's owner.

Sales prices of surplus electricity production as well as the time resolution for pricing differ under six sales groups. Sales prices for the excess production can therefore be sold under very different pricing models. Most hourly pricing schemes require the sales to be independently negotiated with the local power supplier, while coarser time resolution on pricing as well as annual average prices can be obtained if a set of specific criteria are met. From 2019, new PV units -mainly for self-consumption purposes- are transferred to a single new pricing regime named the “flex settlement”. One of the six production groups offer the chance to sell excess production at the instant prices following the spot prices from the Nord Pool exchange. During hours of self-usage, the cost for both electricity and parts of the variable electricity grid cost can be avoided. The variable electricity grid fee varies a lot between different DSOs in Denmark, but is usually around 0.4 eurocent/kWh (ex. VAT) for smaller electricity users. DSOs can charge a consumption tariff on the total consumption of energy users which also have electricity production. The calculation of the energy charges is based on the total consumption with the gross electricity production of the installation deducted. The grid consumption tariff corresponds to charges imposed to cover the DSO's operation and maintenance costs and typically are calculated from standardized net tariffs for consumption with costs for grid loss and grid reinforcements deducted.

One aspect related to smaller producers is the gross electricity production used to calculate the size of the grid consumption tariff. In typical installations smaller electricity producing units, which lack separate production metering, a calculated value is instead used. This value is calculated based on a methodology from the Danish taxation authorities and the TSO. For PV producing units the calculated value is determined by the size of the installed capacity of the unit, with an estimated annual production of 800 kWh for each kW installed.

Today no direct tax incentives for distributed electricity production are in place, except the exclusion of part of electricity taxes for self-consumption for households. This includes savings of electricity taxes during hours of self-usage according to market prices (~0.028 EUR/kWh). Tax benefits associated with the ownership of PV units differ between SMEs and households, mainly due to SMEs already being exempted from most electricity taxes. Based on the organizational setup of the producing unit different appreciation and hence taxation measures can be implemented.

There is a notable private initiative to support the development of distributed PV in Denmark. Since the public support for small-scale renewable energy has been discontinued, Viva Energy A/S together with suppliers and partners in the solar PV industry established a fund from which households and organisations can apply for support. In order to receive the support, the facility must be a Viva Energy-facility delivered by Viva Energy or their partners. The support is possible to apply for all photovoltaic solar systems connected to the electricity grid. The support is 0,6 DKK /kWh for the calculated electricity surplus during the first five years (maximum 50% of annual production).

The promotion of onshore turbines has had high priority in order to meet climate objectives and to lower electricity prices. In recent years there has been a policy shift towards favouring large offshore wind farms over onshore wind developments. In the new Energy Agreement, three offshore farms are planned with a combined capacity of 2400 MW while onshore wind farms are planned to be limited to roughly half of today's number of wind turbines. In the Energy Agreement of 2018, onshore turbine development has been limited to only include the replacement of existing onshore turbines with new and more efficient turbines.

In order to develop a flexible and market driven electricity system, Denmark has initiated the Market Model 3.0, a project mandated by the Energy Agreement [14]. The main focus of the project is the promotion of market-based solutions for the benefit of consumers, considering the effective integration of renewable energy and a continued high level of electricity supply security. The project includes establishing an efficient market design, localising and implementing favourable conditions for flexibility in the market and regulating the different actors and the monopolies, such that the electricity market functions in the best possible way, and in connection to the rest of Europe. This project is closely linked to the implantation of the EU's initiative 'Clean energy for all.

With regards to improving real-time price signals, Denmark has updated a national law 49 in 2018, specifying that the Danish TSO shall, as far as possible, procure all energy and non-energy services that are necessary for security of supply through market-based mechanisms. The law aims at increasing transparency, creating price signals for all services, including non-frequency ancillary services, and thus enabling more market participants, including DER, to participate in the delivery of these services. As a result of this, Energinet is currently working on a pilot project where voltage control is procured locally in a technology-neutral manner. The aim is to develop a product definition which gives new market actors and technologies the possibility to participate in a potential market as well as gaining overall experiences with market-based procurement of voltage control.

As part of the Energy Agreement, Denmark has committed to spend 580 mill. DKK in 2020 on research, development and demonstration of new energy technology. In the beginning of 2019, the Danish Parliament allocated 50 mill DKK to new test facilities at Lindoe Offshore Renewables Center. Denmark plans to install three new offshore wind farms towards 2030. Thereby Denmark will make itself increasingly independent from fossil fuels. The increasing ratio of renewable energy production will require further research, development and demonstration of technologies to fully integrate and exploit the renewable energy when production exceeds demand. The Danish Government also established a fund supporting development and demonstration projects on energy storage. The fund's size is 128 million DKK and it was in December 2019 granted to two Power-to-X-projects. The projects will establish big scale production and storage of green hydrogen. Both projects have an ambition to demonstrate production and consumption of green hydrogen on near market-based conditions.

When planning network expansion at the distribution level, DSOs are obliged to consider whether energy efficiency measures through demand response or decentralised production may reduce or replace the need to expand capacity. Demand response is generally encouraged by the roll-out of smart meters and the establishment of an hourly settlement model in the retail market. These measures enable the use of dynamic prices and potentially near real-time price signals to a wide range of customers.

As part of the project for a new market model for the electricity market, the Danish Energy Agency is currently analysing different setups for aggregators in order to find the best suitable model in a Danish context. A further task is to identify barriers for new market participants and technologies (such as storage) to participate in the market.

By 2020 all Danish electricity end-users will have smart meters installed. Simultaneously, the TSO and DSOs implement a new hourly settlement model, named 'flexafregning', for small consumers. This is the basic precondition for the access to dynamic pricing products that make it possible to benefit from demand response activities. Except of the dynamic electricity price, DSOs can choose to apply a time-differentiated tariff model, and several DSOs have chosen that model to date. Currently, the tariff is based on a static time-of-use model consisting of two different tariff levels for small consumers. DSOs and the TSO are further developing their tariff models including coordination between transmission and distribution levels. The 2018 Energy Agreement also includes an initiative to address potential regulatory barriers in relation to tariffs, in particular how they affect demand response. An interdepartmental working group has been established for that purpose. The Energy Agreement also includes an initiative to explore the possibilities of a dynamic electricity tax. A dynamic electricity tax can for example increase demand in periods with low electricity prices where production of renewable electricity is high.

2.1.3.2 Existing obstacles

The regulatory framework in Denmark can be perceived as complex, since the changes in the support schemes for DERs are frequent. This also increases policy uncertainty. In addition, the taxation and depreciation rules applied as well as the possibility to receive income tax deduction on the installations, have further contributed to the support schemes being perceived as complex. However, the new regulatory regime includes no direct support for DER systems. This does increase transparency in the regulation, however at the same time it can be perceived by the market as too little incentives for distributed electricity generation. With future installations all PV's are regulated under a so-called flex tariff meaning new PV installations are treated equal, lessening the burden of calculating a business case for smaller installations. The administrative processes related to negotiating prices with local DSO's for most installations are deemed to be a complex task for non-professional negotiators and households. The price fluctuations are to a very limited degree reflected in consumer prices today, which further decrease the economic feasibility of systems taking advantage of increased flexibility such as distributed electricity production combined with internal storage. The economic incentives to invest in flexible systems are limited by the current non-dynamic tariffs and taxes on energy that make up the bulk of the consumer prices. The current energy agreement (Energy Agreement 2018) has a specific goal to decrease the number of onshore wind turbines to roughly half of today's numbers. In addition, the lack of support schemes and direct support for PV, will make the establishment of smaller PV systems less economically attractive. Finally, new legislation shifts the connection costs for new DER units from DSOs to the production unit owner.

2.1.4 Norway

2.1.4.1 Current regulatory provisions and business models

The Norwegian Regulation of Grid Operations gives prosumers the right to be connected to the grid. Prosumers are defined as "end users with consumption and production behind the meter, from which no more than 100 kW is put into the grid at any time. A prosumer may not have a licensed power plant or licensed trade behind the meter". Prosumers may use self-consumed electricity free of charge. During hours of self-consumption, the prosumer can avoid cost for electricity and the variable electricity grid cost, as well as electricity consumption taxes, VAT, and the Electricity Certificate cost. Grid tariffs and VAT applies for all sale of self-produced electricity fed into the power grid. The Norwegian energy regulator plans to change the regulation so that in the future, prosumers can distribute self-produced electricity for consumption within an apartment building and/or a building community, without taxes and grid tariffs. In terms of market access, prosumers may sell excess electricity either to the DSO or to an electricity supplier. If the DSO does not want to buy excess electricity, the prosumer must enter into a prosumer-contract with an electricity supplier that offer such contracts. The prices for excess electricity depend on the contract between the prosumer and the DSO/electricity supplier. In many cases, prosumers receive the hourly spot price for their excess electricity. In other cases, the prosumer receives a fixed price for the electricity. Some electricity suppliers also offer solar PV investment deals.

Since January 2019, Norway has completed its smart meter roll-out with a 100% penetration across all customer types. The smart-meters installed provide 15-minute measurements and have allowed the Norwegian tariff design to move towards capacity-based tariffs in the last year. This has turned to a more cost reflective tariff structure where customers can valorise their flexibility potential [15]. Prosumers with excess production less than 100kW are exempt from the fixed production grid tariff which other producers are charged. Consumers with excess production of more than 100 kW at any time are not exempt from the fixed production grid tariff. Until recently, large prosumers had incentives to limit production to 100 kW, rather than paying a fixed production grid tariff. To incentivize large prosumers to produce more than 100 kW, regulation has been changed so that they are charged a production grid tariff of 0.013 NOK /kWh for excess production, instead of the fixed production tariff. The variable component of the production grid tariffs is set by the local DSO in accordance with relevant regulation. The variable component will vary according to the marginal loss in the relevant grid area and may be positive or negative. As an example, the variable production tariff for prosumers in the grid area of BKK (Norwegian DSO) is negative, meaning that the DSO pays prosumers a grid fee for each kWh of excess production. BKK justifies this by the fact that most prosumers contribute to reducing the marginal loss of the grid [10]. In areas with a production surplus, the marginal loss increases with increased production, resulting in a positive variable production tariff. If connection of the production facility requires grid reinforcements, the connection costs are forwarded to the person or company that requests the connection/owns the production unit.

There are ongoing discussions about future grid tariffs in the distribution grid. The current trend is for the peak load (i.e. the maximum consumption within any given year) to have a higher growth rate than that of the total yearly electricity consumption. Since the grid capacity must be dimensioned to peak load circumstances, this gives reduced average utilization for the grid. In the long term, grid tariffs will affect grid utilization and the need for costly grid enhancements. Recently, the Norwegian grid regulator (NVE) suggested that a capacity grid tariff should give customers incentives to reduce their peak load. NVE has also suggested that the energy part in the future grid tariff should only cover the costs related to marginal grid losses. Today, the most common grid tariff for Norwegian residential customers is an 'energy tariff' consisting of a fixed part [EUR/year] and an energy part [EURO CENT/kWh], as shown in the following equation:

Energy tariff = Fixed part + Energy part

An alternative to the energy tariff is a capacity-based tariff. The latter can be specified in different ways. For example, it can consist of a fixed part [EUR/year], an energy part [EURO CENT/kWh] covering only the marginal losses in the grid, and a power part [EUR/kWh/h], as illustrated in the following equation:

Capacity-based grid tariff = Fixed part [EUR/year] + Energy part [EURO CENT/kWh] + Capacity part [EUR/kWh/h]

The settlement of the consumption is based on hourly values from the smart meter. The capacity part can be settled by different methods, such as the average of the three maximum values during one month or the average of three maximum values in defined peak load periods. NVE's has suggested that the fixed part should be a capacity subscription, and that the capacity part should be an additional cost per kWh whenever the consumption exceeds the subscribed amount. According to the regulations specified by NVE, the maximum allowed income for DSOs (obtained by the tariff set by NVE) should not be affected by the applied structure for the grid tariff [16].

Consumers are exempt from paying electricity-tax and value added tax on self-produced electricity. Consumption of self-produced electricity can reduce the energy bill of prosumers by a total of 0.39 NOK/kWh on average. By contrast, central power producers have to pay electricity tax on the consumption of self-produced electricity, except for the electricity used directly in the production process.

The joint Norwegian-Swedish electricity certificate scheme intends to increase renewable electricity production in both countries. In this system, producers of renewable electricity receive one certificate per MWh of electricity they produce for a period of up to 15 years. Since the minimum fee for taking part in the certificate scheme is 15000 NOK, the market is practically inaccessible for prosumers. The same applies for GOs, a voluntary support scheme, which is also traded in MWh.

The construction of new electricity production usually requires allowances both from energy authorities and from local building authorities. However, there are less stringent requirements for distributed electricity production. In most cases, the installation of solar PV panels neither requires licenses from energy authorities, nor from local building authorities. The construction of small wind farms (less than 1 MW) only requires a license from local building authorities. In addition, building regulation and energy efficiency requirements may affect the incentives for distributed energy promotion.

Exchange of energy is the trading of electricity between two geographical markets. Value for society is created by importing from markets at lower prices and exporting to markets at higher prices. With a massive expansion of the Norwegian renewable generation but without a similar increase in load, Norway will be a net exporter of energy. An added value from this export would comes from flexibility in the hydropower system. Norway is a world-leading country in hydroelectricity with vast resources at its disposal and well-developed interconnections with the rest Nordic Market countries. This would create opportunities for the future Norwegian energy system in its interaction with the rest of Europe. Norway has the potential for flexibility provision in different timeframes [17]:

- Short-term flexibility: load or generation can be adjusted in time periods ranging from minutes to hours. The hydropower system makes it possible to optimize the daily export and import profile in order to export more when the prices are high and export less or import when prices are low. Flexible hydropower is also important to increase the value of other renewable resources in Norway, because the net export can be managed flexibly.
- Medium-term flexibility: to provide a backup for periods of up to weeks, often needed in systems

with high wind penetration. This requires access to alternative generation capacity with flexibility to generate for several weeks and also to store energy, for example hydropower plants with reservoirs or natural gas power plants. Studies show that the flexibility of hydropower is unrivalled when it comes to providing this type of flexibility when Carbon Capture and Storage (CCS) is not a commercial technology. If CCS is a commercial technology, natural gas with CCS can provide such flexibility, due to the flexibility in natural gas pipelines.

- Seasonal flexibility: utilizes patterns in generation and load between winter, spring, summer and autumn. Hydropower systems with reservoirs, natural gas in reservoirs and some thermal heat storage systems are ways to store energy between seasons in order to smooth out seasonal differences in price, creating value in similar ways as exchange between different price regions.

It is mentioned that there are clear seasonal differences in the export and import patterns in cables and in the power generation (both hydropower and natural gas). The same differences are observed for pipelines. Both the natural gas and hydropower system are flexible enough to handle these seasonal differences. Balancing services including reserve capacity and balancing energy are system services with a short response time, short duration, and potentially high peak power, and are essential to ensure a continuous balance of supply and demand in the system for stable operation. Studies of balancing markets show that with an integration of European balancing markets, a significant number of system imbalances can be avoided. In addition, such an integration can allow for a foreign participation in these markets, where Norwegian hydropower has good opportunities to deliver reserve capacity and balancing energy to Continental Europe.

In order to increase the availability of resources in the Regulating Power Market (mFRR), a pilot project was launched with the aim to increase the Capacity Market (RPM) volumes, and at the same time gather information on whether one can develop permanent solutions to increase the RPM volumes. The pilot contains two temporary exemptions from current requirements. First, actors can apply to participate with portfolio bidding at a larger geographical area than the station group/node, which is normally required. This applies for 10 MW bids. Second, actors offering flexible load through - so called interruptible load contracts- can apply to participate with the same load in the option market for mFRR (RKOM). The current requirements for the option market for mFRR prohibits such simultaneous participation. The exemption applies only for the pilot period and for a limited volume of up to 50 MW per actor. Volume exceeding this limit will be evaluated separately [18].

Demand side flexibility activity in Norway is currently low, except for the major energy intensive industry selling flexibility to the TSO. For the DSO there are no commercially driven initiatives on-going in DSR. According to interviews executed by the Nordic Council of Ministers in 3 DSOs of Norway, the reason for this is twofold: the market is not yet developed, and the current grid generally has sufficient capacity. As direct involvement in activating flexibility under current regulations is mostly out of the bounds for the DSOs themselves, there is a need for interest by third party players. As third party players currently are missing, the market is undeveloped. Secondly, the normal measure to ensure adequate grid capacity is to build more grids. Consequently, DSOs point to that the current grid is often over-dimensioned. Today there is enough flexibility in the grid, but at the same time they have little information available on the actual capacity utilisation at low voltage levels. With enough capacity within the grid, end user flexibility is currently not needed for the DSOs. Both these factors contribute to that the interest for DSR from DSOs appear to be limited. However, it is acknowledged that the need for DSR may increase in the future due to new consumption and production patterns. In Norway DSR flexibility will mainly be needed to solve local level congestion issues. That is because, as in Sweden and Finland, wholesale balancing can be offered by the controllable hydropower production [19].

2.1.4.2 Existing Obstacles

Market actors in Norway have created a list of perceived barriers. The majority of them cannot be perceived as actual barriers for a sound development. The distributed hydro production mainly consists of several farms or businesses located near to small-scale hydro plants. Further financial incentives (in top of the grid tariff and tax savings) could lead plant owners to invest in private grids to direct power directly to their farm/home/business, replacing the distribution grid. The existing installation of DERs in residential area mainly attracts people with an interest in environment and technology. Thus, it is necessary to apply better information measures. In addition, due to the technological development, the cost of DERs instalment is going to decrease. This will lead DERs to be more attractive. Even though feed-in-tariff is not considered as a barrier for a sound development, the implementation of a more generous and stable feed-in-tariff has been proposed to further promote PV installation. In order to obtain a more cost-reflective tariff, the concept of electricity grid capacity tariffs has been proposed. Even though this trend is considered negative for the profitability of solar PV, it could also have benefits regarding demand response and development of the use of batteries.

2.1.5 Sweden

2.1.5.1 Current regulatory provisions and business models

In Sweden, there is not a clear definition of prosumer entity. However, they can be considered as an electricity user with self-generation, that feeds electricity into the grid. The prosumers may acquire access to the market through an electricity retailer. Currently, approximately 50% of Sweden's suppliers offer to buy excess power from micro producers. The prices that prosumers receive varies, but in general is greater than the NordPool spot prices. DSO is obliged to connect electricity connections. Exemptions can be made in specific cases, such as the recent example of island Gotland, in which since 2017, the DSO announced the stop of connections of new generation due to capacity issues in the grid [10]. However, DSO cannot reject micro-production in already established feed-in connections.

Infrastructure in Sweden is quite advanced, although it will need to be adapted to the capabilities of new smart meters. First-generation smart meters cover Sweden's entire customer base but are only able to provide hourly measurements. At the end of 2018, the government decided to start a renovation process to update the metering infrastructure. The second generation roll-out started in 2019 with a plan of completion by 2025 [15].

During hours of self-usage, the cost for both electricity and the variable electricity grid cost can be avoided. The electricity cost is usually spot-price plus balancing cost, electricity certificate and supplier margin. The variable electricity grid fee varies a lot between different DSOs in Sweden but is usually around 30-45 öre /kWh (excl. VAT) for smaller electricity users. In addition, DSO need to pay a mandatory feed-in payment, "grid benefit". This varies depending on DSO but is usually around 2-6 öre/kWh. The reasoning behind this is that electricity feed into the low voltage grid lower the losses of the DSO and therefore the DSO's costs. A production asset that can deliver a capacity of 1500 kW or less should (according to the Swedish electricity law) only pay the grid cost associated with metering, calculation and reporting, whilst a one-time connection fee should be applied. According to the electricity law, an electricity user with a fuse of maximum 63 A and which can deliver a capacity of 43.5 kW or less should not pay any feed-in tariff. This only applies to net electricity users. The actual grid costs and how these exemption rules are quantified varies a lot between different DSOs, broadly speaking between 10-120 öre/kWh.

The Swedish energy tax on electricity is 34.7 öre/kWh in 2019. Electricity producers with a total installed capacity below 50 kW hydro or thermal, 125 kW wind or 255 kW solar PV are fully exempted for energy tax on electricity usage. Facilities below 255 kW belonging to organizations with a total installed capacity above 50 kW hydro or thermal, 125 kW wind or 255 kW solar PV pay 0.5 öre/kWh. The background for this is EU state aid rules, and Sweden is seeking to fully exempt also these facilities from energy tax on electricity. For electricity users owning/operating electricity generation above 50 kW hydro or thermal, 125 kW wind or 255 kW solar PV full energy tax is applied on their electricity usage. In Sweden a tax deduction of 30% is applied on household services such as labor cost for installing solar PV panels. The 30% tax deduction on installation costs corresponds to approximately 9% of total solar PV investment cost.

Regarding the support schemes for renewable electricity production in Sweden, there is a specific investment support for solar PV generation. The support is granted for up to 30% of investment cost and can be granted to all sizes of solar PV installations and to households, organizations and companies. The expenses that can be granted support can be maximum 37000 SEK + VAT per kW and maximum 1.2 million. In the National Budget for 2019 the investment support budget for solar PV support is decreased with 440 MSEK compared to previously proposed budget. In 2018, a statement by The Committee on Industry and Trade proposed that the support level should be reduced to 15% as soon as possible. The Government has however not yet taken decided to reduce the support level. The joint Norwegian-Swedish electricity certificate scheme intends to increase renewable electricity production in both countries. In this system, producers of renewable electricity receive one certificate per MWh of electricity they produce for a period of up to 15 years. Unlike in Norway, there are quite low entry barriers to receiving electricity certificates in Sweden and many small installations (including households) participate in this system. As mentioned above, one certificate is received per MWh produced renewable energy and the price is market based.

Sweden is leading the global energy transformation in many aspects. The country's power system is almost entirely decarbonized and climate-friendly, market-based policies and public and private support for innovation are in place [20]. Although the Swedish power sector is almost entirely decarbonized, integrating high shares of VRE into the power system will be key in the coming decades. Because the forecasted installed capacity of solar PV is relatively low compared to the forecasted installed wind power capacity, integrating wind into the Swedish power system is relevant for several reasons; nuclear reactors will likely shut down before 2045 due to the end of their economic lifetimes, which calls for the deployment of renewable sources in this energy transition; the demand for electricity is likely to increase due to electrification of the transport and industrial sectors, as well as increased demand from new consumers, such as data centers; the long-term target for Sweden is to have zero CO_2 emissions by 2045 and the long-term target is to achieve a 100% renewable power system by 2040.

Measures to increase flexibility are essentially governed by Commission Regulations which Sweden implements accordingly [21]. The Forum for Swedish Smart grid is a national forum appointed by the Swedish Ministry of the Environment and Energy. The Forum is established as a result of the recommendations from the Swedish Coordination Council for Smart Grid (active 2012–2014). The mission is to implement the action plan, set up by the Council, to further develop a store of knowledge on the website and to support Swedish export within smart grids.

The Swedish Energy Markets Inspectorate has developed an action plan in which a number of measures to achieve increased demand response are identified. The measures consist of proposals for new or amended regulations, knowledge-enhancing efforts, government assignments and cooperation between authorities and other stakeholders to create long- term conditions and rules. The measures focus primarily on household customers as they have a high potential for demand response that is not taken advantage of today.

In Sweden, DER can provide Ancillary Services to the TSO. However, it is not possible to provide aFRR from consumers today. For mFRR, there are no limitations for DR. FCR is open to consumers through demand response since 2019, but there is a limit in participation. This limit is initially 20 MW for FCR-Normal and 40 MW for FCR-Disturbance [22]. Bids for congestion management are ordered from the same marketplace as mFRR, the Nordic Regulating Power Market. If disturbances such as electricity production outages or transmission grid faults occur, and the bids on the regulating power market are not able to solve the disturbance, the "disturbance reserve" is used. The disturbance reserve shall be able to activate within 15 minutes and is today mainly provided by gas turbines. If there are no commercial bids available, the disturbance reserve is used to manage congestions between and inside price areas.

The Swedish TSO also works to further increase flexibility in the system mainly through European and Nordic cooperation projects. Among these, the following can be mentioned:

- Adapting the mFRR market to better fit consumption flexibility (e.g. in terms of bid size).
- Active cooperation with Nordic TSOs to review the price signals that the regulatory framework for the balancing market and imbalance fees give to market participants.

2.1.5.2 Existing obstacles

In Sweden, the solar commission has listed several perceived barriers for DERs development. First of all, the complexity of regulatory regimes leads to significant perceived transaction costs in order to understand all policy instruments and apply for support and exemptions. Furthermore, the lack of knowledge about forthcoming policy implementations renders an environment of negativity about future investments. Similar to the case of Norway, in Sweden the concept of capacity tariffs has been proposed in order to lower variable electricity grid tariff. Moreover, tax exemptions concern only installations below 50kW for hydro/thermal, 125kW for wind and 255kw solar PV. Hence, larger decentralized systems cannot use tax exemptions. However, the Swedish government has not assessed this measure to be in compliance with the EU law. Tax exemption only applies if the electricity is behind the meter. This means that if a prosumer owns multiple buildings in close proximity of each other, it is not possible to use their self-generated electricity in other buildings in order to gain a tax exemption. An open debate takes place regarding that issue. A possible outcome could be that for property owners transferring electricity between different buildings within the same premise, a tax exemption to be considered.

2.2 Spain

2.2.1 Current regulatory provisions and business models

The Spanish electricity market is experiencing some opening regarding Demand Side Flexibility (DSF).

A debate is going on, followed by new regulations, aiming to include aggregation of demand and storage in other national and international markets, by introducing new stakeholders such as the aggregator, the storage holder, the Balance Service Provider (BSP) and the Balance Responsible Party (BRP). Although the regulation is clearly making some steps forward in this respect, the operational procedures are still unknown, and it is difficult to make predictions on how the new markets of flexibility will look like. An answer to these open issues is expected to come between the end of 2020 and the beginning of 2021.

The new regulators are focusing on the participation of flexibility in the wholesale market and in the ancillary services of the TSO, while the DSO seems to have still a marginal role. Nevertheless, local flexibility markets represent a parallel discussion, pushed forward through pilot projects by other non-legislative entities.

2.2.1.1 The Iberian electricity market

The Iberian Electricity Market (MIBEL) manages the electricity market of Spain and Portugal and it is operated by various entities:

- OMIE: Iberian MO, Spanish pole;
- OMIP: Iberian MO, Portugal pole;
- REE: Spanish TSO
- REN: Portuguese TSO

It consists of four main types of markets:

- Derivatives, with a ten-year term, operated by OMIP
- Spot market, composed of day-ahead (D-1) and intra-day, operated by OMIE
- Cross-Border Intraday Market (XBID), being the Iberian offers operated by OMIE
- Ancillary services, to solve technical issues and ensure the balance between generation and demand, operated by REE.

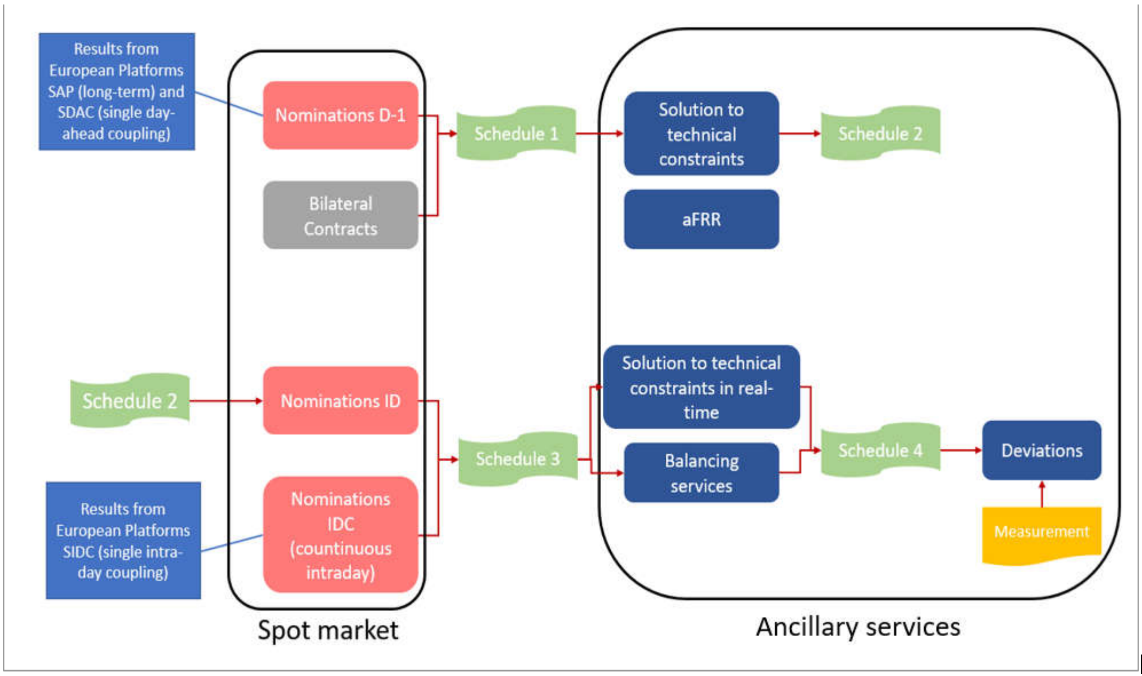

Figure 1: Operation of the Spanish electricity market (scheme created translating a figure in [23])

Figure 1 illustrates the general operation of this market and the interaction between the functions of REE and those of OMIE.

The Day-ahead market closes at 12:00 of the day before the energy dispatch. A first schedule is generated by OMIE. Then REE evaluates the possible technical constraints (congestions, overvoltage, overload, etc.) for the next day and accepts offers to increase or decrease energy delivery. In the day ahead the TSO also assigns the regulation band for aFRR for the next day.

A new schedule is generated, that considers the technical constraints, this will be the base, over which the intra-day modifications are made. The European intra-day exchange XBID overlaps with the Iberian intra-day 6 sessions. A new schedule based on market rules is generated, at each session of the intraday market, but this goes through the validation of the TSO, which ensures the technical safety of the system and the balancing between generation and demand, through the activation of ancillary services (FCR, aFRR, mFRR, and RR).

In Table 2, the complete schedule of the Spanish electricity market is summarized. The colors represent the different entities operating each market. The last column indicates the potential for aggregation to participate in that market. The dashed edge enclosing the replacement reserve (RR) market expresses that these market sessions are not always used by the TSO.

Table 2: Spanish electricity market schedule (Own elaboration based on [24], [25])

PERIOD	HOUR (clearing)	MARKET	OPERATOR	PRODUCT (remuneration)	ALLOWED PARTICIPANTS	MANDATORY	POTENTIAL FOR AGGREGATION
Bi-annual	-	Interruptible Service	REE	Energy & Capacity	Demand (> 5MW)	No	No [1]
Before D-1	-	Derivatives [2]	OMIP	Energy [3]	All - Generation, Demand & Storage	No	No
Day D-1	13h	Day-Ahead (Day D)	OMIE	Energy (24h D)	All - Generation, Demand & Storage	Yes [4]	No
	14h45	Technical Constraints (Day-Ahead)	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconections	Yes	Yes

	15h	Intraday (ID S01)	OMIE	Energy (24h D)	All - Generation, Demand & Storage [5]	No	Yes [10]
	16h30	Automatic Frequency Restoration Reserve	REE	Energy & Capacity	All - Subject to prior qualification and authorization	No	Yes
	17h	*Potencia Adicional a Subir*	REE	Energy	Thermal Units (Coal and CCGT mainly)	??	Yes/No [6]
	17h50	Restoration Reserve (ID S01) [7]	REE	Energy	All - Subject to prior qualification and authorization	No	No [8]
	17h50	Intraday S02	OMIE	Energy (21h-24h D-1 & 24h D)	All - Generation, Demand & Storage [5]	No	Yes [10]
	19h30	Technical Constraints (ID S01)	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconections	Yes	Yes
	21h50	Restoration Reserve (ID S02) [7]	REE	Energy	All - Subject to prior qualification and authorization	No	No [8]
	21h50	Intraday S03	OMIE	Energy (24h D)	All - Generation, Demand & Storage [5]	No	Yes [10]
	22h30	Technical Constraints (ID S02)	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconnections	Yes	Yes
	23h	Manual Frequency Restoration Reserve	REE	Energy	All - Subject to prior qualification and authorization	No	Yes
Day D	Real Time	Frequency Containment Reserves	REE	No Remuneration [9]	Synchronous generation	Yes	Yes [11]
	Real Time	Real-Time Technical Constraints	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconections	Yes	Yes
	Real Time	Cross-Border Intraday (XBID)	Eur NEMOs	Energy	All - Generation, Demand & Storage [5]	No	Yes [10]
	01h50	Restoration Reserve (ID S03) [7]	REE	Energy	All - Subject to prior qualification and authorization	No	No [8]
	01h50	Intraday S04	OMIE	Energy (5h-24h D)	All - Generation, Demand & Storage [5]	No	Yes [10]
	02h30	Technical Constraints (ID S03)	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconnections	Yes	Yes
	04h50	Restoration Reserve (ID S04) [7]	REE	Energy	All - Subject to prior qualification and authorization	No	No [8]
	04h50	Intraday S05	OMIE	Energy (8h-24h	All - Generation,	No	Yes [10]

				D)	Demand & Storage [5]		
	05h30	Technical Constraints (ID S04)	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconnections	Yes	Yes
	09h30	Technical Constraints (ID S05)	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconnections	Yes	Yes
	09h50	Restoration Reserve (ID S05) [7]	REE	Energy	All - Subject to prior qualification and authorization	No	No [8]
	09h50	Intraday S06	OMIE	Energy (13h-24h D)	All - Generation, Demand & Storage [5]	No	Yes [10]
	12h	Restoration Reserve (ID S06) [7]	REE	Energy	All - Subject to prior qualification and authorization	No	No [8]
	12h45	Day-Ahead (Day D+1)	OMIE	Energy	All - Generation, Demand & Storage [5]	Yes [4]	No
	13h30	Technical Constraints (ID S06)	REE	Energy	Dispatchable Generation, Pumped-Hydro, Interconnections	Yes	Yes

NOTES

[1] Service about to disappear. It is considered an unfair bonus to big companies.

[2] Includes futures, swaps, forwards and options.

[3] As a physical or a financial product.

[4] Mandatory participation in the Day-Ahead if participation in the intraday sessions is wanted

[5] Only if they have bid in the day-ahead market.

[6] Service initially created to avoid thermal generation to completely stop their operation and avoid re-start issues. Therefore, other technologies would not be welcomed in this market.

[7] Only if imbalances are greater than 300 MWh/h.

[8] It is a service that will disappear since the XBID market can be used for the same purpose.

[9] It is not a market, there is no remuneration, participation is mandatory for all the generators capable of providing it.

[10] Providing services to retailers (e.g. minimization of imbalances).

[11] However, REE does not seem prone to allow competition in this service

In Spain, the demand can contribute to the stability of the system through interruptible loads, in which big industries offer to reduce their consumption if the system operator requests it, in batches of 5 MW or 90 MW. The service is paid by availability and by activation. The last recorded activation of this service was in 2010. It will probably disappear as it is considered, by EU institutions, an unfair and hidden subsidy to Spanish industries. Moreover, with demand and storage providing ancillary services to the system, the interruptible loads service will not be necessary anymore, as it will be substituted by a more efficient and inclusive mechanism. The only market mechanism for trading flexibility is the national a-FRR, while the other flexibility mechanisms are an obligation for all generation plants. Power plants are paid for their availability during peak hours and the cost is a bit more than 10,000 €/MW per year, representing about the 5%of the electric tariff in Spain [12].

2.2.1.2 Flexibility

2.2.1.2.1 Most recent regulation

20-02-2020 – Integrated National Plan for Energy and Climate draft (PNIEC) 2021-2030: it acknowledges the importance of aggregation and demand response and the active participation of prosumers into the new services.

22-03-2020: The Spanish TSO proposes to change the operational procedures relative to the conditions for Balancing Service Providers (BSP) and Balancing Responsible Parties (BRP), under obligation of the CNMC (National commission for market and competition – the regulator).

23/06/2020: The royal decree RDL 23/2020 is approved, and the Electricity Sector Law (Ley 24/2013) is modified to:

- Include new stakeholders in the energy sector
    - Holders of storage installations
    - Independent aggregators
    - Renewable energy communities
- Define the role of the independent aggregator: participant in the market of generation that offers services of aggregation and that is not related to the electricity provider.
- Define the aggregation activity: aggregation is the activity realized by physical or legal persons that combines multiple loads or generated electricity of consumers, producers, or storage installations, to sell or buy them in the electricity market.
- Allow consumers or storage facilities' holders to receive an income, by participating in the electricity market services. This economic flow comes from retailers and/or independent aggregators.
- Consumers and storage facilities holders, both directly or through a retailer or an independent aggregator, will be able to participate in the services of the electricity market.

2.2.1.2.2 Expected operational procedures

Year 2020 is dedicated to the definition of the operational procedures (P.O.) describing the functioning of the new electricity market, that need to be implemented by 11th of December, 2020. In particular, the discussion is based on the following open issues [26]:

- Participants in the market, BRPs and BSPs;
- Contractual delegation of balancing responsibility of the TSO;
- Scheduling Units (*Unidades de Programación*, UPs) and Physical Units (*Unidades Fisicas*, UFs) for demand and storage;
- Communication of unavailability;
- Pre-qualification and non-qualifying conditions;
- Changes in the solution process of technical constraints;
- Adaptation of operational procedures for measurements.

In general, every stakeholder of the electricity market is also financially responsible for the deviations it generates or can delegate this responsibility to a BRP.

The BSP, instead, is the stakeholder that provides energy and balancing services to the TSO. The BSP, in Spain, provides service by managing its UPs or its regulation zone (ZR), from a control center. These UPs and ZRs need to be pre-qualified, according to certain conditions [26].

2.2.1.2.3 Resources

Until 2019, Spain only allowed conventional power plants and wind farms to participate in the balancing market, but since last December also the demand-side and the storage installations were included in this market. These two elements can provide energy to different services: FCR, mFRR , aFRR and RR

[27].

For the participation in the electricity market, the Spanish resources are clustered in UPs (*Unidades de Programación* – Scheduling Units), the elementary units that can present energy schedules. These elements will facilitate the management of several activities carried out in the market:

- Establishment and daily communication of bilateral contracts
- Sending of offers to the ancillary services market
- Nominations for long-term programs
- Change of schedules from the participants
- Communication of deviations from pre-defined schedules

UPs are composed of one or more Physical Units (UFs, *Unidades Fisicas*) and they are divided in three different categories, depending on the type of source [26]:

- Generation UPs, that include the following UFs:
    - Thermal plant, with more than 100 MW of capacity;
    - Renewables, cogeneration, and excess (like excess from self-consumption, when it is not already represented by the corresponding retailer): in this case the UFs can be aggregated or not depending on the capacity of the source. Below 1MW the UFs are aggregated.
- Demand UPs, that include retailers' customers or individual consumers, in aggregated or disaggregated form, depending on the power contracted, which do not participate in ancillary services. All the customers with power contracted > 1 MW come as a single UF, otherwise they are aggregated under a separate one.
- Storage UPs

2.2.1.2.4 Local Flexibility Markets

OMIE is pushing forward an independent conversation regarding local flexibility markets, by starting a pilot project on this topic, called IREMEL, that is expected to last until 2026. The framework considers two types of markets [28]:

- **Global/European Markets:** Already existing in Spain, they permit the negotiation of energy with agents that are located in different points of the Iberic and European grid, without taking into account the geographical factor associated to the generator/consumer, as long as it is connected to the grid.
- **Zonal and flexibility Market** Given a certain condition of the distribution grid, to which the DERs are connected, the exchange needs to be done by (or is restricted to) assets that are located in a specific location. The negotiation is promoted or restricted by the DSO.

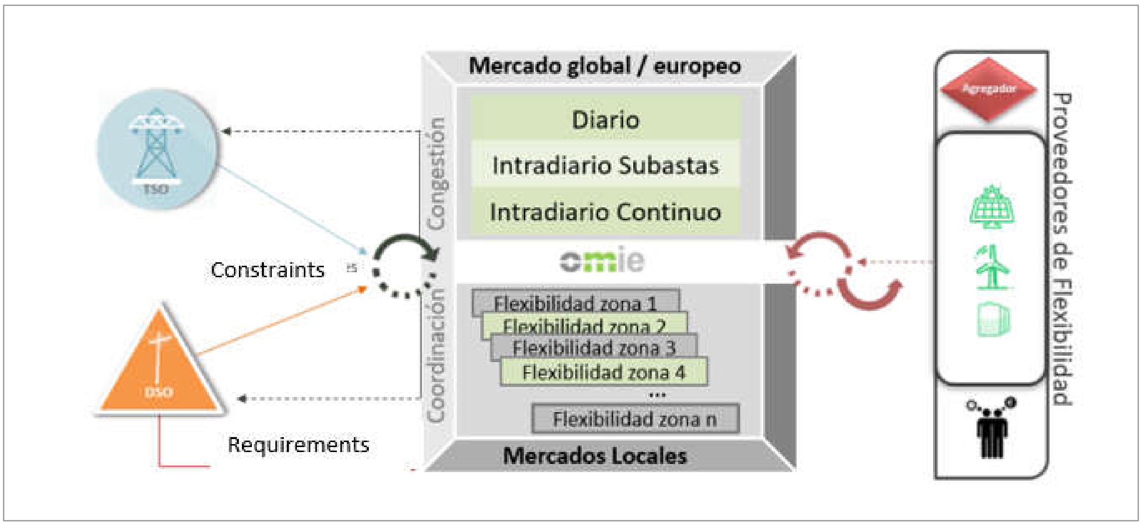

Figure 2: IREMEL Project framework [28]

In this framework the DSO is responsible for the quality of supply of final users, thus it needs to monitor the operation of the distribution grid and forecast eventual issues. During normal operation, the DSO will restrict/partially limit the participation of the local markets to prevent critical (or potentially critical) situations in the distribution or transmission grid (*activation pre-qualification*). Moreover, it can participate into the local markets as a flexibility procurer, sending “requirements” and making use of two flexibility mechanisms:

- *Local products*: for one-time congestion events, and using the local submarket of flexibility, with its own prices. Short-term (1 hour)
- *Flexibility services*: for frequent congestion events, there is a bilateral contract. Medium/Long-term (1 year)

The role of OMIE, as described in IREMEL, is that of a local MO, facilitator and enabler, coordinating the TSO-DSO balance, providing the communication and the economic transaction platforms, and creating flexibility services when required by the DSO.

2.2.2 Existing obstacles

1 Economic Obstacles

- Nowadays, the power generation back up is given by combined cycle plants (with more than 25 GW of capacity installed), hydropower (with more than 17 GW installed) and pumped hydro (with more than 3 GW installed). The sum of the aforementioned installed capacities surpasses the maximum power peak of the national demand, so there is no practical need for new back-up sources. Therefore, any additional installed capacity offering the same service would straggle to compete with this already installed technology, that are participating in the market with the sole marginal cost.
- Distribution grids are not affected by high saturation levels, so they do not require flexibility offers, by now. But this situation is expected to change with the increasing penetration of renewables and EV chargers. The future of flexibility in distribution networks will be determined by the type of investment of the DSO, to reinforce the network: the choice is between the “iron & copper” solutions or the smart flexible grids.
- There are already other mechanisms to allow demand taking part in the market (e.g. Interruptible loads)

2 Social obstacles

- Limited Citizens’ unawareness; citizens could have an active role in pushing this revolution forward.
- Uncertainty from the market and system operator’s side, as it is still not clear which markets will be opened to demand and storage.

3 Regulative obstacles

- Stagnating Spanish regulation: the country is among the last ones in introducing demand as a participant of the electricity market

2.3 Italy

2.3.1 Current regulatory provisions and business models

The Italian TSO (TERNA), together with the Regulation Authority for Energy, Network and Environment (ARERA), has started a process to progressively include distributed resources in the market of ancillary services, through the definition of pilot projects that will allow the organic reform of this market. The pilots have the objective to increase immediately the amount of resources available to guarantee the safety of the electricity sector with a lower cost for the final user, through the provision of reserve and balancing services, towards the decarbonization of the national mix. A further objective is the diversification of the resources.

Among the European countries, and considering the last two years, Italy has made the most important progress to qualify distributed resources for the services market. In 2017, SEDC described the Italian market as totally closed to distributed resources [29], while in a most recent analysis of SmartEn, the country was labelled as an active market [30].

2.3.1.1 The Italian electricity market

The Italian electricity market is operated by:

- GME (Electricity MO - *Gestore del Mercato Elettrico*)
- TERNA (TSO)

It is divided in two main categories [31]:

- The short-term electricity market (*Mercato Elettrico a pronti* - MPE), that includes:
    - **Day-ahead market (*Mercato del giorno prima* - MGP).** A typical day-ahead energy market, operated by GME, where the offers are accepted until 12:00 of the day before the negotiated day and the clearing occurs 55 minutes later.
    - **Intraday market (*Mercato infragiornaliero* - MI).** Also operated by GME, permits to change the programs defined in the day-ahead market through new selling or buying offers. It subdivided in 7 sub-phases.
    - **Daily products market (*Mercato dei prodotti giornalieri* - MPEG).** Permits to exchange energy bilaterally, during D-2 and D-1. The types of products negotiated are of the type “Base load” or “Peak Load”. It is operated by GME.
    - **Ancillary services (*Mercato dei servizi di dispacciamento* – MSD)**. MSD is further divided in two types of services:
        - **Ex-ante MSD**: This is articulated in 6 sub-phases; the offerings are made in the day-ahead, but the results and the actual activation of resources is done in the day of activation. This market is used to solve technical constraints and to ensure a regulation capacity for the next day.
        - **Balancing Market (MB)**: It is also articulated in 6 sub-phases, all of them opening on the day before and closing 1,5 hours before the first negotiable hour of that particular session. The MB is used to exchange energy for aFRR and for the real time balancing between demand and generation.
- **The long-term electricity market (*Mercato Elettrico a termine* - MTE)**. A continuous market, operated by GME, in which the negotiated contracts are of the type “Base load” or “Peak Load” with delivery periods of month, trimester or year.

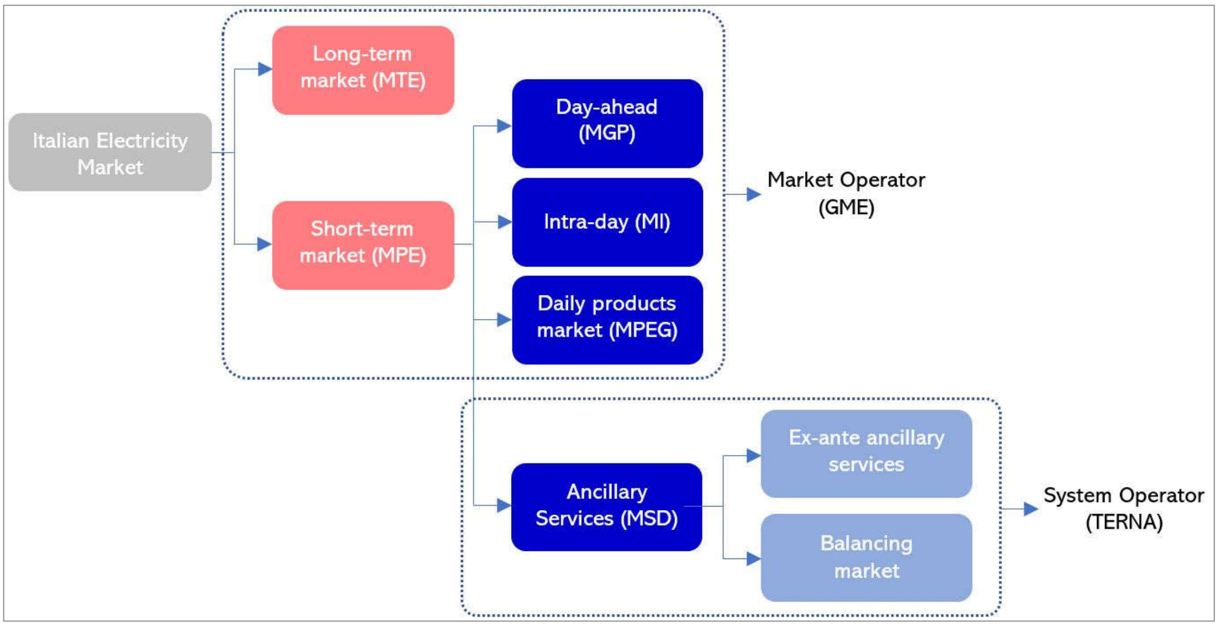

Figure 3: Structure of the Italian Electricity Market

2.3.1.2 Flexibility

2.3.1.2.1 Most recent regulation

The Italian market is developing its regulation about the use of DER and aggregators to provide flexibility services, but it is still ongoing.

- In redacting the **TIDE** (Integrated Text for Electricity Dispatching), the regulation authority for energy, network and environment (ARERA) and the TSO introduced the opportunity for distributed energy resources to provide ancillary services, also introducing the role of the aggregator. This has been done by 3 different pilots which are currently ongoing but showing interesting results. Another 2 pilots are planned for the next future.
- In the **Integrated National Energy and Climate Plan** (December 2019), the pilots are also mentioned together with the explicit intent to formally integrate their role in the existing regulation once these pilots will deliver the expected results.
- The **Italian Decreto di Rilancio -13 Maggio 2020,** allows to receive tax deduction for 110% of the total expenses for the installation of private solar panels with their relative storage systems, only if in conjunction with other energy efficiency interventions.

As mentioned above, the regulation authority for energy, network and environment (ARERA), together with the Italian TSO TERNA, is redacting the Integrated Text for the Electricity Dispatching (TIDE), that will include all the operational procedures to restructure the current auxiliary services and include flexibility.

While doing so, ARERA decided to open the market of ancillary services to distributed resources, such as consumption units, small generation and storage. This opening was carried out through the instrument of a pilot project and has going on since 2017.

In particular, the following UVAs (*Unitá Virtuali Abilitate*, Virtual Qualified Units) were defined:

- UVAC (Consumption Virtual Qualified Units), since June 2017, until November 2018;
- UVAP (Generation Virtual Qualified Units), since November 2017, until November 2018;
- UVAM (Mixed Virtual Qualified Units), since November 2018 (ongoing);
- UPR (Relevant Generation Units), since September 2017(ongoing).

The project has achieved good results both in terms of liquidity of the market and in terms of aggregated capacity, thus the expected next steps are [32]:

- Progressive inclusion of residential loads and other smaller resources into this system;
- Encourage competition ;
- Allow the participation of distributed resources in other services, such as FRR and voltage control;
- Redesign the whole system of ancillary services and network codes based on the lessons learned from pilot projects.

2.3.1.2.2 Resources

As anticipated in the previous paragraph, the distributed resources are entering the market of electricity services via a pilot project organized by TERNA, the system operator in Italy.

This pilot makes use of three main categories of distributed resources to extract flexibility services from (UPRs are not considered at this stage, as they are not distributed resources).

The following table describes each type.

Table 3: UVAC, UVAP and UVAM characteristics

Pilot Project	Characteristics	Minimum Power Threshold	Services	Mode	Remuneration

UVAC	Consumption points	1-10 MW	mFRR (upward) Balancing service (upward)	Reduction of consumption of at least 1 MW within 15 minutes from TERNA's request	= to ancillary services remuneration/ Penalties + long-term contracts*
UVAP	Non-relevant generation points	1-5 MW	Congestion management mFRR (spinning and replacement) Balancing service	Increase or decrease generation of at least 1 MW within 15 minutes from TERNA's request	= to ancillary services remuneration/ Penalties
UVAM	Consumption points Non-relevant generation points Relevant generation points Storage installations	1 MW	Congestion management mFRR (spinning and replacement) Balancing service	Increase or decrease generation of at least 1 MW within 15 minutes from TERNA's request	= to ancillary services remuneration/ Penalties + long-term contracts*

** The inclusion of long-term contracts, as a form of remuneration, is necessary because the industries participating in the pilot must recover the high capital costs invested for the installation of the energy monitoring and control technology.*

In June 2019, the total capacity of UVAs amounted to 830 MW, but the smallest loads, such as the residential ones, were still excluded from this mechanism.

2.3.1.2.3 Expected operational procedures

Through this pilot, ARERA and TERNA allowed previously not qualified sources to participate in the Ancillary Services Market (MSD).

As from the operational procedures defined in the relative Decree 300/17/R/EEL, the actors involved in the participation of the selected distributed resources in the ancillary service market are the following [32]:

- Dispatching Units (UdD): holders of the points of consumption/non-relevant generation;
- BSP: Balance Service Provider, corresponds to the aggregator, it is the holder of the UVA, and it is the actor responsible for the negotiation of services in the MSD. It does not have any contract with the BRP, because it directly interacts with the TSO. So far, more than 25 BSP are registered and assigned to an UVA.;
- BRP: Balance Responsible Party, the financially responsible party in case of deviations that impact the balancing of the system.

While UVAs can only participate in the ancillary services market (MSD), the dispatching units can participate in the energy markets as well (MGP, MI, MPEG).

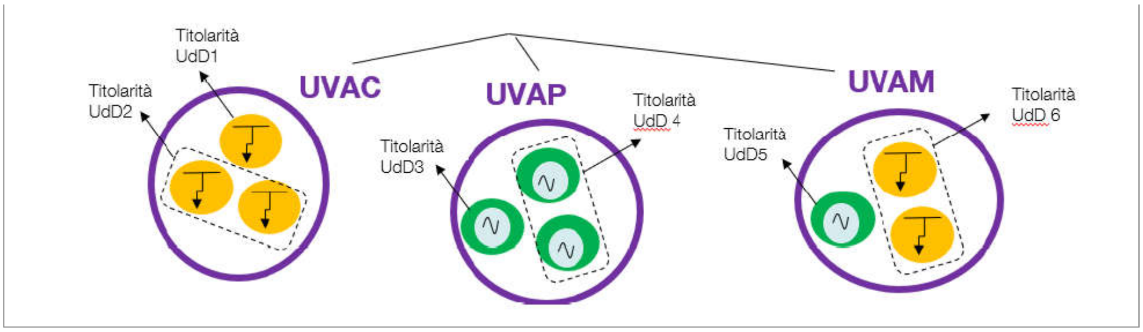

Figure 4: UVAC, UVAP and UVAM composition and holding rights [32]

Each point, within the UVA, has to be equipped with a monitoring unit (UPM), to measure the injected/withdrawn energy and send this data to the concentrator (every 4 seconds or 60 seconds, depending on the type of UVA), which interfaces TERNA's system. During D-1, the BSP must send to TERNA the forecasted baseline (daily schedule) of the next day, for the UVAM it manages. Then, TERNA, during the day, corrects this baseline considering a factor based on the measurement received from the UPM. This baseline helps the TSO to verify the correct execution of the flexibility requests made to that BSP [32].

2.3.2 Existing obstacles

1 Economic Obstacles

- Remuneration for availability is necessary to recover the high up-front investment the demand side must face, in order to become an active participant in the ancillary service market, especially due to the cost of the installation for monitoring and control of flexible loads. Moreover, these stakeholders have to stop or vary the productive cycle, facing economic losses of an activity that is not part of their core-business [32]. Thus, to encourage demand-side flexibility, the capacity is highly remunerated. On the other hand, the energy price cap that UVAM can bid in the ancillary markets are high and not restricting at all. Therefore, the consumption units risk becoming passive elements of the system, offering availability (thus profiting on the capacity), while bidding with a high energy price, in order to avoid being selected as flexibility providers.
- The unbalance between the offers for availability and the offers for energy is observable also in the cashflow figures. During 2018, the ancillary service market spent 4,8 million euros to pay UVAs for capacity availability and only 0,29 million euros for the energy activation [32].

2 Technical Obstacles

- The minimum size selected for the UVAM project is 1 MW. This decision permits to include small loads as participants in the market and will involve residential consumers in the long run. Nevertheless, it represents a drawback when it comes to technology, as this level of capacity is more difficult to control and manage.

3 Regulative Obstacles

- The situation of Local Flexibility Markets is not evolving, mainly due to the disagreement between TSO and DSOs.

2.4 UK

2.4.1 Current regulatory provisions and business models

The UK has a fully liberalized and privatized electricity system that can be considered highly reliable, but it is facing some challenges:

- The increase of renewable energy sources in the north of the country is likely to determine congestion issues in transmission networks of that area;
- The government strategy to electrify massively the heating and transport sectors, installing more

heat-pumps and EV chargers in British dwellings, could lead to congestion issues in distribution networks, especially in some cities.

For these reasons, and to comply with its ambitious decarbonization goals, UK is at the forefront in the integration of energy flexibility in the system [33] , considering especially three types of non-conventional sources: demand, energy storage and distributed generation.

DSF, directly or via aggregation, can already earn from the participation to existing electricity markets (balancing and ancillary services, capacity market) but also providing network charges avoidance (i.e. helping large electricity users to save money reducing their network charges).

Concerning local flexibility markets, a push has been given with flexibility projects funded through national funding mechanisms[1], undertaken by several DNOs and there is also a dedicated workstream for flexibility services within the Open Networks Project. Since 2018, the DNOs have been tendering and procuring for various flexibility services to help solve congestions in the local electricity grids, so the exploitation of flexibility is now business as usual for the DNOs, with local flexibility markets already established to purchase flexibility through online platforms.

2.4.1.1 The British electricity market

The British power system is composed of different stakeholders:

- **Transmission**: National Grid (NG), the British TSO, is divided in two legally separated entities with different functions: NG Electricity Transmission (NGET), owning the high-voltage network in Wales and England, and NG Electricity System Operator (NGESO), responsible for the balancing between demand and generation and for the stability of the grid. The rest of the transmission network of the country is owned by Scottish and Southern Electricity Networks and Scottish Power.
- **Distribution**: SSE and Scottish Power also own distribution grid in Scotland, while in the rest of the country, the main companies owning the network are UK Power Networks, Western Power Distribution, SP Energy networks, Northern power Grid, Northern Ireland Electricity Networks, GTC, ESB Networks, Electricity North-West.
- **Wholesale market**: the day-ahead and intra-day markets are operated by two spot platforms APX (Amsterdam Power Exchange) and N2EX (Nord Pool).
- **Balancing and Settlements**: Elexon is a separate entity, in charge of determining the imbalance volume and the imbalance price, paying the participants of the imbalance market, and charging the non-compliant parties.
- **Regulation**: There are many regulative authorities. The ministry in charge is the department for Energy and Climate Change. In addition to this, Ofgem (Office of Gas and Electricity Markets) is a very influent non-ministerial government department and an independent National Regulatory Authority, whose role is to protect consumers and to build a greener energy system [34].

The electricity British market structure is shown in the following figure.

[1] The NIA (Network Innovation Allowance) or the NIC (Network Innovation Competition), two funding mechanisms created to support research and trialling activities of new technologies or market concepts.

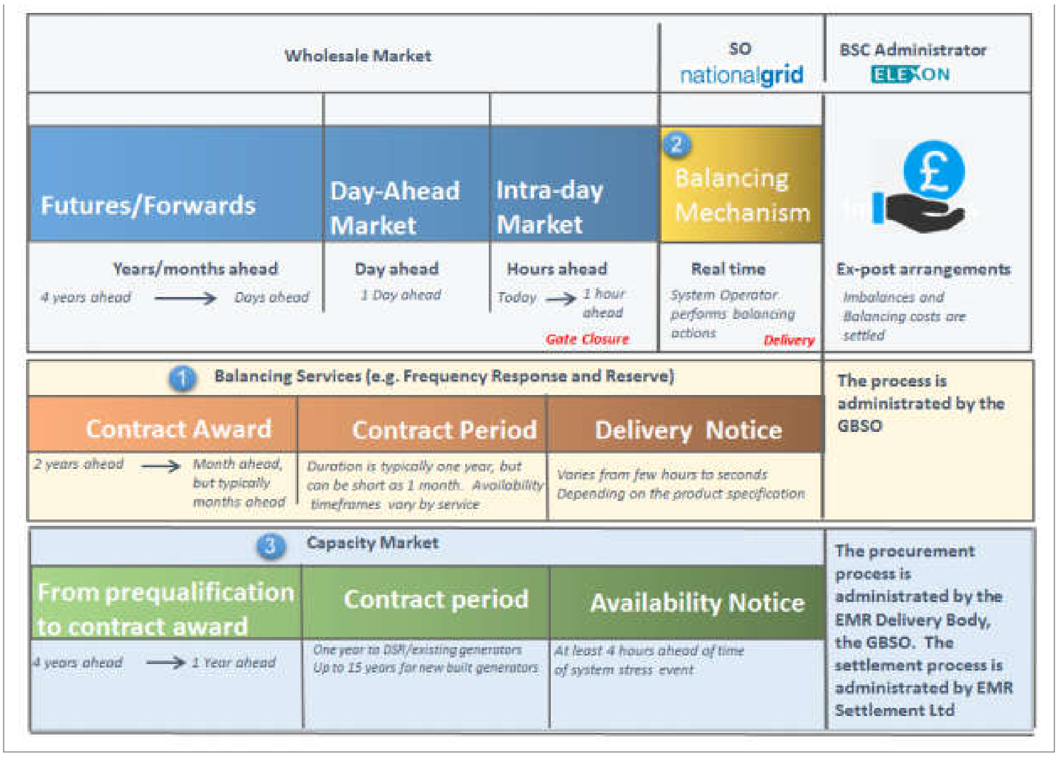

Figure 5: Electricity market structure and timeline [35]

The main markets are briefly described hereunder:

- **Wholesale Market**: includes the long-term and the short-term markets (day-ahead and intraday).
- **Balancing Mechanism:** It represents one of the tools to balance demand and supply. The National Grid ESO makes use of the energy associated in "bids" and "offers", coming from Balancing Mechanism Units (BMU). Bids and offers permit to either increase or decrease the generation or the consumption. BMUs send these signals until one hour before the beginning of the settlement period[2]; this moment is called gate closure. Between the gate closure and the end of the settlement period, the ESO can instruct (or dispatch) BMUs to increase or decrease their generation or consumption.

National Grid describes the Balancing Mechanism (BM) as 'the ultimate flexibility market'. Given the relevancy to the flexibility topic, here below it is provided a more detailed explanation on how the Balancing Mechanism market functions and its relations with the Wholesale Market.

The ESO receives three main groups of data from the BMUs participating in the Balancing Mechanism (as shown in the image below)

- Final Physical Notifications (FPNs): consumption/generation measures for each settlement period, at the end of the day;
- Operational data: technical data like ramp rates;
- Bids or offers: how much a BMUs wants to be paid to modify its consumption pattern.

[2] Days are divided in 48 settlement periods that last half an hour

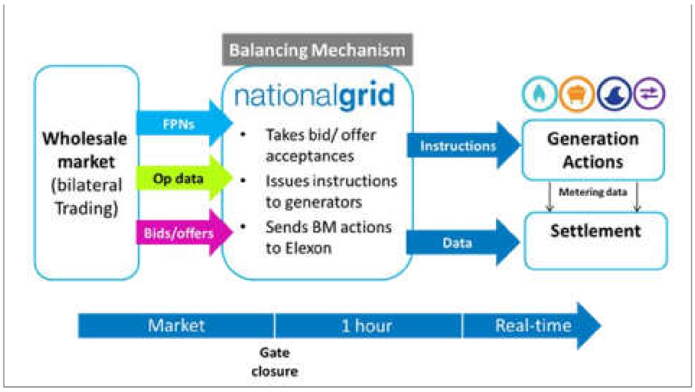

Figure 6: Scheme of the Balancing Mechanism [36]

All these data is used to define the best strategy to solve imbalance issues and it's then passed to Elexon, that will determine the imbalance volume and price each BMU has to pay or receive [36].

- **Balancing services - BS**: It includes around 20 different types of products, including Reserve Services, Frequency Response Services, Negative Reserve Services, Constraint Management Services, Reactive Power and Black Start Services.
  - **Firm Frequency Response - FRR:** It's a Balancing service. There are three response speeds for frequency response. The providers of this service might offer a combination of different response speeds or just one of them:
    - **Primary response** – Activation within 10 seconds from the request of NG, can be sustained for 20 seconds.
    - **Secondary response** - Activation within 30 seconds from the request of NG, can be sustained for 30 minutes.
    - **High frequency response** – Activation within 10 seconds from the request of NG, can be sustained indefinitely.

    Both BM and non-BM participants can become service providers. This can include generators at transmission or distribution level, storage providers and demand [37].
  - **Short-Term Operating Reserve - STOR (Replacement Reserve):** A service procured by the National Grid to help meet reserve requirement. It is open to both BM and non-BM providers. STOR is a balancing service based on a contract, therefore the Service Provider delivers a contracted level of power as pre-agreed, when requested by National Grid. The following parameters qualify a service provider to take part in the STOR:
    - a minimum of 3MW generation or steady demand reduction (this can be aggregated);
    - maximum Response Time for delivery of 240 minutes following instruction from National Grid;
    - ability to deliver the Contracted MW for a continuous period of not less than 2 hours;
    - have a Recovery Period after provision of Reserve of not more than 1200 minutes;
    - be able to deliver at least 3 times per week [38].

    BM providers will be dispatched through the Balancing Mechanism, while non-BM participants will be instructed and metered through STOR Dispatch (SRD PC) [39].
  - **Demand Turn Up**: a product that permits to increase demand or reduce generation in the moments of high renewable output. The providers can be of different types: true demand, combined heat and power, energy storage, other types of generation technologies. The Demand Turn Up providers cannot participate at the same time in ancillary services markets [40].

- Capacity Market - CM: introduced by the Electricity Market Reform, whose goal is to achieve an adequate capacity margin thus ensuring security of supply over medium and longer timeframes. On the providers' side, it provides a steady and predictable revenue stream that permits them to plan future investments. There are three types of capacity auctions: one-year ahead, four-year ahead or Transitional Arrangements. The latter offers support to DSR (Demand Side Response) sources for two years, while preparing the providers to become ready and fully participative in the market [35]. There is a minimum capacity size of 2 MW [35]. In 2018 the CM payments were suspended, because the EC has opened an investigation to reconsider the service a State aid [41].

The several markets and services could seem to have overlapping functions, but they must be considered as different products which have different market requirements, set up and response time.

Apart from TSO services, there exist also a mechanism to **manage constraints of the DNO** (Distribution Network Operators). The latter can negotiate agreements with consumers connected to its network, in order to defer or avoid investments or reduce losses [35].

2.4.1.2 Flexibility

2.4.1.2.1 New regulations/guidelines

2014 Electricity Market Reform: it introduces the Capacity Market that is supposed to support grid stability.

2018 Electricity Balancing Significant Code Review (EBSCR): Modified the calculation method of the imbalance price. Before 2018 the penalization price was determined considering the most expensive 50 MWh of relevant balancing actions taken by the ESO. From the 1st of November 2018, this price started to be calculated considering only the most expensive 1 MWh. This change increased the imbalance price, making it more volatile, and pushed market participants to match supply and demand more exactly. Therefore, the balancing costs has gone down, and the integration of flexible technologies is growing [41].

2018-2020 Wider Access arrangements[3]: NGESO's goal to widen the access to the balancing mechanism (BM) opening to independent aggregators, that in this context are called Virtual Lead Parties (VLP). Before 2019, the only demand side BMUs (Balancing Mechanism Units) allowed were licenced suppliers [36]. To qualify for VLP, aggregators have to enroll in the BSC (Balancing and Settlement Code) and they also need to control at least 1 megawatt (MW) of capacity, which could be generation, demand or energy storage.

2018 ENA[4] Flexibility Commitment: An agreement created by DNOs to boost the use of smart energy technologies and expand flexibility markets at a local level. As a result, since 2018 the DNOs have been tendering and procuring for various flexibility services to help solve congestions in the local electricity grids, so the exploitation of flexibility is now business as usual for the DNOs, with local flexibility markets already established to purchase flexibility through online platforms.

2.4.1.2.2 Resources and operational procedures

UK has high DSF participation especially in the capacity market, balancing markets [33] and DNO's congestion management, but demand is not allowed to participate in the wholesale energy markets. The recent Wider Access Arrangements allowed independent aggregators to enter the Balancing Mechanism, under the name of VLP.

[3] In particular CMP 295, CMP 296, CMP 297
[4] Energy Networks Association (ENA) represents the transmission and distribution network operators for gas and electricity in the UK and Ireland [108]

From the table below it is possible to identify which markets allow demand side flexibility participation:

Table 4: UK's Electricity Market Services and DSF participation

Service	Product	Open to DSF	Remuneration type	Value stacking available	Market Participation
Adequacy	Capacity Market	Yes	Capacity based	Yes	T-4 2016 auction: 1367 MW of unproven DSR and 44MW of proven DSR for £22.50 per kW T-4 2017 auction, 110MW of unproven DSR and 46MW of proven DSR were contracted for £8.40 per kW/year for delivery in 2020/21 – a record low clearing price T-1 2017 auction also delivered a record low clearing price of £6.00 per kW, contracting 521 MW of unproven DSR and 93 MW of proven DSR
Wholesale	Day - ahead	Yes, through suppliers	Energy based	N/A	N/A
Balancing	Intra – day	Yes, through suppliers	Energy based	N/A	N/A
Constraint management	Firm frequency response (or FCR)	Yes	Capacity based and Energy based	Yes across different windows. Yes across same availability windows, but subject to the product and further agreements	2341 MW (in 2018) and 773 MW (in 2017) across all tenders
	Fast Reserve (or FRR)	Yes	Energy and Capacity based	Yes (excluding Response products)	Limited participation (3 DSF providers) due to the 50 MW threshold to participate) – date from 2018
	STOR (Replacement Reserve)	Yes	Energy and Capacity based	Yes (excluding Response products)	10192 MW (accepted tenders) – data for 2018. This number reflects all the tenders for STOR during 2018, across 3 tenders. The average DSF accepted capacity pre tender is around 3GW.
	Balancing	Yes (recently	Energy based,	Yes	Not on operation yet for DSF

	Mechanism (Replacement Reserve)	open for DSF and aggregators acting as Virtual Lead Parties – VLPs)	according to the contracted volumes during Bids and Offers processes		
	Demand Turn Up (DTU – replacement reserve, currently discontinued by the ESO)	Yes	Energy and Capacity based	Yes (excluding Response products)	114 MW
Constraint management	TSO level	Not open	N/A	N/A	N/A

The participation is possible for large Industrial and Commercial customers (I&C, that represents almost 90% of the DSF capacity involved), small to medium enterprises, and aggregators, with a diverse range of technologies including also battery storage, electric vehicles, aggregators and generators (thermal and wind) [42].

Demand Aggregators can participate in the balancing markets as follows:

Table 5: Participation of Demand Aggregators in the UK Balancing Markets [12]

<table>
<tr><th>Market open to DA</th><th>Min bid size (MW)</th><th>Not. time</th><th>Max number of activations</th><th>Product resolution</th><th>Symmetry</th><th>Duration of delivery</th><th>Tender period</th><th>Energy Payment €/MWh</th><th>Capacity payment €/MW/h</th></tr>
<tr><td>Primary response (FCR)</td><td rowspan="5">1</td><td>2s (5%)
10s (100%)</td><td>Continuous</td><td rowspan="4">4h</td><td rowspan="4">NO</td><td>20s</td><td rowspan="4"></td><td rowspan="4">NO</td><td rowspan="4">8.6s on average</td></tr>
<tr><td rowspan="2">Secondary response (FCR)</td><td rowspan="2">30s</td><td>Continuous</td><td rowspan="2">30min</td></tr>
<tr><td>Discrete</td></tr>
<tr><td>High frequency response (FCR)</td><td>10s</td><td>Continuous</td><td>Indefinite</td></tr>
<tr><td>Enhanced frequency response (FCR)</td><td>1s</td><td>Continuous</td><td>4 years</td><td>YES</td><td>Minimum 15 min</td><td>Sporadic</td><td>NO</td><td>9.4 on average</td></tr>
<tr><td>Fast reserve (aFRR)</td><td>25</td><td>2min</td><td>10/day on average</td><td>1 month</td><td>NO</td><td>15 min</td><td>Month</td><td>102 on average</td><td>N/A</td></tr>
<tr><td>STOR</td><td>3</td><td>As max.</td><td>Indicated</td><td>1h</td><td>NO</td><td>2h</td><td>Tendered</td><td>167 on</td><td>1.8 on</td></tr>
</table>

(RR)		240 min	by the service provider				3 times a year	average	average
Demand Turn Up (RR)	1	6h on average	Several times per week	Some hours	NO	On average 4h and 36min in 2018		67 on average	1.5 on average

In 2016, Ofgem counted 19 aggregator companies, of which only 9 were registered as independent aggregators, whereas the others were suppliers or in partnership with a supplier [35]. The types of sources aggregated are summarized in the following table.

Table 6: UK's Aggregator types in 2016 [35]

Both DSR & Generation based Aggregation	11
Exclusively DSR based Aggregation	1
Supplier Aggregator	7
Total	**19**

Independent aggregation arrangements in GB do not account for open supply and imbalance position of the supplier (or its balance responsible party, BRP) [42].

There exist also 4 implicit products for demand side flexibility [33]:

- **Triad Avoidance**: It is used by National Grid to determine Transmission Network Use of Systems (TNUoS) charges and it refers to the three settlement periods of the year (from November to February) with the highest system demand. Large industrial customers are charged for the average consumption they have during these three periods; this way they are incentivised to reduce their consumption when transmission networks are already highly loaded;
- **Distribution Use of System (DUoS) Charge Avoidance:** DNOs are allowed to create their own mechanism to encourage the customers to consume during low demand periods and avoid peak hours, to prevent congestions in distribution networks. The customers offering this support are not explicitly paid by the DNOs, but they receive a discount in their energy bill;
- **Time of Use (ToU) Tariffs:** They allow customers to adjust consumption to the off-peak hours when the price is lower. They are available both for large and small consumers but not all the suppliers are offering them;
- **Flexible Connection:** The DNO can make a bilateral agreement with a large customer, prior its connection to the grid. If the contracted power of the customer exceeds the peak network limits, the DNO can avoid to reinforce the grid, if the customers agrees to reduce its consumption when the network is close to its saturation threshold.

The most relevant value streams for DSF nowadays are related to the ancillary market participation and the network charges avoidance: out of the total value streams for DSF of 4.5GW, nearly 2GW are monetised with the former and 2.5GW with the latter, combined with Time-of-Use tariffs [42].

2.4.1.2.3 DNOs' flexibility market

Great Britain has a learn-by-doing approach in many fields, also when it comes to the creation of new flexibility markets for the distribution networks. The Energy Network Association (ENA) is supporting the Open Network Project, that aims to create a smart grid ecosystem, starting from the last mile of the energy chain, thus homes, businesses, and communities. One of the workstreams of the project is dedicated to flexibility markets and services [43]. In December 2018, DNOs created the ENA Flexibility Commitment, to agree on common objectives and strategies.

GB DNOs are designing and developing the DSF open flexibility services for distribution networks and they are already using this flexibility, even outside of innovation projects [33]. Piclo, a technology company, has received governmental funding to develop and test the first GB-wide flexibility marketplace, that allows DSOs to procure flexibility from the steadily growing number of flexibility providers. The six main DNOs participated in the trial with 175 flexible providers, amounting to a total capacity of 4 GW. DNOs across the country are now willing to extend this experience both in terms of covered network areas and in terms of providers' capacity. The following table refers to the flexibility services created by each DNO, before the Piclo's trials.

Table 7: Product development and flexibility services for the 6 major UK's DNOs [35]

	Remuneration type
UKPN	The flexibility provider (FP) receives a utilisation payment for the delivered energy and availability payment for all period available
WPD	Remuneration will be based on: • arming and utilisation for Secure product. Arming is only paid for the duration of expected utilisation. • availability and utilisation for Dynamic product. Availability is paid in this case, instead of arming, due to reduced expectation of utilisation. Availability reflects a payment for readiness. • availability only for Restore
ENW	Depending on the product, availability and utilisation remuneration will take place
NPG	Information not available
SPEN	Information not available
SSEN	Depending on the product; availability and utilisation payments will be available

2.4.2 Existing obstacles

1 Economic Obstacles

- Big size generators suffer from this model, due to the lower profit made on the ancillary services and are obliged to restructure their pricing mechanisms. Companies like Centrica, SSE or EDF Energy already expressed their concerns with respect to this situation. A direct consequence of this phenomenon is the progressive decommission of old generation plants and the loss of interest in building new combined cycle ones [44].
- Price volatility in the wholesale market is high, but not enough for Demand Side Response providers [33].
- UK is one of the few countries creating flexibility products for DNOs, but so far, the liquidity of this market is insufficient to incentivize new investment in the technology. To overcome this situation Ofgem's network charging and access review should include clear price signals towards the providers of this service [33].
- High competition already existing in the ancillary services arena, among the different services and within the same services, makes access difficult for new parties, such as aggregators [35].

2 Regulative Obstacles

- Market uncertainties hinder wide DSF participation, but the policy is pro-actively pushing for a wider access of these sources. Also, funding to innovation projects is having a key role in proving new technologies and market mechanisms [33].
- Currently, suppliers could be exposed to delivery/imbalance risks due to the activity of independent aggregators. Ofgem has already shared these concerns and has suggested that the costs associated to balancing and delivery risks should be carried by the actors that

produced them, thus in this case, the aggregators [33].

- The Capacity Market presents the following barriers for the participation of aggregators:
    - Impossibility for DSR to participate in the long-term contracts (T-4), making it difficult to obtain finance easily.
    - Despite the apparent technology agnosticism, generators are running the auction with an un-even advantage, as they have lower risks associated to their business
    - The capacity mechanism rewards capacity rather than reliability, as the penalization for non-delivery is capped. This issue does not represent a barrier for the aggregator but for the stability of the system as a whole [35].

3 Technical Obstacles

- Some ancillary services have prequalification requirements that aggregators struggle to meet, for example a very high minimum capacity or a very high run duration [35].
- In 2014 the balancing services were 22, according to [45], each of them with different specifications such as response times, duration of actions, and availability period. This highly complex market, together with the lack of transparency of the SO's website, makes it difficult for participants to understand and compare the benefits and revenue streams they could achieve through each service [35].
- The smart meter roll-out is not completed in UK and it is expected to finish in 2024 [46]. The lack of automatic consumption readings represents an obstacle to the development of new energy markets and to the engagement of residential consumers.
- Principal barriers for the demand aggregation in the UK are: the tender period, which can be a barrier in all markets; the minimum bid size of 25MW in the aFRR market; the fact that services like the Demand Turn Up service did not take place in 2019 [12].

2.5 Belgium

2.5.1 Current regulatory provisions and business models

2.5.1.1 The Belgian electricity market

Belgium has been relying on nuclear energy for most of its electricity generation for more than 40 years. Nuclear generation represents around 50% of the electricity produced in the country (depending on the availability of the nuclear fleet). In terms of generation capacity, nuclear also represents around 50% of the thermal capacity of the country. The last decade, there was a considerable increase of renewable electricity generation capacity, mainly solar and wind. The installed capacity of these 2 renewable sources represents 6,4 GW or 28,8 % of the total installed electricity generation capacity in 2017. Offshore wind farms represent already 44,3 % of the total wind production. Belgium is at the heart of the interconnected European grid. In order to meet the demand for electricity, Belgium has to rely on imports from the neighboring countries [47].

The electricity market in Belgium is composed by the wholesale markets (day-ahead and intraday) and the balancing market. The wholesale markets are operated by Belpex currently EPEX SPOT Belgium, and Nordpool, while the balancing market is operated by the TSO, Elia. The day-ahead power exchange in the Belgian market zone is the Belpex DayAhead Market (DAM). Today, the Belgian day-ahead market (Belpex DAM) is coupled with the Netherlands, Luxembourg, Great Britain, Germany/Austria, France, Norway, Sweden, Finland, Denmark, Estonia, Poland, Portugal, Spain, Latvia, Estonia and Lithuania. Electricity can be traded intra-day on the Belpex Continuous Intra-day Market (CIM). The Belpex CIM is an organized over-the counter market which is cleared continuously. The Belpex CIM is coupled implicitly with the intra-day market in the Netherlands and explicitly with the French intra-day market [48].

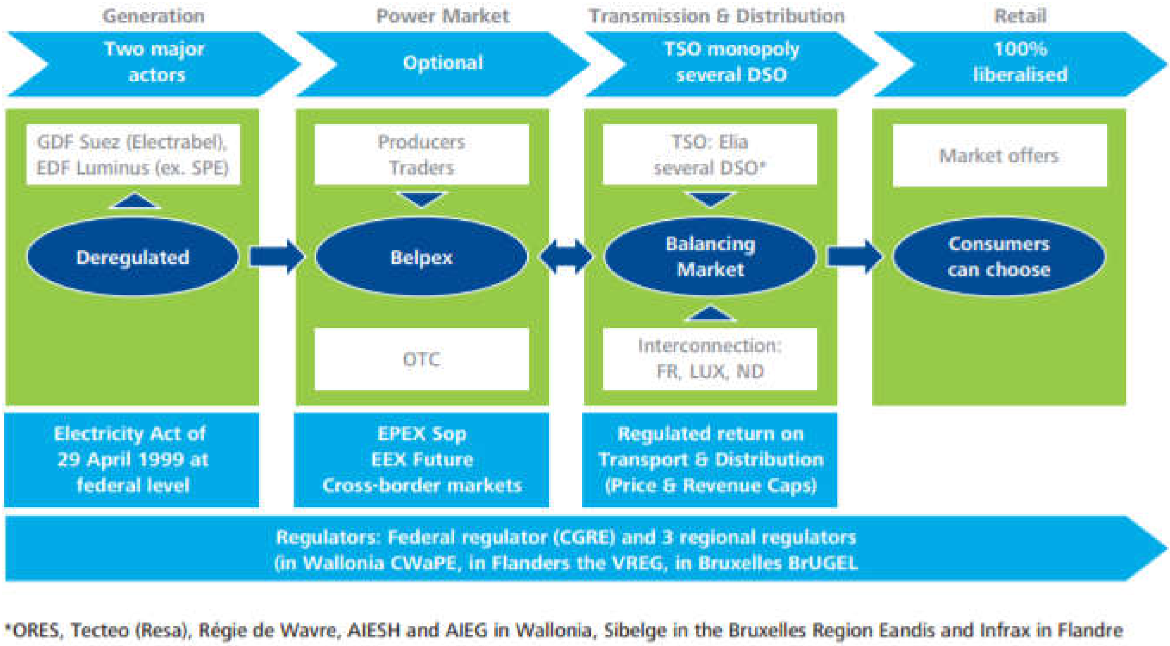

Figure 7: The Belgian electricity market mechanisms [49]

2.5.1.2 Flexibility

2.5.1.2.1 Flexibility sources in the balancing market

Several developments have been undertaken in Belgium in order to enable the use of (newly) available flexibility sources in the balancing market. The goal as pursued by the Belgian TSO (i.e. Elia) in close collaboration with the regulator (i.e. CREG) and the market, is to evolve a product design where all technologies on all voltage levels offered by independent Balancing Service Providers (BSPs) can participate and compete on equal grounds.

Some developments that enable the participation of flexible resources in the balancing market are:

- In 2012, a single-pricing balancing mechanism with additional price incentives was introduced;
- In 2012 & years after Elia (encouraged by the CREG) made substantial efforts to improve balancing publications:
  - Solar and wind forecasting including real-time metering;
  - Real-time publication of system imbalance and activated volumes;
  - Real-time publication of infeed;
  - Real-time publication of balancing warnings;
  - Publication of imbalance tariff close to real-time after the concerned imbalance settlement timeframe.
- In 2018 the balancing market price cap has been increased to a dynamic price cap of 13.500 €/MWh, a value well above the current intra-day maximum clearing price [47].

Recently further developments to improve the balancing market have been implemented and are foreseen, contributing to the above mentioned general objectives. These are described in the following sections.

2.5.1.2.2 Frequency-related ancillary services

In Belgium every Balance Responsible Party (BRP) is responsible for balancing offtake and injection within its customer portfolio on a quarter-hourly basis. However, when BRPs are unable to do so, the Belgian TSO, Elia, may take the necessary steps to reduce the residual imbalance between electricity generation and consumption. To this end, Elia organises a balancing market through which it can access the flexibility offered by BSPs. Depending on the flexibility product in question (FCR, aFRR or mFRR), the balancing market has either already been integrated with the markets of neighbouring TSOs or is in the process of being integrated [50].

The current market functioning rules for the compensation of quarterhour imbalances, referred to as "Balancing Rules", entered into force on February 3, 2020. Pursuant to article 200 of the Federal Grid Code, on the 1st of July 2020 a new design for the FCR and aFRR services should be implemented [51]. In what follows, an overview is provided of all frequency-related ancillary services used in Belgium, including a status of the current design and indications of planned future roadmap evolutions where relevant.

FCR – R1 (primary reserves)

- Purpose: Stabilization of the frequency in the European interconnected system, to ensure grid stability and avoid blackouts.
- Reaction time: 30 seconds.
- Dimensioning: Fixed volume of 3000MW to be contracted for the synchronous area CE (Continental Europe). Yearly split across TSOs based on electricity generation and consumption data for each control area.
- Procurement: Volume split between regional (FCR cooperation) and local procurement. Weekly tender. Move to daily tender and exclusively regional procurement planned and announced for July 2020.
- Can be provided by: All technologies (incl. demand response & storage), all players and all voltage levels. Portfolio bidding is allowed.
- Remuneration: Payment for reservation (MW) only.

aFRR - R2 (secondary reserves)

- Purpose: Automatic restoration of balance and frequency, relieving FCR in case of larger imbalances.
- Reaction time: 7,5 minutes.
- Dimensioning: Yearly sizing with regulatory approval of volumes.
- Procurement: Weekly tender. Move to daily tender planned and announced for July 2020.
- Can be provided by: Currently only large assets with a power-scheduling obligation ("CIPU assets"). Market opening towards all technologies, all players and all voltage levels planned and announced for July 2020. The new design for the aFRR services will have a merit order activation of the aFRR energy bids instead of a pro-rata activation as applied today. Portfolio bidding is allowed.
- Remuneration: Payment for both reservation (MW) and activation (MWh). Move to marginal pricing for activated balancing energy envisaged as from the moment sufficient liquidity has developed.

mFRR - R3 (tertiary reserves)

- Purpose: Solution to cope with major imbalances
- Reaction time: 15 minutes.
- Dimensioning: Yearly sizing with regulatory approval of volumes. Move to daily sizing planned and announced for February 2020.
- Procurement: Monthly tender. Move to daily tender planned and announced for February 2020.
- Can be provided by: All technologies (incl. demand response & storage), all players and all voltage levels. Portfolio bidding is allowed.
- Remuneration: Payment for both reservation (MW) and activation (MWh). Move to marginal pricing for activated balancing energy planned and announced for February 2020.

As a general outlook for the period after 2020, frequency-related ancillary service product evolutions will continue mainly in two ways:

- Firstly, a further inclusion of capacity connected on low-voltage/residential levels is strived for. This may for instance entail specific product design adaptations and alternative metering requirements;
- Secondly, a further regional harmonization and integration of frequency-related ancillary services is intended, e.g. through the EU balancing projects [47].

Imbalance tariffs

Two evolutions were recently proposed regarding the balancing publications. As from September 1st 2019, an estimation of the imbalance tariff is published in real-time on the Elia website, in addition to the current quarter-hourly publication, in order to be in line with the already in place real-time publication of the imbalance volume and NRV (Net Regulating Volume) of the Belgian control area. In addition, as of 1/1/2020 Elia shall, based on a developed IT tool, communicate individually towards the BRPs the estimated real-time volume allocation for DGOs (Distribution Grid Operators), which is one of the components that ultimately determines the BRP's imbalance. The aim of this development is to provide BRPs yet a better view on their individual real-time portfolio balance, which should help them in the prompt management of any imbalances.

In addition, new modifications are in place for the calculation of imbalance tariffs in case of high structural imbalances. The need for revision is triggered by the (planned) increase of installed renewable generation capacity (in particular offshore wind), resulting in an enlarged risk for substantial and persistent system imbalances within the Elia control zone. The imbalance tariffs in Belgium are based on the activated balancing bids in a given quarter-hour and include an additional component in case of high structural imbalances. This so called “alpha component” comes into play when imbalances reach 140MW (which is more or less the volume of contracted automatic Frequency Restoration Reserves). In general, the alpha component is a dissuasive incentive incorporated in the imbalance settlement process to ensure that BRPs maintain their balance and in particular to avoid large and structural imbalances that would otherwise lead to a future increase in reserve needs. This implies therefore an investment incentive for BRPs to ensure sufficient flexibility within their portfolios

Two modifications on the calculation and application of the alpha component are planned as for 2020.

- Firstly, the calculation of the alpha component will change, so that stronger incentives are given to BRPs during high and structural imbalances:
    - Alpha should respond more quickly to changes in the system imbalance and particularly impact in case of structural system imbalance.
    - The impact of the alpha parameter in magnitude should be in proportion to the System Imbalance: the impact of the alpha parameter on the imbalance tariff should be larger for large imbalances than for small imbalances.
    - In case of low system imbalances the need for an additional incentive is low therefore the alpha parameter can be low as well.
    - In case of extremely high system imbalances the additional incentive of a continuously increasing alpha parameter is limited and should not serve as an unnecessary penalty.
- Secondly, the revised alpha component will apply symmetrically to all BRP imbalances so that the alpha component not only punishes BRPs acting against the system, but also rewards BRPs helping the system, as such evolving towards a fully single-pricing balancing mechanism.

It is also noted that the existing alpha component in the imbalance price mechanism already exhibits quite some characteristics of a scarcity pricing mechanism. This extra imbalance price component laid upon BRPs increases the real-time price signal (which again could back propagate to earlier time frames) when the system imbalance of the Belgian control zone increases. By doing so, it provides extra financial incentives to BRPs to avoid large and persistent imbalances. This implies therefore an investment incentive for BRPs to ensure sufficient flexibility within their portfolios. Furthermore, as the alpha-component will also apply symmetrically as from 1/1/2020 on BRPs helping the system when suffering from larger imbalances, the investment incentive for ensuring sufficient flexibility is not only given through the penalization of BRPs being short but also by rewarding BRPs being long in such situation. It must be noted, additionally, that the alpha-component is not only targeting upwards flexibility but applies mutatis mutandis also towards downwards flexibility. In this respect the already existing alpha component must be taken into account in case of proposals for methodologies to calculate scarcity price-adders in a Belgian context [47].

2.5.1.2.3 Demand-side response

Belgium is one of the pioneers in the establishment of an adequate regulatory framework for demand response. Already back in 2013-2014, Belgium was considered by the Smart Energy Demand Coalition

(SEDC) – the European industry association of demand response operators – as one of the three markets in Europe where the market design and environment allowed demand response to be commercially viable. Subsequently, in 2018, the smartEn Map: European Balancing Markets Edition report identifies Belgium as one of the three highest scoring countries in terms of advanced balancing markets for demand response and distributed energy resources, showing a deep investment in market solutions provided by different technologies. Demand response is eligible for the primary and tertiary reserves, as well as the interruptible contracts program. Demand side response is eligible to participate in the wholesale electricity markets (including day-ahead and intra-day) as well as the balancing market and is treated in a similar way as other market participants and balancing service providers. Demand side response can be represented either individually or via aggregators. In 2014, the country increased its demand response capacity to guarantee a secure energy supply in cold weather. As a result, demand response comprises 10 per cent of strategic reserve, and a pilot project is currently exploring the use of demand response in the secondary reserve [47].

At distribution level, the energy market in Belgium is about to change with the advent of Atrias, a national clearing house, and the introduction of a new market communications standard, known as MIG6. The new clearing house will facilitate data exchange between energy market participants, while the new market model will include the latest technologies, such as the availability of smart meters and distributed production. Atrias and the new MIG6 operational since mid-2020; make the demand management opportunities afforded by digital/smart meters fully available [52].

Principal enablers for Demand Response are:

- Third-party aggregators can participate in the market.
- Offers do not need to be symmetrical in FRR and RR.
- The minimum time between two successive activations is 8 h in the mFRR market.
- Prequalification takes place at pool level.
- For FCR and FRR penalties are proportional to the payments, with a multiplication factor of 1.3.

The following table illustrates technical requirements described by Elia, the Belgian TSO, that enable the participation of Demand Aggregators in the Belgian balancing market.

Table 8: Summary of balancing markets open to Demand Aggregators in Belgium [12]

Market open to DA	Min bid size (MW)	Not. time	Max number of activations	Product resolution	Symmetry	Duration of delivery	Tender period	Energy Payment €/MWh	Capacity payment €/MW/h
Symmetric FCR 200mHz ENTSO-E	1	15s (50%) 30s (100%)	Continuous activation	4 hours	YES	10 minutes max	1 day	NO	8.6 on average
R3 (mFRR)	1	15 min	Minimum 8 hours from the last activation	4 hours	NO	2 hours	1 day	145 on average	11.2 on average
Strategic reserve (RR)	1	Several hours before activation	40 times/y	1 winter	NO	4 hours	1 year	At least 10,500	N/A

2.5.1.2.4 Transfer of energy (ToE)

A previous analysis on the obstacles to demand-side participation in markets in 2016, showed that a major obstacle to this participation was the absence of a legal framework that organizes the transfer of energy. In order to address this point, a new market model, hereafter “transfer of energy - ToE”, aimed at allowing the final customer to value its flexibility by himself or by an intermediary of his own choice, regardless of his energy supplier while avoiding any negative impact on the latter as well as on the BRP of the concerned customer, has been adopted in 2017 (law of 13 July 2017 modifying the Law of 29 April 1999 on the organisation of the electricity market). This new legal framework foresees a gradual implementation of the transfer of energy to the FRR markets segments as well as to the DA/ID markets. This model is applicable for any kind of contracts between the final customer and his supplier.

Following this, the transfer of energy is in place in the market of mFRR since 2018. Together with the transfer of energy, alternative models such as the opt-out (flexibility service provider, electricity supplier of the final customer and their BRPs reach their own agreement) and recently the pass through model (only valid for some kinds of contracts), have also been proposed and implemented by the TSO after public consultations and approval of the regulator.

The planning for the operational implementation of this transfer of energy model as well as the alternative models in the other market segments is the following:

- Strategic reserve: 01/11/2019: transfer of energy and opt out; 1/11/2020: pass–through;
- Secondary control markets (aFRR): 2019: opt-out and pass through models, and reassessment of the need for the implementation of a transfer of energy model;
- Day-ahead and intra-day markets: The implementation of the transfer of energy on these two latter markets is subject to the successful completion of ongoing studies on the technical and economic feasibility.

This right conferred on the final customer is in itself a way to encourage the participation to these various markets insofar as it allows him to better negotiate his participation and so to potentially yield a higher income. ToE is not yet applicable for low voltage consumers (notably as a 15’ metering device is currently necessary). Concerning the regulated prices, Belgium has no exemptions from network or energy-related costs for specific classes of consumers, which might affect demand response incentives [47].

2.5.1.2.5 Smart meters

Belgium is still at the planning stage when it comes to smart meter systems, as can be seen by the fact that little relevant regulation exists at this point. Indeed, Belgium lacks a strategic plan for their wide scale deployment [53]. Recently and according to the Belgian Electricity Implementation plan (in accordance with article 20 of Regulation 2019/943 of 5 June 2019 on the internal market for electricity) legal frameworks have been revised according to the different regional contexts to provide for the gradual and targeted roll-out of smart meters. This should give network users more insight into their (hourly) energy consumption so that they can identify ways of using less energy. Smart meters will also help households and businesses shift their energy consumption from times of peak demand to periods of surplus production without inconvenience or loss of productivity. Thanks to the smart meters, it is also expected that ‘smart’ energy contracts will be offered by the suppliers to the customers, e.g. to include dynamic price signals linked to wholesale spot market prices. This would also enable all Belgian consumers to get access to new services and products, better modulate their energy behaviour and get rewarded for doing so, while also serving the interests of the energy system as a whole. Moreover, the national authorities are encouraged to promptly put in place a simple and transparent framework for access to data by eligible parties, as well as consumers and those with their consent, to effectively operationalise the respective provisions (Articles 23, 24) of the Electricity Directive.

The various regional parliaments will vote shortly on the gradual roll-out of smart meters in homes across different parts of the country. The cost-benefit ratio of this technology was still negative until a few years ago. However, prices have since fallen and the technology is seen as a vital means of responding to future challenges [52].

The roll out of smart meters will be progressive and the timing of implementation will be different in the three regions. Flanders has decided on a full roll-out of smart meters over the next 15 years. In contrast, Wallonia & Brussels have not committed on a full roll out [47].

Wallonia:

In Wallonia, the development of smart networks can be centred on three specific objectives:

- A framework for the use of smart meters with phased roll-out;
- Setting up a framework for the flexibility market in line with federal legislation;
- Setting up a framework for alternative networks.

Not later than January 1st 2023, systematic roll out is foreseen in the following cases :

- For residential consumers in default of payment;
- WWhen meter has to be changed;
- For new connections to the grid;
- When the consumer requests it.

No later than December 31 2029 there will be 80% of smart meter installed for:

- Consumers with a consumption ≥ 6.000 kWh ;
- Prosumers, when the net developable electrical power is ≥ 5 kWe;
- For charging points open to the public.

Flanders:

The country's Flemish region appears to have made the most progress on the smart meter front. In the Flemish region, the Decree of 14 March 2014 transposing Directive 2012/27/EU and amending the Decree of 8 May 2009 on energy policy regulates smart meters in open-ended terms. Article 4.1.22/2 of the Decree of 8 May 2009 sets out the basic principles. Firstly, the Flemish government will identify when DSOs can deploy smart meters. Secondly, in case of a smart meter being installed, DSOs are responsible for providing consumers with detailed information regarding their rights, obligations, and the technology's full scope. Thirdly, the Flemish government will determine the mandatory criteria for smart meters. Fourthly, the Flemish government will decide how to share data from smart meters. Lastly, the decree states that parties receiving data from smart meters are responsible for conforming with relevant data protection regulation.

Currently, the Flemish region has implemented around 50,000 pilot smart meter projects, installed by Eandis and Infrax, the DSOs for the region. These pilot projects have taken on board input from various stakeholders and are seeking ways to decentralize electricity generators and find the most appropriate grid areas in which to integrate RE. On 14 July 2017, the Flemish government released a draft decree calling for the segmented deployment of smart grids. Starting 2019, smart meters for electricity and gas will be installed no later than 2035 on all low-voltage connections up to 56 kVA. This will primarily affect new builds or major renovations, or specific types of customer such as solar panel owners and customers with a prepayment meter.

Full roll out foreseen in 15 years:

- No later than 2023, 33% of customers shall have a smart meter.
- No later than 2028, 66% of customers in Flanders shall have a smart meter.
- No later than 2034, 100% of customers in Flanders shall have a smart meter.

Brussels:

In the Brussels-Capital Region, smart meters are currently being installed in new builds, during major renovations and for prosumers. For all other segments the details of the smart meter roll-out are still under discussion.

The roll out is progressive and compulsory:

- When meter has to be changed;
- For new connections to the grid.

Roll out authorized:

- For consumers equipped with a storage unit or a heat pump;
- For prosumers, consumers with electric vehicle;
- For consumers with a consumption > 6.000 kWh.

2.5.1.2.6 Energy storage

In Belgium, energy storage is an important prospect as it prepares to transition away from nuclear energy and increase RE usage. At this time, storage facilities in the country are limited, with only two hydropower plants that have a total capacity of around 1.3 GW. Although the initial aim was to use the plants to regulate generation from the Tihange nuclear plant, they are in fact being employed to balance load in the grid. Storage capacity needs in the country are likely to rise from 7 GW to 12 GW by 2020. To meet this need, a manmade offshore pumped-storage facility is being planned, to support offshore wind power generation. One of the hydropower plants may also be upgraded to increase storage capacity [53]. However, while these planned infrastructure upgrades may help, regulatory challenges must be addressed in order to successfully develop storage technology in the country.

Distribution-level storage could be used to support the distribution network as an alternative to traditional network dimensioning based on peak power. In order to install individual home or neighbourhood batteries and to achieve demand management across a distribution network, a clear regulatory framework is needed. In addition, the focus is on large-scale, long-term storage to bridge seasonal differences and provide a solution for long periods during which the supply of solar and wind energy is not sufficient. Particular attention will also be paid to the potential of hydrogen technologies to convert surplus renewable energy into energy and economic processes (e.g. electricity-gas, electricity-industry, electricity-mobility), with an emphasis on developing a roadmap and launching pilot schemes.

To bolster (energy) infrastructure, the legal certainty and investment security of projects must be supported by a simplified permit application procedure and by optimising existing legislation on urban planning and the environment

According to the Belgian Electricity Implementation plan (in accordance with article 20 of Regulation 2019/943 of 5 June 2019 on the internal market for electricity) [47] the different levels of government will ensure the continuous development of new centralised and decentralised storage systems, and that peak-load shifting is possible where the technical and economic potential exists. An increasing share of these different capabilities will contribute directly to security of supply, in that they will be readily available and can be activated via the market.

Residential storage, SME storage, local storage potential, electric vehicles in storage mode and local tools will increase further by 2030, as will the volume of daily demand shifts.

The Regions are furthermore working on a clear regulatory framework with a view to placing storage behind the meter or at the neighbourhood level and to delivering demand management across the distribution network.

Furthermore, the development of energy storage is encouraged at different levels. The Federal Government manages the Energy Transition Fund, issuing a call for R&I projects linked to areas under the federal government's responsibility (nuclear energy, transport networks, energy storage, offshore energy, etc.) every year. The scope of projects eligible for the fund will be extended to include regional competences. The fund is supported by an annual fee of EUR 20 million paid by the owner of the Doel nuclear power plant to the Federal Government in return for the extension of its operating licences, until 15 February 2025 for Doel 1 and 1 December 2025 for Doel 2.

In September 2016, Belgian Prime Minister Charles Michel launched a proposal for a National Investment Pact with the private sector to create a sound investment climate and sustainable and inclusive growth between now and 2030 through public-private partnerships. The report was published on 11 September 2018. Six 'strategic' sectors were identified, energy being one of them. The investment pact mentioned the development of storage facilities for heat and electricity as one of the investments required to enable the energy transition. These energy-related projects represent a total investment of EUR 60 billion between now and 2030 (versus EUR 150 billion for the six strategic sectors). In general, the private sector will provide around 55 % of the capital funding. Some of this funding will be spent on innovation, research and development.

In Flanders, VLAIO offers grants for R&D projects, including support for development projects at an advanced stage of the innovation process (pilot phase). In addition, VLAIO also provides support through advice and training and by stimulating coordination and networking. VLAIO's grants cover the entire spectrum of R&I projects, including energy and climate (energy efficiency, renewable energy technologies, energy systems, energy storage, carbon capture, use and storage (CCUS), etc.), and are awarded following an evaluation based on the precise innovation involved and the economic added value created for Flanders.

Energy research is also a core part of Wallonia's energy commitments and regional expertise. The energy storage technologies are one of the main fields of research: storage (daily and interseasonal), including batteries (and their recycling) and emergency power supplies; phase-change materials; compressed air storage; accumulators; hybrid batteries (lithium, redox-flow, etc.) and storage management tools.

2.5.1.2.7 Electric Vehicles

Belgium has one of the EU's largest fleets of electric buses, while Electrical Vehicles in total had obtained a market share of more than 2 per cent in the country. Plans are afoot to ensure the use of EVs continues to rise in the country. For example, a joint-stakeholder platform—the Belgian Platform on EVs— has been established to create a national strategy for electric transport, which has produced a policy paper titled "Roadmap 2030 for the Stimulation of Electric Mobility in Belgium." Numerous institutes are researching EVs and hybrid vehicles in Belgium, and their work is driving the EV trend. These include Flanders' DRIVE, "Katholieke Universiteir Leuven" (K.U. Leuven), the Limburg Catholic University College (LCUC), and University of Ghent, "Vrije Universiteit Brussel" (VUB). Some of this research explores the idea of integrating EVs with smart grids as an option for charging EVs, ideally using RE. Other research is looking into ways to use EVs as a solution towards energy storage.

When it comes to regional efforts to promote EVs, the Flemish government has, since 2010, invested more than EUR 16 million in support of EV testing sites. Authorities have also instituted specific tax policies to encourage EV usage, such as tax breaks for businesses using electric or hybrid vehicles and subsidies for those buying EVs domestically, among others.

Large-scale EV deployment relies on charging infrastructure. Thanks to policies supporting the private sector in building charging infrastructure, Belgium has around 1,500 public charging stations, even without a tangible regulatory framework in place [53].

2.5.2 Existing obstacles

2.5.2.1 Legal Barriers

2.5.2.1.1 **No centrally coordinated energy policy**

In Belgium each region has its own regulatory framework for the management of its electricity market:

- The Ordinance of 19 July 2001 regarding the organization of the electricity market in the Brussels Capital region;
- The Decree of 8 May 2009 on energy policy (also known as the Energy Decree) for the Flemish region; and
- \the Decree of 12 April 2001 regarding the organization of the regional electricity market for the Walloon region.

Reaching a cohesive energy strategy is a key challenge for the country. While currently, Belgium's central government and its three regions share competence for energy and climate change, in reality the regions enjoy jurisdiction over policy related to these issues. The situation sometimes results in lack of clarity when it comes to dividing competences between the federal and regional levels. Further, the system as it stands leads to a lack of coordination amongst the entities managing energy and climate policies. Different regional regulators and different support schemes require constantly varying considerations in respect of the submarkets. This implies higher overall costs, a disadvantage which is even reinforced by long-lasting (decision) processes. To this end, it was decided in 2015, to create an energy pact for the country that would encompass a long-term outlook and to identify tangible steps to achieve energy and climate goals both within Belgium and at the EU level. However, political disagreements got in the way of the project fulfilling its ambitions [53].

2.5.2.1.2 **Demand response**

Until now, no regulation exists in the country that defines aggregators or specifies their role in the electricity market and this could explain the challenges with providing ancillary services and serving customers independently. However, a law passed in July 2017, which is yet to be ratified, addresses this gap by defining the functions of independent aggregators. In addition, the law acknowledges that all customers in the electricity value chain have the right to flexibility without restraints imposed by retailers [53].

The aggregators note that they are blocked from full participation in the balancing markets and from the wholesale markets, due to the fact that they must have the retailer's permission to enter these markets with a given consumer (as Elia states, a customer can participate through their supply contract). This consistently causes entry barriers, as retailers may not have the same incentives as consumers/aggregators for market entry.

To expand further and participate in the wholesale and balancing markets it will be necessary to complete negotiations surrounding the standardized process designed to allow consumers and aggregators free access to the market. The Belgian Demand Response market will be unable to grow further without these processes in place. The negotiations have been underway for over a year but have not progressed further. Regulatory and policy intervention may be required to compete as the incumbent players lack the motivation for ensuring a successful conclusion to the discussions [54].

2.5.2.1.3 EV deployment

In the field of large-scale EV deployment identifying the appropriate regulation and policy regarding the installation and running of public charging stations entails a number of challenges. Regulation would need to consider the type of charging technology, charging station locations and ownership, safety, standardization, and pricing. For Belgium, the fact that competence over energy-related regulation is divided across the federal and regional levels exacerbates these challenges. Still, the Belgian Platform on EVs is a move in the right direction, as it promotes trans-regional initiatives towards creating appropriate regulation [53].

2.5.2.1.4 Energy Storage

Energy storage technology is another field where regulatory challenges must be addressed. To help build and run offshore pumped hydro storage projects, Belgium enacted an amendment in 2014 to the Federal Act of 29 April 1999. Unfortunately, the law's scope was rather narrow, and it did not address the country's regulatory gap regarding energy storage solutions. For example, in Belgium, as in several other European states, storage facilities result in a double payment of grid charges, because storage technology is not categorized correctly in the electricity value chain [53].

2.5.2.2 Market Design Barriers

Although Belgium has made significant progress regarding demand response, some obstacles remain. Several of them related to broadening the scope of existing demand response to household consumers, either individually or via independent aggregators. However, aggregators require prior arrangements with the customer's supplier because when it comes to flexible loads, the seller must be the customers' Balance Responsible Party (BRP). Since the supplier is the customer's default BRP, the right to pool the customer's excess load for onward sale on the power exchange has to be transferred to the aggregator. Moreover, the threshold for being a BRP is providing a performance guarantee of EUR 4,000 per MWh, which prevents customers from selecting aggregators and gives suppliers an unfair advantage. Another hindrance to demand response in Belgium is that prequalification requirements, in practice, eliminate all but big industrial consumers. For example, BRP customers must be connected to high, medium, and low voltage grids and must go through the DSO's approval procedure. In other words, household customers, are, in effect, prevented from taking part in balancing markets. In order for the market to be opened to large consumers and aggregators, it will be necessary for Belgium to establish standardized processes enabling market access for consumers/aggregators, which is fully independent of the retailer. These should include processes for: assessment of volumes, data exchange, a governance structure and (if desired) a compensation methodology to be used between the BRP and aggregator/consumer. Without these standardized methodologies in place aggregation has not been fully enabled in a market.

Further, because of a certain fear of policy of having high imbalance prices, price caps were introduced. The price caps on the R2 market are also due to the high market power of currently about 2-3 players offering their services there. These price caps are further tailored for CCGTs. The price caps in combination with a pro-rata activation (no merit order before July 2020) make it difficult for any new player to offer on this market with a different technology from the one the price caps where designed for. In the end there is low competition on the R2 market resulting in higher prices for the TSO and therefore for the end consumer.

In addition, in Belgium the network tariffs are not flexible and very high. As a consequence, the earnings from flexible power supply are marginal for customers which do not provide incentives to shift consumption patterns. To allow flexible tariffs, a redesign of the legal systems seems to be necessary, so that flexible prices are combined with sufficient protection of consumers. Prices could be regulated in another way, for example by obliging suppliers to let their customers choose between a standardized contract with fixed prices or another contract with flexible prices and to oblige suppliers to be transparent about the expected costs of the various contracts for the individual consumers and/or to send consumers with flexible tariffs a monthly bill [53].

In Belgium, the transmission and distribution fee is based on the amount of energy consumed (€/kWh). The Belgian scheme (based on energy consumption), doesn't incentivize consumers to change their behavior and thereby lower the burden to the grid at peak times. In these methods, the costs of using the grids are not sufficiently attributed to the causers of these costs. A level playing field requires that parties who attempt to fit DER efficiently into the system and to minimize the total costs of the grids, are rewarded for these efforts [55].

DSO-connected consumers can participate in R3-DP (since 2014) and SDR as from 2015-16. Other products might open to DSO consumers in the future, though the remaining issues with the lack of transparency concerning DSO blocking of a given consumer's access put this into question. DSOs have gained the right to block consumer access to Demand Response to avoid regional capacity issues. This in itself may be acceptable, however they are not required to measure or prove a potential issue. They are also not required to reimburse the TSO, aggregator or consumer for this decision. This lowers the interest of service providers to engage with DSO connected customers as it adds an extra element of project risk in an already difficult market [56].

2.5.2.3 Technical Barriers

Measurement Provisions currently do not enable full access of customer load to market. Volatility of local energy production (e.g. from locally installed wind turbines) or inflexible consumption, at one site cannot be isolated from the available flexible power/load potential at that same location, and a large amount of the available Demand Response potential remains inaccessible for aggregation. As such, there is a need for "meter behind meter" provisions in the settlement process, allowing full measurement of available load (except R1) [56].

2.5.2.4 Data protection

Given that smart grids monitor energy consumption and fluctuations in supply and demand, this involves collecting user data including personal information, habits, and time spent at home. Apart from analysing user consumption information, such habits could be also inferred using the data collected by sensoring devices. Naturally, this raises concerns regarding data protection and privacy, and the EU member states need to have relevant and effective regulation in place before smart grids become widespread.

In Belgium the national data protection authority—the Privacy Commission—ensures the country's compliance with relevant laws, and Belgian regulation complies with the basic requirements of Directive 95/46/EC on the protection of individuals with regard to the processing of personal data and the free movement of such data. When it comes to electricity, the DSO holds the position of data controller and thus, in keeping with the broad guidelines of data protection, it is responsible for primary data protection. This means that it is required to let the Privacy Commission know before using any kind of automated system for processing personal data. According to the law's rather broad definition, processing includes collection, recording, organization, storage and deletion of personal information, among other things. Arguably, by placing stress on the idea of "automation," the law seems to exclude manual data processing from its scope. Thus, the controller only needs to notify the Privacy Commission when it uses automated systems for data processing.

Moreover, controllers are not required to notify the Privacy Commission when data processing relates to administrative duties, such as billing procedures. This leads to complications, though, because the assumption is that data around consumption is solely used for billing processes. But while consumption data received via smart meters might not be personal per se, when combined with other key data it could suffice to identify a customer. Unfortunately, the law does not seem to factor in this situation. Still, since the law came before the onset of smart metering, this gap is perhaps understandable. Moreover, with meter reading being an annual undertaking in the country, it is plausible that the data is processed too infrequently to pose a major risk to consumer privacy. As advanced metering infrastructure (AMI) is currently at the pilot phase and has not been deployed across the country yet, there is still time to enact legal reform [53].

2.6 Greece

2.6.1 Current regulatory provisions and business models

2.6.1.1 The Greek electricity market

During the last decade, the Greek energy sector has experienced reforms which include among others the liberalization of electricity and natural gas wholesale and retail markets. These measures established sustainable, competitive, and secure energy sources and a regulatory framework that transformed the energy and electricity market, breaking Power Public Corporation's (PPC) monopoly in production, transmission and distribution of energy and increasing competition. Greece has made substantial progress in diversifying the electricity fuel mix, especially in the deployment of variable renewable energy, which increased to almost 22% of the total generation in 2018 [57]. A major recent development concerns the electricity market operation and relates to the abolition of the Mandatory Pool model, currently in force, with the introduction of the Energy Exchange. Greece will be transitioning to the new European Union target market, with forward, day-ahead, intraday and balancing markets. The forward, day-ahead and intraday markets will be operated by the Hellenic Energy Exchange. The balancing market is operated by the Independent Power Transmission Operator (IPTO-ADMIE) The energy market is supervised by the Regulatory Authority for Energy (RAE).

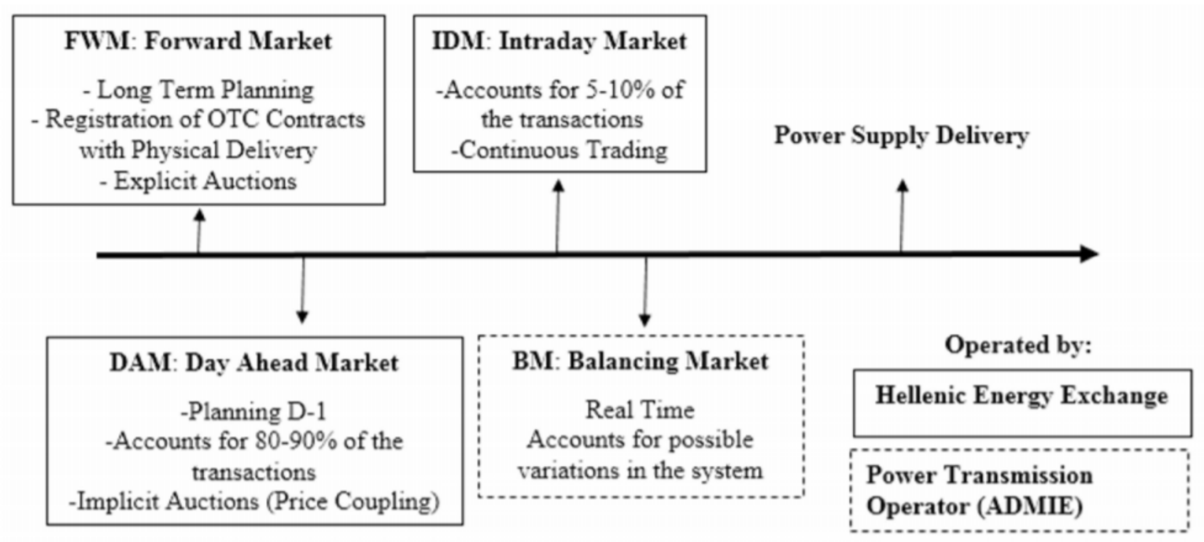

Figure 8: Market structure in Greece [58]

Greece is promoting measures to harmonise the domestic markets in electricity and natural gas with the EU directives and regulations on the markets in electricity and natural gas (target model). The coupling of day-ahead markets between Greece and Italy and between Greece and Bulgaria is expected to be launched in the fourth quarter of 2020 and first quarter of 2021 respectively. The coupling of intraday markets through continuous trading in the region of the Italian border (LIP14) is expected to be launched in the first quarter of 2021 (3rdWave). The launch of the coupling of intraday markets through continuous trading will coincide with the launch of regional intraday auctions on the Greece - Italy interconnection and potentially on the Greece-Bulgaria interconnection, whereas the pan - European intraday auctions (IDAs) are expected to be launched in 2023. The coupling of the markets will, due to improved energy flows via the interconnections, will help increase the liquidity of the interconnected markets and enable the participation of RES in the cross-border trade in electricity. By participating in the new markets, RES will have the incentive and ability to balance their position closer to real time, thus reducing the needs and the associated costs for reserves and increasing system security. As regards regional coordination for safe system functioning, in November 2019 the Greece - Italy and Greece-Bulgaria-Romania system operators agreed to establish a Thessaloniki-based Regional Security Coordinator, responsible primarily for providing the operators with decision making and network security support [59].

2.6.1.2 Flexibility

Greece is promoting measures to enhance the flexibility of the energy system through the involvement of demand in the market, further development of interconnections, integration of flexible units in the electricity system, as well as the provision of incentives for the deployment of storage systems.

2.6.1.2.1 RES and electricity market

In respect of dispersed generation by RES systems, there are auto - production, net metering and virtual net metering schemes in place, with specific technical characteristics, criteria and administrative requirements for including users therein. These schemes also incorporate a specific methodology for the settlement of the electricity generated by decentralised RES power generation systems. The regulatory framework for the operation of these schemes is being updated to take account of technological developments and to allow the use of electricity storage systems, whereas the aim for the future is that these schemes should be modified and adapted accordingly to ensure the smooth functioning of the electricity networks and the cost-effectiveness of the energy system, while at the same time enabling consumers to choose to install and use these systems without facing disproportionate technical or financial obstacles. The development of a specific institutional framework for the promotion of energy communities, which has already been completed and is in place, is deemed to be a necessary tool for strengthening the role of local communities and consumers, and therefore the operation of these schemes will be supported by the use of licensing and operational incentives (e.g. with regard to limits for participation in tendering procedures and possibilities for representation on the electricity market). Moreover, considerable participation of energy communities in net metering schemes (virtual net metering in particular) is expected, thus maximising the benefits resulting for the local economy.

Clear provisions will be made for the direct participation of RES plants in the electricity market without their obtaining any kind of aid or guaranteed contract. However, the sliding feed-in premium scheme will continue to be the key tool for supporting RES technologies in power generation as a whole, whereas specific provision will still be made for plants with a low installed capacity to receive fixed price operating support. In this context, a special monitoring mechanism and procedure is already in place aimed at adjusting the reference price of each technology and category of RES plants in respect of projects that have not yet been put into operation, depending on the evolution of the financing costs and of the development and operating costs of such plants. Innovative and pilot RES projects will continue to be eligible for financial support through operating and investment aid on condition that they have been proved to cause an increase in domestic added value and that they contribute to covering local and/or special energy needs. The sustainability of the RES aid scheme is now ensured through the orderly and transparent functioning of the Special RES Account, and therefore this mechanism will continue to function in the best way possible by structuring the available input mechanisms, ensuring its sustainability under all circumstances and offering investment security and certainty to investors. The development of environmental markets through the use of GO for RES energy is scheduled for the following period and is expected to function as a complementary market mechanism which will further contribute to the orderly operation of the Special Account [59]. In this direction, it is noted that the installation of hybrid RES plants is promoted, either through private projects or through pilot projects such as the CRES's project for the conversion of Ai Stratis into a 'green island' and the Hellenic Electricity Distribution Network Operator's project for 'smart islands', and two hybrid RES plants have been put into operation on the island of Tilos [60] (with battery) and on the island of Ikaria (with pumped storage). Moreover, Greece participates actively in the new EU initiative 'Clean Energy for EU Islands'.

2.6.1.2.2 Involvement of demand in the market

The existing institutional framework has incorporated provisions for promoting demand response systems. The Article 28 of the Hellenic Distribution Network Code foresees the activation of distributed Demand Response by the DSO by establishing “Demand Control Contracts” with individual electricity consumers located in congested network areas. These contracts shall allow the Greek DSO to set limits or even to interrupt, at its own initiative, the supply to the facilities of the contracted consumers, subsequent to their notification, in the periods specified in the contracts.

Concerning flexibility from distributed generation units, according to the Hellenic Electricity Distribution Network Code, the DSO has the right to request from distributed generators to contribute to voltage control by managing injected/absorbed reactive power by including these requirements in the Connection Agreement (Article 77 of the Hellenic Electricity Distribution Network Code). Also, active power of a distributed generator can be limited by the DSO as long as this is included in its connection agreement (Article 78 and Article 68 of the Hellenic Electricity Distribution Network Code). It should be noted though that the above provision of the network code has not yet been implemented in the Greek distribution network.

Curtailment of DER by the DSO is also foreseen in the Hellenic Electricity Distribution Network Code under the following circumstances:

- When this is demanded by the TSO according to the System Operation Code
- Under emergency situations
- In case of faults or maintenance or in order to perform necessary operations on the network.
- If such an option is explicitly included in the Connection Agreement and/or Sales Agreement

Greece to date aims to encourage demand-side participation through long-term capacity compensation schemes and by applying interruptibility schemes. In January 2016, the Interruptible Load Service was instituted under Law 4203/2013, which allows the Greek TSO (Independent Power Transmission Operator - IPTO) to sign specific types of contracts with electricity consumers, based on which consumers then must provide interruptibility services upon receiving a relevant direction from the TSO. The service can be offered by consumers connected to the electricity transmission and MV network of the interconnected system via their participation in auctions. The TSO can proceed to temporarily decrease the active power of interruptible counterparties up to an agreed value in return for financial compensation. The Ministerial Decision (ΑΠΕΗΛ/Γ/Φ1/οικ. 184898, Official Gazette B’ 2861/28.12.2015) contains information about which consumers are eligible to sign an interruptibility contract, the requirements and preconditions to do so, the reasons behind the establishment of the service, as well as the manner, timing and preconditions for providing compensation to those who participate. Additionally, demand control contracts are in place for customers connected to the MV and LV network of the interconnected system and in the non-interconnected islands, as long as they have the necessary telemetering equipment [53]. Moreover, there are contracts for residential customers offering lower tariffs during the night and interruptible load contracts for “agricultural customers”.

At the same time, the possibility of establishing Aggregators and Energy Communities has been instituted, enabling electricity consumers to operate in the electricity market, either as consumers or as producers, and through dynamic electricity tariffs, to restrict both the electricity costs of the System and the costs for consumers involved in these bodies. Law 4342/2015 states that the market codes must contain provisions that oblige the TSO and distribution network operator to treat persons who provide demand response services in an equal and objective way, based also on their technical infrastructure and potential. The law also contains the first definition of “Aggregator.”

Demand participation in the electricity market will be made possible and strengthened through the installation of ‘smart’ meters for all electricity consumers, a project expected to be completed in the following decade. This will allow to send orders to grid users remotely, so that they change their load curve, to reduce electricity prices and to participate in ensuring the power adequacy of the electricity system. In Greece, the Hellenic Electricity Distribution Network Operator (HEDNO) is managing the smart meter deployment project, in keeping with a five-year national strategy to “smarten” the country’s grid. Smart meters have already been placed at important low-voltage (LV) customer locations and also at medium-voltage (MV) customer sites. HEDNO has also installed two telemetering centers, one to collect remote meter readings from all MV customers and RES producers, and the other to collect remote meter readings from all major LV customers (>55kVA) including photovoltaics (PV). HEDNO is legally obliged to ensure 80 per cent of consumers are part of a telemetering system by the end of 2020. However, according to current projections, this does not appear to be possible [53].

Regarding net metering and active consumer scheme the quantitative objective is to set up and operate new autoproduction and net metering systems, primarily with a view to covering own needs of over 600 MW by 2030 (to reach in total more than 1 GW of installed capacity), and to engage aggregators through the possibility of participation of energy communities and of people in energy markets.

New technologies will make it possible to decentralize generation and to balance generation and demand locally. Law 4414/2016 also stipulated that all new power plants would have to participate, above a certain power limit, in the electricity market by submitting an appropriate, priced supply - forecast either on their own or through the Aggregators. If they submit an incorrect forecast, RES plants will be charged with the corresponding charges-fines.

At the same time, Greece, by developing a pricing framework, aims to promote the setup of electricity storage systems both in the autonomous systems on non-interconnected islands and in the interconnected system of Greece. The full regulatory framework for the operation of storage systems in the electricity market will have been developed and it will be possible to develop these systems as part of generation units with simplified administrative procedures to authorize their operation by 2020. More specifically, provision is made for the utilisation and development of various forms of storage, also depending on the costs and the development of the relevant technologies (pumped storage, batteries, conversion into gas, etc.), as well as storage through the promotion of electromobility. A key objective of centrally distributed storage systems is the development of storage units, including existing ones (Sfikia-Thisavros ~ 700 MW) and including projects of common interest (PCIs). The precise additional required power of storage systems, capacity, and technology of storage units will result from relevant studies that will be based on both the economic benefits they provide to the operation of the system and their contribution to power adequacy and flexibility of the System. Policy measures to promote the installation of electricity storage systems may vary depending on the technology and type (centralised, dispersed) of the storage system (such as pumped storage projects in the area of Amfilochia and Amari, Crete). In particular, the promotion of centralised electricity storage systems is possible through the implementation of an appropriate purchasing mechanism, which will motivate the construction of storage systems over other electricity generation plants.

Laws 3468/2006, 3851/2010 and 4414/2016 have detailed provisions dealing with the operation of hybrid stations in the non-interconnected island electrical systems (NIIEs) and within the interconnected system [53]. The setup of storage systems on non-interconnected islands aims to increase RES penetration in these systems (in addition to the existing 20%) and to strengthen the system's generation capacity in order to meet the demand, whereas the setup of storage systems in the interconnected system, in addition to reducing energy costs and increasing adequate capacity, aims to strengthen RES penetration and provide flexibility and ancillary services in the System. More specifically, Greece is promoting the setup of storage systems with RES plants on smaller islands that will retain their autonomous operation by applying pilot modes of operation and using management to achieve RES penetration levels of over 60%, whereas the objective for one of these islands (Agios Efstratios) is to achieve a RES penetration level of more than 85%. Hybrid RES plants have also already been commissioned on the island of Ikaria and on the island of Tilos. On the island of Tilos, the TILOS project is testing the integration of an innovative local-scale, molten-salt battery energy-storage system in the real grid environment. It is planned to test smart grid control system and provision of multiple services, ranging from microgrid energy management, maximisation of RES penetration and grid stability, to export of guaranteed energy amounts and provision of ancillary services to the main grid. The battery system is used to support both stand-alone and grid-connected operations, while ensuring its interoperability with the rest of microgrid components and demand side management. New case studies examining different battery technologies and microgrid configurations (stand-alone, grid connected and power market-dependent) are being prepared using advanced microgrid simulating tool. The prototype molten-salt, battery-storage system will improve micro-grid energy management and grid stability, increase renewable energy use and provide services to the main grid [59].

2.6.1.2.3 Electrical vehicles

The Inter-Ministerial Committee for the implementation of the project 'Promoting electromobility in Greece' was established and entrusted, inter alia, with the drafting of a national operational plan for the development of electromobility, the management and coordination of all actions and operations for promoting electromobility at an inter-ministerial level, the planning and implementation of an integrated package of incentives and the definition of the physical planning and setup of the regulatory framework for electric charging infrastructures. The plan has been published for public consultation and the respective Bill for 'Promoting electromobility in Greece' has been filled in July 2020. The Bill provides tax incentives aiming to reduce the usage cost of electrical vehicles and promote the construction of new charging points. It also provides significant incentives aiming at attracting investment in technologies and sectors of e - mobility (batteries, chargers, vehicle parts) in the areas of Western Macedonia and Megalopolis, where lignite power plants are located. Provisions are introduced for the creation of a competitive, transparent and functional market model for electric vehicle users and an investment friendly environment for enterprises [61].

The Greek DSO HEDNO is planning to install public electric vehicle charging facilities in public spaces in line with Eurelectric's DSO model, the Ministry of Environment and Energy, and the approval of the Regulatory Authority for Energy (RAE). According to the DSO model, DSOs develop and operate a public access Electric Vehicle charging network as an extension of the regulated service they provide. With the adoption of the 'DSO model', the regulated services provided by HEDNO are extended to electric motor users in proportion to the current network users. Investment initiatives from the private sector are expected as is the transition to the liberalised market model upon the market's maturity.

This particular public network charging infrastructure model makes it possible for any user without discrimination to charge an electric vehicle regardless of the Electric Vehicle Charging Infrastructure Provider (EVCIP) they have a contract with.

Charging infrastructures in public places require new roles and introduce new dynamic relationships between operators in the electricity market to provide innovative services and serve the needs of electric vehicle owners, creating competition between:

- Electric Vehicle Charging Infrastructure Providers (EVCIP), within the meaning of Law 4277/2014, and final consumers, as well as
- Electric Vehicle Charging Infrastructure Providers (EVCIP) and Electricity Providers.

The strategic plan for the development of charging infrastructures in HEDNO public places initially includes the installation of about 150 charging stations in Greek islands and at a later stage 1,500 charging stations in mainland Greece. The purpose of the project is to serve the charging of Electric Vehicles in urban public spaces (22kW, 3 phases, AC Mode 3), as well as to install fast charging infrastructure (DC Mode 4) on highways aiming at the development of a major nationwide network infrastructure that will make a significant contribution to the promotion of electrification [62].

2.6.2 Existing obstacles

2.6.2.1 RES in power generation

In promoting RES in power generation, the complexity, delays and volatility of the existing institutional framework are the main challenges to the licensing of RES plants for power generation. The development of an integrated framework with regard to the siting of RES facilities, applicable across Greece and subject to clear-cut rules, criteria and constraints, is critical in ensuring higher RES penetration in power generation. Furthermore, the overall reform of the licensing framework is imperative in view of the new operating support scheme, the aim for the development and operation of a large number of new RES projects, as well as the possibility of direct participation in the electricity market in accordance with the requirements of the new directive. The effective coordination and cooperation between the institutional bodies involved and the development of an efficient mechanism for monitoring all operating parameters are deemed to be necessary for the effective functioning of the revised licensing framework and for monitoring the effectiveness of the existing aid scheme. In general, a substantial improvement in the implementation control and monitoring mechanism is required for numerous policy measures, and there are specific cases in which the necessary regulatory framework is yet to be completed.

The completion and full implementation of the new electricity market model is crucial for the effective functioning of the new plants which will be under obligation to participate in the electricity market. A critical parameter and challenge for the following period will be the fact that due account should be taken of all the specific characteristics, stochastic production from RES plants in particular, in order to adapt at a planning level, respectively, the operating parameters of the new energy markets that will allow for the optimal RES share in the new operating model of the electricity market. At the same time, a significant challenge is the definition of a temporally stable framework for conducting these tender procedures with predefined auctioned capacity values, as well as the handling of non-optimal outcomes between the tenderers and/or selected plants. At a technical level, it is also critical for the following period to develop an appropriate institutional framework for storage units and have them participate in the electricity market. The participation of these units is considered to be crucial for attaining high shares of RES in the electricity market. In this context, plans have to be made immediately also for making possible the deployment of storage units within a RES plant, using simplified procedures. A similar challenge for the following period is to develop and operate new categories of RES projects with technological innovation and/or local added value for power generation. The setup and functioning of small wind turbines incorporates such potential characteristics, and delaying the completion of the regulatory framework for this category of projects also delays the essential evaluation of such systems in terms of the economy and social acceptance. Offshore wind farms are expected to pose a new challenge for the regulatory framework, as the timely and integrated development of such a framework is a necessary prerequisite for launching these projects in the following decade.

As regards **net metering**, the challenge is to gradually expand the scheme and attain higher growth rates. At the same time, however, a mechanism will have to be developed gradually for monitoring its impact on regulated charges. In addition to that, the provision of technical support is crucial in specific policy measures, such as in the case of energy communities. As regards the measures for expanding the transmission system and the distribution network in order to allow for the optimal and timely setup of new RES projects, there are various challenges which need to be addressed rather immediately, as there have been long delays caused already (also in issuing generation authorisations) in the implementation of RES plants and their integration in the energy networks. The management complexity and time lags due to external factors are the main challenges to the setup of such plants, and there is a need to address the congestion of the power grid in order to allow for setting up new RES capacity in areas with a high potential. Generally, it is necessary to put in place a more dynamic plan for integrating new RES plants in the power grids, which should incorporate the different regulatory and technical challenges and external parameters in a transparent and effective manner. As regards the non-interconnected islands, the Management Code should take into account the new requirements for RES plants that affect even their operational/financial plan and require the completion of all necessary implementation tools. A challenge — in technical and licensing-financial terms — that is expected to emerge gradually in the following period consists in the radical renewal of the equipment of end-of-lifecycle plants, although this is expected to culminate after 2030.

The digital transformation of the Greek DSO, HEDNO, with a view to being able to respond to the challenge of increased RES penetration, management of decentralised systems for energy generation and storage, and electricity transactions, is pivotal. Congestion management needs to be handled through close cooperation between HEDNO and the Independent Power Transmission Operator (ADMIE), by implementing appropriate infrastructures and mechanisms to ensure mutual network visibility. Network development should take account of the change to the focus of decentralised generation. The development of new financial instruments that are compatible with the new market environment will contribute to the implementation of the required investments. The regulatory framework needs to change to propose incentives for the implementation of such projects, e.g. payment of an additional rate of return on capital costs and/or setting of minimum performance indicators for the attainment of actions and targets. Finally, it is necessary to provide funding mechanisms for the energy upgrading of the residential buildings of energy-vulnerable households and other social groups with specific electricity consumption patterns in the context of autoproduction and net metering schemes [59].

2.6.2.2 RES in buildings

Moreover, an appropriate regulatory framework should enable different sources and different energy operators (hydrogen, biofuels, biomethane) to function on a complementary basis, contributing to most cost-effective and sustainable system functioning. Measures for ensuring the penetration of RES in new uses and sectors, the energy coupling of sectors and the development of relevant pilot and innovative applications should be a policy priority in the following decade.

The potential for further RES penetration in buildings remains high and requires adopting specific policy measures for utilising it efficiently. A key tool will be to implement a regulatory framework for the mandatory share of RES in covering the energy needs of the building sector (setting a minimum share rate). In this context, the provisions for nearly zero-energy buildings will contribute to the further penetration of RES applications in the building sector, taking into account technical and economic sustainability criteria, contributing to the attainment of the objectives set in the context of improving energy efficiency in the building sector. The above provisions of the regulatory framework will be incorporated in the revised Regulation on Energy Efficiency of Buildings, while special emphasis will be placed on the exemplary role which public buildings used by the State must play by laying down limits for a minimum share of RES taking into account economic sustainability and energy benefit criteria. In addition, efforts need to be made to maximise synergies with both the policy for maintaining the autoproduction and net metering scheme and other policy measures in the field of the energy efficiency of public and private buildings [59].

2.6.2.3 RES in transport

As regards policy measures for promoting RES in transport, it should be stressed initially that the electrification of the transport sector, with high shares of RES in the electric mix, will contribute automatically to a higher RES share in energy consumption, plus the benefits relating to improved energy efficiency and reduced emissions and pollutants. The most important problem of electromobility is the high initial cost of electric vehicles, which has also undermined the sustainability of the required charging infrastructures. Completing the institutional framework for the operation of the electromobility market and developing the required infrastructures are an important parameter for, as well as a challenge to, the further promotion of the use of electric vehicles, along with reducing the purchasing cost of electric vehicles, which is expected to accelerate based on estimates from the global automotive industry in the period up to 2025 Please note that increasing the fleet of public transport vehicles of all types, as well as of the special-purpose public vehicles (municipal transport, municipal school buses, etc.) that will be powered by electricity, aiming to reduce the use of private vehicles, will contribute both to an increase in the RES share and an improvement in energy efficiency in the transport sector. An additional challenge is to increase the use of electric micro-mobility vehicles, whether private or municipal available for rental, by utilising appropriate infrastructures and mechanisms for the use of such vehicles. Similar challenges are there with regard to vehicles used by businesses for supply and loading/unloading purposes. Important challenges include providing consumers with information on the benefits of electromobility establishing incentives for people and businesses, completing the regulatory framework, having sustainability criteria certified by voluntary schemes, and more effectively analysing and processing the statistical data collected by the information system, taking into account the reporting requirements of the new directive [59].

2.6.2.4 Internal energy market

Completing the regulatory framework and implementing the necessary technological infrastructures are prerequisites for launching new electricity markets and coupling them with the other European ones through interconnections. At the same time, measures for proper market functioning, i.e. the existence of liquidity for spot markets, the provision of adequate hedging, the restriction of manipulation and the capability of active consumer participation, are necessary for the successful functioning of the internal market. Developing a mechanism for market monitoring indicators for assessing the level of market concentration through cooperation between the competent bodies is important, while at the same time mechanisms also need to be developed to analyse bidding behaviour and thus detect anti-competitive practices [59].

2.6.2.5 Network and interconnections

In this context, the best technical and cost-effective enhancement and expansion of energy infrastructure in both the transmission system and the distribution network for tackling congestion that prevents further growth of RES plants in specific areas will also be, for the following period, a core measure for the optimal integration of RES in energy networks. For example, the possibilities of improving the capacity of existing substations (adding transformers) and upgrading them generally should be utilised. Apart from that, new regulatory models for the allocation of charges for new network and system development projects (substations in particular) should be designed, to facilitate the implementation of such projects for connecting small producers. Moreover, the substations already constructed by producers (primarily for connecting wind farms) could be utilised on the basis of the pilot project that is under implementation in order to cover network distribution lines, as this would allow for connecting more RES plants to the network, whereas the regulatory framework would need modernisation in this direction. To that end, HEDNO has already prepared preliminary studies in order to identify the required enhancement of the distribution network, in terms of the number of high/medium voltage transformers that will be congested and will, therefore, need enhancement and of the corresponding distribution lines that will exceed the RES feed-in capacity and will, therefore, need enhancement too.

With regard to policy measures for developing infrastructure for international and domestic interconnections, the major challenges are management complexity, time lags due to external factors and availability of resources, which require dynamic planning with the option of incorporating the different regulatory and technical challenges and external parameters. In addition to the above, there is a need to completely digitize networks and meters management to reorganise the electricity markets and enhance competition. In particular, it is necessary to take measures to install digital, 'smart' meters and to install centralised systems for the control and management of the operators' property. The centralised control systems of the operators should communicate with the network components via a telecommunication link [59].

2.6.2.6 Energy Storage and demand response

Both centralised and decentralised storage units require the development of a comprehensive regulatory and statutory framework for their operation in energy markets and their integration in electricity networks. The regulatory framework should be developed in a way that normalises the integration of storage systems in new or existing RES plants without, however, distorting the compensation paid to these plants. The role of transmission and distribution operators in identifying the requirements and characteristics of the development of storage infrastructures, also subject to the provisions of the relevant EU directive and regulation, is expected to be crucial. Right now, battery deployment could be integrated with that of large hybrid stations catering to the MV level. However, no provisions exist for batteries in residential or public buildings, for electric vehicles, V2G technology on how to communicate with the power grid, or for how to sell demand response services. Moreover, in the non-interconnected island electrical systems (NIIES), the current operating procedures are dominated by conventional generation work under the assumption that only conventional generation units can provide the ancillary services necessary for grid stability. This precludes the ability of aggregating a battery or an EV fleet to supply the same service. Another barrier to developing storage capacity in Greece relates to the grid fees regime in the country. Greece is one of three EU Member States that charge grid fees for charging and discharging storage units by way of treating them as generation assets. As a result, owners of storage units have to pay grid fees as generators when charging units and as consumers when discharging them. The regulatory treatment of storage units in this manner follows the true nature of these assets, and it is clear that regulatory reform will be needed to address this challenge as it poses a disincentive towards investing in storage technology [59].

In this context, the necessary regulations/acts are already being prepared, to make possible the optimal use of these tools. Similarly, demand management and response schemes should be implemented. Participation in demand response schemes should gradually cover not only large industrial consumers, but all consumers, whether individually or through aggregators. In addition, demand response schemes in Greece are unfolding at a rather gradual pace largely because the infrastructure is not ready. For example, smart meters, which are mandatory to accurately record consumption and to allow consumers to control and adjust consumption, are still in the preliminary rollout phase [53].

2.6.2.7 Data protection

In Greece, no legislation specifically addresses data access and security for smart grids, however, this falls within the country's general data protection laws. An important factor to examine is the legal definition of "personal data" when discussing smart grids. There is a strong likelihood that information recorded through smart meters could be categorized as personal data and might thus pose an obstacle towards the rapid rollout of smart grids. In the smart grid context, another area that has yet to be clarified is the role of data controller, in charge of ensuring data protection. Laws in Greece related to data protection call upon data controllers to take institutional and technical measures towards guaranteeing security and confidentiality in the data processing process. Considering that smart grids give rise to a high risk of data intrusion, risks to electricity infrastructure and perhaps to national security, it is crucial that data protection laws be combined with establishing standards for the various technological components related to smart grids, including smart meters. The smart meter rollout that has taken place thus far in Greece did not seem to follow specific technical requirements towards guaranteeing data protection and security [53].

2.7 Cyprus

2.7.1 Current regulatory provisions and business models

2.7.1.1 The Cyprian Electricity Market

The energy sector in Cyprus is undergoing fundamental transformations concerning its structure and organisation, its institutional framework and the diversification of its energy mix. The Cypriot electricity sector is today 100% covered on the supply side and more than 90% on the generation side, by the state-owned Electricity Authority of Cyprus (EAC). In an effort to open up the market to new participants, the Cyprus Energy Regulatory Authority (CERA) has proposed the Net-Pool model as being the most appropriate trading arrangement approach for the Cyprus electricity market. The formulation of a net-pool incorporates both, a bilateral contracts market and a central day ahead market. In the near future, an intra-day market would be organized. The proposed design includes also a real time balancing mechanism that provides the TSO with the ability to purchase the required operational reserves, activate balancing services, and settle imbalances.

2.7.1.2 Flexibility

Currently, the electricity market in Cyprus cannot support neither flexibility services nor aggregation and demand response. Flexibility services, aggregators and demand response will be able to participate through a fully functioning competitive electricity market (CEM), which is planned to become operational by the end of 2021.

As far as the internal energy market is concerned and regarding the competitive electricity market, in 2020 and 2021 it is expected that a number of key projects that are under tendering or implementation will materialize and interconnected, so that electricity is traded on competitive terms, based on the design principles of the Regulation (EU) 2019/943 on the internal market for electricity as applied for Cyprus (Article 64). The completion of the two primary systems, i.e. the Meter Data Management System (MDMS) (completion est. December 2020) and the Market Management System (MMS) (completion est. Oct. 2021) will signify the operation of the competitive electricity market based on the Trade and Settlement Rules v.2.1.0. In parallel, the DSO is in the process of initiating the roll out the Advanced Metering Infrastructure (AMI) with 400.000 smart meters (installation will be completed within 7 years) together with a better control of the distribution system (Supervisory Control and Data Acquisition/Advanced Distribution Management System - SCADA/ADMS). All the above systems are a prerequisite for the gradual removal of barriers of entry for new electricity market participants and technologies (active customers, citizen energy communities, aggregators, demand response). In addition, it is noted that changes are subject to the social behaviour of individuals and the willingness of consumers to change their behaviour.

The list of policies and measures currently in place to achieve the internal energy market objectives are [63]:

- Cyprus TSO Ten Year Network Development Plan 2019-2028 according to Article 63 of the Laws for the Regulation of the Electricity Market.
- Regulatory Decision 01/2017 on the Implementation of a Binding Schedule for the Full

Commercial Operation of the New Electricity Market Model.

- Regulatory Decision 05/2017 on the Implementation of a Binding Schedule for the Full Implementation and Operation by the DSO of the Meter Data Management System (MDMS).
- Regulatory Decision 02/2018 on the Implementation of a Binding Schedule for the Mass Installation and Operation by the DSO of Advanced Metering Infrastructure (AMI).
- Ministerial Decision on 4/7/2018 for amendment the national law to enable operation of the electricity market and make the MO/TSO independent from the vertically integrated electricity company. The revised Bill was forwarded to the Law Office for the necessary legal vetting.
- Regulatory Decision 03/2019 on Storage Systems that are installed before the metering point.

2.7.1.2.1 Expand aggregation

Currently, the Trade and Settlement Rules (TSRs) allow for the aggregation of RES-only generation and the size of the aggregated capacity is limited in the range of a minimum 1MW up to a maximum of 20 MW. A new bill has been submitted which, among other measures, expands the aggregation scope to allow the aggregation of sources of generation irrespective of the primary type of fuel or technology, of storage systems as well as of the supply side (demand response). TSRs will be reviewed and amended in accordance to the new law. Aggregators will also be allowed to participate in the wholesale energy market, the balancing and reserve markets on an equal footing with conventional generation. Changes in the national legislation are expected from September 2021 to January 2022 [63].

2.7.1.2.2 Use of flexibility by the DSO

Until January 2022 changes regarding the provisions of the recast Electricity Directive 2019/955 are expected, that enable the DSO to procure flexibility services, including congestion management in their service area, especially from distributed generation, demand response, storage and other market participants (including those engaged in aggregation). The specifications for the flexibility services shall be defined by the DSO in close cooperation with the Cyprus Energy Regulatory Authority (CERA) and the Transmission System Operator of Cyprus (TSOC). The local flexibility markets shall be operated by the MO in close cooperation with the DSO [63].

2.7.1.2.3 Non-discriminatory participation of “Demand Response” in the envisaged CEM

It is estimated that by 2030 there is going to be in Cyprus an untapped Demand Response potential of around 50 MW. The existing Trade and Settlement Rules (version 2.0.1) were reviewed in October 2019 and a related proposal was submitted by the TSOC to the Regulator for approval. This proposal better reflects the provisions of Article 15(8) of the Directive 2012/27/EU [63].

Demand Response will not be applied in the beginning of the market operation as Cyprus is an immature market. However, the proposed arrangements could, under appropriate additions, accommodate this service in case, in the future, it is considered that such a service provides added value to the electricity sector of Cyprus. Demand Response is a service that can be provided either by suppliers serving load or by entities (Demand Response Agents) who aggregate smaller retail customers and directly bid corresponding capacity into the wholesale markets. In this respect Demand Response programs run by the DSO could directly participate in the wholesale arrangements as well. Demand Response Agents should therefore accede to the Market Rules and become market participants. In case of demand response, corresponding Agents should also be allowed to offer load curtailment at the Day Ahead Market (DAM) stage under arrangements that approximate those of generating units’ orders. However, since the DR Agent may not coincide with the supplier representing corresponding load, the latter will be also compensated in case of load curtailments i.e. the system will effectively double pay the same service. It is therefore required that the supplier’s Physical Position after the DAM closure is appropriately adjusted in case the DR Agent has scheduled a demand curtailment in the DAM. For such an adjustment to be possible, each DR Agent should submit Orders in the DAM per portfolio of meters registered under each retail supplier [64].

2.7.1.2.4 Non-discriminatory participation of Electricity Storage in the envisaged CEM

There is an estimated 130MW pumped storage potential by 2030 in Cyprus. The Regulator on 5/7/2019 has published its Regulatory Decision No. 03/2019 (ΚΔΠ 224/2019) in the Official Gazette of the

Republic of Cyprus with which the Storage Systems installed upwards the metering point and which are not combined with local consumption of electricity could potentially participate in the Wholesale Electricity Market. This Regulatory Decision also instructs the TSOC to take into consideration the technical parameters of Storage Systems and proceed with the necessary amendments to the Trade and Settlement Rules (TSRs) and the Transmission and Distribution Rules (TDRs) until the 31/7/2020. These systems will be able to participate in all the stages of the CEM and be able to contract bilaterally with RES Generators and Aggregators of RES-E for clearing their imbalances collectively. The storage systems will not be charged for use of the grid during the charging cycle. Specific products for high-performance ancillary services could be defined (e.g. fast primary regulation, synthetic inertia.), to be provided by storage systems and remunerated according to a “pay-for-performance” scheme [63].

2.7.1.2.5 Introduction of an intraday market

Currently, the electricity market is open to independent suppliers and generators that may engage in energy-only bilateral contracts, which are cleared on a monthly basis. All balancing and ancillary services are provided by the incumbent Electricity Authority of Cyprus. A fully functioning competitive electricity market (CEM) is scheduled to become commercially operational by the end of 2021. The CEM will comprise of a Forward, a Day-Ahead, a centrally run Integrated Scheduling Process and a Balancing Market. An Intraday market will be introduced at a later stage. Specifically, the revised Trade and Settlement Rules provide for the introduction of an intraday market 24 months after the operation of the CEM. Intraday trading is required in order to minimize the exposure of market participants to imbalances. If the interconnection of Cyprus with Greece via the Euroasia Interconnector takes place, a cross-border intraday market with a continuous trading up to one hour before delivery will be introduced [63].

2.7.1.2.6 Introduction of dynamic-pricing retail contracts

According to the final provisions of the Electricity Directive (recast), dynamic pricing retail contracts will be introduced gradually as the installation of smart meters is roll out and the competitive electricity market becomes operational. Cyprus shall provide the necessary regulatory framework to ensure that final customers who have a smart meter installed can request to conclude a dynamic electricity contract from a supplier that has more than 200.000 final customers. Suppliers with less than 200.000 final customers will not be obliged to offer dynamic-pricing retail contracts. These measure will not be active before September 2025 [63].

2.7.1.2.7 Priority Dispatch for RES and High Efficient Combine Heat and Power (HECHP)

CERA, in close cooperation with the TSO and DSO, shall amend, if necessary, the existing TSRs to provide for a correct interpretation of the concept of priority dispatch for RES and HECHP. Day-ahead and upward balancing offers by RES and HECHP should be cleared before offers of other sources with the same price; thus, RES and HECHP shall have priority only if they offer the same price as other sources. The action will be completed by December 2020 [63].

2.7.1.2.8 Technical Bidding Limits

CERA will review and decide whether to allow for the submission of a Negative Priced Downward Offers in the Balancing Market, so as to provide an incentive to RES to participate in downward balancing [63].

2.7.1.2.9 Strategic Reserve

CERA and the TSOC (MO) will review the need of strategic reserve and if required introduce a strategic (contingency) reserve mechanism to address short-term capacity adequacy concerns. Units participating in this mechanism will be held outside the electricity market and will be dispatched in case day-ahead and intraday markets have failed to clear and the TSO has exhausted all balancing resources. The TSO shall conduct Yearly Auctions for the procurement of Contingency Reserve. The Contingency Reserve will be technology-neutral, i.e. will allow the participation of DR, Storage and RES with the necessary technical capability. The design of the Contingency Reserve is already provisioned in Chapter 5 of the most recent version of the Trade and Settlement Rules (v2.0.1). These provisions shall be reviewed by the Regulator and the TSOC so as to ensure compliance with Articles 21 and 22 of the Regulation (EU) 2019/943 on the internal market for electricity and in light of the position of the

European Commission to the pre-notification of this mechanism by the TSOC (DG Competition, State-Aid, Case no. SA. 53729) [63].

2.7.1.2.10 Advanced Metering Infrastructure

The objective to deploy an Advanced Metering Infrastructure, including the roll-out of 400.000 smart meters by January 2027 will enable the optimization and control of the distribution system, increase the penetration of distributed renewable sources, enable aggregation of RES, demand response and storage and increase direct final customer participation in all market stages (active customers). Furthermore, it will contribute to increased system observability, load and generation forecasting accuracy, accurate system analysis and planning, load management alternative to ripple control, optimization of the operation of the distribution system, supervisory control and data acquisition of Photovoltaic systems.

The existence of a smart meter is necessary for the provision of consumer functionalities, such as near real-time feedback on their energy consumption or generation. Smart meter functionalities will be prescribed according to the requirements of Article 20 of the Electricity Directive (recast), which, among others, foresee for the provision of information to final customers on actual time of use.

Timeline: 400.000 smart meters will be equally divided in seven (7) installation rounds, each round consisting of the installation of 57.143 smart meters. The completion date for the first round is January 2021 and for the seventh round in January 2027 [63].

2.7.1.2.11 Meter Data Management System

Competitive market operation and customer participation require the installation of an MDMS system for the central data management of the Advanced Metering Infrastructure (AMI). The MDMS shall provide integration with the Meter Data Collection Systems and other utility information systems (SCADA, GIS) and functionalities such as Data Warehousing and Management, Meter Operations, Data Validation-Editing-Estimation (VEE). Third-party (suppliers, MO) connection to Meter Management through the External Information System (EIS), to implement the energy market provisions related to the provision of the metering data of individual customers to their Suppliers as well as the aggregated invoices to the Energy Suppliers in the market. MDMS also allows the DSO to operate as an independent entity in a multi-energy supplier market and to facilitate DSOs main business processes. The MDMS is expected to be completed by December 2020 [63].

2.7.1.2.12 SCADA/ADMS

The project includes the design, engineering, supply, installation, configuration, testing and commissioning of a Supervisory Control and Data Acquisition/Advanced Distribution Management System (SCADA/ADMS) and its integration with the GIS and Transmission SCADA/EMS System operated by the TSOC. The SCADA communicates with 175 RTUs installed at MV Level equipment. The ADMS shall provide, among other functionalities, applications for Power Flow, Switching Order Management, Short Circuit Analysis, ShortTerm Load and Generation Forecasting, RES Management and Curtailment, Emergency Load Shedding and Restoration, Cyclic Load Shedding and Restoration, Outage Management System and Power Quality Monitoring. The project for SCADA/ADMS is expected to be completed in 2021 [63].

2.7.1.2.13 Citizen Energy Communities

In order to empower citizens, the national legislation needs to be amended, according with the Electricity Directive (recast), to provide a framework for the activation of citizen energy communities, ensure fair treatment, a level playing field and a well-defined catalogue of rights and obligation, such as the freedom of contracting, supplier switching rules, DSO responsibilities, network charges and balancing obligation. The rights and obligations should apply according to the roles undertaken such as the roles of final customers, generators, suppliers, DSOs. Access to an energy community’s network should be granted on fair and cost-reflective terms. The Regulatory Framework for the Citizens Energy Communities will be ready from September 2021-December 2021 [63].

2.7.1.2.14 Net Metering

Support schemes for the production of electricity from renewable energy sources for own use such as Net-metering for self-consumption have been implemented since 2013 as national policy to promote RES electricity. Currently the Net-metering category is applied for small scale photovoltaic systems with capacity up to 10KW, for all consumers (residential and non-residential). The scope of the net-metering is to provide the option to residential and small commercial consumers to cover all or part of their electricity consumption from a PV. The generated RES electricity is subtracted from the building's overall electricity consumption. Consumers pay only for the difference between the energy consumed and energy produced (net electricity used) plus a cost that reflects the cost of the electricity grid to support continuous supply and taxes (VAT, RES levy).

The above scheme is expected to continue, with some modifications in the near future in order to enhance better the self-consumption for small systems. For household owners and for those having a building permit prior of 2017, there is a support scheme in operation for the period 2018-2020. The grant support was set at a level of 250 Euro/kW installed with a maximum possible grant per system of 1,000 Euro. In addition, if the above measure is combined with rood insulation there is a total grand of 3,000 Euros, where the grand for PV itself is increased to 300 Euro/kW. Furthermore, a support scheme for vulnerable consumes is in place since 2013 with the financial grant of 900 Euro/kW with the cap recently revised from €2,700 to €3,600 [63].

2.7.1.2.15 Self-consumption / Net billing

With Self-consumption and Net-billing schemes, PV generated energy has to be self - consumed within the same 20-min time period it was generated in. If local energy demand exceeds PV production, energy is imported from the grid. With Self-consumption scheme, excess PV generation is exported to the grid without any economic compensation nor any additional fee. A compensation for excess energy is foreseen by the Net-Billing scheme. The size of these systems is basically unlimited (up to 10MW). This support scheme is the most effective for both industrial and commercial consumers, since the self-consumption is almost excluded for all the taxes for the energy that is self-consumed.

Consumers are billed on energy consumed from the grid at the retail electricity price and receive a credit based on a variable tariff known as the 'avoidance cost' for any excess power they inject back into the grid. The avoidance cost is intended to reflect the savings offered to the country by avoiding the generation of fossil-fuel based energy. If the PV system owner generates more power than they consume during any two-month period, the avoidance cost credit is rolled over into subsequent billing periods and is likely to be cancelled out over the course of each year because of the constraints applied to the generation capacity of eligible arrays. In the unlikely instance of a system owner exporting more power to the grid than they consume, the excess does not secure any credit.

Prosumers who qualify for net billing are taxed on all the energy they consume, whether generated on-site or imported from the grid, and also pay a fee for using the network. There was a debate during the public consultation regarding the self-consumption fee, which is something that needs to be examined in more detail, taking into account the results of the study contacted from JRC, under the Administrative arrangement of SRSS/C2017/077. The study concluded that the existing framework for network charges has to change moving towards a usage-based capacity charging system [63].

2.7.1.2.16 Electrical Vehicles

In transport financial incentives for the purchase of electric vehicles have been announced in late 2019. Charging points and infrastructures for electric vehicles have been installed in public buildings and in public roads. There are currently 18 double charging stations in Cyprus: 6 charging stations in Nicosia, 5 in Limassol, 2 in Larnaca, 2 in Ammochostos and 3 in Paphos. Additionally, the Department of Electromechanical Services is proceeding to the installation of 10 fast charging stations in highways and public roads. This action will be completed in 2020. 3 additional charging stations will be installed by the Public Works Department in 2020 through the European Programme EnernetMob. These numbers are expected to grow as the electric vehicles are increasing, the expectation is that the registration of electric cars will increase considerably after the year of 2024-2025. New electric car sales are expected to comprise the major vehicles on the road by 2030, since Cyprus has end to end distance of less than 350 km. This means that with the autonomy that the new cars are having with 64kWh-80kWh batteries, they can cover a distance over 500km. On top of that, other support schemes that will be put in place, i.e. net-metering (up to 2kW) for car charging can also help reducing the cost of electricity charging significantly [63].

2.7.1.2.17 RES in buildings

Obligatory installation of RES in new buildings has been introduced since 2010, but it has been gradually tightened up in order to meet by 31st of December, 2020 NZEB requirements.

According to the Order 1/2014 of the Minister of Interior, incentives are provided regarding the increased RES in certain types of developments. These incentives associated with increased building ratio (5%) and in some cases a minimum amount of RES is required for the application of other incentives, under the Development Plans. The regulation is associated with the installation of PV and solar systems in new or existing developments (sizeable composite use developments, tall buildings, Industries etc.) [63].

2.7.1.2.18 RES in the electricity sector

In Cyprus, electricity from renewable sources is no more promoted through subsidies since 2013, where a net metering scheme and self - consumption has been put in place. In addition, the new scheme on net billing for PVs and Biomass (CHP) plants and commercial RES plans that were announced in the period 2017-2019 will also operate through the market mechanisms, once those will be put in force.

As it was highlighted through a number of studies, the penetration of RES in electricity sector (RES-e) can reach the maximum limit at a very early period, 2023-2024, due to various technical constraints that are related to the isolated nature of the electricity system of Cyprus. After the above period and if Cyprus remains electrically isolated from other electricity networks, the penetration from RES-e will only be increased once RES-e, coupled with storage technologies, materialises.

From 2015 onwards, all new RES projects are not receiving any subsidy, while self - consumption schemes do not support any subsidy in electricity prices. For household owners and for those having a building permit prior to 2017, there is a support scheme in operation for the period 2018-2020. The grant support is set at 250 Euro/kW installed, with a maximum possible grant per system of €1,000. If the above measure is combined with roof insulation, the overall grant is €3,000, where the grant for PV itself is increased to 300 Euro/kW. Furthermore, a support scheme for vulnerable consumes is in place since 2013, currently amounting to €900/kW with a cap of €3,600. It is also noted that, as of 2015, all new support schemes for RES electricity production receive a tariff based on the current EAC Fuel Cost, calculated according to the methodology set by CERA. Once the competitive electricity market operates, the respective projects will receive only the market price based on the market rules. In the Heating and Cooling sector, support schemes have been implemented for providing economic incentives for the installation of solar water heaters in homes, as well as for major energy upgrading projects in existing buildings, where high efficiency heat-pumps for heating and cooling, as well as solar collectors for heating were also supported. Some pilot and demonstration projects on CSP Technologies for heat storage, heat process and solar cooling were also developed with very promising results.

New RES generators with installed capacity above 1 MW may either: a) directly participate into the market on a per plant basis or b) be represented by an aggregator. Operators of such plants may choose to bilaterally trade their output or trade it through the DAM or both. Participation to the DAM will be possible through priced Orders (Offers). New RES generators with installed capacity below 1 MW as they cannot offer energy quantities, on a half hourly basis, greater than 0,5 MWh shall be represented by an aggregator. In case of direct participation, RES operators should forecast their output per plant and may opt to trade all their forecast quantities in the DAM. In case though they hold bilateral contracts, they should nominate relevant quantities at the OTC registration platform by 9:00 EET on D-1. RES operators wishing to also participate in the DAM, should submit priced orders for the residual quantities. The quantities selected by the DAM algorithm will receive the DAM clearing price. The arrangements for the operation of an aggregator are differentiated. For market monitoring reasons an upper limit of 20 MW and a lower limit of 1 MW is imposed to the total size of RES installations that an aggregator could gather under its portfolio. The aggregator should submit a cumulative forecast and pay imbalances based on the total metered quantities of the RES plants it represents. This means that the aggregator, for imbalance settlement purposes, will hold one RES Generation account with multiple RES injection metering points registered within it. The imbalances of RES aggregators will be calculated on the basis of the total injected energy as this is registered at the corresponding meters represented by the aggregator. The settlements between the RES aggregator and the RES plant owners do not fall under the scope of the market design. In case the RES plant operator (or the RES aggregator) is metered to lower than the OTC and DAM position quantities (final position) then the RES operator (or the RES aggregator) has to pay the imbalance price for the quantities for which it was found short. If though metered long (compared to its final position), under the imbalance settlement arrangements, the RES operator (or the RES aggregator) should receive the imbalance price for the spill quantities. It is clarified that imbalances are counted based on the half-hourly metered quantities registered by each plant, even in the case of aggregators. Therefore, all new RES plant wishing to operate outside the NGPs should carry adequate metering equipment [64].

2.7.2 Existing obstacles

2.7.2.1 Technical Obstacles

The Cyprus power system has the typical characteristics of isolated Mediterranean island grids: largely unexploited renewable energy potentials, heavy dependence on liquid fossil fuel imports, limited capability (i.e. low system inertia) to react to contingencies and events, high daily and seasonal demand fluctuation, no grid connection (yet) to neighbour countries. The present generation fleet in Cyprus includes steam, combined cycle gas turbine, internal combustion compression ignition engines and gas turbine units, which are located in three sites (Vasilikos, Dhekelia and Moni). Operational constraints are set on some generators for complying with emissions limits. In general, the conventional generators have not been designed for a very flexible operation that might be required in the future.
Cyprus is also characterized by an abundant solar energy resource across the whole year: the average global solar can reach 2000 kWh/m^2. Wind energy is instead quite limited over the island of Cyprus, with an annual average wind speed below 4 m/s in the majority of areas.
Flexibility capabilities of the existing generation fleet could be increased in terms of ramping, minimum time off and on, start procedure, response speed of controller. However, the economic impact for the power plant operator needs to be better assessed. Increasing significantly the flexibility could increase variable operational costs and/or reduce efficiency [65].

2.7.2.2 Regulatory Obstacles

In Cyprus the new electricity market is currently designed. Currently the market cannot support neither flexibility services nor aggregation and demand response. CERA proposes the development of a set of regulatory arrangements per market segment aiming at creating an appropriate market environment for market participants to activate in the electricity sector of Cyprus. It is however underlined that the proposed arrangements include substantial regulatory intervention as, due to the current 100% concentration of the market, these arrangements are initially trying to mimic a competitive environment with a view to gradually enforcing it [66].

2.8 Germany

2.8.1 Current regulatory provisions and business models

2.8.1.1 The German electricity market

Germany sits at the heart of an interconnected European electricity system. Because of its central geographical situation within Europe, it is an important player on the European electricity market and a hub for Europe-wide power flows. Germany is also exporting more and more electricity to its neighboring countries. Import and export flows are driven by the wholesale prices on national electricity exchanges, which are influenced by the respective demand for electricity, the amount of electricity generated from renewable energy, and the fuel costs for conventional power plants.

Electricity is physically exchanged with nine direct neighbouring countries – Denmark, the Netherlands, Luxembourg, France, Switzerland, Austria, the Czech Republic, Poland, and Sweden (via a submarine cable). Germany exported around 82.7 billion kWh of electricity to its neighbours in 2018, while itself importing 31.5 billion kWh. Germany has the highest installed power plant capacity in Europe and also generates and consumes the most electricity [67].

Germany is internationally recognized as one of the first nations to adopt a sound energy policy aimed at achieving high shares of nonconventional renewable energy sources (NCRES) in the energy matrix. It has been following a long path in which regulations, priorities and technologies have changed considerably. The first law allowing decentralized renewable power grid feed-in appeared in 1990, and the main instrument to promote the adoption of NCRES, the renewable energy law ("Erneuerbarenenergiengesetz"), was enacted in 2000. The latter has received four amendments that respond to changes in the political priorities of the so-called energy transition ("Energiewende"). This law started out being protective of NCRES adopters, whereas in its latest version, NCRES generators are left free to find their own places in the market. At the beginning, it was important to provide warranties for the adoption of new unconventional technologies. At present, it has been proven that the technologies do work and that a transition is possible, so the efforts are more concentrated on making the market accept a high penetration of NCRES. In 2018, 226 billion kilowatt-hours of electricity were generated from renewable energy sources, attaining a 37.8% share of gross electricity consumption [68].

Germany's domestic electricity market was fully liberalized in 1998. Although there are currently over 800 individual providers, the majority of the country's electricity is still generated by four big energy companies: E.ON, RWE, Vattenfall and EnBW. The German transmission system is the most important hub in the European electricity market. There are four TSOs:

- Amprion GmbH operated the largest system in Germany (11,000 km) and was sold in 2011 by RWE to a consortium of financial investors.
- TenneT operates 10,7000 km. This grid was sold by E.On in 2010 to the Dutch TSO.
- Elia (50 Hertz Transmission GmbH) operates 9,750 km; the grid purchased from Vattenfall by the Belgian TSO in 2011.
- TransnetBW GmbH operates 3,300 km and is still owned by EnBW.

In 2013 more than 900 DSOs were operating in Germany.

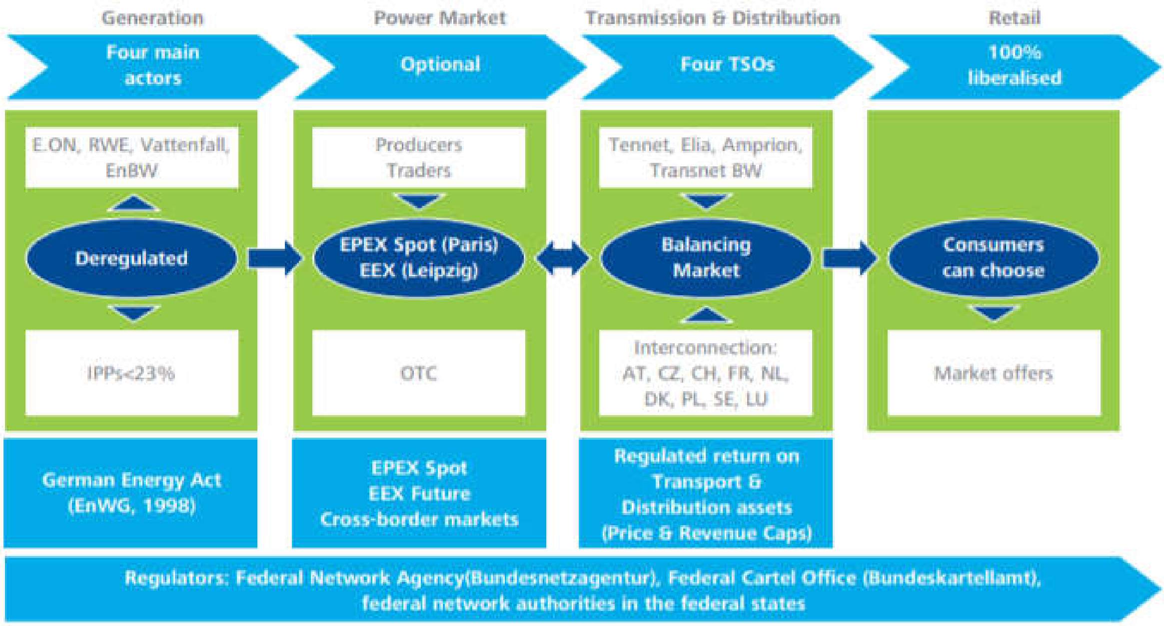

Figure 9: The Germany market mechanisms

2.8.1.2 Flexibility

2.8.1.2.1 Legislation to encourage flexibility

In June and July 2016, the Bundestag and the Bundesrat adopted the Acts on the Further Development of the Electricity Market and on the Digitalisation of the Energy Transition. These Acts put the rules in place for competition between flexible supply, flexible demand, and storage, and also enable innovative business models to be developed for use within the electricity market 2.0. This electricity market design guarantees that Germany can continue to rely on a secure supply of low-cost electricity even when a large share of the electricity is derived from renewable energy sources. In addition, the Federal Network Agency opened a procedure to stipulate auction rules for balancing capacity in 2015. In order to pursue flexibility generation and better align private electricity generation and the electricity market, the White Paper on the Electricity Market Design envisages the revision of special grid charges to allow for greater demand side flexibility [69].

The key measures in the White Paper are now being implemented in the Electricity Market Act and the Capacity Reserve Ordinance. Important measures include:

- Guaranteeing free price formation: The price signal will be the heartbeat of the further developed electricity market. Prices send important information to the market players. They are the only way to show how scarce electricity is at any time. The measures taken will strengthen free, competition-based price formation and will permit price peaks to occur on the electricity markets. Free price formation on the wholesale electricity market will ensure that there is sufficient investment to create the capacities required. The level of capacity maintained will be that demanded by the customers - no more, but also no less. This is the crucial difference compared with state-run capacity procurement mechanisms, where the state simply stipulates the level of capacity to be maintained. In many cases, this results in expensive overcapacities. In the energy-only market, in contrast, security of supply is delivered cost-efficiently by the market. For example, it can function like this: customers can insure themselves against price peaks, paying a premium for this; peak-load power plants use this premium as a constant source of income even if they only generate electricity during a few hours a year – i.e. at times when there is a real shortage of electricity. This business model can be mapped by cap futures. Ultimately, it makes sure that sufficient capacity is always available. The only precondition is that it must be possible to trade in electricity at every point in time in the future. The trading products for this exist on the EEX electricity exchange [67].
- Monitoring security of supply: Monitoring of security of supply will be improved in order to safeguard energy security in the new regulatory environment. The monitoring will no longer focus solely on national output levels, but will give greater consideration to the contribution to security made by the European internal market in electricity. The electricity market 2.0 is to take a thoroughly European approach. This will also reduce the cost of maintaining capacity in Germany.
- Upholding balancing group commitments: The responsible electricity providers and traders (i.e. in this context the "balance responsible parties") will be required more rigorously to purchase sufficient electricity for their clients. To achieve this, the balancing group and balancing energy system, as the key instrument for a secure power supply, will be adapted, and the requirement to uphold balancing group commitments will be strengthened.
- Prolonging the grid reserve: In order to respond to congestion in the grid and to ensure secure grid operation, the grid reserve will be prolonged beyond 31 December 2017, and the rules on cost reimbursement will be brought into line with practical needs. The grid reserve will be needed until key grid expansion projects have been finished.
- Improving transparency on the electricity market: Transparent and up-to-date electricity market data can promote efficient generation, consumption and trading decisions. For this reason, a national information platform and a core energy market data register will be set up.
- Reducing and sharing more fairly the costs of grid expansion: More efficient grid planning reduces the costs of grid expansion. In future, it will no longer be necessary to expand the grids to cope with the "last kilowatt-hour" generated by wind and PV installations. The costs will also be shared more fairly. The level of grid charges varies considerably from region to region in Germany. A major cause of differing regional grid charges is what is known as "avoided grid charges". For this reason, avoided grid charges will be abolished for installations which are newly constructed from 1 January 2021.
- Introducing a capacity reserve: The capacity reserve will be established outside the electricity market in order to ensure security of supply in the face of unforeseeable events. Taking a "belt and braces approach", the capacity reserve safeguards the electricity market 2.0. After all, security of supply is of key significance for an industrialized country like Germany [70]. A new capacity reserve, which is strictly separated from the electricity market, will provide an additional safety net for unforeseeable and extraordinary events – it provides additional security for the electricity market. Unlike the 'capacity market', the capacity reserve consists solely of power

stations which do not participate on the electricity market and do not affect competition and pricing. The capacity reserve will be available from 1 October 2020 and will have a volume of 2 GW. The transmission system operators have already invited bids from power stations to take part in the capacity reserve. The relevant ordinance for this entered into force on 6 February 2019. At the beginning of 2018, the European Commission gave the go-ahead under state aid rules for the capacity reserve [67].

In addition, in March 2016 the Federal Network Agency initiated a discussion on uniform and fair rules for aggregators in the provision of balancing capacity. The reform of the Incentive Regulation Ordinance (Anreizregulierungsverordnung) has provided the necessary framework for ensuring that the distribution grids can reliably and innovatively perform their central role in the energy supply system. The Act on the Digitisation of the Energy Transition (Gesetz zur Digitalisierung der Energiewende) adopted in the German Bundestag is an important step towards defining the framework for digitisation in the electricity sector [69].

2.8.1.2.2 TSO contribution to flexibility

The provision of balancing energy would be one way of activating flexibility.

The German TSOs have the task of constantly maintaining the power balance between power generation and offtake in their control area, with the aim of keeping the frequency in the European interconnected grid constant at 50Hz. As a reserve, the control power compensates for fluctuations in the power grid, or more precisely the power grid frequency. To fulfil this task, the TSOs need control power in different qualities (FCR or Primary Control Reserve (PRL); aFRR or secondary control power (SRL); mFRR or in German Minutenreserveleistung (MRL).

Auctions in Germany are held on a common platform (www.regelleistung.net) for the four TSOs. Switzerland, Austria, the Netherlands and Belgium have joined this platform and procure a part of their reserve jointly. Auction rules were revised in 2011 by the Federal Network Agency, to allow an increased participation of small electricity producers such as RES in addition to demand-side management aggregators and storage systems. To further facilitate market entry by DERs, another revision of rules for secondary and tertiary reserve is currently underway as of 2015/2016.

There is no technical discrimination either for primary or secondary reserves.

For primary reserves, a call for tenders is organized on a weekly basis. The minimum bid is 1 MW and the products are symmetrical. However, it is possible to aggregate plants that can only contribute positive or negative reserves in a pooled bid. The bidder must provide reserves for an entire week. In order to allow small reserve providers to comply more fully with the time requirement, it is possible to contract prequalified third parties to provide collateralization.

Primary reserve remuneration is pay-as-bid and offered for capacity provision alone, without separate remuneration for energy. In 2011, more far-reaching adjustments in favour of DERs were discussed (i.e. daily tenders, shorter product duration, asymmetrical bids), but they were rejected owing to trade-offs with system stability and transaction costs. Accordingly, rules for primary reserve provision remain unaffected by the current revision.

For secondary reserves, products are asymmetrical. A call for tenders is currently organized on a weekly basis. A change to daily auctions, however, is being considered to facilitate bids by distributed flexibility resources including intermittent RES. Also, a shortening of product duration is being discussed. Currently, bidders can propose reserves for peak periods (working days, 8:00 a.m. to 8:00 p.m.) or off-peak periods (the rest of the time). Under the new regime, they would bid for six timeslots of four hours each on the day following the auction. The minimum bid of 5 MW will remain but the revised rules propose to allow bids of 1 MW, 2 MW, 3 MW, and 4 MW so long as bidders only make one bid per secondary reserve product within the balancing zone. This is to give small generators or aggregators of small-scale flexibility resources another participation option besides pooling.

Secondary reserve remuneration is pay-as-bid. Bids are selected on the basis of capacity prices, but remuneration is offered both for capacity and energy if a reserve is activated. A change to uniform pricing (with bids based on energy prices) is being discussed but viewed critically by the Federal Network Agency. Under the current system, successful bids with low capacity prices and high energy prices are common. Since reserve scheduling follows a merit order based on reserves' energy prices, the consequences for total reserve provision costs are limited. With a uniform pricing rule, all utilized reserves would be remunerated at the energy price of the last successful bid in the market, which could lead to significant cost increases.

The German market design does not have any administrative barriers to entry but still has major issues concerning technical optimization, especially with the provision of primary reserves [2].

The TSOs procure the control reserve products across control areas and partly in cooperation with the neighbouring countries. The invitation to tender is carried out in an open, transparent and non-discriminatory procedure in accordance with the requirements of the German Federal Cartel Office, in line with the specifications of the Federal Network Agency and European regulations.

A prerequisite for participation in the regulated market is the qualification of the market participants at the respective connection exchange. Due to the possibility of pooling, it is also possible for small systems and loads to participate in the standard reserve market. The modalities for participation in the MfRRA regulate market access from qualification to settlement uniformly for all market participants.

As part of the consistent further development of joint procurement, the German TSOs are cooperating on the operational side through the coordinated use of control energy within the framework of the grid control network and are thus able to call up control energy across control zones at optimum cost [71], [72].

2.8.1.2.3 DSO contribution to flexibility

Under the current regulatory framework, the distribution network operator does not have sufficiently precise instruments at its disposal to encourage or make use of flexibility and thus avoid, for example, additional network expansion [73]. Network-supporting load management can help to avoid congestion in the distribution networks. While distribution network operators have an instrument at their disposal for controlling production plants in the form of integration of renewables and CHP plants upwards of 100 kW into congestion management, they have no comparable tool on the consumption side. Germany will therefore continue to develop the legal framework in respect of flexible consumption equipment. As part of the project entitled “Digitisation of the Energy Transition – Barometer and Key Subject Areas” commissioned by the Federal Ministry for Economic Affairs and Energy, a concept was developed for network-supporting load management in the distribution networks. The Federal Ministry for Economic Affairs and Energy has drawn up a list of discussion points for further development of the legal framework. On this basis a broad, open-ended stakeholder process is currently taking place to determine whether and how the expert recommendations should be implemented. The aim is to enable distribution network operators to manage flexible loads within a clearly defined framework (e.g. during electric vehicle charging processes) in a way that supports the network, where otherwise unreasonable costs for network expansion would arise due to rare peak loads.

The core of the concept will be to divide the network connection capacity of flexible consumption devices such as electric vehicles and heat pumps into two parts in future. By default, the network connection capacity then contains a part that is unconditionally and unrestrictedly available to the consumer and a second part that is conditional on network-compatible use. The network operator could then limit or postpone consumption if the simultaneous utilisations push the distribution network to its capacity limits. This avoids high investments for merely short-term peak loads and increases the potential of flexible consumption devices for the distribution network [74].

According to active legislation in Germany (depending on size of company), DSOs can undertake several roles. For example, the DSOs SWW and SWH have four roles, those of:

- DSO
- Retailer
- (possible) Aggregator
- Owner and operator of RES and storage, CHPs

This opens the floor for use of flexibility (even without existing legislation), by using the reserve market and the possibilities provided by the reserve market which are among others are to apply for licence, to guarantee 1 MW availability permanently within 3 time frames/levels among which the participants can choose, and to hire specialists to deal with and operate the requirements, acting as full BRP.

This state can be reached by:

- Forming VPP (virtual power plants)
- Setting up and operating large battery systems
- Aggregate sufficient amount of local flexibility from customers, prosumers (all sizes), DRES
- Hiring own staff on balancing or hiring a balancing service provider

For example, the German DSO SWW has three roles, those of the DSO, retailer and aggregator of local flexibility. Without access to reserve market SWW cannot make any profit „in the market "; but can use the aggregation of local flexibility for active displacement and balancing of required load between generation and demand. The first progression towards the operation as of local flexibility aggregator is to integrate an 8 MW storage system, which is currently under construction, into the distribution grid. Through this integration the company achieves the point where it can deal with positive and negative flexibility on the reserve power market. The energy generated by all the renewables will also be aggregated to a virtual power plant. This virtual power plant is going to be traded on the reserve power market regarding its load, the generated work is subjecting to balancing mechanism of the renewable energy law (EEG) in Germany, so it will be purchased from the DSO, forwarded to the TSO and ends up on the European Energy Exchange (EEX). The only thing that is going to be changed is the relation between procurement and demand. The used and traded flexibility from the prosumer is going to decrease our needed amount of procurement, what is in a turn going to decrease our costs of procurement the same way.

Flexibility allows to integrate the amount of locally available energy and avoid the procurement on the market. Through this integration SWW is able to use this flexibly produced energy in the local grid and avoid the respective procurement. This act is conforming to the current legal and regulatory situation in Germany.

To measure the worth of the flexibility SWW assumes its value as mixed price of:

- avoided grid use (grid charge) from the TSO
- avoided procurement of energy on the wholesale market

2.8.1.2.4 Measures to increase the flexibility of the energy system with regard to renewable energy production

Safeguarding the energy system's flexibility

The Federal Government's goal is to decrease obstacles to flexibility, giving all technologies the same market access. For the first time, in an arduous process, the Federal Ministry for Economic Affairs' papers – 'An Electricity Market for the Energy Transition' (Green Paper on Electricity) from October 2014, and the White Paper on Electricity, from July 2015 – have stated all obstacles to flexibility and discussed measures for eliminating them. Some of these measures were already implemented in the Electricity Market Act of July 2016. The Results Paper 'Electricity 2030' by the Federal Ministry for Economic Affairs built upon these insights and looked at which obstacles to flexibility are still present and could emerge by 2030, in addition to which measure can eliminate them [75].

Fair grid financing, serving the system's interests

The goal is for the grid remuneration system to support the grid users by helping them to contribute, through their market behaviour, to secure and favourably-priced electricity supply. For this, the systemic approach to grid remuneration must be adapted to a modern electricity system. A check is being made on how best to reduce obstacles to market- driven flexibility of producers and consumers, without thereby incentivising the grids to acquire inefficient dimensions [75].

Implement the 'using instead of curtailing' measure

In the context of the 'using instead of curtailing' measure, CHP installations take on an obligation, in relation to the transmission-grid operators; they commit themselves both to curtail their CHP-electricity input in the grid-extension areas particularly at risk of bottlenecks, if the transmission grid has a bottleneck, and to generate the necessary heating through a power-to-Heat (PtH) facility. This eases the load on the grid bottleneck and avoids a curtailment of electricity from renewables, matching the extent of the CHP-input reduction and of the additional consumption from the PtH installation. The system's overall flexibility is increased: CHP facilities equipped with electrical-heat generators can now operate flexibly on the electricity market, as sources of supply and demand, and the transmission-grid operators can deploy this flexibility potential in running the grid [75].

Flexible CHP facilities as an interim technology

From today's perspective, modernised CHP facilities can make an important contribution to GHG reduction until approx. 2030 and also play a role beyond then. To do this they must save emissions on the electricity and heating markets and react flexibly to the fluctuating input of renewable energies. The Federal Ministry for Economic Affairs wants to create pilot projects for modernised CHP facilities; it is therefore initiating tender processes for projects that set up innovative CHP systems. The aim is that the innovative CHP systems show how CHP facilities in general can integrate renewable heating and renewable electricity by responding with double flexibility. At time of high feed-in levels of heating from renewable energies, the CHP facility's heat production is reduced, thus saving fuels and emissions. At times of high feed-in of electricity from renewable energies, the CHP facility reduces its electricity generation, once again saving fuels and emissions. Additionally, if there is a very strong supply of electricity from renewables, and thus low or declining power-exchange prices, the electric heat-generator can ease the burden on the electricity market. The technology converts rigid minimum production, conditioned by heating factors, into flexible demand for electricity. To resolve acute grid bottlenecks, CHP is also deployed in the context of the 'using rather than curtailing' rule. In the future, CHP is to be further developed and comprehensively modernised, to give it a future in the energy-transition context. On this topic, representatives of the Federal Ministry for Economic Affairs, the Federal Ministry for the Environment, the parliamentary parties, the trade associations and the Länder are currently discussing various options for action. Yet even before the outcome, adaptations to funding support are needed, due to the EU law on state aid, so as to avoid giving too much funding support to individual segments in terms of installation type. So the relevant ruling is being adapted in the so-called Omnibus Energy Act (draft legislation by the Federal Government, dated 05 November 2018) [75].

Optimisation measures on redispatch

The objective is that renewable energies will account for a growing share of electricity generation, and that sector coupling will make advances; thus it is becoming increasingly important to consider how the interplay between the electricity market and the electricity grid can be arranged so that the whole system can be operated securely, in a cost-favourable way. The measures currently envisaged include the following:

- Higher capacity-use on the existing grid, to raise the grids' transport capacity.
- Organising redispatch more efficiently, to make the step-by-step switchover of current feed-in management into a plannable process with a balancing-out, both in energy-use terms and in commercial transaction terms. To this end, the Federal Ministry for Economic Affairs is taking care of the research project 'Development of measures to advance efficient safeguarding of system security in the German electricity grid'.
- Cross-border redispatch. The Federal Ministry for Economic Affairs began the research project called 'Study into purchasing of redispatch' for quantifying the reduction potential that cross-border redispatch has. The project also includes studies into a (European) framework of arrangements, ensuring that foreign capacities are sufficiently securely available, and that the issue of cost reimbursement/cost distribution is clarified. Independently of this research project, as part of Code Capacity Allocation and Congestion Management (CACM, Arts. 35 and 74), transmission-grid operators and regulators are developing a method for coordinated, cross-border redispatch and for a cross-border division of the costs [75].

Flexibility check

At present there are still rulings that make it harder for market participants to act flexibly – so-called barriers to flexibility. If all technologies are to get the same market access, this means eliminating these obstacles. It is especially cost-favourable if the various options for flexibility – expanded electricity grids, flexible power plants and consumers, storage facilities, trading electricity with the European neighbours – enter into competition against one another (Electricity Market 2.0). No particular technology should gain preference because it gets unilateral funding support and is granted exceptions. The market can decide the question better. Thus the decision was adopted, jointly with the EU neighbours in electricity use, that Germany and those neighbours are to conduct a so-called flexibility check. The purpose is to identify and strive to eliminate obstacles to further increases in flexibility in the electricity market [75].

2.8.1.2.5 Description of measures to enable and develop demand response

Management and system stabilisation through strengthened cooperation between transmission-grid operators and distributor-grid operators, and (other) market players

Based on cost-benefit analyses, grid operators decide the grid level on which system services are rendered. Grid operators' and other market players' responsibility must be clearly defined and data must be exchanged efficiently and securely. The Federal Government is further developing intelligent management concepts, so that decentralised producers, stores of energy and energy loads can increasingly take on system responsibility. [75].

Dynamic electricity-price contracts and smart meters

According to the European Commission's proposed directive for the internal electricity market, electricity suppliers are to be able to offer dynamic electricity-price contracts. Final-users who have installed a smart meter obtain a legal entitlement to such contracts. Electricity suppliers are then to be obliged to inform final-users about the opportunities, costs and risks of such a dynamic electricity-price contract. The national regulatory authority is to monitor the market development of dynamic electricity-price contracts. In Germany, the Energy Business Act, Art. 40 (5), obliges suppliers to offer a price-rate for the final consumption of electricity that provides an incentive to save energy or that steers energy consumption, provided that doing so is technically feasible and economically reasonable. Today the use of sophisticated smart meter gateway is obligatory; starting from a consumption of 6.000kWh/year for (non-business) customers. Business customers are to be metered and monitored every 15 minutes [75].

Establishing a register of core market data

From 2019, the Federal Network Agency's register of core market data brings together the core-data of all electricity-supply facilities connected with a power-grid, in Germany's market for electricity and gas, in addition to all (other) market players, in the form of a uniform online database [75].

Metering Point Operation Act

In Germany, since 2016, the Metering Point Operation Act is the act forming the legal framework for the rollout of smart meters. It requires the roll-out of certified equipment units, with a seal of quality from the Federal Office for Information Security (BSI); this guarantees IT security and privacy by design. To maximise the benefit, the Metering Point Operation Act uses comprehensive protection profiles and technical guidelines to standardise the smart-meter gateway, as a communication platform for numerous application cases (Smart Metering, Smart Grid, Smart Mobility, Smart Home, Smart Services). The efficient roll-out is the only option permitted: statutory upper-limits to prices secure acceptance and economic viability. It is now up to the companies to begin the roll-out (particularly manufacturers of equipment units and operators /system administrators). They must guarantee that reliable technology is operated, and by reliable companies. Only then can the Federal Office for Information Security launch the roll-out.

2.8.2 Existing obstacles

- The Federal Ministry of Economics and Energy rejects market platform models for flexibility coordination and advocates retaining the cost-based redispatch[5] [76]. This decision is based on possible efficiency losses that could be caused by opportunistic behaviour of market participants

[5] The power plant operators report the expected electricity production for the following day to the TSOs. The TSOs create an overview of the total German entry and exit. In order to keep the grid stable, we instruct the power plant operator to postpone the planned electricity production if necessary.

[77].

- Another problem is the duration of the accounting period, which in Germany is 15 minutes. In other countries, different intervals have been chosen for the accounting period, some of which are significantly longer than fifteen minutes. This is an exclusion criterion for a cross-border coupling of intraday markets in this time frame. For further market coupling, a first necessary step would be the European harmonisation of the accounting period [78].
- Another problem is the length of time between the close of trading and the delivery date. For example, on the day-ahead market, products are traded predominantly on an hourly basis. However, hourly product points are an obstacle to the participation of flexibility options with time constants of less than one hour, as they have to promise to supply electricity continuously for one hour or to reduce their consumption continuously. The intraday market, on which quarter-hourly products are traded, is therefore of great importance for the participation of flexibility options with lower time constants [78].
- The expansion and promotion of electricity generation on the basis of renewable energies is a socially recognised goal of energy and climate policy in Germany. However, the concrete implementation of promotion via a work-related remuneration per MWh of electricity generated hinders the flexibility of generation, as it considerably limits the reaction of renewable energy plants to the actual market conditions [78]
- In Germany, the Federal Network Agency is currently speaking out against the introduction of flexible network charges. One of the reasons it cites is that it is difficult for consumers to predict the actual level of network charges. Control signals would either have very little effect or could have an extremely large, in some cases prohibitive, influence. They could, for example, be an obstacle to the implementation of regional energy concepts or the investment of private households [79]. Furthermore, the determination of regional fees is associated with a high effort and incorrectly determined network fees could have a negative influence on the overall system optimization. The Federal Network Agency is therefore currently refraining from these fees [77].

3 New market operation approaches

3.1 Innovative European and national flexibility projects within EU

3.1.1 Enera

Enera (https://projekt-enera.de/) is a project funded by the German ministry of Economic Affairs and Energy, as part of the SINTEG research program. The goal of the project is to experiment an exchange-based flexibility market for grid congestion management. The project's three pillars are: Network, Market and Data. Enera is a joint project between TenneT (one of the German TSOs), Avaconn Netz, EWE NETZ (DSOs) and the power exchange EPEX SPOT. The project uses flexible resources in order to avoid curtailment, especially coming from renewable resources [80]. The pilot is implemented in the Northwest of Germany (Counties of Aurich, Friesland & Wittmund), where there is a high share of renewables (235%), mainly stemming from wind power.

The actors participating in the project are [4]:

- (Certified) Flexibility providers: Power Plants, Aggregators, VPPs, Storage, Renewables
    - EWE Trading
    - Volkswagen
    - Statkraft
    - Baywa Re
    - Quadra Energy
    - Alpiq
- Flexibility Market platform: The Enera Flexmarkt runs on a separated platform along with the intraday market. The platform facilitates market – based congestion management and is run by EPEX SPOT. EPEX SPOT acts as a neutral intermediary between system operators and flexibility providers.
- Flexibility demand: Flexibility demand is requested from the system operators (Tenne T - TSO, Avacon - DSO, EWE Netz - DSO). In the scope of Enera, network operators are allowed to buy flexibility in the intraday market.

The Enera Flexmarkt was launched in February 2019. The first successful trade on the flexibility platform was completed by the automobile manufacturer Audi participating in the Enera flexibility market with its power-to-gas (P2G) plant. Through its trade, Audi committed to increase its consumption by 2 MW [80]. Since Enera launch, 23 local market areas have been involved in the project, more than 4000 orders have been placed and more than 130 transactions have been executed by 9 market participants (6 Flexibility Providers, 3 System Operators). The Enera project will end in December 2020. After gaining many great experiences and results by using and demonstrating the Enera flexmarket, the activities in the market have been stopped and the platform has been shut down in July 2020.

The flexibility certification in the Enera flexmarket is done by the system operators, in order to ensure a physical impact of the flexibilities on the grid. The flexibility providers, respectively the marketers, need to register the flexibility assets at the connecting system operator. The connecting system operator itself is responsible for approving the assets connected to his grid for participation in the Enera flexmarket and accordingly certifies the assets registered by the marketers. The system operator also runs a flex registry for managing basic data regarding these assets. The member onboarding process is done by EPEX SPOT, which admits interested participants to the market comparable to the usual market access procedures on the exchange for wholesale markets. The flexibility providers have to sign a trading agreement, while the system operators sign a market access agreement. Their market admission is based on special market rules that were developed for the Enera flexmarket.

For the Enera flexmarket, no trading fees or fees for becoming a market participant are charged. Flexibility providers submit offers and network operators submit flexibility demand orders that are continuously matched on the platform. As congestion is specific to certain locations in the grid, the opening of "on-demand" locational order books in the intraday timeframe is set up in Enera. In terms of locational tagging, each order belongs to a certain node predefined by Enera. The local order books consist of orders from one or more nodes. The local order book system is based on four important elements [81]:

- Local trading certifications are delivered by System Operators to market participants
- “2 C’s rule”: need of Congestion and Competition to open a locational order book
- Strict compliance rules for local trading
- Cooperation between transmission and distribution over locational trading

Access to the Enera trading platform is standardized, such that market parties can use the same API which they use to trade in the intraday (energy) market when using EPEX SPOT’s services. The Local Flexibility Market (LFM) is complementary to the zonal Intraday and the balancing markets. The Flexibility Providers can bid the same asset on both the zonal Intraday market and a locational order book (when certified by the relevant SO for this local market area). The offers can differ in price. However, if all offers on the different markets were cleared, the activations would be incompatible. The responsibility to avoid double activation lies with the flexibility providers [4]. The trading system used for the Enera market place is the same system which is known from the intraday trading of EPEX SPOT. System operators – as the only buyers – place their flex demand, whereas marketers placed their flex offers. A matching process ensures that two bids are executed when a flexibility offer is compatible with a flexibility demand. Continuous trading allows market participants to send, accept or cancel bids at any time. If a transaction is concluded and executed, the market participants involved are informed. Finally, the billing of the flexibility provision is done by the requesting system operators themselves. For this purpose, the Enera project provides them with a central verification platform that allows them to track and verify the contractual provision of flexibility on the basis of master and transaction data. The verification mechanism takes into account any other congestion management and control power calls, so that the verification platform provides the necessary information for billing.

The products are standardised and their specifications were designed in a way to mirror wholesale Intraday delivery periods as part of a continuous market, in order to make trading as easy as possible and to boost liquidity. Both 15min products and 60min products are available. Trading takes place continuously 24/7, possible until 5 minutes before delivery. Minimum tick size is 0.1 MW, minimum increment in price is 0.1 EUR/MWh. Financial settlement takes place bilaterally between System Operators and Flexibility providers on the basis of transactions. The main characteristics of the contracts and projects participating in Enera are summarized in the table below [82].

Table 9: Enera 1.0 contracts and products

<table>
<tr><th>Attribute</th><th>Description</th></tr>
<tr><td>Market area</td><td>Local market areas form the lowest granularity and correspond to network topological regions (transformer areas) in which the connected flexible assets have the same or at least approximately the same sensitivity to all potential congestions.</td></tr>
<tr><td>Trading procedure</td><td>Continuous trading</td></tr>
<tr><td>Trading period</td><td>24/7</td></tr>
<tr><td>Tradable products</td><td><table>
<tr><th>Product name</th><th>Delivery period</th><th>Comment</th></tr>
<tr><td>RES_Hour_Power</td><td>60 minutes</td><td>Flexibility from Renewable Energy Source</td></tr>
<tr><td>RES_Quarter_ Hour_Power</td><td>15 minutes</td><td>Flexibility from Renewable Energy Source</td></tr>
<tr><td>Non_RES_Hour_Power</td><td>60 minutes</td><td>Flexibility not from a Renewable Energy Source</td></tr>
<tr><td>Non_RES_Quarter_ Hour_Power</td><td>15 minutes</td><td>Flexibility not from a Renewable Energy Source</td></tr>
</table></td></tr>
<tr><td>Gate opening</td><td>Trading will open on the day before delivery at 15:00</td></tr>
<tr><td>Gate closing</td><td>Five minutes before delivery start</td></tr>
</table>

Minimum price increment	0.1 €/MWh
Minimum price	RES products: - 9999.9 €/MWh Non_RES products: -50 €/MWh
Maximum price	RES products: + 9999.9 €/MWh Non_RES products: + 9999.9 €/MWh
Minimum volume increment	0.1 MW
Trading phase	During trading the market will be in Balancing Trading phase. During this phase regular orders can only match with balancing orders
Available order types	limit orders , iceberg orders
Available order categories	balancing orders, regular orders
Available execution conditions	None, IOC (Immediate-or-cancel), FOK (Fill-or-kill)
Available validity conditions	Good for session, Good till date

An indicative example of a trade execution in Enera Flexmarket is given below and is based on the first local trade in Germany [83].

- The DSO EWE NETZ forecasts a congestion in a few hours due to high feed-in and therefore needs downwards flexibility to alleviate it.
- The DSO sends a flexibility demand order for 2 MW downward flexibility at – 45.50 €/MWh in the EPEX SPOT flexibility marketplace for delivery from 17h00 to 18h00.
- The Certified Flexibility Provider, Audi, sees the flexibility demand from the system operator (EWE NETZ) at an acceptable price in the area where their plant is located.
- Audi submits a matching flexibility offer order via the EPEX SPOT flexibility marketplace interface.
- The orders are matched in the trading system and the transaction is executed (2 MW have been traded at -45.50€/MWh).
- Audi now has the obligation to deliver the flexibility according to the contract specifications. These specifications are part of characteristics of the traded product and have been pre-determined.
- Based on this trade, Audi will increase their consumption at a given time and at the chosen location.
- The resulting BRP imbalance has to be closed on the intraday. This localized physical impact allows EWE NETZ to alleviate a congestion before it occurs in a safe and competitive way.

3.1.2 NODES marketplace

The marketplace NODES is a joint project between Norwegian Utility Adger Energi and the European Power Exchange Nord Pool, established in 2018. Merging the experience from these two companies and from independent experts around Europe, the fundamental marketplace was developed. Main objective of NODES is to operate a market platform that strives for flexibility valorisation and gives the opportunity to buyer of flexibility to alternate its consumption/production according to a contract. In the current framework, DSOs have no marketplace to purchase local flexibility in order to solve local grid issues. Moreover, TSOs are unable to leverage the flexibility existing in the distribution grids. NODES is directly aiming to bridge that gap. NODES is able to counteract market abuse by concurrently increasing transparency and market players number engaging in distributed flexibility marketplace [84]. Ultimate goal of NODES is to develop the link between the already developed Flexibility Marketplace with the existing platforms operating intraday and balancing markets, thus creating a fully integrated marketplace for flexibility independent of any market party [84].

In the context of NODES, different Use Cases have already been implemented. Specifically, in Germany within the region of the DSO Mitnetz Storm, NODES marketplace was leveraged in order the excess wind power to be absorbed through demand response from Entelios Aggregator. NODES was proven a better alternative to manage excess renewable production situations, by saving investment and operational costs utilizing local.

In addition to the abovementioned Use Cases, the following ones are under development. Smart Senja project in Northern Norway will demonstrate how flexibility can be used to secure power supply at the distribution grid, by leveraging the opportunities NODES marketplace can provide. In the following years, NorFlex project in Norway will demonstrate technological solutions how local flexibility can solve grid problems locally and centrally (examine the availability of flexibility to the existing TSO mFRR reserve market). NODES platform will be used to as a mean for flexibility valorization. Furthermore, Western Power Distribution has launched IntraFlex, a new innovation project with NODES and Smart Grid Consultancy. The Network Innovation Allowance funded project will look to deploy the NODES platform in the UK and create new, closer to real-time, flexibility market for the DNO. Elvia AS in Oslo has started a cooperation with NODES in order through the FlexLab project, the bilateral agreements (LonFlex contracts) and other bids (ShortFlex) between customers offering flexibility and DSOs to be emerged and the dispatch process to be automated. Finally, a project under the title sthlmflex, for demonstration of a market-based TSO-DSO coordination through regional flexibility market in the Stockholm area has been initiated. This project has contracted with NODES to operate the market, while offering a market-based coordination alternative as well as integration to the TSO mFRR market.

In NODES, no standard product definitions are set. Instead, flexibility providers have the choice to specify their offers using a wide range of parameters, namely order, location, time, profile, and availability parameters. However, from the buyer side, a DSO can create a template that predefines some of the available parameters. This gives DSOs the opportunity to define their own local products they can use when requesting flexibility. On the NODES platform, BRPs and network operators can procure local flexibility in the intraday timeframe. The offered flexibility, which is not needed locally, will be forwarded to other existing market platforms, more specifically the intraday and balancing market. The interfaces between NODES and the existing markets are not yet in place. In NODES, flexibility providers tag their offers with a grid location (GL). One or multiple GLs constitute a local pricing zone. The local pricing zones can differ depending on whether the TSO or DSO is buying flexibility and can be adjusted dynamically on short notice (cfr. weeks). For example, congestion at the TSO-level can be solved by flexible assets located in different ''DSO local price zones''. Thus, the TSO when buying flexibility will consider a local price zone which is an aggregate of multiple ''DSO local price zones'. It is worth noting that for the majority of operating hours, flexibility is not needed locally at the actual GL, but it can still have value in the rest of the system, for balancing purposes by the TSO. NODES allows participants to differentiate their offers, depending on whether flexibility is sold locally or centrally and connects distributed flexibility to both DSO and TSO markets [84].

The following roles are identified in the NODES marketplace:

- **DSO**: NODES enables DSO to model congested grid areas and publish them as local markets in the NODES market platform. When a local market is created, suppliers of flexibility can register their flexible assets and offer ramp down or ramp up of consumption or production to the DSO to alleviate local bottleneck. By establishing local flexibility markets DSOs can keep grid costs down and utilize the grid more effectively while still maintaining security of supply.
- **TSO**: NODES enables TSO to access distributed flexibility sources to solve imbalance issues at the transmission grid. TSO can create local markets by aggregating GLs initiated by the DSOs. When such a local market is created, flexibility providers can register their assets and offer flexibility services to the TSO to alleviate system-wide imbalances.
- **Flexibility Providers**: Under the umbrella of Flexibility Provider exist Aggregators, Power Suppliers, BRPs, Microgrids and technology companies. They can control consumption or production units and sell consumption/production ramp-up or ramp -own to local DSO. By utilizing NODES link to TSO balancing markets, flexibility can be sold to TSO's when there are no local bottlenecks.
- **Aggregators**: Bring local flexibility to the market. In multiple future projects with the TSO and the DSO, aggregators test different business models that works for both the asset owner, the relevant system operator and the aggregator. There is no flexibility market unless all these three conditions are met.

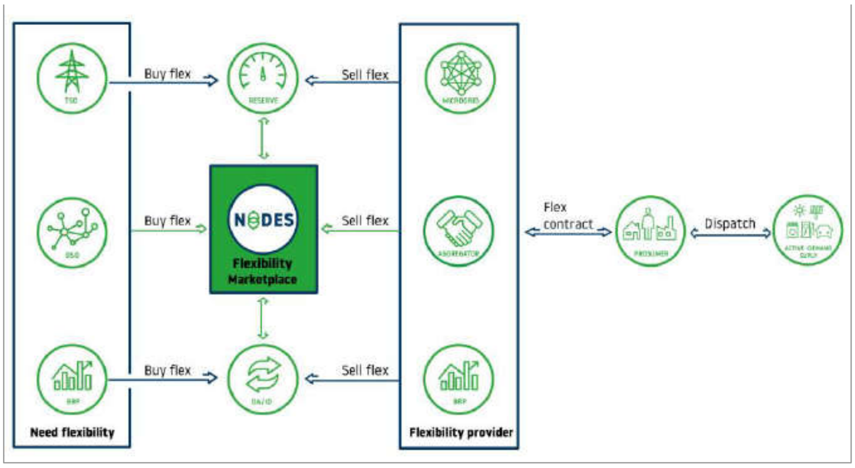

Figure 10: Roles in NODES market design [84]

3.1.3 Piclo Match

Piclo is an independent software company that has been active in the energy industry since 2013. In October 2016, Piclo launched its first energy application, Piclo Match, a peer-to-peer energy matching service [4]. The second application of Piclo is Piclo Flex, an independent marketplace for trading energy flexibility online. Piclo flex is a separate platform from the existing sequence of electricity markets. Its trial operation started on 2018 and the commercial offering was launched at mid-2019.

Tenders are organized on Piclo Flex with a lead-time of six months or more, and the contract duration is between a couple of months and four. DSOs (namely UK Power Networks - UKPN, Scottish & Southern Electricity Networks, Western Power Distribution, and SP Energy Networks) usually run two procurement processes per year on Piclo Flex. Here we mainly focus on how UKPN uses Piclo to trade flexibility. The first tender is announced near the start of each year with the winners announced a few months later. Contracts generally begin at the end of that year. The second tender is published each autumn, with the winners announced a few months later. Contracts generally begin the following summer [85]. Contracted flexible resources on Piclo Flex do not have to adhere to dispatch instructions by the DSO for the full contracted period but only during a service window within the contracted period (e.g. winter week-day evenings), which is predetermined at the time of the tender [4].

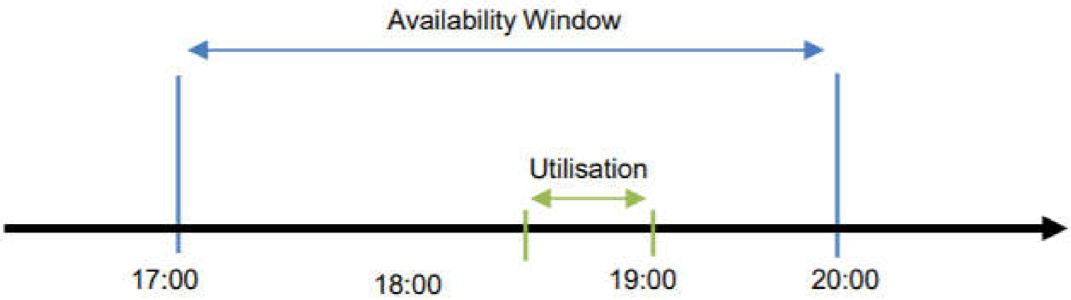

Figure 11: Proposal for availability window and utilisation by UKPN [86]

A pre-qualified flexibility provider participating in the tender has to submit both an availability offer - the price in £/MW/h for availability and a utilization offer - the price in £/MWh for utilization and the maximum running time. According to UKPN proposal availability payments are paid to all successful participants (on a pay-as-bid basis) whether or not they are utilized, provided they can demonstrate their availability when required. Utilization is intended to cover the opportunity cost of being utilized, but if fixed, the payment may not match the costs perfectly for all participants. The fixed utilization price can be either set high or low. This approach allows participants to compete solely on availability, which makes the assessment relatively straightforward and transparent. If participants expect to be over- or under compensated for utilization they can adjust their availability bids accordingly [86].

In Piclo Flex, standardized products are in place. The short-term activation product is determined per competition area at the time of the tender. At the time of writing, UKPN has 28 competition areas defined in Piclo Flex. Besides location and voltage level, the key operational parameters are the service window (and the contract duration during which this service window holds) and the minimum and maximum running time. All other technical parameters are validated during the prequalification process.

Table 10: UK Power Networks – Product Definitions [87]

Activation methods employed	Pre-Fault		Post-Fault
	Manual	Automatic	
Type and direction	Active power; demand turn down/ generation turn up		
Minimum / maximum bid size	100kW minimum capacity (can aggregate within area); no maximum		
Minimum / maximum duration (of delivery)	0.5hr minimum; longer is more valuable		
Definition of congestion point (identification of the congested area)	Defined by the feeding area of the network assets(s) subject to the congestion		
Bidding period (time granted to the market parties to offer bids)	Months ahead		
Selection period (time required by the DSO to select the bids which will be activated)	Months ahead		
Activation period (time before activation signal and ramp up period)	Close to real-time		
Maximum ramping period	Of the order of minutes		
Minimum full activation period	30 minutes		
Mode of activation	Manual	Automatic	Automatic
Availability windows	Defined at procurement		
Maximum number of activations (per day, per week, per year)	Defined at procurement according to requirement		
Recovery time: Minimum time between activations	Defined at procurement according to requirement		
Baseline methodology (basis upon which availability is assessed/delivery is compensated)	Defined at procurement		
Measurements requirements	Minute by minute metering		
Aggregation allowed	Yes (within appropriate geographical area)		
Penalty for non-delivery (fixed or dependant on the bid size and/or duration, €10,000 , € 1,000…)	Loss of revenue based on performance; impact on future procurement/utilisation, and potential for termination of contract		

Currently Piclo Flex is solely used by DSOs and the cooperation with the TSO is limited at the moment. When a DSO activates a resource for congestion management, the DSO has to notify the TSO. Flexibility trading services consists of nine steps starting with analysis of where congestion may be a problem on the network followed by the intermediate steps. Of the nine steps, the first, network analysis to forecast needs, is the responsibility of the DSO; the next three are the functions of an online marketplace, open to all buyers and sellers; the following two steps require physical dispatching and operations performed in real time; this is followed by validation, settlement, and feedback – referred to as post-event settlement process. A cloud-based platform like Piclo Flex can facilitate each of these steps of the process:

1. Step 1: Online Marketplace

The first function developed by Piclo is the online marketplace. This provides a trusted and independent marketplace where buyers and sellers can assemble to trade efficiently, at low cost, with speed and price transparency. Like any marketplace, a key role is providing visibility to the participants of each other; so sellers of flexibility services understand the needs of those who will procure the services, and buyers can see the amount of potential flexibility that is available. Piclo Flex provides DSOs with visibility on where flexibility assets are located and how these correspond with their congested areas of need. A common interface across DNOs increases reach, transparency, speed, and efficiency, thus increasing the potential success of the trading and procurement processes. Platform automation also reduces the costs of transactions while increasing the scale of transactions by significantly decreasing the time and effort required to trade.

2. Step 2: Real-Time Operations

The real-time operations can be facilitated by an online platform by enabling dispatch signals to be automated. With the results of procurement stored on the marketplace platform all that is needed from the DNO is one dispatch signal to the platform, which can then automatically allocate to the appropriate providers and communicate via agreed channels.

3. Step 3: Post-Event Settlement

The post-event settlement steps can be facilitated by automating the data communications as well as validation and settlement calculations, as well as providing a common platform for feedback.

3.1.4 GOPACS

GOPACS is a Grid Operators Platform for Congestion Solutions and was launched in January 2019. GOPACS is owned and operated by the Dutch TSO (TenneT) and four DSOs (Stedin, Liander, Enexis Groep, and Westland Infra). The Dutch DSOs (Enduris, Coteq and Rendo) also support the initiative and investigate their participation in GOPACS platform.

GOPACS acts as an intermediary between the needs of network operators and markets with the aim to mitigate congestion in the grid in an efficient way. The collaboration also prevents an action performed by one grid operator from aggravating another grid operator’s problem [88]. GOPACS is integrated into the existing sequence of markets. GOPACS is not a market platform itself, but is connected to a national intraday platform, Energy Trading Platform Amsterdam (ETPA), which is operational in the Netherlands. GOPACS intends to be connected to more market platforms at a later stage. On ETPA, locational flexibility offers for network operators are seen as a subset of the (wholesale) intraday order book. Offers from flexibility providers active on ETPA can be procured by GOPACS if they add a locational tag, called European Article Numbering (EAN) code. There are no static geographical zones defined in ETPA. Instead, GOPACS identifies through its algorithm which assets offer the cheapest solution to solve congestion. Only flexible assets connected to the transmission grid are active. In the near future, also DSO connected assets at lower voltages are expected to participate. Network operators and market parties (BRPs) can procure the same flexibility. Flexibility providers have the option to offer the same flexibility at two different prices by placing two orders (e.g., one portfolio offer for the intraday wholesale and a second offer with locational information). The flexibility provider is responsible for avoiding double activations. GOPACS is one of the first implemented TSO-DSO coordination platforms. In its current version, GOPACS assures that no conflicting activations occur. In the future, the idea is also to identify synergies between the needs of different network operators.

Table 11: Key Characteristics of GOPACS project [4]

Timeframe	Intraday
Market clearing	Continuous trading
Price zones	No static zones, dynamic dependent on congestion needs
Voltage level flexible units (at present)	110 kV or higher, soon also 50 kV or lower
Number of flexibility providers	5–10
Indication of the magnitude of the available flexibility	10-100 MWh per trade

3.1.4.1 The Intraday Congestion Spread (IDCONS) product

GOPACS platform defines the Intraday Congestion Spread (IDCONS) product which is a combination of two offers in opposite directions, an ask and a bid, with the same starting time and duration. The buy and sell orders have the same format as intraday wholesale orders, and orders match in starting time, volume and duration but are located in a different area. The bids supported by GOPACS may have a time span of 15 minutes, 1, 2, 3 4, 5 and 6 hours. The 15-minute bid can start at whole clock hours (and entire clock hours plus whole quarters). Biddings of one or more hours can only start on whole clock hours. There are no minimum or maximum prices or volumes defined for IDCONS. The current shortest bids activation time for GOPACS is 15 minutes. Bids whose actual time to start time of the bidding period is less than 15 minutes will not be called. In case a longer activation time is desired by the participant, the participant must withdraw the bid in time at ETPA. The activation time of bids can therefore be determined by the participant itself [89].

Firstly, congestion management with GOPACS can happen only if the parties have indicated the location and to allow orders to be used for an IDCONS-product. Secondly, the System Operators (SOs) estimate whether an IDCONS combination will achieve the desired results cost-efficiently. SOs have an interest to find the cheapest possible combinations that can achieve congestion management, while not causing other congestions, as they are paying for the spread. There is motivation for market parties to mark offers suitable for IDCONS and offer more aggressively. This is firstly because offers suitable for an IDCONS have higher risks due to physical delivery commitment. Secondly, offers are more likely to be activated in the case of congestions. Thirdly, the bid-ask spread is paid by a third party. This means that locational asks are submitted at higher price and bids at lower price, than for the system level IDM. Market parties can also submit two offers regarding an underlying asset, where one offer is marked for IDCONS and another more conservatively priced offer, for the system level intraday market IDCONS-process can start by SOs first looking at locational market bids and then selecting suitable ones. However, if there are no suitable bids available in the market, SOs submit notifications to ask for more offers in certain areas for a specific duration and regulation direction. Thus, IDCONS-products are case-specific.

The market platform carries out the clearing of IDCONS and informs the market parties involved and the grid operators of this fact. The general process and availability requirements of the market platform apply here. In addition to fees that may apply to the market parties involved in transactions on the market platform, acting grid operators also owe a fee to the trading platform for the use of IDCONS.

If an order is cleared as a part of an IDCONS, the market parties must deliver at least the service indicated in their offer. This means that a Flexibility Service Provider (FSP) with an ask must upregulate equally or more in the predefined EAN and the FSP with a bid must downregulate equally or more in the other location. The validation of this flexibility delivery is defined relative to the planned network use at this location, which can in general be a: unit-based market position, schedule or a baseline-defined from historical behavior. Self-dispatch and portfolio bidding is in place in Netherlands and in other European countries. Since, there are no unit-based market positions for IDCONS settlement, the delivery is compared to generation or load schedule of the connection. If a connection does not have a plan, the IDCONS party is responsible to deliver an alternative plan. Verification of the delivery is also monitored by grid operators from more detailed or real-time metering data [89].

If an offer is matched as an IDCONS-trade, the market party must follow a schedule of a unit and physically deliver the service. Position freezing can limit the interest of market parties to bid into such markets and at least increases safety margins and bid prices due to obligatory physical delivery. Currently SOs place IDCONS announcements to call for more locational offers usually 2-12 hours before delivery and the situations are approximately 1-10 hours long [90]. GOPACS congestion management is shown in the following figure.

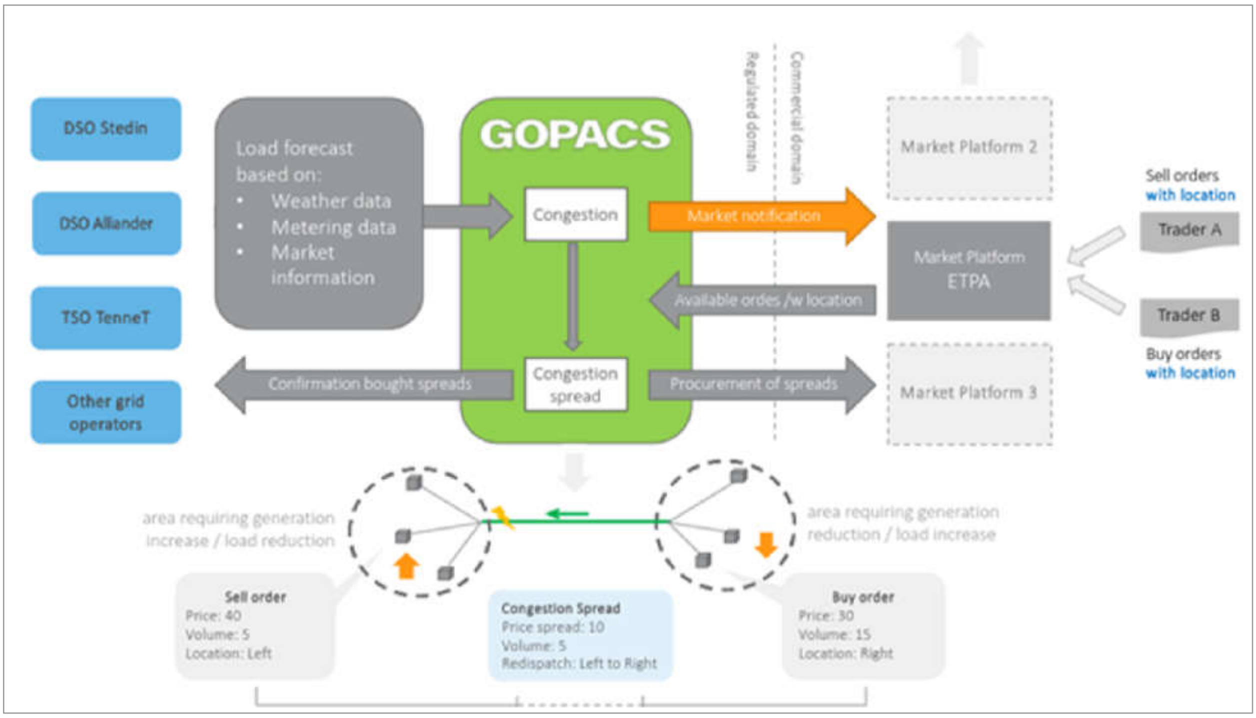

Figure 12: IDCONS product on GOPACS platform

3.1.5 Flexible Power by Western Power Distribution

The “Flexible Power” market has been created by Western Power Distribution (WPD) to deliver the procurement of demand response services. The market was first launched as trial in 2017 and commercially in winter 2018. The market operates by WPD in areas of the UK, Midlands and South & West Wales. WDP requests flexibility within specific areas called Constraint Management Zones (CMZs). WPD is procuring demand response services within CMZs it has identified and published on its Flexible Power website. As flexibility providers can participate all the potential suppliers or aggregators that meet the minimum eligibility criteria i.e. are able to provide minute by minute metering data, or are able to respond within 15’ of receipt of dispatch signal and hold response for at least 1h.

Flexibility is procured through three products that are attributed to CMZs. These are the “Secure”, the “Dynamic” and the “Restore” products. The Secure service is used to manage peak demand loading on the network. This service is expected to be required on weekday evenings and may occur throughout the year due to the seasonal ratings of assets. As these requirements are predictable, Secure requirements are declared each Thursday for the following week (commencing Monday). Payments consist of an Arming fee which is credited when the service is scheduled and a further utilisation payment awarded on delivery. The week-ahead declarations are scheduled to allow customers to participate in alternative services when not required for the Secure service. Arming Payments are intended to provide certainty of income and should be representative of profit so that it is payable whether or not event takes place. When armed the expectation is to utilise. Flexible Power will notify if conditions change and can still send dispatch if preferred. Arming can be clawed back if utilisation is lower than contracted. The Dynamic service has been developed to support the network during maintenance work. This will generally occur during British Summer Time. As the service is required following a network fault, it consists of an Availability and utilisation fee. By accepting an Availability fee, participants are expected to be ready to respond to utilisation calls within 15 minutes. Dynamic availability windows are declared each Thursday for the following week (commencing Monday). The week-ahead declarations are scheduled to allow customers to participate in alternative services when not required for the Dynamic service. Arming is only paid for duration of expected utilisation. Availability is a more conventional concept, reflecting a payment for readiness. Needs are established based on real-time operations and therefore response preferred within 15 mins. Availability can be clawed back if utilisation is lower than contracted using same method as Secure CMZ. The Restore service is intended to support the network or help restoration in the occurrence of rare faults. Such events are rare and offer no warning as they depend on failure of equipment. Under such circumstances, response can be used to reduce the stress on the network. As the requirement is inherently unpredictable, Restore is based on a premium 'utilisation only' service. Premium Utilisation will reward demand response that aids network restoration, but is unable to pay arming or availability fees. Participants declared available for the Restore service are automatically accepted and will be expected to respond to any utilisation calls within 15 minutes will receive an associated utilisation fee. A summary of the CMZ services is shown in the table below.

Table 12: Summary of CMZ Services [91]

	Secure	Dynamic	Restore
Advance Payment	Arming	Availability	None
Utilisation	Medium	High	Premium
Service declaration	Week Ahead	Week Ahead	Week Ahead
Accept / Reject	Week Ahead	Week Ahead	Automatic Accept
Dispatch Notice	Week Ahead	15 minutes	15 Minutes
Seasonal Requirement	All	Summer	All
Site Type	Half Hourly Metered	Half Hourly Metered	Half Hourly Metered
Generation	√	√	√
Load Reduction	√	√	√

3.1.6 SmartNet

The SmartNet project (01/01/2016 to 30/06/2019) proposed new coordination schemes between transmission and distribution networks to favor the integration of renewable energy sources. Even though the focuswas not axed on trading flexibility, the work suggested new market approaches to procure ancillary services (AS).

The five TSO – DSO coordination schemes derived to optimize the processes of procurement and activation of flexibility by system operators were the following [92]:

- Centralized AS market model: the TSO operates an AS market for both resources located at transmission and distribution level, with no or little involvement of the DSO.
- Local AS market model: the DSO operates a local market to solve distribution grid problems and then aggregates and offers the remaining flexibility bids to the TSO market.
- Shared balancing responsibility model: the balancing responsibilities are divided between TSO and DSOs according to a predefined schedule, and each SO organizes his own market. DER flexibility is not accessible by the TSO
- Common TSO-DSO AS market model: TSO and DSO have the common objective to minimize the total costs needed to satisfy their respective services (AS for TSO and local services for DSO). This objective can be reached with two variants of coordination

- a common (centralized) market for both TSO and DSO needs
- a decentralized architecture, but with a dynamic integration of a local market operated by the DSO.

- Integrated flexibility market model: there is one centralized market open to TSO/DSOs but also to commercial market parties (e.g. BRPs).

The market architecture, roles and interactions for the different models proposed within SmartNet are described in Figure 10 and Table 10.

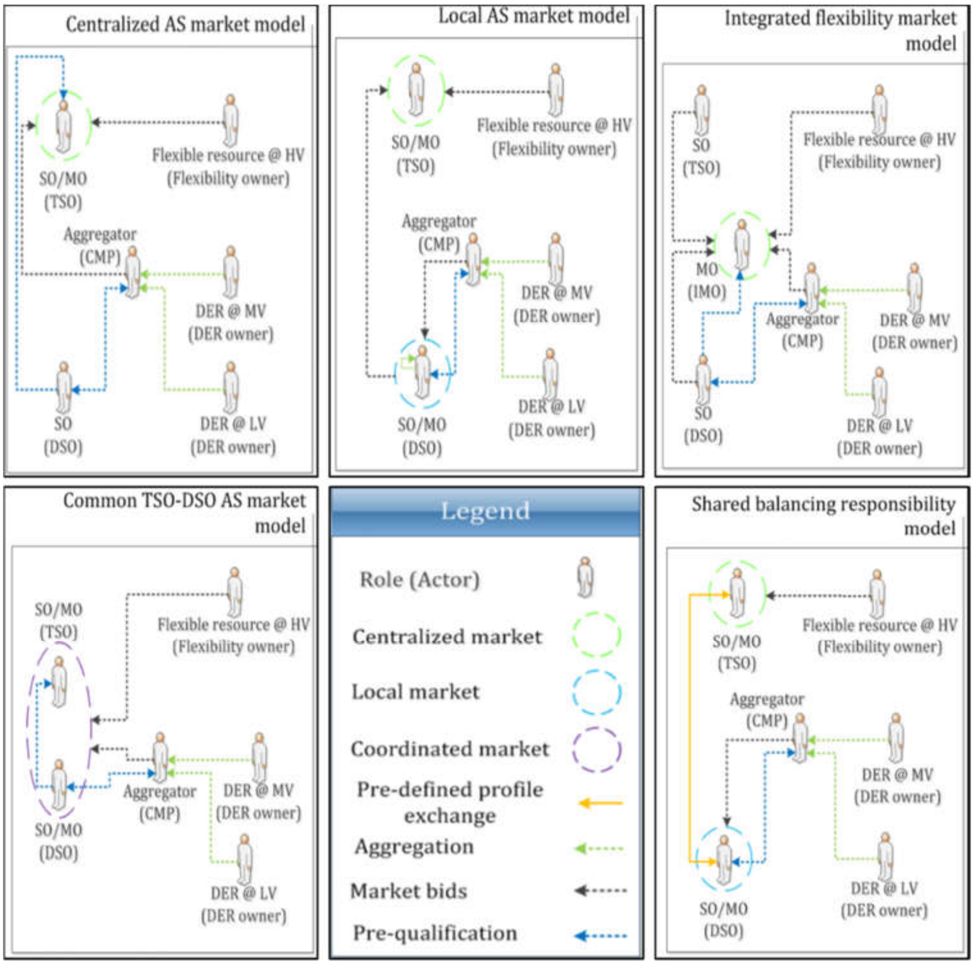

Figure 13: Roles, market architecture and stakeholder interactions for the AS market models [93]

Table 13: Roles in the different SmartNet market models [93].

Market design	TSO role	DSO role
Centralized AS market model		
There is one common market for ancillary services, operated by the TSO, for both resources connected at transmission and distribution level. There is no separate local market.	The TSO is responsible for the operation of its own market for ancillary services. The TSO does not take DSO constraints actively into account. A separate process (system prequalification) could be installed to guarantee that the activation of resources from the distribution grid by the TSO does not cause additional constraints at	The DSO is not involved in the procurement and activation process of AS by the TSO, except in the case that a process of system prequalification is installed to guarantee that the activation of resources from the distribution grid by the TSO does not cause additional constraints at the DSO-grid (e.g. congestion). The DSO is

	the DSO-grid (e.g. congestion).	not procuring local flexibilities in real-time or near to real-time.
Local AS market model		
There is a separate local market managed by the DSO. Resources from the DSO grid can only be offered to the TSO via the DSO/local market and after the DSO has selected resources needed to solve local congestion. The DSO aggregates and transfers bids to the AS market, operated by the TSO. The DSO assures that only bids respecting the DSO grid constraints can take part in the AS market	The TSO is responsible for the operation of its own market for ancillary services, where both resources from the transmission grid and resources from the distribution grid (after aggregation by the DSO) can take part.	The DSO is the operator of a local market for flexibility. The DSO clears the market, selects the necessary bids for local use and aggregates and transfers the remaining bids to the TSO-market. The DSO has priority to use the flexible resources from the local grid.
Shared balancing responsibility model		
There is an AS market for resources connected at the TSO-grid, managed by the TSO. There is a separate local market for resources connected at the DSO-grid, managed by the DSO. Resources from the DSO-grid cannot be offered to the TSOgrid. DSO constraints are integrated in the market clearing process of the local market.	The TSO is the operator of the AS market, limited to resources connected at the transmission level. The TSO is responsible for the balancing of the transmission grid.	The DSO is the operator of a local market. The DSO contracts local flexibility for both local congestion management and balancing of the DSO-grid. The DSO is responsible for the balancing of the DSO-grid, i.e. respecting the pre-defined schedule.
Common TSO-DSO AS market model		
There is a common market for flexibilities for both TSO and DSO with both resources connected at transmission level and connected at distribution level. TSO and DSO are both responsible for the organization and operation of the market. DSO constraints are integrated in the market clearing process. Two alternatives are considered: (1) all constraints are integrated in one only optimization process that encompasses both TSO and DSO grid constraints (centralized variant), (2) a separate local DSO market for local grid constraints runs first (without commitment to the market participants) and communicates with an AS market operated by a TSO with transmission grid	The TSO and DSOs are jointly responsible for the market operation of the common TSO-DSO market (centralized variant) while they are jointly responsible for the final outcome of the two separate market runs (decentralized variant). The TSO is contracting AS services from both transmission and distribution. In practice, in the centralized variant, the joint responsibility could be organized by allocating the responsibility to a third party, under guidance of both TSOs and DSOs.	The TSO and DSOs are jointly responsible for the market operation of the common TSO-DSO market (centralized variant) while they are jointly responsible for the final outcome of the two separate market runs (decentralized variant). The DSO uses flexible resources from the distribution grid in cooperation and interaction with the TSO.

connected resources. The outcome of the second market communicates back to the first market to find the optimal solution to be communicated to the market participants (decentralized variant).		
Integrated flexibility market model		
The common market for flexibilities is organized according to a number of discrete auctions and is operated by an independent/neutral market operator. There is no priority for TSO, DSO or CMP. Resources are allocated to the party with the highest willingness to pay. There is no separate local market. DSO constraints are integrated in the market clearing process	TSOs are contracting AS services in a common market. TSOs can sell previously contracted DER to the other market participants.	DSOs are contracting flexibilities for local purposes in a common market. DSOs can sell previously contracted DER to the other market participants.

The project was validated on three pilots: Italy, Denmark and Spain. The main outcomes of the project can be comprehensively described as:

a. *Italian Pilot*: Centralized remote control demonstrated in the field from generation connected to sub-transmission grid for both active and reactive power. The coordination showed that reactive power loop was avoided but on the other hand, service requirements were not fulfilled through demonstration activities. In addition to that, TSO developed a virtual capability that allows to know the availability of resources in real-time, DSO shared information regarding the topology and constraints of the distribution grid for the calculation of the operational limits (P, Q) at the connection points between the operators.
b. *Danish Pilot:* A technical aggregator was developed having the capability to respond to any penalty signal, and thus being energy, price or emission efficient. Under the aggregator umbrella, 30 summer houses with a swimming pool and either boiler or heat pump were considered. Moreover, a real clearing platform was established with connections to both TSO and DSO, Economical Aggregator and the Technical Cloud-based Aggregator/controller. Finally, the establishment of a cloud-based control of smart buildings in such a way that they can support the future smart grid (eg. Voltage control and congestion management) can be considered as an important milestone for the Danish pilot activities.
c. *Spanish Pilot:* Main goal was to leverage base station flexibility to provide shared responsibility services. Specifically, DSO was able to operate local energy markets to avoid congestion and maintain scheduled profile, except of the case were downward balancing was needed and the cases that there was not enough flexibility available. In addition, power-frequency regulation / balancing was accomplished by maintaining the exchange program at the TSO-DSO coupling points. Finally, demand response aggregation demonstrated by using storage flexibility. The results of the Spanish Demo are highly replicable, with more than 250MW across Europe, due to the existing ICT infrastructure [94].

3.1.7 COORDINET

CoordiNet (01/01/2019 to 30/06/2022) is a Horizon2020-funded project which aims to establish different collaboration schemes between TSO/DSO/consumers in order to ensure a smart, resilient and secure energy system.

In total seven coordination schemes between TSO/DSO are defined. These schemes are obtained based on four classification layers answering to the following questions; which need of operators the flexibility provision addresses (local or central), which stakeholder buys the flexibility (TSO/DSO/commercial party), how many markets are considered (local, Balancing, etc.) and whether or not TSO has access to flexibility. This classification and the corresponding cooperation schemes are depicted in Table 11.

Table 14: CoordiNet's defined Coordination schemes [95]

Market Model	Need	Buyer	TSO access to DER	Description
Local	Local	DSO	NA	No market coordination is considered between DSO and TSO.
Central	Central	TSO	Yes or No	No market coordination is considered between DSO and TSO. TSO has direct access to distribution grid flexibility.
Common	Local & Central	DSO & TSO	Yes	Both TSO/DSO needs are fulfilled in a single market under a system wide, simultaneous optimization.
Multi-level			Yes	Local and central needs are fulfilled via a combination of local and central markets. Unused bids from DSO can be transferred to AS market.
Fragmented			No	Similar to the multi-level with the difference that distribution grid bids can be solely used to fulfil DSO needs.
Integrated		DSO, TSO & commercial parties	Yes	Similar to common market with the difference that this model allows a threefold of market stakeholder
Distributed	Local	Peers	NA	Peers are the sole buyers and providers in the market(s) to solve distribution grid issues.
	Local & Central			Peers are the sole buyers and providers in the market to solve distribution & transmission grid issues.

It is worth mentioning the distributed market model. For CoordiNet project the case of development solely to cover central needs is excluded. Depending on the system operation needs, the establishment of more than one markets may be implemented. In this case, grid-related issues are solved under the context of a market where peers are the sole buyers and providers. One possible implementation of this approach is to establish a peer-to-peer market setup, in which peers establish direct connection to neighboring peers. The current regulatory framework needs to be restructured in order to encompass a market setup like this. In addition, a proper design is necessary to avoid unnecessary energy imbalances or grid constrained solutions. Hence, a well-design distributed market approach to exchange flexibility from peers in order to alleviate problems for operators could be proved complicated. In the context of the Swedish demo, distributed market model through peer-to-peer market setup is implemented to alleviate local and regional DSOs from congestion related issues.

The roles of DSO and the independent aggregator under the context of collaboration between TSO and DSO are elaborated in the project. The adoption of a specific role is based on the activities of an actor. DSO may play a versatile role as data manager, neutral market facilitator, market officer of contracting flexibility, MO and operator of local and regional balancing area. On the other side, independent aggregators are considered as market facilitators to allow the participation of small-scale flexibility.

In total three large scale demonstration projects across 10 different locations in Spain, Sweden and Greece are going to be developed [96]. In the Greek pilot, two main grid services are of high interest: congestion management (1) and voltage control (2). For these services, capacity and energy products (active and reactive power) are relevant. The BUCs have been separated depending on the applied coordination scheme. The Greek pilot market is planning to test a multi-level market mechanism (a) as well as a fragmented mechanism (b). The Spanish demo, targets to solve congestion (1), balancing (2), voltage (3) and islanding (4) issues that can be solved through a close cooperation between the actors: the Spanish TSO, the DSOs and Flexibility Service Providers (FSPs). Thus, the Spanish demo targets to offer four types of grid services. To foster the market for these services different products can be procured. Among others, the products for these market include active or reactive power, short term or long term procurement, and frequency reserves. Two BUCs will at least be realized on the basis of a common market mechanism, while one BUC targets to a central- one to a local market mechanism in a first stage. The Swedish demo focuses on congestion (1) in the distribution grid or between the transmission and distribution grid and balancing (2). In the Swedish grid, one has to differentiate between the regional DSOs, who have the connection to the TSO and the local DSOs who cover smaller parts of the systems but are connected to the regional DSO. For the grid service creation, both energy and capacity products are relevant. The development of these services is however strongly dependent on the realization of the coordination schemes, which have been identified to develop towards a multi-level market mechanism (a), distributed market mechanism (b), and a local market for the local DSO in Gotland (2).

3.1.8 EU-SysFlex

EU-SysFlex (1/11/2017 to 31/10/2021) is a Horizon2020-funded project which aims to identify long-term needs and technical scarcities arising in the new era of pan-European electricity system, by identifying and demonstrating new types of systems and flexibility services. Moreover, it is working to incentivize the necessary flexibility and solutions to enhance the market and regulatory framework. Ultimate project goal is to create a long-term roadmap of actions for Europe to facilitate the large-scale integration of new technologies and capabilities.

In total, seven demonstration activities take place in seven different countries, namely Portugal, Italy, Germany, Poland, Estonia, France and Finland, creating a list of 12 BUCs based on the nature of the managed flexibility (active or reactive power) and the service delivered by the demonstrator [97]. Services regard frequency control, congestion management and voltage control. Wide range of flexibility sources is utilized in the demo activities, including centralized pump storage plants, batteries, wind and photovoltaics (PV), heat loads, electric vehicles (EV) and super-capacitors.

The role of DSO and its involvement is extensively elaborated, in the case that flexibility sources needed by TSO are connected to the distribution grid. DSO has to be involved, in order to handle the consequences with respect to potential voltage constraints or congestions on the distribution grid. Besides two BUCs in Finland, all the rest BUCs consider DSO as a stakeholder and give an extensive role in the flexibility market design. Different market designs are defined based on the service nature and the regulatory framework of the demonstrator. Specifically [98]:

1. *Local Market:* The concept of local market design is proposed where flexibility from the distribution grid is processed before it is available to be utilized for services in the transmission system. In case of Italian Demo, the local MO activates local flexibility (from flexibility bids) in order to alleviate congestion issued existing in the distribution grid. Then, DSO may select the optimal activations to solve the foreseen congestion management. The remaining flexibilities are aggregated and submitted to the real-time ancillary services markets (mFRR, RR, and transmission system congestion management), managed by the MO of transmission system.
2. *Bilateral agreements with local market*: In case of Finnish demo, reactive power provided from assets connected to DSO to alleviate voltage issues in TS. It is proposed the concept of a local market that bilateral agreements between DSO and aggregators exist. The Local MO clears the market based on the bids, the needs for reactive power (assessed by DSO) and the existing bilateral contracts.
3. *No-market framework*: There are BUCs in the project that flexibility is not procured under a specific market design. In the Italian Demo, for the provision of reactive flexibility power for voltage control and congestion management, long-term agreements between DSO and DERs aggregators take place. In case of the German Demo, active power flexibility by DERs through Generation Aggregators is offered in a mandatory way. DSO selects flexibility in a Merit Order List to solve problems existing in its network, and then sends remaining flexibilities to TSO. Moreover, for reactive power management, reactive power is set in grid connection contract.

The following identified business roles are included in the BUCs descriptions [98]:

Table 15: Business roles description

Role	Description
Asset Operator	Operates assets in distribution grid, such as storage, consumption and generation.
Generator	Invest, operate and maintain assets.
Generation asset Operator	Operate one or several assets.
Distribution Network Flexibility Provider	Provides flexibility from assets connected to DN.
Transmission Network Flexibility Provider	Provides flexibility from assets connected to TS.
Aggregator	Aggregates and maximizes value of resources connected to the distribution grid. In case of the Finnish Demo, the retailer plays the role of Aggregator.
Generation Aggregator	Aggregates and maximizes value of generation portfolio resources. In addition, provides flexibility by generation assets to the SOs.
BRP	Manages operational planning of imbalances within its responsibility zone and ensures financial liability.
DSO	The versatile role of DSO can be comprehensively described as: Ensure transparent and non-discriminatory access to DN for each user, operate DN in a secure, reliable and efficient way, optimize DN for planning and support TSO in carrying out its responsibilities and coordinate measures.

TSO	The versatile role of TSO can be comprehensively described as: Ensure transparent and non-discriminatory access to TS for each user, operate TS in a secure, reliable and efficient way, secure real time physical generation-consumption balance, optimize TS for planning, implement dedicated actions and emergency measures in stress events.
MO in Distribution	The versatile role of TSO can be comprehensively described as: Ensure transparent and non-discriminatory access to TS for each user, operate TS in a secure, reliable and efficient way, secure real time physical generation-consumption balance, optimize TS for planning, implement dedicated actions and emergency measures in stress events.
MO in Transmission	Organizes auctions for assets connected to TS in order to provide electricity related products in the Markets. Moreover, manages\operates trading platform and is also responsible for market clearing and results communication.
MO	Organizes auctions for assets connected to both TS and DN in order to provide electricity related products in the Markets. Moreover, manages\operates trading platform and is also responsible for market clearing and results communication.
Metered Data Operator	Provides metered data to authorized data in a transparent and non-discriminatory manner.
Forecast Provider	Provides forecasts of DERs based on historical data to other roles.

The existing regulatory framework in the demonstration countries has a few barriers that have to be overcome. These mainly regard the gap in the regulation about local market managing both active and reactive power flexibility in distribution. Indicatively, for the Italian demo, there is lack of regulation framework regarding local market for the case of active power provision. In the Portuguese demo, a local market for reactive power provision shall to be introduced and more type of resources shall be included to participate in the case of active power flexibility provision.

3.1.9 DOMINOES

Dominoes (01/10/2017 to 31/03/2021) is a European research project supported by Horizon 2020. The DOMINOES consortium is composed by 8 partners from 4 European countries, namely Finland, Portugal Spain and UK. The project aims to enable the discovery and development of new demand response, aggregation, grid management and peer-to-peer trading services by designing, developing and validating a transparent and scalable local energy market solution. The project will show how DSOs can dynamically and actively manage grid balance in the emerging future where microgrids, ultra-distributed generation and energy independent communities will be prevalent.

The main stakeholders identified within the project are: prosumers and the established local community (Consumer / prosumer, Flexibility provider, Energy provider, Energy procurer, Forecast provider), DSO (Flexibility procurer, Data manager, Forecast provider, Distribution grid optimizer, Distribution constraints officer, Technical validator), aggregator (Aggregator / VPP, BRP, Flexibility procurer, Flexibility provider, BSP) retailer (Aggregator, BRP, Energy provider, Energy procurer, Flexibility procurer), service provider (Forecast provider, ICT solution provider, Device operator) and TSO (Flexibility procurer, System operator).

The DSO, the aggregator, retailer or an energy service provider should be able to act as an energy community service provider (ECSP) for providing the local market service. The ECSP will establish the local market and provide access to compatible stakeholders who can then offer services that enable supplier contracts, grid services, balance service, representing the local community outside its boundaries at the centralized market, data management, information interfaces and exchange.

In addition, the aforementioned stakeholders can participate in the local market by e.g. acquiring flexibility to support grid operations (DSO) or market operations (aggregator, retailer, BRP). The prosumers and consumers can participate in the energy community as energy community participants enabling them to receive and share energy with other energy community participants, participate in demand response services, enable the participants to decide on the distribution of value of their energy resources. The roles of the TSO, wholesale market parties, centralized generation, other service providers, technology providers as well as other parties such as regulators and standardization organizations are also considered.

The following table provides information regarding the Use cases of the project:

Table 16: DOMINOES project Use Cases

Use Case	Brief Description	Actors
Local market flexibility and energy asset management for grid value	This use case explores capabilities that the DSO can develop to better monitor and control the grid in the event of a local grid occurrence by procuring and activating available flexibilities offered by local entities	DSO Prosumers Consumers Aggregator Data manager Forecast Provider
Local Market Data Hub Manager and technical validation and flexibility too	This UC mainly describes the information exchange between eligible and relevant market players and the DSO as data manager. Other services were also not considered, since they will be provided outside the LEM domain: Residential energy sizing optimization; Consumption profile. Receive flexibility information from Household Energy Management Systems.	Local Flexibility Provider Local Flexibility Procurer Energy Service Provider DSO Data manager Technical Validator Regulator
Local community market with flexibility and energy asset management for energy community value	Use of flexibility and management of resources for the benefit of the local market	Consumer Prosumer DSO Retailer Energy Storage/renewable Generation-DER
Local community flexibility and energy asset management for retailer value	Use of flexibility and energy asset to provide value to the retailer	Retailer Wholesale Market
Local community flexibility and energy asset management for wholesale and energy system market value	The usage of flexibility and management of energy assets of the local community for the wholesale and energy system market value	Consumer Prosumer TSO DSO Retailer Aggregator

DOMINOES developed six business models that are defined based on the models that have already been described. Business models or cases are directly related to each of the use. In the following table we summarize the business models developed within the DOMINOES Project [99].

Table 17: DOMINOES project business models

Business Model	Provider	Market offer model	Revenue
Aggregation of small-scale flexible loads as a universal virtual power plant	FSP (aggregator/ community manager)	The FSP will offer the aggregated flexibility as a solution for the provision of balancing services to grid operators and balance responsible parties. The community aggregator can sell the flexibility to be used for: reducing grid congestion, avoiding expensive grid upgrades, limiting any penalties for failing to balance supply and demand, and avoiding buying energy when prices are high.	The flexibility provider will be payed according to flexibility provided to its clients (DSO/BRP/TSO). Besides, the FSP can charge a fee to the community members for optimization of time-of-use, reducing cost of energy and optimizing the use of renewables production.
Aggregator flexibility provision to DSO for network management	Aggregator	DSO congestion management situations are usually solved internally by the DSO. Aggregators offer a new service to help the DSO solving such situations. Competitors can be producers, consumers and prosumers with direct contracts with the DSO, and some specific types of aggregators, such as Curtailment Service Providers. The deployed flexibility is delivered to the distribution system in reply to the DSO request, materialized as a reduction or an increase of the load.	The DSO will have to pay the required services to the aggregator. The services will be paid in Euro / MWh (required). The aggregator acts as an intermediary between the DSO and the aggregated resources. The aggregator pays the flexibility deployment to its aggregated resources. This can be done paying for the flexibility which is made available (e.g., monthly Euro /MW). The payment for the deployed flexibility can result from an asymmetric pool model (Euro / MWh). For that, the aggregator makes a call auction to its aggregated resources, which will present their bids. The asymmetric pool model will be applied, where all the accepted bids, required to meet the flexibility amount required by the DSO in MWh, are paid at the clearing price (equal to the most expensive accepted bid, in Euro / MWh).
		DSO provides a transactive platform where end-users can make local energy transactions with their neighbors. End-customers receive signals from	DSO will not be directly paid. This business model prevents penalty costs though. Therefore, the DSO will get a revenue

Using transactive energy for network congestion management	DSO	the DSO to promote local energy transactions aiming at alleviating network congestion issues. The DSO can provide incentives to end-users when their local transactions contribute to the reduction of penalties caused by congestion situations.	calculated by the difference of penalty cost avoidance minus the incentives paid to the end-consumers. It should be taken into account that regulation in Europe and the rest of the world might be different so that the revenues' calculation could vary depending on particular circumstances.
Sharing the exceeding PV generation in the scope of energy communities	Community Manager (CM) acting as an aggregator	The Community Manager (CM) acts as an aggregator of consumers with demand response (DR) capacity and of public PV plant, providing the technological platform to share the information among players. Optimal scheduling and sharing of PV generation among the community is provided aiming at the reduction of bills and green self-consumption. Competitors can be the regulated entities that pay for the PV generation delivered to the grid.	The service will be paid as a fixed fee to the CM or aggregator. The CM will also receive a fee for the service paid by the community members. Also, the DR and energy delivered to the market will be paid to the CM so it can share some incomes with the community. The consumers providing DR will receive the benefits of PV in the proportion of the contribution made by DR, as a discount in their bills.
Retailer as user of the local market	Flexibility available from consumers, prosumers, producers, DER and other actors playing in the local market. The flexibility will be made available through the local MO	Use of the local market flexibility to be valued in the wholesale market or to optimize the retailers' portfolio	Revenues from optimizing the participation in the wholesale market Revenues from reducing imbalances in the retailer's portfolio
Energy service provider in enabling / assistive role for local markets and providing ECSP capability for retailers, communities or	Energy service provider (role can be taken by multiple parties)	ICT infrastructure to manage local market that can be used for energy community benefits to (ECSP role): • Optimize the use of own/local generation and enabling energy sharing and trading • Maintain loads below certain threshold • Optimize wholesale market purchases	Fee for setting up the local market. Subscription fee for maintenance of the local market and/or share of benefits from provision of flexibility services and optimization of wholesale market participation

other service providers		• Provide flexibility services for the market • Provide information services to end-users/energy communities (e.g. timely distribution of consumption and generation; environmental impacts of own/community consumption; proactive condition monitoring for electric appliances) As an ICT tool by other stakeholders for multiple purposes: • DSOs: flexibility services (capacity management etc.) Retailers: wholesale market optimization • Aggregators: aggregation of resources for market flexibility services • Third parties wanting to provide services for energy communities Other services can include: • Forecasting • Load/consumer profiling/segmentation	

3.1.10 INTERRFACE

INTERRFACE (TSO-DSO-Consumer INTERFACE aRchitecture to provide innovative grid services for an efficient power system) is a European research project supported by Horizon 2020. The project started in 01/01/2019 and will end in 31/12/2022. The core objective of the project is the greater coordination between TSOs and DSOs. INTERRFACE project will design, develop and exploit an Interoperable pan-European Grid Services Architecture (IEGSA) to act as the interface between the power system (TSO and DSO) and the customers and allow the seamless and coordinated operation of all stakeholders to use and procure common services.

INTERRFACE identifies the following actors within the project [100]:

Table 18: INTERFACE project actors

Role	Description
Supplier/Flexibility Provider	An entity that offers flexibility in generation, load or storage of electrical power.
TSO	Ensure transparent and non-discriminatory access to TS for each user, operate the grid in a secure, reliable and efficient way, secure real time physical generation-consumption balance, optimize TS for planning, implement dedicated actions and emergency measures in stress events
DSO	Ensure transparent and non-discriminatory access to DN for each user, operate DN in a secure, reliable and efficient way, optimize DN for planning

	and support TSO in carrying out its responsibilities and coordinate measures.
Consumer	A party that consumes electricity.
Producer	A party that produces electricity.
Party connected to the Grid	A party that contracts for the right to consume or produce electricity at an Accounting Point
Meter data responsible	A party responsible for the establishment and validation of metered data based on the collected data received from the Metered Data Collector. The party is responsible for the history of metered data for a Metering Point.
MO	A party responsible for installing, maintaining, testing, certifying and decommissioning physical meters.
Resource aggregator	A party that aggregates resources for usage by a service provider for energy market services.
Resource provider	A role that manages a resource and provides production/consumption schedules for it, if required.
BSP	A party with reserve-providing units or reserve providing groups able to provide balancing services to one or more LFC Operators. Based on Electricity Balancing - Art.2 Definitions.
Reserve allocator	Informs the market of reserve requirements, receives tenders against the requirements and in compliance with the prequalification criteria, determines what tenders meet requirements and assigns tenders.
BRP	A party that has a contract proving financial security and identifying balance responsibility with the Imbalance Settlement Responsible of the Scheduling Area entitling the party to operate in the market. This is the only role allowing a party to nominate energy on a wholesale level.
Scheduling Agent	The entity or entities with the task of providing schedules

The Use Cases analyzed within INTERRACE project are presented in the following table:

Table 19: INTERFACE project Use Cases

Use Case	Services	Scope	Objectives	Actors
Congestion management “SO-Supplier”	Congestion management operational for DSO	To provide flexibility by means of power production from programmable DG system (CHP plant)	Provide flexibility in the balancing market	Flexibility provider TSO BSP
Congestion management “LV regulation Power	Power Quality for DSO	Use of battery storage and DR program to optimally exploit the local production of	Increase power quality in suburban branches of LV grid with a high share of	DSO BSP (acting also as demand aggregator) Flexibility Provider

quality"		renewable energy	renewable energy	
Congestion management "Local Energy Community" Business Use Case	Congestion management operational for DSO	Exploit the synergies among energy network in a municipal scale multi energy microgrids in order to maximize the self-consumption of locally produced renewable energy	Increase the flexibility of the microgrid in order to reduce the amount of electricity flow back to the TSO	DSO, BSP (acting also as demand and renewables aggregator)
Aggregated CM service to the TSO/DSO Fast balancing reserve to the TSO Non-frequency ancillary services to the TSO/DSO	Congestion Management operational (TSO, DSO) mFRR & non-frequency services (TSO)	To provide CM service to the TSO/DSO by using part of the power/energy capacity of one (or more) Battery Energy Storage Systems (BESS) installed in multi-user buildings (or group of homes) with PV and particular loads, such as EV and data centres.	To provide CM services to the TSO/DSO by using battery energy storage system (BESS) integrated in end-user communities (group of households, multi-user buildings) to form a controllable aggregated demand resource.	TSO DSO Flexibility resource provider
Single Flexibility Platform	Congestion management operational, short-term, long-term (DSO) mFRR, aFRR, FCR (TSO)	First priorities: congestion management short-term, mFRR	An envisaged service that may serve network reinforcement deferral, network support during construction and planned maintenance where location specific flexibility assets are being activated for shaving or shifting peak demand and production in order to compensate for the lack of network connections, loads or production units	FSP Aggregator BRP BSP MO TSO DSO Supplier Billing Agent, Imbalance Settlement Responsible Flexibility Register TSO/DSO Coordination Platform
Distribution grid users	Congestion management	Enable the market participation of small consumers: mainly households but the P2P local	Support the congestion management of the DSO, considering the real load ability	Consumer Producer Party Connected to the Grid Meter Data

participating in P2P local market	operational (DSO)	market concept enables the market participation of any low voltage and medium voltage users – consumers, prosumers, distributed generators, storage).	of grid assets, by using a smart asset management system to consider assets' type, their age, condition and other parameters.	Responsible MO
Flexibility services for DSO congestion management and allowing more renewable connection without unreasonable DSO network investments	Congestion management (TSO & DSO)	The use-case is to be demonstrated in Bulgaria and/or Romania with TSO-DSO partners	Help DSOs organize a decentralized local market for distributed resources connected to DSO-grid in order to solve local grid constraints, aggregate and offer remaining bids to TSO	MO Resource Aggregator Resource Provider DSO TSO Consumer
Regional inter-zonal provision of Balancing (FCR, aFRR, mFRR) services in South-East Europe	FCR, mFRR, aFRR	Market design of the regional inter-zonal provision of Balancing (FCR, aFRR, mFRR) services in the South-East European system. The Use-Case describes the algorithm to be developed for the optimal power market reserves clearing for the provision of FCR, aFRR, and mFRR services	Aims at the regional integration of balancing markets, considering also secure grid operation and security of supply and in addition facilitating the access for smaller market players.	BSP TSO Reserve Allocator Flexibility Services MO (FSMO)
Spatial aggregation of local flexibility using market platform connecting wholesale	Congestion management at DSO and TSO	Introduce spatial dimension into the existing wholesale market design, develop a market tool that facilitate TSO-DSO coordination, use auction type market platform incorporating	Realize an efficient way of solving grid related constraints through the usage of shadow prices, provide intra-zonal congestion price signals for, both DSO and TSO, incentivizing flexibility resources,	Party Connected to the Grid BRP Resource Provider Resource Aggregator Scheduling Agent MO TSO DSO

and local flexibility		complex constraint, locational information from local flexibility sources	applying PUN concept	

3.1.11 Ecogrid

The Ecogrid trial project was carried out on the Danish island of Bornholm (which is fully integrated into the Nordic power system) for 1900 domestic and 100 industrial customers between 2011 and 2015. The aim of the project was to trial a regional real-time market where DERs including flexible demand customers are incentivised to react to variations in electricity prices based on local congestion. Trades were not carried out P2P but through a central market with no local matching of supply/demand. However, the aim of the real-time market was to provide local price signals to reduce congestion which does promote matching of local supply/demand by DERs. The prices were updated every 5 minutes (close to real-time) to reflect the need for regulating demand and supply based on system imbalances. It was aimed to alleviate congestion, allow DERs to be better utilised in the market and allow small scale DERs to be used that would otherwise have been left unused. In the Ecogrid project, balancing was carried out by the TSO with the real-time market providing balancing at a higher resolution in parallel to the balancing (known as regulating in Denmark) market. This followed the 'Total TSO' model where the TSO is optimising the dispatch of DERs. The advantage of this approach is that the real-time market and balancing markets can be coordinated centrally. The disadvantage is that for the trial to be carried out over the whole country, the complexity in computation and communications in managing the real-time markets could be excessive for a single TSO. In terms of congestion management it was found that real-time price signals reduced the overall peak load on Bornholm by 1.2%. It was estimated that wind power curtailment using this scheme could be reduced by 80%. However, the project was not successful in reducing distribution feeder congestion [101].

3.1.12 TDI 2 Project - Power Potential

A UK funded project was the Transmission Distribution Interface (TDI 2 project) run by UK Power Networks (UKPN) and National Grid (03/01/2017 - 30/12/2019). The aim of the project was to alleviate congestion in the UKPN operated south east of England network using active network management along with the increased role of the DNO to aggregate DERs. The project aim was to create regional power markets managed by the DSO which allows procurement of reactive and active power services from DERs. Reactive power was procured on forward tender basis. Active power services were re-dispatched in real time by NG or UKPN such as that request were within envelop of the DNO constraints on the network. The DSO then selected the optimum DER services to satisfy network constraints and presented the available services and costs at each grid supply point to the System Operator (SO), National Grid, who selected the most economical option to satisfy grid constraints. This project along with the Cornwall local energy market were at the cutting edge of demonstrating the potential of the role of the DSO in coordination distribution markets. [101].

3.2 Innovative flexibility market solutions beyond Europe & adaptation in the European electricity market

3.2.1 USA

3.2.1.1 New York Reforming the Energy Vision (NY REV)

Andrew Cuomo, Governor of New York, launched the New York REV (https://rev.ny.gov/) with the aim of creating a clean and resilient energy system for the state. The general goal of the project is to build a consumer-centered framework for energy markets while improving the integration of DERs.

New York transitioned REV adopted a reformed retail electric industry framework under which utilities will no longer simply serve as the operator of the local electric grid. Instead, they will also serve as the system coordinator and market manager of the local grid, while remaining under regulatory oversight.

The new electric system being created will be driven by consumers and non-utility providers, and it will be enabled by utilities acting as distributed system platform (DSP) providers. Utilities will be responsible for reliability, and the functions needed to enable distributed markets will be closely tied to the functions need to ensure reliability. The utilities acting in concert will constitute a statewide platform that will provide uniform market access to customers and DER providers. Each utility will serve as the platform for interface among its customers, aggregators, and the distribution system [102] .

For example, the utility Con Edison, operating in New York, has implemented the initial stages of DSP functionality. As DSP provider, Con Edison is developing the capabilities, processes, and systems that will enable key DSP functions: integrated planning, DER interconnection, and DER management (DER integration); information management and customer engagement (information sharing); and procurement, market coordination, wholesale tariff, and settlement and billing (market services). DSP functionality and capability is developing in two phases. In the first phase, DSP 1.0, DSPs provide retail settlement and billing services to customers based on the Value of Distributed Energy Resources (VDER) tariff, and wholesale settlement and billing services to aggregators for Non Wire Alternatives (NWA) procurement, as shown in the following figure. DER aggregators and their customers can also access wholesale settlement and billing services through the New York Independent System Operator (NYISO) [103]. The VDER tariff was introduced in 2017, when, as part of the state's Reforming the Energy Vision, the New York Public Service Commission required the state's investor-owned utilities to begin transitioning distributed solar photovoltaic (DPV) customers to a new VDER tariff. The VDER is a net billing structure under which the customer pays a volumetric rate for grid electricity and is credited for exported DPV output at a separate rate that reflects the value of solar [104].

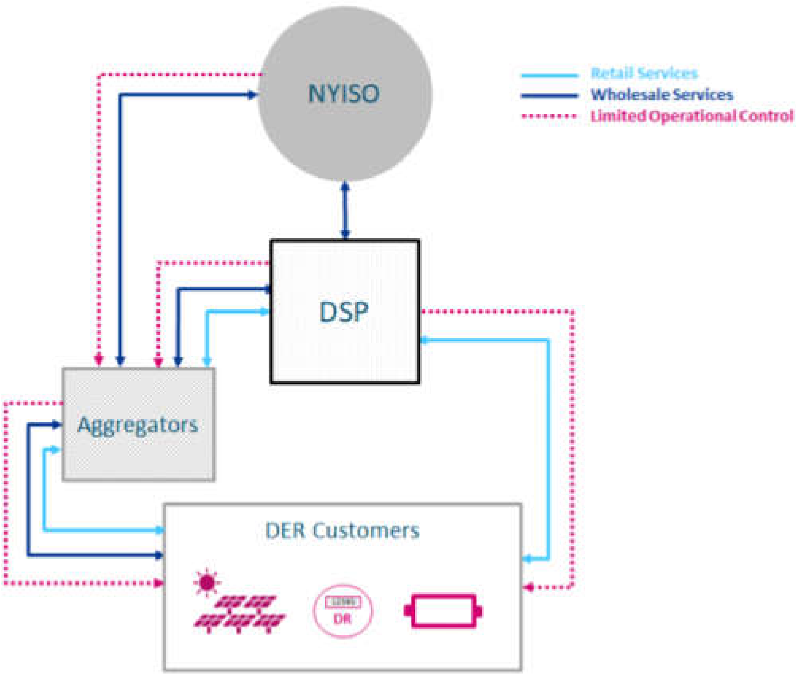

Figure 14: DSP 1.0 Wholesale and Retail Services [103]

DSP 2.0 builds on the functions and capabilities of DSP 1.0, adding greater visibility and operational control over DER. Greater visibility and operational control allow for the creation of integrated markets for wholesale and distribution services. In DSP 2.0, DSPs offer wholesale scheduling and dispatch services, allowing customers and aggregators to maximize the value of their resources across NYISO wholesale markets and distribution markets. Aggregators can still access wholesale markets directly through the NYISO. The NYISO also has enhanced capabilities to monitor and control DER. This function implies a full operational control between the components of Figure 13 [103].

In the scope of the project, DERs would sell three types of products: real energy, reactive power, and reserves. Real energy relates to what is directly consumed by the customer; reactive energy is necessary to maintain voltage at the required level; and since DERs cannot be accurately forecast, reserves are needed to cover potential forecasting issues. The market would run a forward market for electric products and related service and then a clearing market for imbalances [105].

The integration of DERs is favoured through different mechanisms:

- Accurate pricing: by applying a granular pricing, which depends on time and location, the system would identify when and where to make the most of the use of DERs.
- Facilitating the access to the market: the creation of a market with easier access and reduced participation costs.
- New products: the market would support the addition of new types of products and services from DERs like price responsive flexible load which would maximize the penetration of DERs.

3.2.1.2 Delaware EV pilot

In the University of Delaware (US) the Vehicle to Grid (V2G) project presents an interesting aggregator potential business. The EV aggregator in Delaware acts as an intermediary firm between PJM (local TSO), and flexibility service providing EVs. This project has a fleet of electric vehicles (EVs) whereof the aggregator collects information regarding EV availability by calculating the current state of charge and planned trips. Furthermore, the regulator receives the regulation dispatch signal from PJM. The aggregator sells capacity to the grid operator, PJM in this case. So far, it only participates in frequency regulation. In PJM, the aggregator bids in the hourly auction market for frequency regulation and is for the available power capacity each hour ($/MWh). When participating in this frequency regulation, EVs receive a dispatch signal from the local TSO (PJM) and are remunerated accordingly. If the regulation service offered by the Delaware EV aggregator has not met the performance thresholds over a specified time period in terms of correlation (delay) and precision, PJM is able to disqualify the aggregator [106].

3.2.1.3 LO3Energy/BrooklynMicrogrid

The Brooklyn Microgrid (BMG) project, run by LO3 Energy, consists of a microgrid energy market in Brooklyn, New York, on which community members can trade (locally generated) energy P2P with their neighbours. Currently, participants in the BMG are located across three distribution grid networks in the BMG's region.

The idea of the project is to build a microgrid that would be able to take over the main grid when weather events (hurricane etc.) occur. The area of the Brooklyn Microgrid is especially exposed to grid failures. The Brooklyn Microgrid provides a local solution which relies on [107]:

- <u>The virtual community energy market trading system (EMTS)</u>: This system provides the technical infrastructure for the local electricity market. It is based on a private blockchain. Market participants are local consumers and prosumers. The market mechanism is a closed order book with a time discrete double auction in 15 min time slots. Any prosumer *P* and consumer *C* willing to trade electricity in the next time slot, can submit buy or sell orders via their EMTS to the market. Any order includes an order quantity and price. For now, consumers constantly bid their maximum price limit for their preferred energy sources (e.g. local renewable energy). Prosumers bid the minimum price limit that they request for selling their generation on the microgrid market. Similar to a merit-order dispatch, the highest bidder is allocated first, then the lower bidders are allocated. The last allocated bid price represents the market clearing price for this time slot. Consumers that do not undercut the clearing price will be supplied by additional energy sources (i.e. hyper-local energy or traditional ''brown" energy) allocated over a similar bidding mechanism or predefined prices. Other market mechanisms, including a pay-as-you bid order book in which each transaction may have an individual transaction price are investigated. Financial transactions are carried out between the allocated market participants according to predefined payment rules.
- <u>The physical microgrid</u>: An electrical microgrid is build in addition to the existing distribution grid. The physical microgrid acts as back-up to prevent power outages. By uncoupling from the traditional grid, it can operate in island mode. Then, critical facilities (e.g. hospitals) receive energy at fixed rates. Residences and businesses have to bid on the microgrid's remaining power. .

3.2.1.4 Clean Coalition Community Microgrid

The Clean Coalition (https://clean-coalition.org/) is a nonprofit organization whose mission is to accelerate the transition to renewable energy and modern grid through technical, policy, and project development expertise. Their main effort has been put in the definition and implementation of Community Microgrids.

Their vision of a Community Microgrid is that it should be community-centred instead of DER-owner-centred. The core features of a Community Microgrid are the following:

- It targets thousands of customers instead of only a small neighbourhood as it is often the case when talking about microgrids.
- The DER would be placed next to the electrical grid instead of in a household.
- The locations of the DERs is an important part in their vision. Indeed, a DER should be placed on the location where the community can make the most of it and should not be owned and controlled by a single household.
- Their model and the way it is implemented aim at being replicated even if weather and geographical conditions are different. Their model is based on a strong coordination between transmission and DSOs. It assumes at least a 25%-DER penetration. This setting allows to introduce a Wholesale Distributed Generation (WDG) platform which is in charge of serving local loads through a complete transmission and distribution system.

They targeted and are starting to implement their first Community Microgrid in the Goleta Load Pocket. The Goleta Load Pocket is in the coastal Southern California and the region lies at the end of a transmission grid which make it extremely exposed [108]. The region suffers from regular forest fire and the Goleta Load Pocket needs to be protected. The Clean Coalition launched a project that aims at 100% protection back-up. To ensure such a target, they plan on building 200 MW of solar and 400 MWh of energy storage [109].

For most of the Community Microgrid configurations, the Clean Coalition will design a Dispatchable Energy Capacity Services (DECS) market mechanism, or Dispatchability Adder, that will unleash the untapped value that Community Microgrids can provide in the form of fully dispatchable renewable energy. A Dispatchability Adder is a fixed ¢/kilowatt-hour (kWh) bonus on top of the Feed-In Tariff (FIT) rate, and offers a value for the Dispatchable Energy Capacity Services (DECS) provided by solar and storage. [110]. An overview for the operation of the DECS market mechanism is given in the figure below.

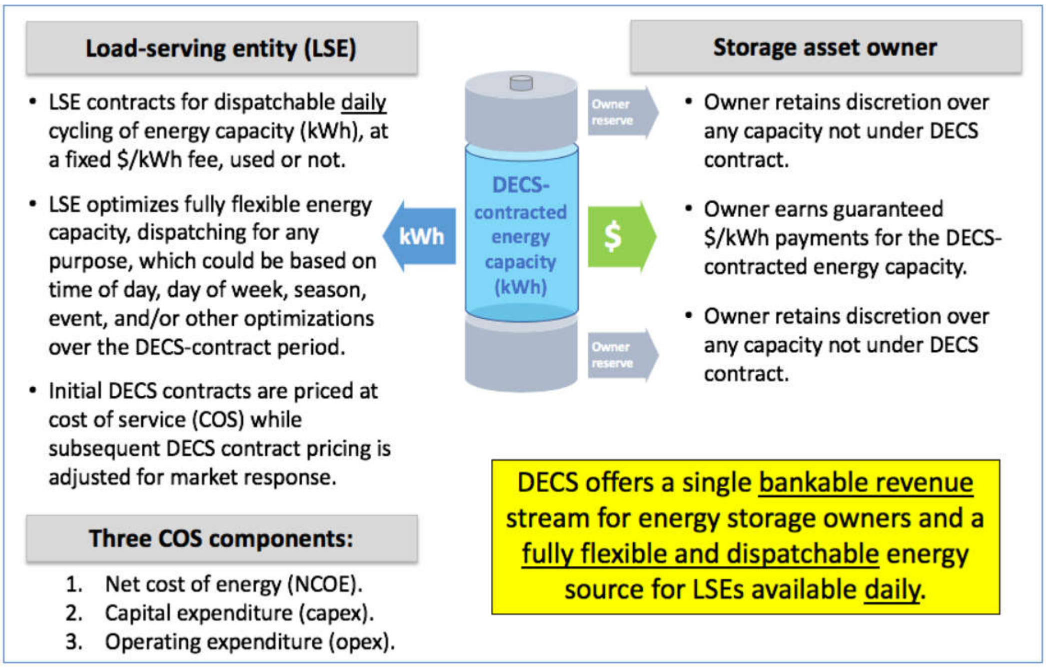

Figure 15: Dispatchable Energy Capacity Services [110]

3.2.1.5 California Independent System Operator flexibility product

California Independent System Operator (CAISO) in the United States was among the first independent system operators in North America to implement a separate flexibility ramping product. In November 2016, CAISO implemented Flexible Ramp Up and Flexible Ramp Down Uncertainty Awards, which are ancillary service market products to procure ramp-up and ramp-down capability for 15 minute (min) and 5 min time intervals. The product is procured in terms of megawatts (MW) of ramping required in a 5 min duration, and any resource capable of fulfilling the ramping requirement can participate. Market participants do not provide bids for this product but are instead compensated according to their lost opportunity cost of providing other services in the ancillary service market. The price for providing ramp-up service is capped at USD 247 per megawatt-hour (/MWh), while the price for providing ramp-down service is capped at USD 152/MWh [111]. In contrast to conventional ancillary services, this product focuses on addressing net load changes between time intervals, and not on standby capacity aimed at meeting demand deviations within a time period. In addition, an innovative feature of this proposal is that it is continuously procured and dispatched [112].

3.2.1.6 Southern California Edison project

Southern California Edison recent procured a capacity of 2.2 GW of behind-the-meter solar PV generation, storage, and demand-side management to alleviate congestion in particular zones of the grid. Besides being a complex process because of the necessary cross comparisons between technologies, location of assets, and the diverse nature of contracts with suppliers, it reveals emerging business models in which generation and distributed energy resources are treated on a par with conventional generation. Of particular interest is the agreement with distributed solar generation company Sun-Power which assumes and enhances the role of aggregator. Upon requirement of the utility, the aggregator commits to achieving savings through solar power, which it procures at specific sites from generation facilities scattered throughout different grid locations—a Virtual Power Plant—without exporting it to the grid [112].

3.2.1.7 East Bay Community Energy Community Choice Energy program

East Bay Community Energy (https://ebce.org/) is the local electricity supplier in Alameda County (California). EBCE proposes to their customers to consume electricity coming from renewable energy sources. In addition, the earnings are reinjected in the community to fund local clean energy projects and jobs. EBCE is a community choice aggregator (CCA). This new actor in electricity markets is part of the community choice aggregation program deployed in seven states in the US (now referred to as Community Choice Energy - CCE) [113]. A CCE allows a city or county (or groups of cities or counties) to become the default electric supplier in its jurisdiction(s). By doing so, it offers an opportunity to residents of a specific region to locally influence the sources of their electricity. The primary risks in a CCE program are customer opt-outs, energy price fluctuations, and changing state regulations. A successful CCE program requires that a significant majority of residential and commercial customers obtain their electricity from the program. This is one reason why CCE programs strive to maintain competitive pricing, while lowering greenhouse gas emissions, and providing higher renewable content than an incumbent utility. EBCE will hedge that risks by developing a diverse portfolio that includes a mix of long-term and short-term contracts and direct investments in power projects [114].

EBCE partners with the utility Pacific Gas & Electric (PG&E) to provide greener electricity to EBCE's consumers. Note that California is one of the most active area of the world in terms of renewable energy sources' integration. In 2018, renewable represented 39% of the energy mix of PG&E[6].

EBCE gives the opportunity to their consumers (particular or business) to consume renewable or

[6] https://ebce.org/power-mix/

carbon-free energy. They separate wind and solar Californian power (renewable) and large hydropower sources (carbon-free). They derived 3 premium contracts for their customers for which they choose the percentage of renewable and carbon-free power they're willing to consume:

- Bright Choice: it guarantees at least 38% renewable and a potential addition of 47% carbon-free.
- Brilliant 100: it guarantees at least 40% renewable and a potential addition of 60% carbon-free.
- Renewable 100: it guarantees 100% renewable Californian wind or solar power.

3.2.2 Australia

3.2.2.1 Open Energy Networks (OpEN)

The Open Energy Networks is a joint project between Energy Networks Australia and the Australian Energy Market Operator (AEMO). The goal of the project is to suggest the best strategy to integrate DERs into Australia's electricity grid.

The study shows that Australians already install DERs, especially solar panels [115]. The number of electric vehicles and batteries is also expected to increase significantly by 2030s. This will add a nonnegligible number of flexible loads in the market. There are no standards for integrating renewables in the market yet, but the study suggests that the future market framework should allow DER to participate, individually or through aggregation.

The study provides 2 different models for developing the distribution market framework that might be worth looking into:

- The single integrated platform: in the setup, AEMO would run a centralized platform which aims at optimizing the dispatch on the transmission and the distribution level. Aggregators and energy retailers would develop portfolios of DER customers to provide system services offerings to AEMO's central market platform. AEMO would assess all bids and offers and optimizes the dispatch of energy resources considering both transmission and distribution network constraints. AEMO would have the commercial relationship with DERs via aggregators/retailers and would be responsible for financial settlements to market participants.
- The two-step tiered platform: in this model, DER dispatch is taken care of the DSO in charge of the associated distribution network. AEMO would be directly in charge of the transmission wholesale market and indirectly involved in the distribution network. This would work in a hierarchical way since the DSO would receive bids and give dispatch instructions accordingly but before the dispatch occurs, AEMO indirectly has to validate the schedule by making sure that the grid is safe under the conditions imposed by the dispatch.

3.2.2.2 Distributed Energy Roadmap from West Australian Government

In the South West of Australia, the number of installed solar panels is exploding: one third of the households have rooftop photovoltaics and 2,000 are build every month [116]. Correctly integrating them to the power system is crucial for the grid and the consumers.

The roadmap developed by the West Australian Government gives a set of actions required to achieve the targeted goal of deploying a DER-friendly power system. The main tasks are the following:

- Clearly define the role and functions of DSO and Distribution Market Operator.
- Massive addition of energy storage accompanying the significant installation of solar PVs.
- Create tariffs incentivizing the use of DERs. The roadmap insists on the importance of having new tariff structure that incorporate time-based price signals, in particular low rates during day the day because of the solar generation and a higher price in accordance with peak load and night.
- Protection of the customers. In order to ensure their participation in the market, the operators need to ensure data protection of the users as well as simple and accessible information. Facilitating the decision making for the households should also be favoured through understandable mechanisms for DER participation.

3.2.3 Latin America

In Latin America, the integration of renewable energy sources comes with another challenge: making the electricity procurement more reliable. For example, in 2019, the System Average Interruption Duration Index (SAIDI) is roughly 2.3 hours[7], more than 10 times higher than in Germany. Having that in mind, reliability is the main challenge in Latin America at the time, but it is not incompatible with the deployment of renewable energy sources. We focus on Chile and Brazil as examples [117].

3.2.3.1 Chile

Chile has the most aggressive renewable development policy. The goal is to push coal plants out of the system as fast as possible with a 2030-target of 40% power supply through wind and solar. Since reliability is still an issue, Chile is primarily focusing on energy storage, direct (batteries) or indirect (electric vehicles, demand response). As a consequence, migration of uncertainty coming from the renewable generation is done by investing on storages.

Another concern raised in Chile is how electricity should be priced in distribution networks. Historically, price computation has been working effectively in Chile and has been exported to other Latin American countries, but experts question the effectiveness of the approach with a high penetration of DERs.

The way the government tries to increase DER's penetration is by imposing certain targets to generation companies. Every year, each generation company must demonstrate before the Independent Coordinator of the National Electricity System that a certain percentage of the energy produced comes from renewables. If not, a special charge must be paid. The national goal is 20% by 2025.

3.2.3.2 Brazil

At the moment, in Brazil, hydropower is the main responsible for electricity supply. It is also a flexibility provider due to the large reservoirs and an interconnected national transmission system. Solar and wind are to increase rapidly in the coming years and discussions about how best to integrate DER are happening.

Several aspects of flexibility are questioned in Brazil. First, two types of flexibility are considered: long-term (seasonal flexibility) and short-term. Concerning short-term flexibility, the possibilities include ramping, demand-response and a closer attention to the forecasting effort on renewable generation.

There is also an active discussion about pricing in Brazil. For many years now, the price of electricity has been set weekly and hourly prices implementation is now largely considered to better capture the uncertain nature of DER and properly reward flexible assets.

In the early 2000s, the government launched a 20-year program called PROINFA (Portuguese acronym for 'the Programme to Foster Electric Power Alternative Sources). The initiative aimed at developing a total of 3,300 MW of renewable energy generation equally distributed among wind, biomass and small hydro projects. Later, in the early 2010s, the Brazilian National Development Bank (BNDES) provides low-interest financing for renewable energy projects that meet local content requirements.

3.3 Proposals and recommendations for the European electricity markets

3.3.1 Recommendations to encourage flexibility by reforming wholesale electricity markets

[7] SAIDI is the average total duration of outages (in hours) experienced by a customer in a year. Source: https://databank.worldbank.org/reports.aspx?source=3001&series=IC.ELC.SAID.XD.DB1619

3.3.1.1 Adapting short-term markets

In order to encourage flexibility, the design of short-term energy markets should be enhanced and refined at all levels, including timelines, bidding formats, clearing and pricing rules, and their integration with reserves and regulation markets. Some recommended reforms include:

- Increase time granularity by making trading intervals shorter and closer to real time. Market signals should be made more time-specific and gate-closure times reduced to reveal the flexibility of resources that can respond quickly to fast-changing conditions. This can be done through continuous trading, discrete intra-day auctions or a combination of both.
- Increase locational granularity by using zonal or nodal prices. The increased deployment of variable renewable energy, particularly wind, may result in a constrained transmission network. Markets must reflect such network constraints. Zonal pricing is a simplified approach to address this, but it comes at the expense of market efficiency, particularly in regional markets. Zonal pricing works well when transmission congestions are structural and systematic, and when predefined price zones are easy to determine accurately. However, variable renewable energy can alter power-flow patterns significantly, thus exacerbating the limitations of zonal pricing. In this context, nodal pricing can often provide better operation and investment signals but may be harder to implement.
- Reform wholesale-market bidding formats to incorporate increased detail in the representation of generation and demand characteristics. With higher variability, and given the need to fully exploit flexibility from storage or demand response, it is important to rethink and reform the bidding formats used by participants in energy markets to submit their bids. These need to go beyond simple price-quantity bids and move toward advanced schemes that allow market participants to hedge against increasingly variable short-term market conditions and to better represent the characteristics of demand response and storage.
- Adapt existing pricing and market clearing rules. Current pricing and clearing rules either focus on minimizing the cost of economic dispatch at the expense of having uplift payments outside the market, or on providing uniform payments to all market agents at the expense of higher complexities. The right balance ought to be met according to the policy priorities in each context.
- Strengthen the link between energy and reserves markets. This imperative reflects an important key fact: supplying one of them implies modifying the ability of power plants to provide the other. Strengthening this link involves co optimising energy and reserve procurement both in day-ahead and shorter-term energy markets. Where that is difficult, frequent market sessions for the procurement of reserves could be organized, aligned with the timelines of energy markets. Furthermore, system operators should abandon inflexible reserve requirements and implement new solutions to procure and price reserves according to the actual value they provide to the system [118].

3.3.1.2 Adapting balancing markets

Redesigning of balancing markets is essential to ensure that they reward flexibility and to facilitate the effective use of all resources. Essential adaptations include:

- Redefining balancing products and define innovative products to unlock the potential of new, flexible resources. To the extent possible, balancing energy should be procured from the most economic resources available in real time, even if those resources do not acquire longer-term commitments in day-ahead or other reserve markets. Different price signals should be given to resources performing differently and to the extent possible, limiting participation based on size or technology should be avoided. Furthermore, upwards and downwards reserves should be two distinct products.
- Facilitating variable renewable energy contribution to grid stability. To efficiently exploit all available flexibilities, including those offered by renewables, new reserve products should be explored. When service providers with different response capabilities compete to provide the same balancing product, performance-based remuneration can help avoid defining too many reserve products and markets, and can also reduce overall reserve requirements.
- Avoiding dual-imbalance pricing. Because dual-imbalance pricing does not exactly reflect the costs of imbalance, it distorts real-time price signals. Although portfolio aggregation can mitigate the deviation risks that renewable producers face when dual-imbalance pricing is applied, the

practice still provides a competitive advantage to larger companies over small providers and distributed energy resources. Where it is applied, responsibility for balancing supply should be assigned to each generation unit to prevent competitive disadvantages [118].

3.3.1.3 Flexibility through capacity and generation - adequacy mechanisms

Long-term support mechanisms, including capacity or adequacy mechanisms and support schemes for renewables, are widely used to guide generation investments according to country policy priorities.

- Renewables should be allowed to participate in generation-adequacy mechanisms. Renewable generation can be a valuable contributor to system adequacy, especially in power systems with a high share of conventional (i.e. reservoir-based) hydropower. Therefore, regulations should avoid introducing systematic technology-specific market-entry barriers, and allow renewable technologies, including variable renewables, to participate in generation-adequacy mechanisms on a level playing field, where and when it is technically possible.
- Capacity mechanisms do not necessarily substitute for support mechanisms. Long-term support mechanisms should be designed in a coherent way to ensure that the incentives provided through renewable-energy support schemes account for possible remuneration earned in the capacity market (as well as in other markets).
- Economic support for renewables should be market compatible. Where policy makers consider offering economic support for renewable technologies, this should be done in a way that is compatible with markets. Several designs for support schemes are available, all of them offering advantages and disadvantages. A balance must be found between optimal investment incentives and market compatibility, determined according to policy priorities. Mixed approaches may be explored to achieve a compromise solution.

3.3.2 Recommendations to encourage flexibility by fostering smarter distribution systems and active network users

3.3.2.1 Adapting distribution systems

The efficient deployment of high levels of distributed energy resources, including distributed generation (DG), demand side management and small-scale storage, requires innovative approaches to planning and operating distribution networks. Conventional grid access and connection rules and practices should be adapted accordingly and smart-grid technologies should be deployed.

- Rethinking planning for DG. Grid connection has traditionally followed the approach of reinforcing the grid as much as necessary to prevent any operational problems. This is a safe and robust strategy and requires very low levels of network monitoring. But as DG penetration levels increase such an approach can be costly, especially in areas with high concentrations of DG, and can cause long lead times for connecting new DG sources. Therefore, as DG penetration levels grow regulators should gradually rethink network planning and grid connection.
- Co-ordinated approach to grid connection. Grid-connection application processes should be reviewed to speed up DG connection and to allocate grid capacity more efficiently. A first-come-first-served approach can mean higher connection costs for later applicants due to reinforcement requirements. It also results in inefficient grid development due to economies of scale. Therefore, co-ordinated approaches should be explored such as working in batches per network area.
- Disclosure of grid condition information. Information disclosure obligations should be levied on DSOs such that new DG units have information on the condition of the grid for a point of connection. Publishing the available generation-hosting capacity allows DG promoters to estimate whether their application will be successful and determine which location will result in lower connection charges. Ultimately, this facilitates the integration of DG.
- Remunerate DSOs based on their active grid management. Large penetrations of DG introduce complexities in distribution planning since the location of DG units can be highly uncertain. Integrating DG efficiently requires active network management as an alternative to conventional grid reinforcements, such as solving network constraints in real time, or close to it. Regulation

should promote this transformation. One important way to do that is to require utilities to submit detailed business plans based on cost-benefit methodologies as part of the remuneration process.
- Enable advanced forms of contracting between DSOs, generators and consumers. Active network management requires the development of smarter grids as well as closer interaction between all relevant actors. The latter can be achieved through flexible connection contracts that limit curtailment of generation or demand in exchange for some form of compensation or under specific conditions. As the presence of DER grows, more advanced forms of contracting flexibility services, such as bilateral agreements or market-based approaches, could be implemented.
- Promote smart grids. Technology risks, and the absence of economic incentives, prevent the development of smarter distribution grids. Policy and regulation should promote and support innovation, implementation of pilot projects, the exchange of lessons learned, and the sharing of best practices. The creation of public-private collaborative networks and the definition of knowledge sharing and information disclosure obligations can facilitate information exchange.

3.3.2.2 Rethinking the remuneration of DSOs

The regulation focus should shift from short-term cost reductions to the promotion of long-term efficiency. DSOs should also be encouraged to implement innovative grid planning and operation solutions (i.e. smarter distribution grids). This involves:

- The focus of regulation should shift from ensuring that companies invest sufficiently in networks to assessing grid operators based on their performance, as measured by an extended set of indicators. Those indicators could include customer satisfaction, grid-connection lead times, the carbon footprint or available distributed generation hosting capacity. When these indicators can be objectively measured and controlled by the DSOs, incentive (and penalty) mechanisms can be implemented.
- The required novel methods of managing the network reduce the need for investment in distribution assets but increase operational expenditures. Traditional regulatory approaches discourage novel methods if DSOs are remunerated mostly based on their capital investment. Incentive systems should reward both operational and capital expenditures of DSOs.
- Regulatory benchmarking, a method of determining remuneration for DSOs, usually relies on past information. It implicitly assumes that future developments will follow a similar trend. This assumption is questionable in a context requiring innovation. Hence, cost-assessment methodologies should increasingly rely on forecasted data and well-justified investment plans submitted by the regulated companies.
- Promoting efficient investment in distribution networks requires adopting a long-term perspective given the long life of the assets and the time required before innovation yields benefits. Regulators should progressively extend the length of the regulatory period to incentivize DSOs to pursue long-term efficiency. Remuneration formulas should be more flexible to accommodate possible uncertainties in such a dynamic environment. This may include the introduction of profit-sharing schemes and automatic-adjustment factors [118].

3.3.2.3 Decoupling distribution revenues from energy volumes

Distribution revenues should be independent of the volume of energy distributed, as this, in the case of distributed generation or self-consumption, may be translated into a reduction in revenues without a corresponding drop in costs. This decoupling of revenue essentially consists of adjusting network tariffs ex post so that DSOs recoup exactly the allowed revenues. Moreover, if cost-assessment tools are unable to capture the impact of DG on distribution costs, economic compensation on top of conventional revenue allowances may be necessary to account for it [118].

3.3.2.4 Improving tariffs and metering

Self-consumption and the adoption of distributed storage behind the meter can yield benefits for both end-users and the power system as a whole. Therefore, regulation should actively promote self-consumption by adopting a cost-reflective design for retail tariffs and supporting the roll out of advanced metering technologies.

- High levels of self-consumption may negatively impact the financial viability of distribution utilities and the recovery of fixed power-system costs. Such issues become more prevalent in markets with high shares of renewable sources supported by net-metering policies since they implicitly value the energy injected into the grid at the retail electricity price. To keep up with these developments, regulations in many systems have limited individual or aggregate installed capacity, reduced the period of time over which energy injections can offset energy withdrawals, and changed the structure of retail tariffs and compensation rules. However, these do not provide a real long-term solution for jurisdictions with high penetration of active agents.
- The sustainable development of high levels of on-site generation in mature liberalised markets entails adoption of self-consumption schemes with hourly netting intervals, or even shorter. In addition, retail tariffs should be cost reflective. They should be based on the value of electricity at each time and location, the individual contribution of the network users to network costs, and a charge to recover other regulated costs so that the economic signals sent by energy and network charges are not distorted.
- Advanced-metering infrastructure should be installed so that adequate locational and time granularity in the tariffs can be communicated to end consumers. Electronic meters capable of recording bidirectional energy flows every few minutes are needed for the development of self-consumption and to stimulate end users' demand response, including distributed storage. Economies of scale and standardisation are important when deploying advanced meters.
- The changes that advanced power systems are experiencing are strictly interlinked with the power system digitalization. The evolving role of information and communication technologies for the efficient management of the power system calls therefore for a close cooperation between electricity and telecommunication regulators [118].

3.3.2.5 Encouraging the new roles of DSOs

As the energy transition evolves, a growing share of the resources needed to ensure secure and flexible system operations will be connected at the distribution level. In this new environment, DSOs must bridge the gap between flexibility providers (i.e., distributed generators, responsive demand and aggregators), markets and transmission/independent system operators. To do this, they should adapt their planning and operational practices accordingly and play new roles as market facilitators and DSOs.

- Regulation should allow distributed energy resources to participate in upstream energy and ancillary services, particularly when these resources become widespread. DSOs should facilitate this participation and carry out activities such as ex ante technical validation, to ensure that no constraints arise in the distribution grid, and ex post verification of the provision of the services.
- To facilitate well-functioning retail markets and the participation of distributed energy resources in wholesale markets, it is critical that market agents have transparent and non-discriminatory access to metering data. This might be seen as a conventional task of DSOs, but concerns arise when a metering data manager, traditionally a local DSO, is also a market participant. In this context, alternative models for data management could be explored, such as creating a new regulated entity responsible for data management (central hub) or opting for a decentralized approach. There is no consensus on the most appropriate model, but regulations must always ensure non-discriminatory access to data and protect consumers' privacy, particularly after the deployment of advanced metering.
- DSOs should make use of distributed energy resource flexibilities by actively integrating with the resources connected to their grids. Ad hoc regulatory mechanisms such as non-firm connection agreements, bilateral agreements or local markets may be necessary. Regulators should clearly define the responsibilities of DSOs, especially where a DSO belongs to a vertically-integrated company in a context of retail competition [118].

3.3.2.6 Adaptation of market design for aggregation and demand side flexibility

The first phase of introducing flexibility as a resource should focus on making flexible consumption of electricity interesting for individual suppliers. Aggregators might be the necessary driving force to attract suppliers to participate [119]. Large industry and commercial suppliers can contract directly with buyers whereas households are more dependent on aggregators. At the same time, strong requirements on minimum bidding volume and bid duration restrict aggregators participation possibilities. Due to the fact that large upfront investments are needed for contracting, metering and control of demand response, barriers of market entry for aggregators should be reduced. Furthermore, market rules should involve a definition of performance criteria for demand response, for example related to the performance in terms of demand response correlation, delay and precision that is also applied by local DSOs. Due to the fact that demand response affects traditional load curves, a change in such consumption might lead to increased cost to suppliers that procured electricity ex-ante [106]. Therefore, some financial compensation models have been suggested to allow third party aggregators to trade flexibility of end-users that have been ex-ante contracted by suppliers for their traditional consumption curves. In [118] the authors analysed various contract types, and propose a nonlinear incentive compatible contract for the aggregator to activate flexibility from suppliers. Suppliers select a suitable volume of flexibility they are willing to provide to the aggregator for a given payment among a variety of options. In return, the aggregator controls and manage their loads. The suppliers can restrict the loads to be controlled. In addition, the aggregators should offer innovative services to make the flexibility resource more attractive to suppliers. The contracts should distinguish between available flexibility and actual activated flexibility with an attached payment schedule. For instance, aggregators can offer a service in return for available flexibility and pay the contracted price for activated flexibility. Aggregators have to engage in bilateral contracts with the buyers as well, and as indicated by the analyses of [118] a two-part linear contract is a suitable alternative for the aggregator to extract profit, and simultaneously the optimal value chain profit is obtained. The buyers must pay a wholesale price for each volume of flexibility they demand from the aggregator as well as a fixed payment, and it should be agreed in this contract as well whether the buyers must pay for all available flexibility or the activated flexibility. The latter reduces the risk for buyers, making it easier for them to participate. The lump sum payment could be used to pay for having a certain amount of flexibility available at given times while the wholesale price pays for activated flexibility. Bargaining power will decide the allocation of profits among the participants. As buyers may not be aware of the value of flexibility in the beginning, it is reasonable to assume that the aggregator cannot extract the whole value chain profit and must give the buyers attractive offers. For instance, a grid company may demand a risk premium for postponing investments as there is uncertainty and thus higher risks involved. The contracts can typically be individually tailored rather than being standard contracts in this phase. Besides providing value in traditional electricity markets, aggregators can also provide potential value for evolving markets, for example in local balancing for distribution grids. These types of markets are not yet existent in Europe. Recommended is that policy makers set the right environment and cooperation possibilities with DSO's and TSO's regarding this geolocation based demand response. Of course, it is possible that demand response in those settings could be mandatory or on tariff basis, but this entirely depends on decisions regarding market design [106]. When more demand side flexibility is mobilized and multiple buyers become aware of the value of it, a market place can evolve. In a market place the opportunities of flexibility becomes apparent and makes it easier for buyers and suppliers to trade flexibility. This will also increase the transparency and the competition among flexibility traders, making the trading more efficient. For a relatively new traded resource it is important that participants have easy access to the resource. Thus, a market place is an important step for making flexibility available. Existing electricity markets can be an additional market place for trading flexibility. The existing market barriers should be removed for this to happen, making it possible for new entrants to submit bids of flexibility into these markets. As discussed in [118], an aggregator might extract profits from trading in the Reserve Option market. If the aggregator possesses a large flexibility portfolio, he can exploit a combined business model where contractual relationships are the primary source of income and trading in existing markets serve as a supplementary income source. The transition phase can eventually lead to creation of new markets for trading well defined flexibility products with large market volumes. Local markets will provide flexibility to all potential buyers. The local dependency of grid companies' challenges is addressed by these markets and the MO can serve as the coordinating role instead of the aggregator. Unlike an aggregator, a MO tries to maximize total market benefit. Thus, trading flexibility through markets will in most cases lead to more efficient outcomes than bilateral contracts coordinated by aggregators.

However, it should be noted that existing electricity markets and separate flexibility markets are designed for different purposes. Whereas the existing markets intend to trade electricity and secure electricity reserves, flexibility markets aim to provide flexibility to the system by letting all potential buyers and suppliers participate. Flexibility is a virtual resource physically linked to electricity, hence the markets affect each other. Three key factors affect the long-term existence of parallel markets in the electricity system. First, the prices in the existing electricity markets and the local flexibility markets are of importance. A large gap in the prices may exclude one of the markets. For instance, if the flexibility markets operate with significantly higher prices than the electricity prices few buyers are interesting in procuring flexibility. Some buyers, however, value the flexibility high enough to trade in the flexibility market if they do not have access to flexibility from other trading methods which leads to the second key factor. Barriers of market access prevent certain actors to freely participate in all markets. If some buyers and suppliers do not have access to provide flexibility in electricity markets this indicates a need for a separate market. Without an intermediary party like an aggregator or a retailer, small suppliers can realistically be excluded from electricity markets due to certain barriers. Finally, balancing of the electricity system is crucial and the parallel markets must secure balance in order for both of them to exist as electricity and flexibility is physically linked. If flexibility is activated in a flexibility market, this affects the electricity balance of the system. Hence the markets must be coupled and should be operated synchronously. Coupling the markets ensures that the flexibility is employed where it offers the most value, and the same resource can be activated for different purposes in the power system while inducing both private earnings and the economy at large.

3.3.2.7 Facilitating the development of infrastructure for storage and electric vehicles

The development of electric mobility requires careful regulation of the contractual relationship between the various actors involved: electricity distribution operators, electricity suppliers, charging point operators, mobility service providers, and electric vehicle (EV) drivers. DSOs will play a key role in the deployment and operation of new grid-edge infrastructure such as public EV charging stations, or distributed storage. The major regulatory question is whether to consider them part of the business model of DSOs or open them to competition. The former can collide with unbundling rules and lead to a suboptimal utilization of these technologies, while the latter may make it harder for DSOs to benefit from their potential contribution to grid planning and operation.

- Market forces alone may not be able to foster the development of public charging infrastructure. Policy makers may have to kick-start the infrastructure development, for example by giving DSOs responsibilities. However, this may be challenging. On the one hand, unbundling rules may prevent DSOs from selling electricity to electric-vehicle users; on the other hand, treating EV charging points as part of the regulated asset base may imply that rate payers would be subsidizing EV users. To avoid such problems, other policy alternatives might be adopted to provide the initial policy push.
- Distributed storage will be another game changer in the power sector, also for its potential to supply grid-support services. For this reason, DSOs may seek to own and operate storage devices. However, unbundling provisions could rule this possibility out since storage operators may wish to provide other services under competition to obtain a positive business case. Thus, exemptions on the unbundling obligations may be considered in some cases. In others, DSOs may be entitled to contract services with storage operators through auctioning.

3.3.3 Recommendations to encourage flexibility by enhancing interactions between the DSO and the TSO

With the change in paradigm driven by more flexible and decentralized resources connected directly to distribution networks and the more active role of DSOs operating those resources, there is an increasing need for coordinating actions between TSOs and DSOs at the operational level. The flexibility connected at the distribution level may be an efficient resource for solving network problems, not only at the distribution level but also in the transmission network. Several models enabling this co-ordination between the distribution and wholesale levels can be envisioned. All these typically require some form of aggregation of a large number of DER, either by the DSO itself (which may be hampered by unbundling rules) or by competitive agents such as retailers and aggregators who deliver services at both the distribution and wholesale level. There are several operating situations – such as line congestion, voltage support, the load condition of the TFO or black-start – where TSO-DSO co-ordination would be beneficial. Those coordinated actions require DSOs to implement innovative technology solutions that are available but not yet deployed, such as grid monitoring, two-way communications with flexible customers and with the TSO, and network quasi real-time simulations.

DSOs and TSOs must have in place constraint management procedures in order to tackle constraints on their networks, including the right to require modification of flexibility activations in accordance with these procedures. To ensure safe, secure and cost-efficient distribution and transmission network operation and development, both the DSOs and TSOs must have access to flexibility services and all technical relevant data needed to perform their activities both at pre-qualification stage and in real time (or close to real time). DSOs and TSOs shall exchange relevant operational data with each other. When congestion areas occur, DSOs and TSOs will make the appropriate information available to all concerned parties (BRP, aggregators, suppliers etc.). Relevant activation of flexibility – or its modification - by DSOs or TSOs shall be exchanged with each other in advance, before the selection of the flexibility to be activated. Regulated revenues should allow the recovery of these costs in a way that does not distort the optimal economical arbitrage for the system between distribution and transmission system grid reinforcement/development versus costs of managing grid congestions without this grid extension. To this end a clear regulatory framework should be designed to handle conflicting physical needs. It is important to distinguish between competition for the same flexibility provision, which should be resolved based on the willingness to pay (market-driven resolution of the conflict), and contradicting physical needs (resolution of the conflict according to what is optimal from a technical point of view).

Some challenges of future research in this topic are:

- Creation of adequate bi-directional data exchange platforms of information about flexibility pre-qualification and activation between TSO and DSO. The European Project SmartNet proposed five different coordination schemes between TSO and DSO with impact in the procurement of ancillary services (frequency control services) and local system services, which can be an adequate framework to develop new coordination algorithms and platforms. Moreover, the "amount of flexibility" can be quantified and exchanged with the flexibility maps, which require additional research for a better communication/visualization of the embedded information
- Integration of the information about current and short-term distribution grid operating conditions in the selection of flexibility activated by the TSO for frequency control purposes. An interesting research challenge is to cover the following scenarios: (i) ex-ante validation: the DSO assesses in advance if the available frequency control offers are technically viable or if they can create local constraints in the distribution network, and defines different grid status (yellow, red) for the flexibility offers; (ii) pre-activation validation: the TSO communicates to the DSO in advance (e.g., 15 min before) the pre-selected flexibility offers for the next operating period. The DSO conducts a technical validation of the offers and returns a validated activation program, which might include changes in the offers activation in case of technical constraints violation. Nevertheless, this operational validation of flexibility should not exclude a close interaction between TSO and DSO during the pre-qualification of flexibility resources.
- A third possibility is to have the DSO managing the distribution grid flexibility like a technical virtual power plant, where, from the TSO perspective, each transmission network node is a virtual generator that can inject or consume active/reactive power. However, this solution means a radical change of the regulatory framework (e.g., share of costs, benefits and responsibilities between TSO and DSO, market conditions for flexibility contracting by the DSO) and requires modifications in traditional optimal power flow tools [1].

3.3.4 Proposed adaptations of the NY REV for the European Market

The New York REV market design provides a comprehensive proposal for putting in place a coordinated market that integrates transmission and distribution system operations [105]. In the process, we translate the nomenclature of the REV design to EU market design parlance. Whenever appropriate, we signal fundamental differences between the EU and REV design such as missing markets or coordination barriers.

The REV design relies on the '3R' principle: integrated T&D markets will trade three fundamental products: real energy, reactive energy, and reserve capacity. These products are traded with a high spatiotemporal resolution, i.e. they are priced every 5 to 15 minutes at the level of individual medium voltage distribution nodes. In order to delineate the envisaged market design, we describe the individual agents that are active in the market.

We list in the following some points in which the REV design differs from the existing EU design. All that is implemented in the REV design and not in EU design should be considered as potential proposal for EU markets:

- The EU market does not have a real-time market for reserve capacity.
- In balancing market parlance, if the prosumer is eligible for offering reserve, it should correspond to a balancing service provider or a free bid that is eligible for providing real-time balancing capacity.
- Otherwise, the prosumer can be interpreted as a member of the portfolio of a balancing responsible party.
- The REV design assumes a unique real-time energy price. In EU design terms, this implies that the balancing price that BSPs receive for reserve activation is identical to the imbalance price that BRPs are exposed to, which is reasonable, since the former supply balancing real-time energy, and the latter demand real-time energy. This is, for example, the market design that has been put in place in the real-time balancing market of Cyprus.
- Real-time energy is considered as a separate product with a different locational marginal price at every high-voltage transmission node, thus the starting point is a locational marginal pricing model.

Specifically, concerning distribution systems, the main differences are the following:

- There is no real-time market for real power at the medium voltage level. Instead, distribution system resources often procure energy from a retail supplier (time of use charges and demand charges may sometimes be integrated by the retail supplier). Moreover, distribution system resources face network charges that are a mix of energy and capacity charges and are determined by the distribution network operator in order to recover infrastructure investment costs. Thus, the spatiotemporal resolution is currently lacking: there is a static pricing of energy, and it is not adaptive to the location in the distribution grid.
- There is no real-time market for reactive power at the medium voltage level.
- There is no real-time reserve capacity market at either the transmission or distribution level.
- The DSO currently does not co-optimize real and reactive power. Instead, it sizes the network so as to ensure that operating constraints are not violated with high probability and sets network charges so as to recover cost of network upgrades.
- There is no congestion revenue that is explicitly associated to reactive power flows.

4 Flexibility metrics

At the system level, measuring the flexibility available is important to determine if the system is able to face the flexibility needed due to the uncertainty of the non-controllable generators and loads [1]. There is no general methodology to measure power system flexibility. In recent years, however, a number of assessment concepts have been developed, varying in approach as well as in complexity [120].

Minniti et al. [121] state that flexibility cannot be characterized using a single metric and propose several dimensions that should be taken into account for the assessment of flexibility, namely capacity, duration, ramp rate, direction, energy content, response time and location. In [106] a flexibility service is a multidimensional good characterized by the three attributes: its direction (up or down); its electrical composition in capacity or power and its availability defined by starting time and duration. Metrics of flexibility are reviewed in Villar et al. [1]. The report in [122], remarks that no universal flexibility metric exists, but proposes the Effective Ramping Capability (ERC) to measure the flexibility available from conventional plants. The ERC is based on the probability that a unit will be able to deliver its maximum ramp at any time, determined from historical dispatch data, and thus intended for planning studies. Lynch et al. [123] propose a very simple flexibility metric consisting on dividing the up ramp of the net load by the available ramping capacity of the system. The latter is computed as the summation of the ramping capacities of each unit based on its production, power and ramp capacities, so when the index exceeds 1 load shed ding is needed to balance the system. In the paper of Thatte and Xie [124] an operational flexibility metric called lack of ramp probability (LORP) is proposed for the real-time economic dispatch. The flexibility metric measures the ability of a system to use its generating resources to meet both expected net load changes as well as forecast errors. In [125], a unit flexibility is characterized by three metrics, namely the energy, the power and the ramp rate the unit is able to provide. Another approach can be found in [126] where the flexibility required is computed by statistically bounding the difference of consecutive net load power values for different time steps with an envelope. Integration allows to express these required flexibility as an envelope of energy called energy-based operating reserve requirements. At the distribution level, the behaviour of flexibility providers depends on weather conditions or customers' habits or decisions, and metrics proposals depend on the resources purpose. For example, [127] proposes a method to compute the system flexibility as the ability to vary the active or the reactive power output of the distribution network considering the connected units. Another key aspect related with demand response is the demand baseline estimation, which is how the customer's load would have been in the absence of DR events (actual load). Baseline estimation is essential to assess the magnitude of the DR resources available and their value for the system [128]. The report of [129] collects basic baseline estimation principles: accuracy, simplicity (easy to understand and to reproduce) and integrity (no incentives to irregular consumptions). In the paper of [120] more flexibility metrics are reviewed and new are proposed. The flexibility chart by Yasuda [130] is presented as a rather simple metric designed to compare available flexible capacity to peak load. Lannoye, et al. [131] have been among the first to propose a metric to assess flexibility for long-term/adequacy planning, the insufficient ramping resource expectation (IRRE), which reflects the expected number of observations when a power system cannot cope with the changes in net load. The authors further built upon this concept and developed further metrics to assess flexibility, e.g. the number of periods of flexibility deficit (PFD) method [132] and the flexibility assessment tool "Inflexion" [133]. The proposed metric is technical, focusing on system operation and planning indicators. The IEA's Flexibility Assessment Tool (FAST; revised version: FAST2) is another example of such a framework [134]. It measures the maximum upward or downward change in the supply/demand balance that a power system is capable of meeting over a given time horizon. Again, a technical metric is sought to assess the flexibility needs of the system. The authors of [120] conclude that the established concepts to measure flexibility vary in the approach as well as in the adopted complexity, but principally tend to focus on aspects that can be quantitatively measured, mostly technical characteristics, relevant to the broad topic of power system balancing, but unavoidably leave other aspects aside. As they note, it is important to assess the different facets of flexibility, on the one side the technical options but also non-technical enablers such as grid, market, regulatory or policy frameworks, as they are highly interrelated. Thus they measure the flexibility of a power system by assessing five broad categories of flexibility options: supply, demand, grid, energy storage and markets (including regulation). The five categories are further divided into a total of 14 domains. These domains consist of a mix of quantitative and qualitative KPIs which cover the flexibility aspects related to the topic and are presented in the table below.

Table 20: Flexibility Metrics [120]

Flexibility Category	Flexibility Domain	Flexibility Metric
Grid	Transmission Grids	Level of congestion Grid development plans TSO/DSO coordination Advanced control measures
	Interconnections	Cross-border transmission capacity Expansion and optimization plans
	Distribution Grids	Capability for monitoring and controlling network Smart system implementation R&D Allowance to procure local flexibility
Storage	Small-Scale Storage	Implementation, plans and incentives for small-scale storage
	Large-Scale Storage	Level and further potential of bulk storage
	Sector Coupling	Status and plans for sector coupling
Markets	Wholesale Markets	Temporal resolution: gate closure times, product lengths Market coupling Removal of price caps Liquidity of markets Spatial resolution Market barriers Balancing
	Balancing Markets	Temporal resolution: gate closure times, product lengths Minimum bid size Allowance of aggregators Cross – border exchange Removal of price caps
	Retail Markets	Status and plans for sector coupling
Supply	Conventional Generation	Operational flexibility of conventional power plant fleet

		Plans to phase out inflexible generation Incentives for flexible generation Generation and flexibility adequacy from all resource
	Distributed Generation & Variable Renewables	The flexibility inherent in this domain is influenced by a series of aspects, including: Shares of DG & VRE achieved Related development plans Diversification of VRE Dispatch rules Forecasting methods Incentives for geographical and technological diversification
Demand	Energy Efficiency	Assessment of energy efficiency measures and future plans
	Large-Scale Demand Side Flexibility	Potential Programs Participation in wholesale & balancing markets Supply
	Small-Scale Demand Side Flexibility	Share of households with smart meters Programs R&D demos Aggregators EV share, eHP share Incentives for flexible demand

5 Conclusions

Increasing amount of renewable based distributed generation at distribution systems, leads to an increased need for active distribution network management dealing with local network congestion and voltage issues [135]. Development of local flexibility markets aims to provide a market-based solution to these issues. At the same time, the emergence of innovative solutions is catalysing the development of new, flexibility-enabling business models [112]. In order to allow new resources of demand side flexibility like controllable loads, Electric Vehicles (EVs) and distributed generation units to participate in the flexibility market it is necessary to adapt the market design through new market players and define new roles [106].

The analysis of this report shows that progress of integrating flexibility sources and relevant business models into the market is different among the Member States. For example, regarding aggregation for demand side management, which is one of the most consolidated existing business models for power system flexibility, it can be seen that the Nordic countries (Denmark, Finland, Norway, Sweden) and UK are front runners in promoting the aggregation service. Southern countries are still lagging in allowing the aggregation of small-scale resources (Greece, Italy, Spain).

Nevertheless, even if legally open for the aggregation service, impractical requirements limit the participation of aggregators even in more mature, concerning demand side flexibility, markets. Some key findings that would hinder the participation of demand side flexibility in the market, mainly in the form of aggregators, are the minimum bidding values, bid duration, symmetric bidding requirements, activation time and strong penalties for non-supplied services [121], [106].

Below a summary of national markets open to demand-side flexibility is presented.

Table 21: Markets open to demand-side flexibility for European countries [12], [18], [136]

Country	Status of market opening to demand side flexibility
UVAC	Consumption points
Nordics	Markets open to Demand Side Flexibility in Finland: • Day-ahead Market • Intraday Market • FCR-N • FCR-D • aFRR (currently not procured) • mFRR • Strategic Reserve (RR) • Peak load reserve Markets open to Demand Side Flexibility in Denmark: • Day-ahead Market • Intraday Market • FCR/ FCR-N/ FCR-D • aFRR • mFRR • Strategic Reserve (RR) Markets open to Demand Side Flexibility in Norway: • Day-ahead Market • Intraday Market • FCR-N • FCR-D • aFRR • mFRR

	Markets open to Demand Side Flexibility in Sweden: • Day-ahead Market • Intraday Market • FCR-N • FCR-D • aFRR • Strategic Reserve • Balancing Market (RPM)
UK	Markets open to Demand Side Flexibility in the UK: • Primary response (FCR) • Secondary response (FCR) • Frequency Control by Demand Management (FCDM/FCR) • High frequency response (FCR) • Enhanced frequency response (FCR) • Fast reserve (aFRR) • STOR (RR) • Demand Turn Up (RR) • Supplemental Balancing Reserve (SBR/RR)
Belgium	Markets open to Demand Side Flexibility in Belgium: • primary (FCR) and tertiary reserves • interruptible contracts program • strategic reserve • wholesale electricity markets (including day-ahead and intra-day)
Germany	Markets open to Demand Side Flexibility in Germany: • Day-ahead Market • Intraday Market • FCR • aFRR • mFRR • Interruptible loads
Italy	Demand side participation at the Ancillary Services Market through the pilot project UVAM. The project aggregates: • Consumption points • Non-relevant generation points • Relevant generation points • Storage installations
Spain	Demand-side participation only in the tertiary reserves
Greece	Demand-side participation through: • long-term capacity compensation schemes • interruptibility schemes. Interruptible load service can be offered by consumers connected to the electricity transmission and MV network of the interconnected system via their participation in auctions.
Cyprus	Not supported

According to the analysis of best practices and enablers from existing markets in Europe, it is seen that prequalification of market agents at pool level, as in Finland and the UK would enable the participation of consumers in the markets. Taking Belgium and UK as example, it is recommended that DAs sign contracts directly with prosumers without the interaction of BRP/retailers and DSOs. The Finish market is a great example of how, at least in FCR markets, the minimum bid size can be reduced 0.1MW. As in Finland, a product resolution of 1hour is proposed with daily auctions. Capacity payments are necessary for this type of service and should be higher than in other markets. For the mFRR market the common notification time is 15 minutes. A minimum bid size of 1MW, as in the market of Belgium, would be proposed as a convenient bid size to open the market to aggregators and particularly tertiary building DAs. In the countries analysed, mFRR is not a symmetrical service and has a duration between 15 minutes and 2 hours. A duration of delivery between 15 minutes and 1 hour is well suited for tertiary buildings. Regarding the tender period, FRR is in most cases tendered monthly or yearly. However, prediction of DA flexibility one month or one week ahead is difficult for DA. In the Finnish market flexibility is contracted until 45 min before the hour of use. The Finnish case can serve as a good example for allowing participation of DR in the market, while even a daily tender could be proposed for enabling DR participation.

From the projects described in this report it is clear that distributed flexibility markets are developing around the world, however the coordination of these markets to provide system wide benefits (constraint management, minimised grid reinforcement) continues to be an area for development. Main challenges in the design of flexibility markets is to serve the requirements of both TSO and DSO and to guarantee an adequate return on investment for new market players. Different models, e.g. separated markets for TSO and DSO, hierarchical and peer-to-peer, have been proposed but most of the proposals mean a radical change in the current regulatory framework. Furthermore, it is important to embed the distribution grid technical constraints in the market clearing process, considering different temporal scopes (e.g., real-time, a priori) [1]. DSO future role in flexibility markets and the necessary regulatory changes are also significant issues to be addressed. Given the crucial role of incentives, market design and regulation can either hinder or help their consolidation and evolution as a tool to increase flexibility. Regulators and system operators are already playing a key role in market design innovation and have a substantial impact on the consolidation of emerging business models [112].

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9 List of abbreviations

Abbreviation	Term
aFRR	Automatic Frequency Restoration Reserve
ARERA	Regulation Authority for Energy, Network and Environment (Italian)
AS	Ancillary Services
BRP	Balance Responsible Party
BSP	Balance Service Provider
CCE	Community Choice Energy
CCS	Carbon Capture and Storage
CEER	Council of European Energy Regulators
CMZ	Constraint Management Zone
D-1	Day-ahead
DA	Day-ahead
DECS	Dispatchable Energy Capacity Service
DER	Distributed Energy Resource
DKK	Danish krone
DNO	Distribution Network Operator
DPV	Distributed Solar Photovoltaic
DR	Demand Response
DSF	Demand Side Flexibility
DSO	Distribution System Operator
DSP	Distribution System Platform
DSR	Demand Side Response
ENTSO-E	European Network for Transmission System Operators for Electricity
EU	European Union
FCR	Frequency Containment Reserve
FCR-D	Frequency controlled disturbance reserve
FCR-N	Frequency controlled normal operation reserve
FRR	Frequency Restoration Reserve
GME	Italian Electricity Market Operator - *Gestore del Mercato Elettrico*
GO	Guarantees of Origin
ICT	Information and Communications Technology
ID	Intra - day
IMO	Independent Market Operator
IREMEL	Integration of energy resources through local electricity markets - *Integración de Recursos Energéticos a través de MErcados Locales de electricidad*
MB	Balancing Market (Italy) – Mercato di Bilanciamento

mFRR	Manual Frequency Restoration Reserve
MGP	Day-ahead market (Italy) - *Mercato del giorno prima*
MI	Intraday market (Italy) - *Mercato infragiornaliero*
MIBEL	Iberian Electricity Market
MO	Market Operator
MPE	Short-term electricity market (Italy) - *Mercato Elettrico a Pronti*
MPEG	Daily products market (Italy) - *Mercato dei prodotti giornalieri*
MSD	Ancillary services market (Italy) - *Mercato dei servizi di dispacciamento*
N/A	Not Applicable
NEMO	Nominated Electricity Market Operator
NOK	Norwegian Krone
NWA	Non Wire Alternatives
NY REV	New York Reforming the Energy Vision
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OMIE	Iberian Market Operator, Spanish pole
OMIP	Iberian Market Operator, Portuguese pole
PNIEC	Integrated National Plan for Energy and Climate (Spain)
PO	Operational Procedures
PV	Photovoltaic
RE	Renewable Energy
REE	Spanish Transmission System Operator (*Red Eléctrica de España*)
REN	Portuguese Transmission System Operator (*Redes Energéticas Nacionais*)
RES	Renewable Energy Sources
RES	Renewable Energy Sources
RKOM	Regulating power options market
RR	Replacement Reserve
SEDC	Smart Energy Demand Coalition
SEK	Swedish krona
SO	System Operator
TERNA	Italian TSO
ToE	Transfer of Energy
TSO	Transmission System Operator
UdD	Dispatching Unit (Italy) – Unitá di dispacciamento
UF	Physical Unit – *Unidad Física*

UK	United Kingdom
UP	Scheduling Unit – *Unidad de Programación*
UPR	Relevant Generation Units – Unitá di Produzione Rilevante
USA	United States of America
UVAC	Consumption Virtual Qualified Unit - *Unitá Virtuale Abilitata di Consumo*
UVAM	Mixed Virtual Qualified Unit - *Unitá Virtuale Abilitata Mista*
UVAP	Generation Virtual Qualified Unit - *Unitá Virtuale Abilitata di Produzione*
VAT	Value Added Tax
VDER	Value of Distributed Energy Resources
VLP	Virtual Lead Party
WPD	Western Power Distribution
XBID	Cross-Border Intraday Market