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Integration of small scale DERs in the ancillary services

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STATUTORY DECLARATION

I declare that I have authored this thesis independently, that I have not used other than the declared sources / resources, and that I have explicitly marked all material which has been quoted either literally or by content from the used sources.

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Abstract

The Energy System is going through a deep phase of change from a centralized towards a decentralized power system, due to the massive increase of RES. Traditional thermal and programmable units will no longer be available to provide ancillary services required by TSOs for systems security. Flexible Resourced connected at distribution level such as DG or storage systems could be integrated in real time markets to provide such services and to further increase the hosting capacity for V-RES. In order to avoid a conflict of interest between system operators an optimized coordination between TSO and DSO is required, which is also emphasized in the EU Clean Energy Package. In this thesis a literature review was done to investigate on the potential of small scale DER to provides ancillary services and on possible coordination schemes for TSO and DSO to redefine the role of DSOs in the procurement and activation of ancillary services. A cost analysis was done to analyze and compare costs when the DSO operates a local market to solve congestion at distribution level and hence increases grid efficiency versus the business as usual approach which to date is grid reinforcement. Cost and requirements for ICT and market operation were duly considered.

Kurzfassung

Das Energiesystem befindet sich aufgrund des massiven Anstiegs von erneuerbaren Energien in einer tiefgreifenden Phase des Wandels von einem zentralen zu einem dezentralen Energiesystem. Herkömmliche, meist thermische, Kraftwerke werden nicht mehr zur Verfügung stehen, um die von den ÜNB für die Systemsicherheit gebrauchen Regelreserven zu erbringen. Flexible Ressourcen auf Verteilnetzebene, wie beispielsweise Batteriespeicher von E-Autos, könnten in Regelenergiemärkten integriert werden, um den Netzbetreibern Flexibilität bereitzustellen und um den massiven Ausbau von EE auf Verteilnetzebene zu ermöglichen. Um einen Interessenkonflikt zwischen den Netzbetreibern zu vermeiden, ist eine optimierte Koordination zwischen ÜNB und VNB erforderlich, welche auch im EU Clean Energy Package explizit erwähnt wird. In dieser Arbeit wurde eine Literaturrecherche durchgeführt, um das Potenzial von dezentralen Energie Ressourcen zu analysieren, sowie eine optimierte Zusammenarbeit von ÜNB und VNB zu untersuchen, um die Rolle von VNB bei der Beschaffung und Aktivierung von Systemdienstleistungen neu zu definieren. Eine Kostenanalyse wurde durchgeführt, um Kosten und Vorteile zu analysieren bzw. vergleichen, wenn VNB Resources auf Basis eines Marktes aktivieren, um Engpässe auf Verteilungsebene zu lösen und somit die Netzeffizienz steigern, gegenüber dem bisher üblichen Ansatz des Netzausbaus. Kosten und Anforderungen für IKTs müssen hierfür genau berücksichtigt werden.

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List of Abbreviations

ACER	Agency Council Energy Regulators	EAA	Equivalent Annual Equity
		EC	European Commission
APG	Austrian Power Grid	EMS	Energy Management System
AS	Ancillary Services	EV	Electric Vehicles
ASM	Ancillary Service Market	HV	High Voltage
BESS	Battery Energy Storage System	LFM	Local Flexible Market
		LV	Low Voltage
BRP	Balancing Responsible Party	IP	Internet Protocol
		MV	Medium Voltage
BSP	Balancing Service Provider	NC	Network Codes
CAPEX	Capital Expenditure	NPC	Net Present Cost
CEP	Clean Energy Package	NPV	Net Present Value
CEER	Council of European Energy Regulators	RTU	Remote Terminal Unit
CIM	Common Information Model	SO	System Operator
		OPF	Optimal Power Flow
CPI DG	Consumer Price Index Distributed Generation	SCADA	Supervisory Control and Data Acquisition
DER	Distributed Energy Resources	TCP	Transmission Control Protocol
DMS	Distribution Management System	TSO	Transmission System Operator
DSO	Distribution System Operator	VPP	Virtual Power Plant

1 Introduction

1.1 The Energy System Transition

The global energy scenario goes thrugh a deep phase of changes as a result of climate change, deployment of distributed energy resources, new information and communication technologies, electric vehicles and energy storage systems. The European Union has set up ambitious targets after the Paris Agreement signed on December 2015, which sets as goal to hold the increase in the global temperature well below 2° C above pre-industrial levels [1] and to strengthen the commitment for the reduction of greenhouse gas emission, agreed on the Kyoto Protocol [2]. In the European Union currently around 32 % of energy is provided by RES. With the increase of electrification of sectors such as transport, heat or other industries, according to [3], electricity consumption is expected to increase by 18 % by 2030. In order to preserve the actual 32 % share coming only from RES as seen in Figure 1, the number of renewables will have to increase further.

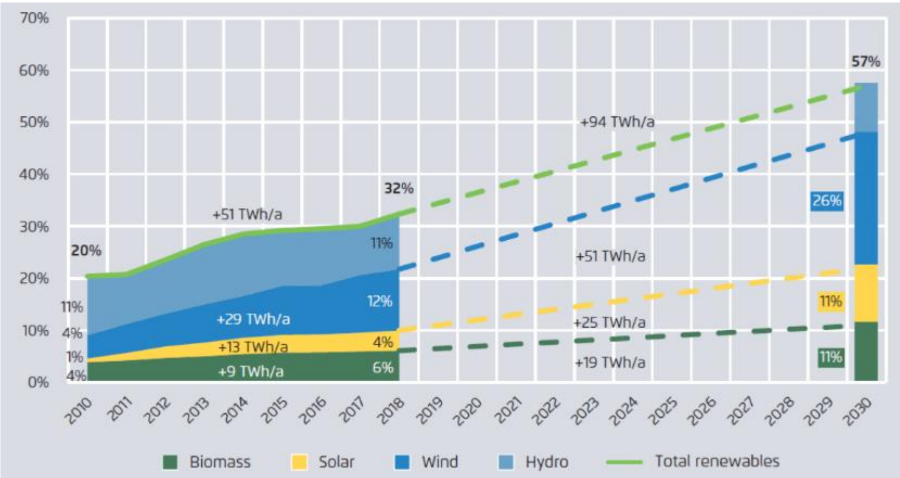

Figure 1: Energy production mix in the European Union in 2018 and estimated growth by 2030 [3]

To achieve the 2030 target of a relative share of 53% coming only from RES, would mean that the increase of annual renewables injection must almost double. Renewable distributed energy sources, unlike centralized units are characterized by small capacities connected to medium or low voltage level [4]. This poses numerous challenges to the European energy grid structure. In fact, the increase of energy injection from non-programmable energy resources takes place at expense of the programmable fossil source, which must be turned off because no longer needed to satisfy the demand. Additional flexibility will become an increasingly valuable resources to balance the system between generation and consumption and to avoid large scale blackouts [5].Therefore it will be of fundamental importance to use efficiently the services that distributed generation offer. For an efficient integration of those resources, also the energy market will have to evolve from a centralized towards a decentralized system with novel market actors providing new services.

1.2 Austria's path towards a climate-friendly society *#mission2030*

Austria is commitment to climate targets, and has ambitious plans for 2030, namely the reduction of gas emission by 36 % compared to 2005. Which means that coordinated climate and energy policies are needed to keep a secure, sustainable and competitive economic welfare. *#mission2030* strategy [6] provides guidelines in different areas to achieve this target, while ensuring Austria's competiveness. The Energy sector is affected the most and asked for action. The existing network infrastructure should be transformed for the integration of a high volume of RES while ensuring the already high level of security of supply. Austria with a share of 33.5 % of energy coming from RES, is already a front runner in the European Union [6]. According to *#mission2030* the Federal Government wants to increase this value up to 100 % (national balance). In [7], by 2030 an installed capacity of 9 GW and 12 GW for PV and wind respectively is expected to be connected to the Austrian grid, which may create huge fluctuation in the injected power as shown in **Figure 2** and thus affecting the overall balance of the system. Therefore, a radical change in the electricity network and market structure is needed.

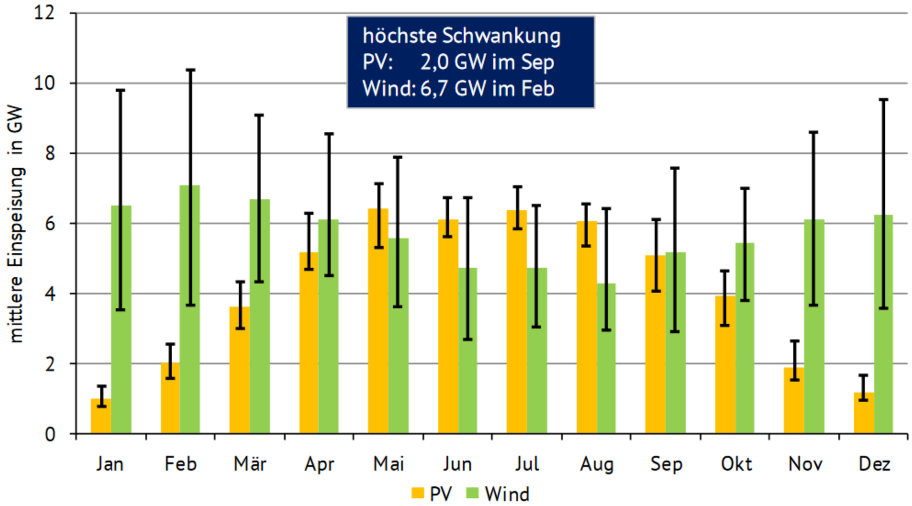

Figure 2: Estimated fluctuations due to RES (wind and PV) in 2050 [7]

1.3 Towards a smarter grid

As in many other sectors, also in power systems digitalization took place towards smarter grids. Smart Grids can also be described as an intelligent coordination of actors involved in the electric system. The main challenge of smart grids is the implementation of an additional digital layer on top of the grid structure in order to improve IT and communication capabilities to foster the interaction with end users. In particular in the last year the idea of a so called local energy community raised, where energy is produced and consumed locally as shown in **Figure 3** [8].

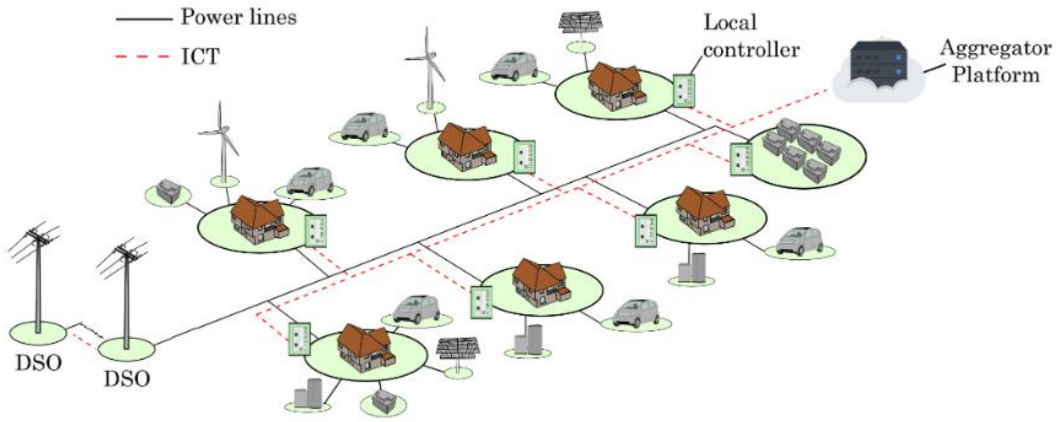

Figure 3: Representative figure for local communities in future grid structure, energy is produced and consumed locally [8]

With the evolving of new technologies such as smart sensors, smart control and smart meters the efficiency and power quality can be improved [9], [10]. In chapter 6 the standardized smart grid architecture model is shown, it is an important tool for a consistent naming of definitions used by many research projects and thus also in this thesis.

1.4 Thesis outline and objective

The objective of this thesis is to analyze the future role of DSOs in the 2030 horizon and to investigate on possible coordination schemes to integrate small-scale DERs in the ancillary services. Answers are sought for the following research questions:

> *How can we use resources at distribution level to support the system at transmission level for congestion management or frequency restoration? Which role and responsibility will the DSO take over to allow an efficient use of DERs? How can the TSO access to those resources without creating a conflict of interests?*

In order to partially answer those questions first it's necessary to analyze the state of the art in the European power system, to investigate which resources could provide flexibility and to identify the main barriers impeding small scale DERs to participate in real time markets **(chapter 2)**. A profound literature review was done to investigate on how the coordination between TSO and DSO could be implemented and which one could best fit for the Austrian scenario.

In **chapter 3** new market actors, likely to enter the market by 2030 are presented. Especially the role of the aggregator and how those actors procure resources in the current models and how this could be done at distribution level.

In **chapter 4** the current role and responsibility of DSOs is presented and the organization at European level which also include the different remuneration schemes for DSOs at the state of play.

In **chapter 5** possible coordination schemes based on literature review are presented. Identifying the main drawbacks in terms of implementation, market clearing, ICTs and regulatory issues.

In **chapter 6** a general overview on ICT requirements for prequalification, aggregation, activation and extended TSO observability are presented.

Finally, in **chapter 7** a rough cost estimation was done to estimate the costs and savings (EAA comparison) for the DSO when he acts as aggregator (of information) in the global power system and operates a local flexibility market to solve congestion at distribution level. The results and main findings are finally discussed in **chapter 8.**

2 Electricity Markets and Networks

2.1 Introduction

In Europe the electricity markets are generally divided in to the three different and independent markets[1], the Day-Ahead, Intraday and Balancing/Ancillary Services Market (ASM). As shown in **Figure 4** the Day-Ahead market, as its name suggests is a market that runs the day before the actual operating day, generally the base energy, based on historical data, is traded in this market. In the Intraday market participants trade in order to match their production to the actual demand in 15 minutes timeslots.

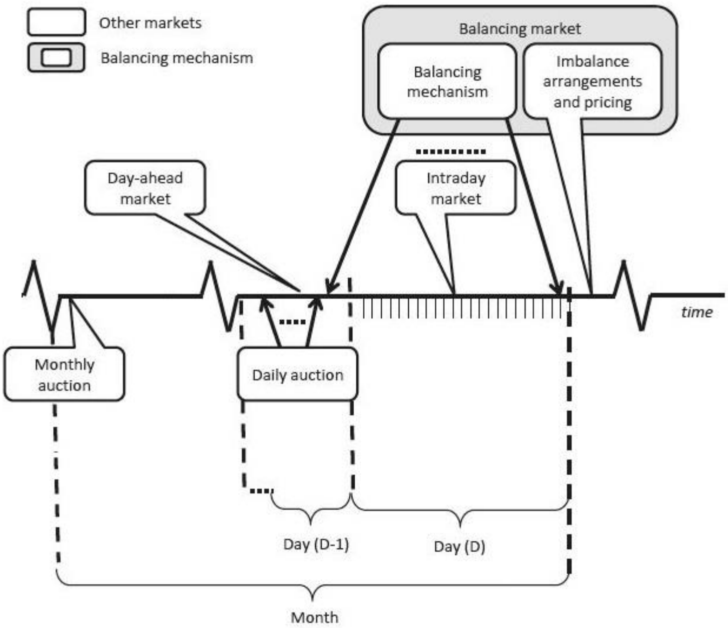

Figure 4: Time frame of electricity markets, Day-Ahead, Intraday and Balancing Market [9]

In the Ancillary Service Market, energy is traded which is required to keep balanced the entire power system and to guarantee a secure and a stable power supply [11], hence only generators that satisfy technical qualifications are entitled to it. Normally the TSO, responsible for the balancing of the system, is the only acquirer.

In the present thesis focus is put on the ASM and congestion management, due to high volatility of RES and the penetration of DERs, this market will be influenced the most in the coming years. The power generation mix in the EU will change considerably in favor of RES and it is expected that electricity coming from RES will increase up to 50%. In particular, non-programmable and variable RES such as wind or solar (PV) will reach around 25 % by 2030 [12] and therefore reserves and flexibility could lack

[1] The detailed procedure differs slightly in European countries, the overall scope is the same

in the future power grid. The importance of the ancillary services is becoming clear, being indispensable for balancing purposes.

At European level there has been an evolution regarding network codes and the creation of a well-functioning internal single European energy market. Which was reached for the Day-Ahead Market by means of price coupling, but need to be optimized for intraday and ancillary service markets across Europe, also required and promoted by the European Commission in the CACM [13], [12]. The actual network code defined by ENTSO-E aims at creating an integrated and harmonized European Balancing Market to increase grid flexibility and shared reserves. Hence, the TSOs in each country will have to explore alternative options to organize reserves and capacity dispatch. In this work as in other studies such as [14], the main goal is to investigate on new actors that could enter the market. On who can or should be the aggregator (TSO, DSO, retailers or any other third party) and what kind of market models or coordination schemes, between TSO and DSO, need to be adapted to accommodate as a many DERs as possible. Moreover, the role of the DSO is analyzed further to assess the potential for a more active role of the DSO.

In the long perspective local energy markets could become part of the electricity market design [15]. For the national regulatory authorities (NRA), it is of fundamental importance to investigate on drawbacks, benefits and innovative incentive methods, in order to set the correct regulatory framework and the avoidance of any market or distortion[2]. The NRAs therefore play an important role to provide the right incentives for the development of the network such as grid reinforcement or the deployment of new technologies in smart grids or flexibility programs [16] in different European countries aiming a harmonized European ASM market.

2.2 Clean Energy Package and new guidelines for Electricity Balancing

In 2016 a new package of proposals, namely the "Clean Energy Package for all Europeans" (CEP) has been published, addressing sectors such as renewable energy sources, energy efficiency, energy governance or novel market designs. The latter is the motivation of this thesis. Furthermore, the package emphasizes the role of the consumer which should be a central player in the future energy markets e.g. providing flexibility, with the overall scope to bring benefits from a technical, environmental and economic perspective. In 2018, early 2019, after the agreement by the Council, the new laws entered in force and each Member State has two years to translate it into national law.

2.2.1 Electricity Directive and Electricity Regulation

The new electricity regulation and directive, replaced the Electricity Directive (2009/72/EC) and the Electricity Regulation (2009/714/EC), establish the novel designs for the future EU electricity markets,

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[2] The electricity market can be seen as natural monopoly

adapting new actors and technologies in order to be able to accommodate the expected growth in RES by 2030. In particular, it highlights the need to integrate more flexibility in order to integrate a greater share of renewable energy sources. To the Agency of Energy Regulator (ACER) was granted additional competences. In the released *white papers* [17] of the Council of European Energy (CEER) and ACER for the adoption of the Clean Energy Package, in particular the new role of the Distribution System Operator (DSO) is emphasized, which comes along with the decentralization of the energy market. The increase of flexible resources and to further incentivize costumers to provide flexible resources to the entire grid.

CEER and the Austrian Regulator *E-Control* has defined the so-called *3D-Strategy* depicted in **Figure 5** for the implementation of the CEP in the electricity sector, focusing on Digitalization, Dynamic Regulation and Decarbonization. Digitalization and Dynamic Regulation will be of fundamental importance in the future grid design. More in detail, the role of the DSO, aspects of ICTs and cybersecurity.

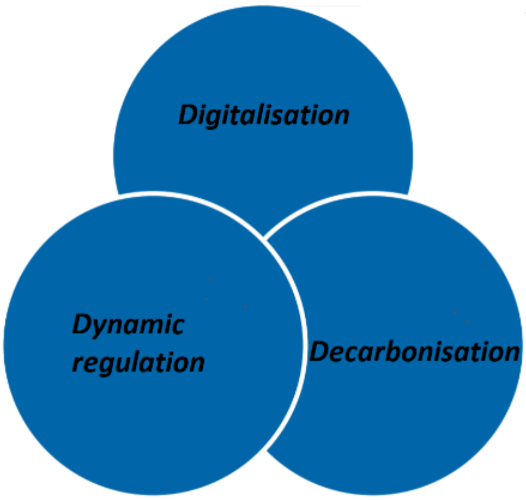

Figure 5: 3D-stragey of regulators for the implementation of CEP in the electricity sector [19]

Flexibility, new market actor and the new role of the DSO are subject of this thesis. Those actors will be affected the most, especially because a high volume of RES at DSO level is expected in the coming years. *E-control* has defined the three main actors represented below, where to focus in the coming years and which will need revised regulation [18] [19].

Active Costumers:

- Consumption, storage, local communities
- Data collection, smart metering
- Enable the participation of all costumers to energy markets

Independent Aggregators:

- Aggregate resources
- Independent party participating to energy trading
- Access to all markets

Distribution System Operators:

- Allow the usage of flexibility, to optimize grid efficiency
- Digitalization

In particular in the regulatory proposals [20] of CEER it is emphasized that: *"National regulatory Agencies should review the progress on TSO/DSO coordination in a more decentralized system… to redefine respective responsibilities"* and to give DSO the possibility to explore market-based procurement for flexibility services.

2.2.2 European Network Codes

The European network codes developed by ENTSO-E and ACER are a set of rules for the harmonization, integration and efficiency of electricity markets with the overall scope to achieve the objectives set by the European Commission (EC). Throughout this thesis reference will be made to it, in particular codes regarding System Operator (SO) or Electricity Balancing (EB). The complete list of rules can be found in [21].

2.3 Roles and Responsibilities

In the electricity system, each actor has different roles and responsibilities. The Transmission System Operator is an important and fundamental actor in the electrical grid, to keep it stable. The national TSOs are also required to closely cooperate with neighboring TSO to increase efficiency, for congestion management or capacity allocation. Furthermore, the TSO is responsible to maintain the grid stable by keeping in balance production and consumption.

Another key user is the Balancing Responsible Party (BRP). The BRP is responsible to balance their own portfolio of resources, in other words a list of generating units able to modify production. BRPs are remunerated and rewarded if balance is maintained and penalized if not. The TSO, being a regulated party, must act financially neutral, thus he is not allowed to own generating units. Moreover, he is also responsible to operate the balancing market. In Summary the TSO is an important actor to keep and maintain the security of supply within national, but also European borders [22].

The Distribution System Operator (DSO) is responsible for the local distribution grid, for power quality and data management of all end customers of his grid. Moreover, it needs to provide information to the TSO for the settlement of imbalances or e.g. grid reinforcement [22].

2.4 Ancillary Services

To ensure the power quality, but more importantly, to prevent blackouts it is essential to keep the balance between generation and consumptions in real time. TSOs and DSOs continuously monitor their transmission or distribution networks respectively in order to keep frequency and voltage within operational systems limits, this is generally done via the so-called ancillary services (AS). Those services generally include frequency regulation, voltage control, spinning reserve, operating reserve etc. AS for balancing are provided by generators, mainly connected directly at HV and the TSO is responsible to procure those services in order to ensure operational security [13]. Primary, secondary and tertiary control are activated either automatically or manually by the TSO to keep frequency in the operating constraints of 50 Hz as depicted in **Figure 6**.

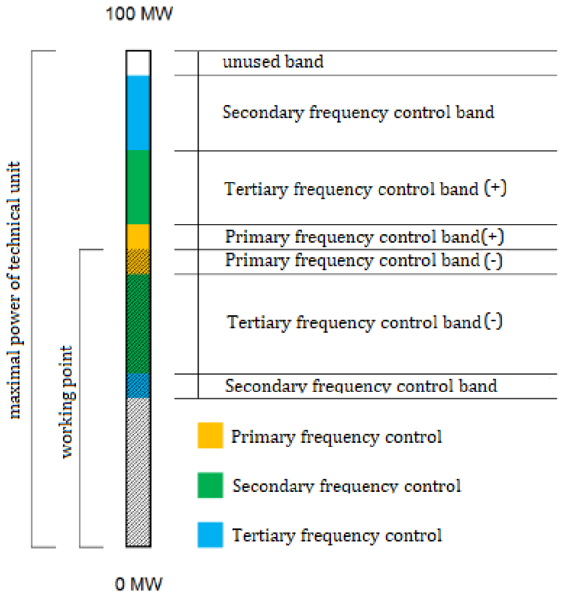

Figure 6: Overview on ancillary service activation in the Austrian control area [23]

The activation of those reserves is done within seconds or minutes respectively to contain and restore frequency, as represented in **Table 1**. Those values are defined by ENTSO-E, because an instability of one control area can affect the entire synchronous area within seconds, leading to European blackout.

Ancillary service	Minimum bid size (MW)	Notification time	Activation
FCR	1 MW	< 30 Sec.	Automatic
aFRR	5 MW	> 30 Sec. < 15 min.	Automatic
mFRR	5 MW	>15 min.	Manual

Table 1: Ancillary Services and activation time [23]

The way balancing is handled within each country differs due to historical reasons and national specification, for instance, the provision of ancillary service can be mandatory or optional [24]. In any case the provision is subject to technical criteria and constraints which need to be prequalified ex-ante. In the APG control area the required energy is procured via regular tender where APG is the sole buyer [25]. A detailed description of the technical APG prequalification can be found in [23].

2.4.1 Primary Control Regulation

The primary frequency control, also called Frequency Containment Reserve (FCR) at ENTSO-E level, is needed to maintain frequency within the thresholds of ±*200 mHz* in the entire synchronous area[3] and to keep the system stable at all times. It acts when the frequency exceeds the dead band of ±*50 mHz* [23] as shown in **Figure 7**. FCR interrupts frequency deviations, it does not restore the frequency to the nominal value. It is later corrected by the Frequency Restoration Reserve (FRR) and finally by Reserve Restoration (RR).

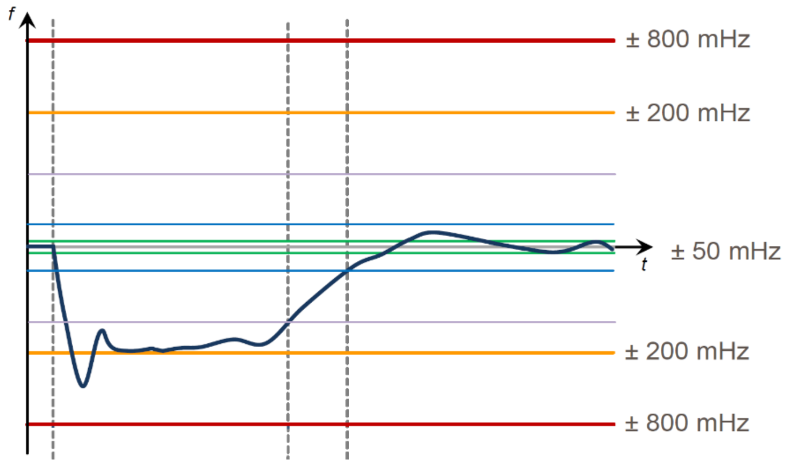

Figure 7: Thresholds for the activation of Frequency Containment [23]

As already mentioned, those requirements are established by ENTSO-E, but AS regulations, tenders or technical prequalification are freely stated by each country, which in turns leads to heterogeneity in the European grid [26].

In the Austrian control area the procurement is optional and market organized, the required energy for *FCR* in 2019 was roundabout ± *66MW* [25]. Bids are ranked according to prices until the volume of the control power is reached. Accepted bids are remunerated with the pay-as-bid approach. Only technical units with a capacity above 1 MW and an activation time of 30 seconds are allowed as defined in the *Elektrizitätswirtschafts- und -organisationsgesetz* (§ 68 ElWOG2010). In addition, they need to have

[3] Synchronous area is the ENTSO-E grid, all generators participate to the reestablishment of the frequency

proper communication and information technologies and the capability to keep the injection for at least 15 minutes, until *aFRR* is fully activated [27].

2.4.2 Secondary control Regulation

Also called automatic Frequency Restoration Reserve (aFRR) is mainly needed to stabilize imbalances in the control area. As mentioned in 2.4.1 frequency deviations are corrected by the aFRR in order to bring frequency back to the nominal value (*50Hz* in Europe). It is activated immediately and in most control areas automatically after the FCR, in any case it has to be activated within 15 minutes after an imbalance occurred [28].

In Austria the provision of aFRR is optional and market based. Reserves are tendered separately in positive (UP reserve) and negative (DOWN reserve) direction (increase or reduction of the power injection). The minimum rated power is *5 MW* for generators and/or aggregated power plants (virtual power plants). As with FCR the technical units need to satisfy the technical prequalification such as proper information and communication, monitoring etc. [23]. Penalty clauses do apply if the service provider cannot meet the obligation to provide secondary control power.

2.4.3 Tertiary Control Regulation

The tertiary control regulation, defined as mFRR, is activated in order to guarantee the provision of adequate aFRR at any time. In Austria mFRR reserves are procured on an organized market [29]. The provision is optional with a minim rated power of *5 MW* and *1 MW* step size. Pay-as-bid approach is adopted and is remunerated through the Balancing Responsible party via imbalance settlement. The activation time is 15 min after frequency deviation took place and if the deviation in that control area lasts longer than 15 min. It is activated manually by the Austrian Power Grid operator [23]. Technical prequalification needs to be satisfied in order to participate to the tenders.

2.4.4 Voltage Control

Voltage control is mainly a local problem and thus used by the DSO to maintain the voltage within limits, set by power quality specifications. Due to the presence of distributed generation and unpredictable load changes the voltage profile varies along the feeders and the DSO can act by changing the reactive injection of e.g. generating units connected on his own grid. With the increase of DG in the distribution grid, overvoltage may arise, and a curtailment of DG is needed. It becomes even more challenging as reactive supply is disrupted due to variable reactive injection profiles and the displacement of synchronous generators [30].

2.4.4 Congestion Management

Congestion management is an important issue of SO, due to the increase of demand or the unforeseen injection of energy, the transmission lines become congested. Congestion management is avoided through the TSO at transmission level by means of re-dispatch. In recent years with the increase of

DERs, congestion management became an issue also in local grids in which the DSO is responsible. Scenarios as shown in **Figure 8** where the lines are congested only for few hours a day, namely at peak hours, is a well know scenario for many DSOs.

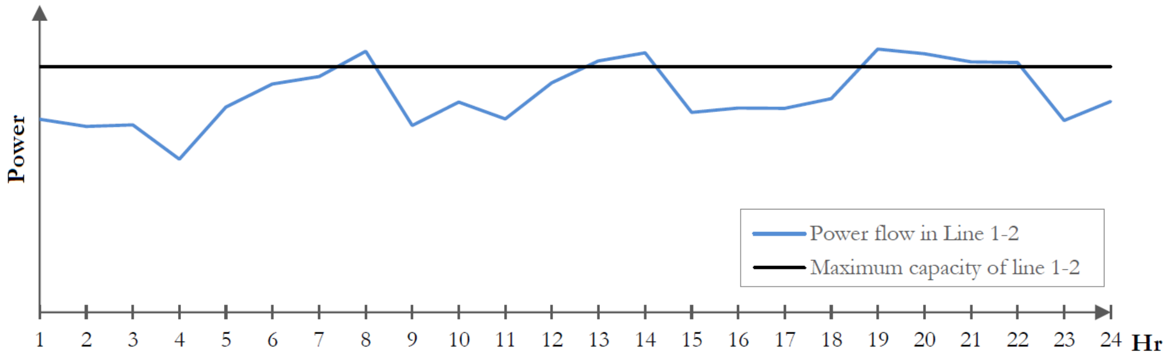

Figure 8: Congestion in peak hours, maximum line capacity is exceeded [9]

Normally, those hours are morning hours between 7am and 8 am, the mid hours due to PV injection and evening hours between 6pm and 9 pm due to increased load demand. Especially with the increase of electric vehicles this problem will increase.

2.5 New Ancillary Services in the 2030 Horizon

The balancing market have originally not been designed to integrate such high shares of VRES nor in a distributed way nor for an integration with cross boundaries. Therefore, with the current regulation and technical aspects there are some discriminatory and mainly technical barriers for a participation of RES, in particular small-scale DERs. Since DERs are and will plentiful, but rather small in terms of capacity and flexibility, it is only throughout right aggregation, pooling or commercial parties that they can bit and participate on the AS markets. This problem that many countries in Europe are facing was investigated in study [31], which results has shown, that to foster the participation of DERs, not only an aggregation of units is required, but also a smaller bid size in the ASM market is needed and thus the bidding process should be revised.

As already mentioned before AS differ from the European countries, with different market rules and technical prequalification. Study [32] lists the main barriers that hinders DERs to enter in AS markets, especially it provides a comparison among countries in Europe by comparing rules of participation at FCR and aFRR. According to [32], the Danish ASM resulted to have one of the best frameworks to allow small and non-programmable units to enter into balancing markets. So, does [31], which shows that a too high minimum bit size is still the main obstacle to prevent and allow a participation of small end costumer units, even if aggregated. Study [32] then concludes, that by opening the market to new actors such as aggregators no big intricacy is added in the market design and thus feasible, in fact DERs, if coordinated, can provide good flexible products.

According to [33] three main categories can be defined, to face the lack of flexible resources participation:

1. Open the ASM to new actors and new technical units: aggregators and novel services suppliers, DERs or demand side management
2. Introducing new services to better respond in real time: the possibility to contract and incentivize active participation based on data management
3. Change the ASM structure and coordination schemes: the reinforced cooperation between TSO and DSO

A first step implicates the clarification for the specific requirements and organizational frameworks, with the various possible roles and responsibilities in order to efficiently integrated new actors. The objective of this thesis is to identify possible coordination schemes between TSO and DSO and the needed requirements and specifications regarding ICTs as well as the investigation on the economic impact in terms of CAPEX and OPEX. It is worth to mention, that a reorganization of the market design would imply a disruptive change in the present trading and market mechanism, but still the definition of possible coordination schemes is a first step to define new roles and interaction patterns.

With the massive roll out of smart meters in Europe, devices that allow the measurement of consumption and load profiles, voltage levels or interruption events in 15 min samples [34], consumers can respond upon power signals coming from a centralized party. Moreover, the advanced metering infrastructure (AMI) already fully in place in Sweden, Italy and Spain allow time-use tariffs and is therefore helpful for demand forecast, efficient grid and power flow as well as state estimation. They do not satisfy the requirements for a near real time monitoring. For sure they pave the path for smarter grids and flexible markets [35].

An essential question is, how those flexibility/AS markets should be shaped. Somehow, this question has already been answered by regulatory entities such as the CEER [36], EDSO [37], ENTSO-E [38], EURELECTRIC [39] and SEDEC [40], by outlining possible market implementation and aggregation models from a general point of view. Most of the entities conclude that a change in the market will affect partially or entirely the market, the grid or the system itself as shown in **Figure 9**, thus making it complex. However, for a proper functioning of novel markets, the roles, responsibilities and regulatory frameworks need to be reviewed [41].

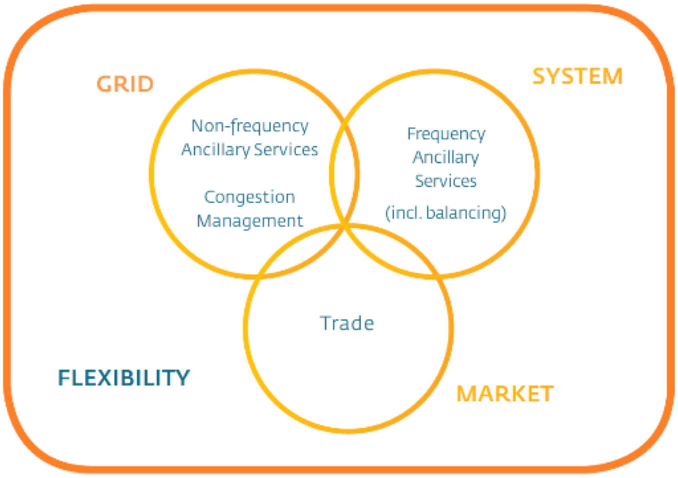

Figure 9: Representation of all zones coupled each another [46]

3 New Market Actors

3.1 Introduction

Operating a power system with a high penetration of RES introduces uncertainty and variability, also related to a decrease of system inertia. However, only through integration or aggregation, DG will be able to provide the same capacity and flexibility as do currently conventional power plants. For this reason, to provide market access to these resources new market structures and regulatory frameworks are needed [42]. As already discussed, DG can provide a wide range of services required by the TSO or DSO [4].

According to the thematic factsheet of the European Commission [22], the wholesale and retail markets should boost the development of new innovative actors and services. To reach more flexibility in the market, it should be given the consumer the possibility to actively participate in the market, ensuring that the markets provide the right signals and allow flexible trading. Moreover, a better coordination approach should be introduced to integrate RES in the market [22], [15]. The latest EU Clean Energy package includes some of those recommendations, in particular article 32.1 states:

"Member States shall provide the necessary regulatory framework to allow and incentivize distribution system operators to procure services in order to improve efficiency…"

It emphasizes explicitly that the procurement should be done by the DSO on a market based, non-discriminatory and transparent way [43].

As mentioned in [44] in the very next future, the improvement and the cost reduction of ICT will allow DSO to supervise and manage their grid at a reasonable cost. In the recent year, notably two major alternatives have evolved, namely Peer-to-peer (P2P) and control based [45].In this context an important obstacles should be mentioned, namely the incurring and unavoidable costs to participate to the markets. First, the owner (prosumer) need to be engaged and second, the prosumer has to interact with the market or with other end-users (P2P), the right ICT equipment needs to be in place [46].

In the recent years, new concepts of aggregation the so called Virtual Power Plants (VPP) has emerged enabling DERs to participate in the existing market, even if mainly only at TSO level or only with TSO interaction. According to [47] there are two types of VPP. A technical VPP and a commercial, the latter only manages and optimizes DER portfolios to be sold in the wholesale market neglecting the technical constraints. The injection schedule is then passed to the technical VPP operated in that balancing area.

Study [47] concludes that this approach won't be accurate enough especially because of the conflict[4] between TSO and DSO.

As key reference one main sources has been identified. The USEF - Universal Smart Energy Framework seems to be a promising common standard to build an integral market for the trading of flexible resources. In chapter 3.2.2 the main outcome is presented with a particular attention on the Austrian case and the implementation of those models at DSO level [35], [41].

For the contract agreement and the remuneration of flexibility services. Third parties, regulated or non-regulated aggregators will need to interact further when it comes to the remuneration phase as discussed in [48] and in chapter 3.2.2

3.2 Aggregator

In the context of new commercial market models, the role of the aggregator comes up. The aggregators can bridge the gap between the electricity markets, system operators and small-scale DERs and is responsible for the management and the optimal use of those services, from and to the end-user (prosumer) as depicted in **Figure 10**, in other words the aggregator acts as interface between the prosumer, system operators and the energy markets [32].

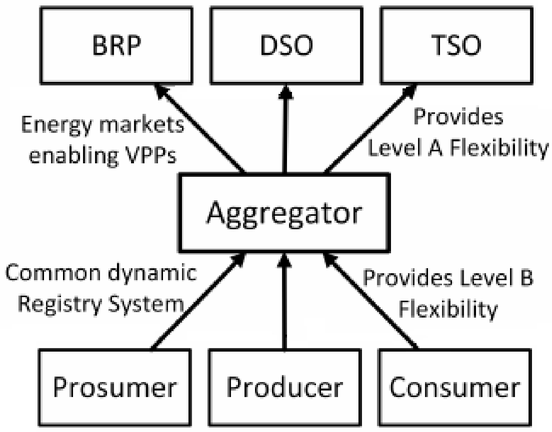

Figure 10: Aggregators interactions with other actors; acts as interface between end-costumers and SOs [32]

As already mentioned before small scale DERs can provide a variety of services generally needed by the DSO or the TSO. The value of flexibility can be enhanced by pooling those resources, which otherwise would be too small to participate in the markets individually, but not only, also costs of participation can be reduced significantly [5]. Prosumers will potentially be able to interact and

[4] TSO primary task is to avoid system imbalance, while DSO is avoiding congestion at the same time using the same resources and grid infrastructure

cooperate in the markets and compete directly with traditional energy utilities or indirectly through aggregators [35].

The aggregator which can be an existing company, or a third, up to now, deregulated party, acts on costumer's behalf. The aggregator is not only responsible to bring the resources on the market, but also responsible to provide the agreed services upon request. Aggregation can involve either generation, demand response or both such as storage; in any case, it must comply with market rules and power system regulation [39], [49]. The aggregator will then be seen as a single player/actor from the electricity market and the other stakeholders [14] as shown in **Figure 10**. Of course, one of the main tasks is the aim to optimize and trade the resources in order to gain the highest profit for himself and for the costumer. In **Figure 11** a common timeline of the trading mechanism is depicted

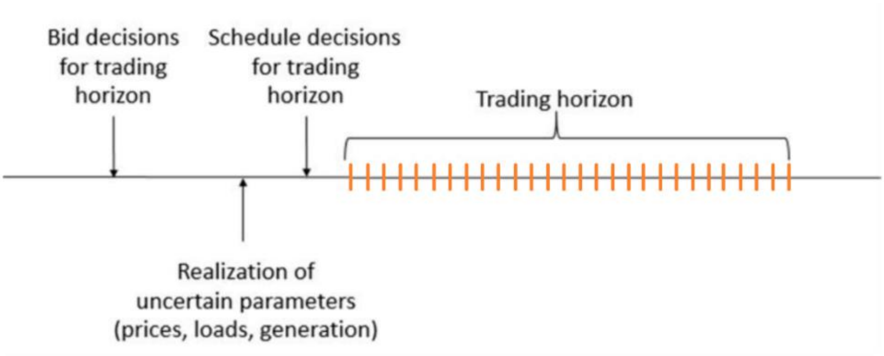

Figure 11: Trading mechanism and timeframe for aggregators [14]

For the end-customer, it would be difficult to evaluate the profitability. Generally the Aggregator builds a portfolio of assets to meet the size, and possibly, also the timing constraints of chosen flexible products or from assets of different prosumers. Of course, the Aggregator[5] is totally free to choose the products. For instance, he could specialize only on one single product as long as he does not violated any constraints set by the system operators [41] which always has to be prequalified a-priori as discussed in chapter 3.2.2. Moreover, bidding strategies and energy schedules ahead of time rely on predictions. Any inaccuracy or unforeseen event, is translated in an increase of costs, making it important to integrate smart metering data for forecasting or state estimation. The work [9] analyzed the effect of uncertainty of costumer's behavior and strongly suggests to consider this variable when flexibility is procured.

In summary one can say, that the aggregator has four main jobs to incentives the participation of small customers [49]:

1. to study which customer can provide profitable resources
2. to actively promote those service to the end-customers

[5] Up to now aggregators are not regulated by the NRA and therefore allowed to contract with costumers focusing only on profit maximization

3. to install information and communication devices[6]
4. to provide incentives and the right remuneration scheme

However, as can be seen from the listening above and also discussed in the USEF standards [41], many roles of the aggregator do overlap with the main roles of the DSO and/or the supplier. Hence, it is reasonably to analyze how the DSO or the energy supplier could act as aggregator or independent actor (e.g. market operator) in pooling DERs connected to his own grid in a more efficient way, especially because the customer is or may not be interested/encouraged in investing in required installations (ICTs) or does not have expertise to make it by himself. Many end-customers, especially residential areas still do not have access to the dynamic price signals due to the lack of ICTs [50]. In like manner the energy supplier could exploit energy resources, which normally involve supplying energy, offering to the end-user a lower fee for the availability of that resource. Furthermore, the aggregator needs to make sure, that the load/injection decisions do not cause any problems for the electrical grid. Thus, the scheduled injection profile needs to be consulted by the DSO/TSO. The DSO/TSO evaluates if the power quality is violated and validates the results, which are then sent back to the aggregator [51], [49]. Again the role of the DSO and the aggregator partially overlap.

In [32] two methods were defined, telemetry and financial aggregation. Telemetry is the aggregation where also the power flow is included and generally aggregator implements algorithms to optimize the energy dispatch. The financial model instead, allows only the aggregation of bids. In a similar matter as with the VPP described earlier.

For the sake of simplicity, in this work only aggregation models for curtailable generation and curtailable loads[7] are analyzed. The optimization of other aggregated loads and generators, such as shiftable loads or storage systems are complex and the optimization problem, the objective function, subject to many constraints. For instance, thermal loads could be defined as a shiftable load, the energy consumption can be reduced for a period of time, but generally a higher amount of energy is needed when reactivated, also known as rebound effect (described in chapter 5.4). This has to be included in the optimization power flow and in the aggregation modelling process, making it complex especially for larger grids and hence out of scope of this thesis.

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[6] The installation of the right ICTs might be no longer of Aggregators competence, it is expected that the NRA will set incentives to foster the digitalization in the grid. Moreover it is important that the ICTs are rolled out in compliance with the common European Standards for Smart Grids.

[7] Curtailable generators are resources that can reduce the injection, curtailable loads corresponds to the actual load shedding which should not be confused with the automatic load shedding for security reasons. They are independent from actions before or after the activation

3.2.1 Barriers for Aggregators in Europe

Currently there are still several obstacles in the European Markets to release the full participation of aggregators, one reasons is the conflict among the stakeholders [50]. The aggregation of DERs creates conflicts among stakeholders as can be seen in **Figure 12**. The aggregator can establish more than one contract per consumer in order to offer services to the BRP, TSO/DSO or to the supplier. Each of which will have their own interests and requirements. The regulatory recommendations for the deployment of flexibility in [48] addresses those issues and states that *"clear and fair contractual"* requirements for all the parties need to be developed. In order to:

"…avoid barriers to entry, aggregators should never be obliged to negotiate with the BRP or supplier of a consumer, moreover the costumers should have access to the best demand side flexibility offer of their own choice. "

Obviously, the main goals of a regulatory authority is to create a non-discriminatory market environment to all parties [35].

In summary one can say, that the regulatory framework lacks behind and the clear interaction between TSO and DSO need to be deployed further, as well as new market architectures able to accept bids coming from small scale DERs. Redesigning the markets in a way that DER aggregators are involved to attract and encourage investors to create new business models [35] in order to accelerate the process towards a decentralized controlled and smart distribution grid. Nonetheless, aggregators are key enablers for investments in the demand response and the pooling of DG, which will be of strong support for the power system but hardly able to replace all the capacity and flexibility currently provided by traditional, thermal units [52].

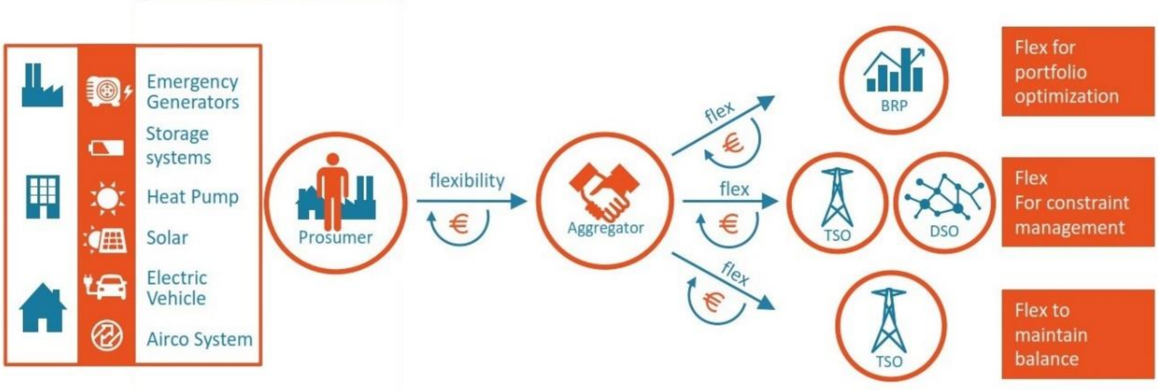


Figure 12: Aggregators portfolio to be offered to other market participants [41]

3.2.2 Aggregator Implementation Models [41]

In the USEF study [41], which provides a general framework for the implementation of schemes for aggregators, seven models are introduced. This model is useful to define the actor's roles and responsibilities, especially regarding additional roles that the DSO should have to be involved in providing balancing or congestion management services. It is worthwhile to re-propose them in this context as it creates standards and recommendations for existing and potential aggregator models at transmission level and but also for the integration of demand response at distribution level.

The framework categorized the implementation models in four categories as depicted in **Figure 13**, answering questions such as what roles the Supplier and Aggregator covers in a single market, the assignment of a single BRP or dual BRP (Supplier and Aggregator) and how energy is remunerated among the actors [41]. However, there is much debate on how aggregation will work best in practice especially with different regulatory frameworks within Europe and the existing markets.

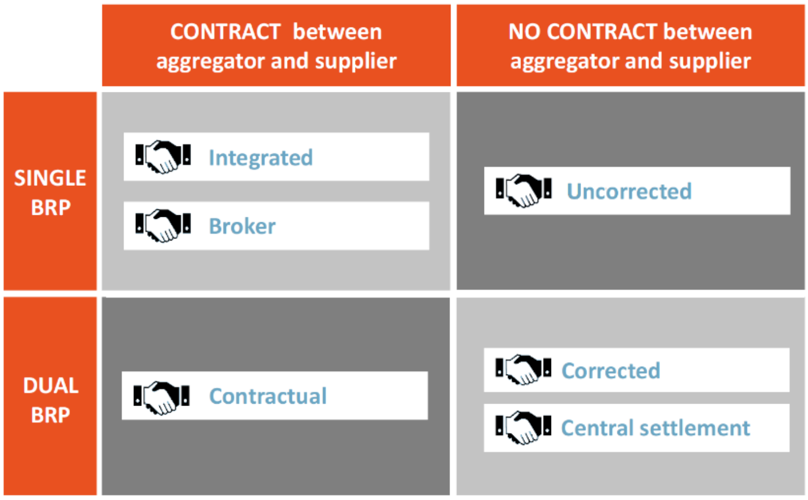


Figure 13: Representation of possible model for aggregator s and suppliers [41]

In some models, where there is a contract between Aggregator and Supplier, have already been implemented in Europe. For instance, the integrated model is common in Scandinavian countries while in Germany and Austria the contractual model is used. The contractual model, which refers to the Austrian scenario, is briefly described in the following chapter

Contractual model

In the contractual model the Aggregator has a contract with the BRP_{agr}, which delegates the responsibility for the imbalances coming from the activation of flexible resources and a contract with the Supplier for the transferred energy not provided to the prosumer as scheduled. The Aggregator/ BRP_{agr} has in turn a contract with the BSP regarding the provision of flexible resources (coming from the prosumer). In Austria, this model could be compared to a practice example of a VPP such as *NEXT Kraftwerke* or the *Oekostrom AG* [53]. Generally, VPP are categorized as commercial or technical power plants, only the latter is considering also grid constraints. [46].

Oekostrom AG is classified as a BRP_{sup} and BRP_{agr} and is currently investigating on the integration of small-scale DERs in the ancillary services and how to valorize distributed generation of customers to encourage apartment houses to invest in those resources. One issues to be solved in the Austrian scenario is still the activation of small-scale DERs, which involves investments in proper soft - and hardware and telecommunication, as emphasized in [53]. To define the relationship between actors and stakeholders for the activation of flexible resources generally four stages are considered. Those are:

1. Contracting
2. Validation and Planning
3. Operating phase
4. Settle

and are presented in the following chapters.

Contracting phase

As shown in **Figure 14**, the aggregator purchases and contracts flexible resources with the prosumer in order to be able to control and add those resources to his own portfolio. The BSP in turn contracts resources for his own portfolio with the aggregator, which he can then offer at the TSO tenders. In order to not violate any constrains on the distribution grid the aggregator informs the DSO about its portfolio

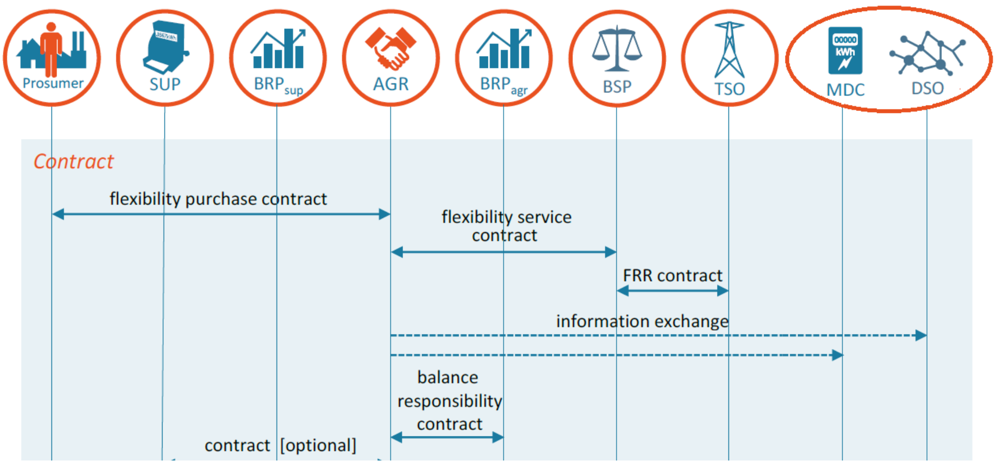


Figure 14: Interaction of all involved parties in the contracting phase [41]

of accepted resources. In this step he also requests to access to the measurement data for the activation of his resources for balancing or congestion management purposes, in the best case near real time. The aggregator also stipulates a contract with the BRP which is responsible for the imbalances created from the activation of the aggregated resources in that balancing area. In some cases, the aggregator also contracts with the BRP_{sup} and BRP_{agr}. [41]

Planning and validation phase

Before the actual operation, for instance one day before the activation the aggregator validates the status of his portfolio according to the forecast provided from the prosumers and the available resources. The DSO even though the contract was signed already may impose restriction if grid constraints are violated or may request flexible resources to resolve any violation. Once the predicted state of the resources in his portfolio is known, the aggregator can sell them to the BSP, which in turn can offer and provide them to the TSO. The TSO uses the services provided by the BSP for balancing the system. The BRP_{agr} and BRP_{sup} inform the TSO about their injection/withdrawn program [41].

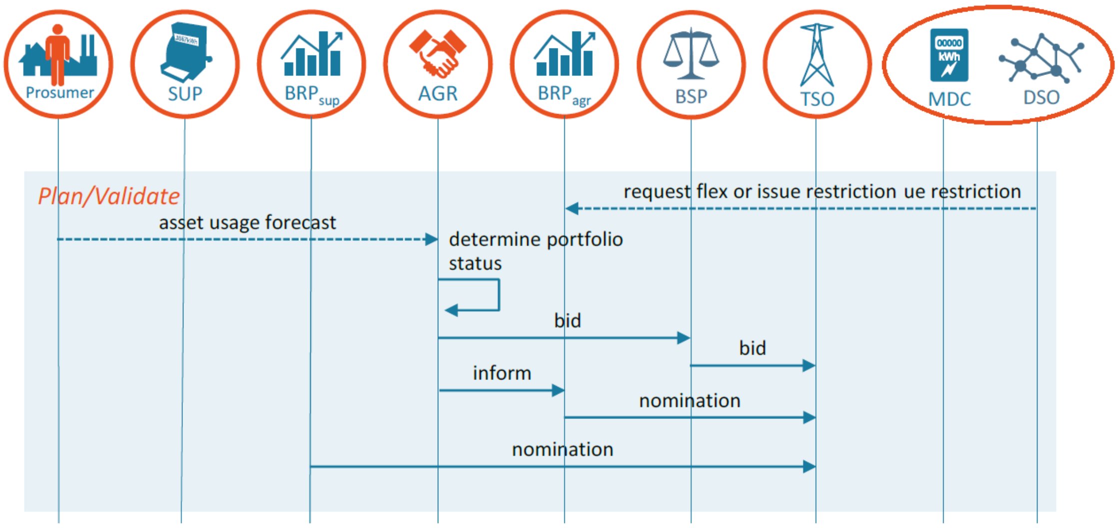


Figure 15: Interaction of all involved parties in the planning and validation phase [41]

Operational phase

During the operational phase the resources from the prosumer are measured and monitored throughout metering services sent to the Aggregator and BRP which in turn forward them to the TSO. As soon as the TSO detects imbalances he requests the necessary balancing services from the BSP in order to contrast them by activating through the aggregator the prosumers resources (ncrease or decrease on demand side). The aggregator informs the BRP_{sup} of the activation, if that resource fall into the BRP_{sup} portfolio to avoid counterbalancing. Finally the DSO collects and registers the metering data to carry out the necessary calculation, since the activation of those resources changes the energy profile, for instance the BRPsup has an imbalance in its portfolio [41].

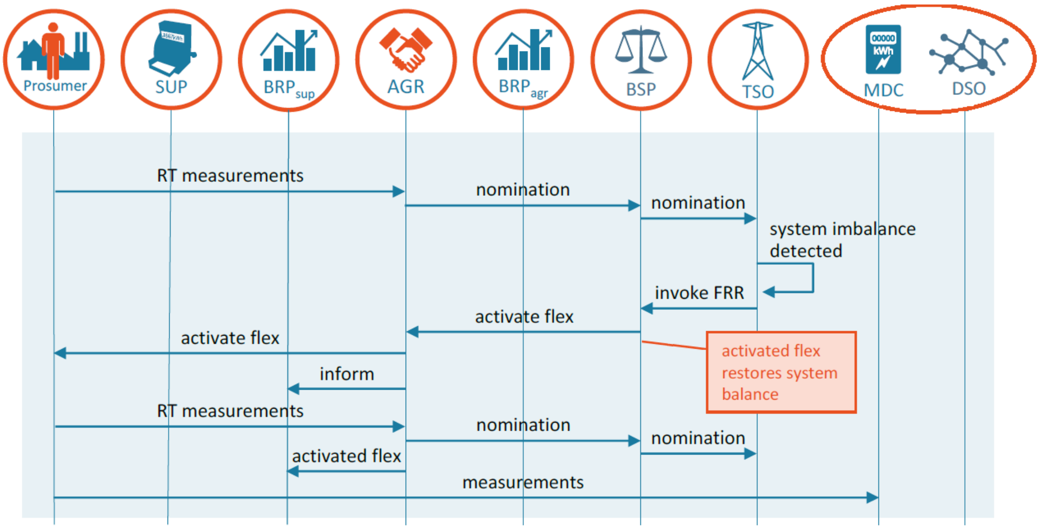


Figure 16: Interaction of all involved parties in the operational phase [41]

Settlement phase

In **Figure 17** the green arrows represent the financial transfer. The DSO, also responsible for the metering collects and provides the measured data to all involved stakeholders in order to be able to quantify the activated flexibility. This data is used for "*transfer energy*[8]"to compensate the supplier and the imbalances in the BRPs portfolio caused by the activation of flexible resources, in **Figure 17** the perimeter correction. As highlighted in USEF model, the specific transfer of energy depends of the different implementation models that were described before. Once the *energy transfer* is concluded the BSP is remunerated by the TSO for the provided balancing service. This is the basis for the remuneration scheme for the Aggregator and the prosumer [41].

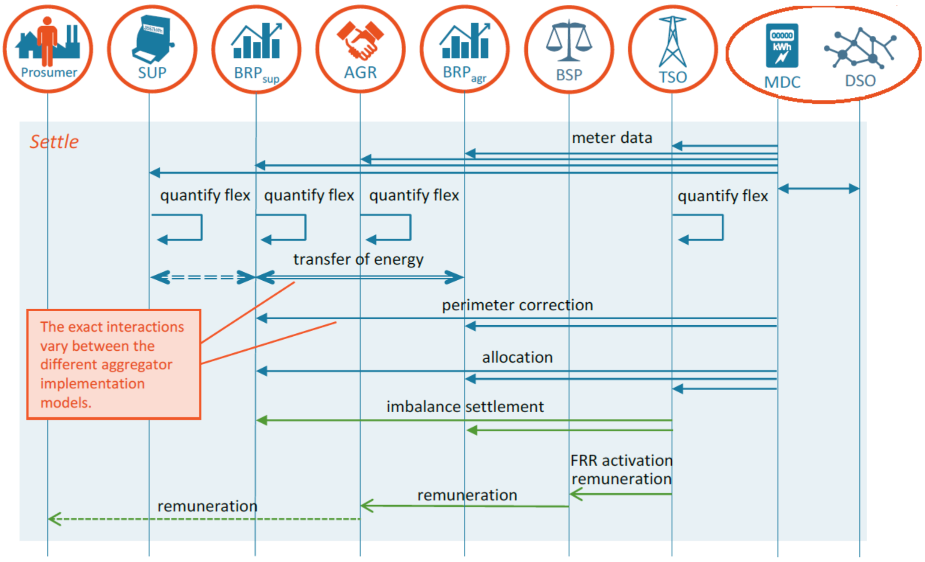


Figure 17: Interaction of all involved parties in the settlement phase

[8] The transfer of energy generally includes also financial remunerations

3.3 Demand Response

Flexibility can also be achieved from the load side through active demand response (DR) from energy storage or load shifting. It is defined as the ability of the electricity consumer to change their consumption pattern based on signal coming from the market [49]. Loads can be controlled upwards and downwards, while other resources like solar and wind power downwards exclusively.

Market4RES reports D2.1 [54] and D6.1.1 [26] stated that demand participation in the market could result in a considerable decrease of systems operational and investment costs which in turn would pave the way for a higher competition and thus contribute to a reduction in prices. *Market4RES* reports are not considering capital expenditure and operational cost for a proper communication among DERs. Only a discussion on the main barriers which include adequate equipment and communication protocols is provided, it can be found in [24].

For demand response, customers use their own generation, energy storage or other controllable resources. Obviously, those must be controlled automatically. Manual control would be too unpredictable, expensive and slow.

The participation of demand response varies not only among different countries but also inside boundaries among regions due to different energy generation mix [49]. Thus, a participation to a central balancing market might be distorted and mainly dependent from a costumer's location. In **Figure 18** different European countries policies for participation of DR is depicted. It is shows that e.g. in Austria and Germany the participation to the demand response is partially open while in France and the UK it is commercially active. Italy and Spain the commercial aggregation and so also DR is still not allowed.

In the French scenario, e.g. the NEBEF mechanism allows end-users (aggregated or not) to sell the energy by reducing the demand only on the day-ahead market and in Finland demand side is also allowed to participate to the restricted ancillary services [32].

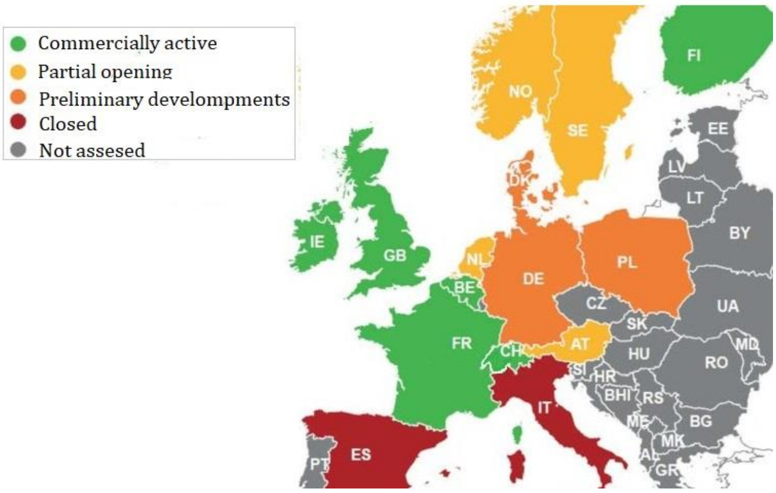


Figure 18: European countries allowing or partially allowing demand response [49]

However, even where aggregated demand response is active and commercially allowed to bid in the electricity market or ancillary services market, the volume of participation of DR is still marginal. Mainly because of the design of most wholesale markets which do hinder a direct participation of DR e.g. minimum volume or response duration which exclude small users or aggregators a-priori [32]. A detailed technical description on technical specifications was already provided in chapter 2.4.

Therefore, several changes need to be addressed to allow the participation of small scale DERs and DR. On one hand the market design needs to be revised defining the boundaries of responsibility and the roles of each stakeholder and on the other hand standardize the data exchange among them to ensure a safe, secure and reliable control mechanism.

3.4 Overview on Flexible Resource for the provision of AS

Demand response, flexible resources and the extension of traditional demand-side and load management is a key practice for the future smart grids to improve systems reliability, efficiency and to tackle local problems. Currently limited due to two reasons. First, the lack of regulatory framework for ICTs; secondly, the main resources are disaggregated and of small or of medium in size. The main application areas and most promising technologies as stated in [30] are in load shifting, demand-side balancing services, advanced meter infrastructure (AMI) and also post-meter technologies[9] [35]. Especially in the industry sector where bigger loads can be modified and most of the communication infrastructure is already in place for energy management purposes, DR is more convenient. Oppositely, for the residential sector is more complicated [8].

Generally grid reinforcement is capital intensive i.e. the reinforcement of feeders, substations and power lines. Considering that those additional investments are essentially required, but needed only for some hours a day or a year, namely only when the load is peaked as discussed in chapter 2.4. Most grids are oversized. Thus it is important to investigate if such an approach is actually economical efficient or if the investment into new technologies such as DR, storage or DERs could constitute an economically more profitable way to avoid congestion [55], [8]. Specially, flexible resources may assist the system to deal with congestion issues. They have the ability to use its resources to respond to changes in the systems demand, in the best case, in near real time. To put it differently, it is the modification of injection or consumption in reaction to external signals i.e. price signals or activation through the DSO or TSO [39].

Figure 19 shows the different needs for flexibility. For instance, the flexibility for energy range from hours to years. In other words, the planning for energy transfer should be done months ahead. On contrary, flexibility for voltage is needed only for few minutes a day. Each technology and resource has a different capability which will be discussed in the following chapters [56].

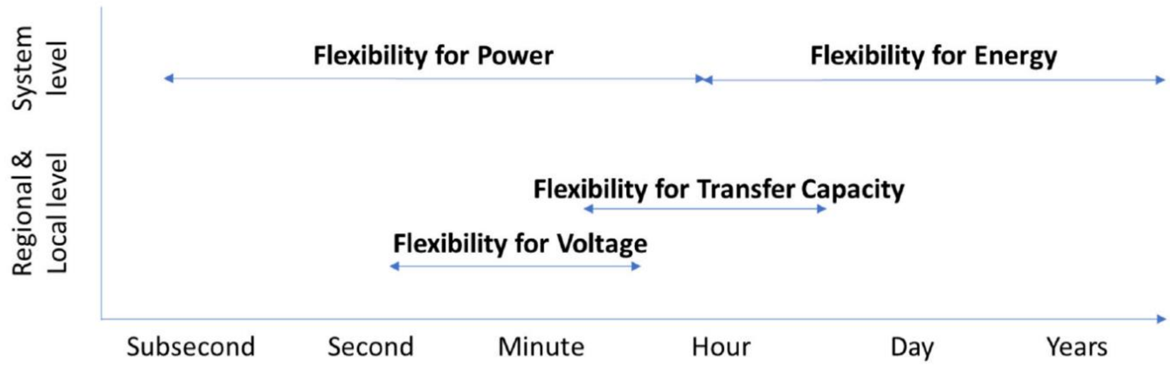


Figure 19: Use of flexibility for different purposes depend on time and service [39]

[9] Post-meter technology is referring to all in-home appliances able to respond to signals coming from the smart-meter

Demand side flexibility or DR refers only to costumers capable to shift its load without a decrease of the comfort standards. Consumers respond to prices either *implicitly* though a contract with the supplier or *explicitly* through an aggregator that bids on his behalf [24]. A really simple mechanism to boost the DR is to offer consumer the dynamic electricity prices. With the massive roll out of smart metering infrastructure this became even more important [57]. Nonetheless, the use of those resources is limited due to the different location and technical capabilities. Only with the deployment and the installation of new infrastructure such as ICTs it is possible to overcome this issue.

In study [39], which studied the requirements for interaction between aggregators and markets, three possible market uses for flexible resources are presented.

1. Portfolio optimization: used by stakeholders to meet and to balance their energy obligations
2. Balancing: for to the procurement of balancing services in terms of capacity
3. Constraints management: allows system operators to tackle network constraints to maintain the quality of service.

For the sake of simplicity, in this thesis mainly balancing and congestion management services are considered. Portfolio management affect mainly the aggregation and remuneration scheme, but does not influence the coordination in real time considerably.

3.5 Capabilities of DERs to provide AS

Different DER technologies are currently in place or will be available in a larger scale in the future. The use and activation of those resources should be possible in both direction for UP and DOWN reserve or in other words the increase or the reduction of generation should be possible. In this context different technologies are available or will be available in the coming years. Storage systems and load reduction are the two most promising technologies. Stationary storage systems or electric vehicles will be available in large scale according to [3] and the increase of PV and wind plants as well as a further increase in volume of DR (shiftable and curtailable loads). In **Table 2** the technical capability to provide ancillary services of the main DERs are shown. Only frequency regulation is represented. A filled dark green square means a good capability, orange means no or poor capability for that specific service [58].

AS	PV	Wind	Storage BESS	CHP	Load shifting	Curtailable loads
FCR						
aFRR						
mFRR						

Table 2: Resources capability to provide AS [58]

Certainly, some of those technologies may also be available for other services such as voltage control, but in this context not of main interest even though important for the overall system security [50].

3.5.1 Wind and PV

Generally the provision of ancillary services at transmission level by wind turbines is already in place in many countries such as Germany or Portugal. Regarding PV the integration is more complex especially because the PV plants are high in volume but rather small in terms of size and generally dispersed and connected only at MV or LV [58]. Moreover, PV plants do not have a natural inertia as wind turbines can provide. Still, PV plants if of meaningful size can provide ancillary services especially FCR and aFRR as shown in **Table 2**.

3.5.2 Combined Heat and Power (CHP)

The combined heat and power (CHP) technology which refers to generation of electricity and a useful heating systems used in larger industrial plants. In this context the CHP could provide ancillary services, especially FRR being able to restore frequency slowly. The provision of active power compared with other technology is rather slow and therefore not suitable for FCR, but still if aggregated an interesting technology in the future smart grids.

3.5.3 Shiftable and curtailable loads

Shiftable load and curtailable loads or in other words demand response(DR) can be useful for the provision of AS as shown in **Table 2**. Curtailment of loads can be activated within seconds and therefore suitable for FCR without any discomfort for the customers. Shiftable loads instead, can be a good solution for the provision of FRR. It is worth to mention, that the integration and the use of a shiftable loads also the post-activation, or in other words the rebound effect, period should be considered making it complex for the real aggregation, which was investigated in [59].

3.5.4 Stationary Battery Energy Storage Systems

BESS, connected to the grid can provide a wide variety of ancillary services. This is due to their capability to consume or to inject energy (charging or discharging) even for longer periods and is thereby suitable for a lot of ancillary services. FCR which requires a fast response so as aFRR and mFRR for a slower respond but require a longer injection time. Furthermore, as shown in **Figure 20**, active and reactive power can be adjusted easily making it an ideal product for artificial inertia or voltage control especially at distribution level. Electric vehicles can provide similar services, but being a "mobile" storage it is difficult to integrate them into the AS were reliability and programmable fast response is indispensable [58].

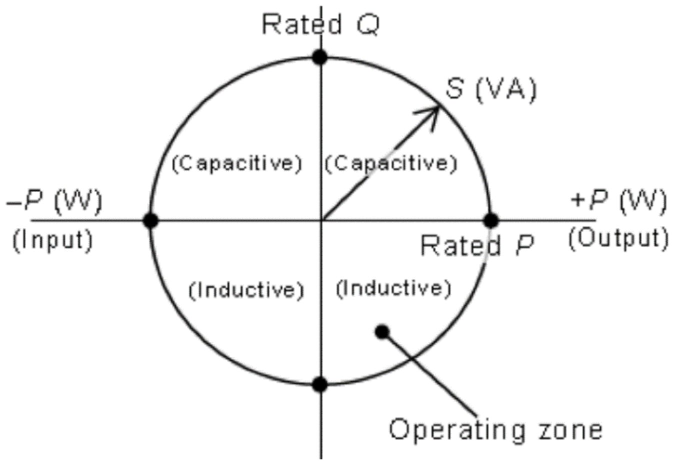


Figure 20: BESS can provide a wide range of services and can modify reactive and active power injection easily [58]

Small scale-BESS are already present in high numeber in the European grid. One good expample for BESS are back-up batteries for mobile radio station. Generally those staions have a contracted powef of around 5 kW – 15 kW and most of the time not in service. According to [60] in annex A4 only in Austria there are 18'023 radio base stations. Using this capacity may provide a good service beeing a stationary and already existing technology, in addition new stakeholder such as mobile phone companies may be interested in partecipating in the markets.

3.5.4.1 Example of BESS: Radio Base Station batteries

It is important to find and use of already existing services based on availability. A good example could be the use of Radio Base Stations (RBS) for cellular telephony in which there are emergency supplies such as UPS and generators as shown in **Figure 21**. The RBS for mobile telecommunication may be seen as multi-site laod, widely distributed across Europe and easily controllable. In fact, mobile telecommunication uses a large number of plants of this type, managed with a centralized control system. Furthermore a site can be easily replicated and therefore the use of flexibility can be implemented easily at all installations in an aggregated form. It is estimated that in Austria more than 18,000 RBSs are almost powered by back-up batteries [60].

It is necessary to assess wheter the interruption rate is compatible with the use of new services, e.g. the provision of flexibility for congestion management. With reference to the year 2018 for the LV outtage of the service, show that in that year 1 ÷ 2 short interruptions (less than 3 minutes) occurred on average [61]. Which means that this resource is available almost the entire year. Considering all the above mentioned aspects the radio base station batteries may have a huge potential to provide flexibililty [62].

Figure 21: Back-up batteries in Radio Base Stations for mobile services [62]

3.6 Methods for Aggregation and Remuneration

The way flexibility is integrated may vary depending on the type, the shape, quantity and direction of that specific resource, but also by the security constraints set by the SO as already discussed in chapter 2.4. In many European Countries it is a common practice to give priority to RES and thus curtailment has to be avoided. The so called rebound effect applies when a reduction is only allowed if shifted to a later period e.g. thermal loads, where a sudden change does not affect costumer's needs but it has to be compensated in a later period of time. This has to be considered by the SO because it may create further problems. In **Figure 22** this effect is made clear, when the consumption violates any constraint the SO may activated flexibility but has to deal with an increase in consumption in a later stage. The aggregator may play an important role in order to include this effect and to gain profit [9].

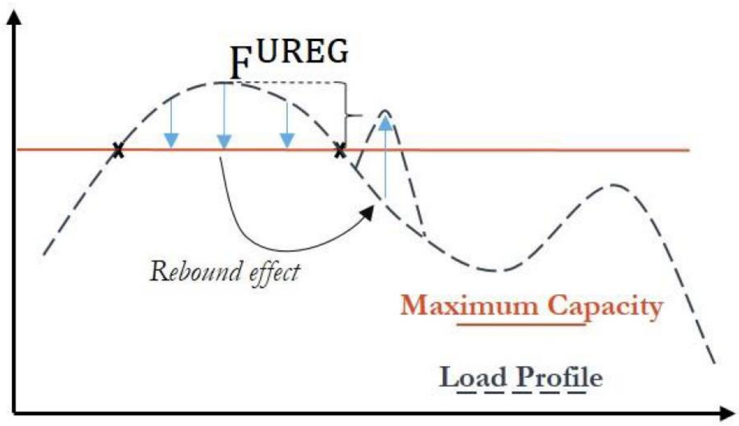


Figure 22: Rebound effect which must be considered by the system operators [9]

3.7 Illustrative example: Vehicle to Grid (V2G)

For the aggregator the BESS will play a key role especially with the increase of EV batteries in the coming years, they have a good capability to provide many services. The EVs consumption and the size differs from one car to another. Moreover, the aggregator cannot always rely on this resource, which are affected by many factors [63], such as time, weather condition or location. Also, the charging and discharging time has to be added to the EV capability. To tackle all those problems the aggregator needs to optimize the portfolio carefully adding many uncertainties and thus making it a rather complex procedure. In **Figure 23** a pilot project [63] shows the number of possible bids and the capability of EVs to provide ancillary services. Almost the entire day batteries can provide DOWN reserve, but also the valuable UP reserve. As mentioned, aggregation depends on time, for instance in early morning between 6am and 9am, when cars are in motion those resources are not available and the same goes for the late afternoon The aggregator may use also the indirect control approach where the user is encouraged with financial incentives to control the charging process. Unlike the direct approach which requires a two-way communication, the user does not have to provide any information and is allowed to decide when to charge the battery. The aggregator plays a substantial role to mitigate those variations [63].

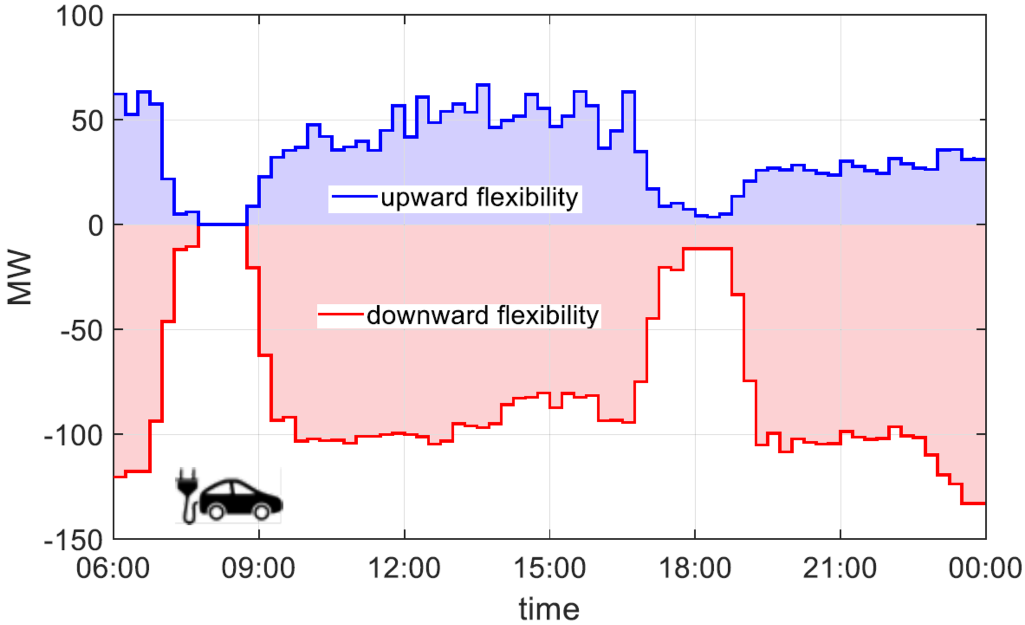


Figure 23: Capability to provide UP (blue) and DOWN (red) reserve by electric vehicles [63]

4 DSOs in an Evolving Environment

4.1 Introduction

As previously mentioned, the DSO could play an important role in the procurement of ancillary services from DG or any other distributed resources, including demand response or energy storage systems. Generally, the TSO procures DG resources directly centralized, without the involvement of the DSO, which can lead to problems in case of increasing volumes of DERs at DSO level, especially because DSOs are responsible for maintaining the local constraints within certain specifications and margins to ensure quality of service [39].

In the current system where the DSO cannot participate in electricity market, if they would for instance, only perform load control to avoid congestion or to improve the network efficiency e.g. voltage control, it would interfere with the market based load control [49]. At his point it is worth to mention, that the TSO is already receiving location specific information about the status of injection, but only from prequalified units, not for small scale DERs, thus in the future grid coordination between TSO and DSO is absolutely needed.

Today, coordination is focused mainly on network planning and/or for the PQ-process [23], in this case the DSO is allowed to specify grid limits ex-ante. However, coordination between the system operators should be improved to accommodate the increasing volume of DERs, for example the DSO could provide support to local or national system by delivering ancillary services [64]. ENTSO-E explicitly promotes TSO/DSO interaction and collaboration for the benefit of consumers and states in [65]:

"TSOs should identify the requirements for system services (especially for frequency control or system restoration) and how these might be delivered by distribution connected service providers".

Therefore, the role of the DSO is evolving, moving away from the conventional "fit and forget" approach to a more active managing role. In particular, the DSO could take over two main roles of support. First, by acting as counterparty to the TSO offering the capacity of ancillary services present on his own DSO grid, second by managing its own local flexibility (ancillary) service market in order to solve local network constraints e.g. congestion management. Real-time price signals and activation could be a main driver for coordination and probably be the most efficient way to allocate resources and services, of course only if properly coordinated [4].To tackle this problem several papers have been published, all of them mention the importance of the aggregator when referring to the upgrade to a local AS market [35], [66]. Moreover, it is emphasized the importance to review the regulatory framework, the need for changes to incentivize and remunerate not only the grid reinforcement, but also the development in smart grids and the effort to improve network efficiency such as optimized congestion management [35], [67].

The activation of AS at distribution level affect also the BRP currently in place[10]. Referring to the Austrian case, the BRPs get only ex-post information, in other words the activation or procurement of AS is noticed just after it happens [68]. In **Figure 24** the information flow between actors in Austria is depicted, especially between SOs (arrow 13) which as stated in the Electricity Market Codes [68] of E-Control is done monthly.

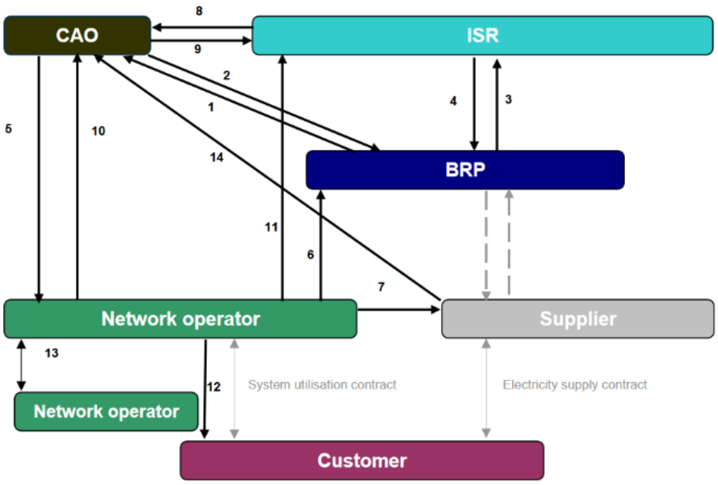


Figure 24: Information flow between actors, the Austrian case [68]

Until now the DSOs are not allowed to procure flexibility services in most European countries. In Germany and in Belgium contractual agreement has already been established, allowing costumer to reduce their network tariff by allowing the use of curtailment generators or thermal loads [35] [55]. Undoubtedly, with the increase of flexible resource the DSO can optimize the use of his grid if activated systematically. Flexibility should be dispatched in order to minimize the overall required grid investments. This was analyzed and discussed in detail in the recent research project [9]. By increasing flexibility in 10 % steps until a flexibility rate up to 50 % the benefits for the DSO [11]increased considerably, up to 5 % per substation.

[10] The organization and remuneration schemes of BRP is different in each European country

[11] Grid efficiency by optimizing congestion management

4.2 The new Role of DSOs – Regulatory Overview

In the liberalized electricity market structures, SO remain natural monopolies[12], they have a key responsibility on one hand for the neutral market facilitation and on the other to ensure fair market access and a secure operation. They have to facilitate the participation of all market parties while complying with national and EU regulations. SOs should remain neutral towards all other stakeholders [46]. The national regulatory authority (NRA), *E-control*, is responsible for overseeing system operator's activities [9].

With a high quantity of generation coming from small scale DERs the regulation of active congestion management is becoming increasingly important, being of benefit for customers tariffs and DSO grid efficiency [69]. As foreseen by the Clean Energy Package [19], all Member states should define the necessary regulatory framework to allow DSO to acquire services and guaranteeing the effective participation of all market participants.

Thus European energy regulators CEER, as stated in [69], [36] and mentioned in chapter 2.2, have committed themselves to develop guidelines for national regulators to facilitate the use of flexibility at distribution level with the aim to reduce tariffs and avoid unduly market distortion. Undoubtedly this will influence each national organization and the interaction of TSO and DSO. A tricky challenge for regulators will be to define an effective way to deploy ICTs in the future grid and to properly integrate costs when determining tariffs [48]. It is important that the required investments are properly covered by grid tariffs (chapter 4.3.1) in order to promote and remunerate SOs for deployment in smart grids, as ICTs are a fundamental asset for activation of flexible resources [46]. The DSOs should have the possibility to decide between both the investment (CAPEX) and the service-based solution (OPEX) for the most cost-efficient ones, as stated in EUROLECTRIC [39].

The new emerging market actors, in particular third parties like the aggregators, will have an important role in the future grid too. In order to enable (independent) aggregators to fully enter into the market responsibilities, roles and regulatory framework have to be clarified. With the current regulatory framework in Europe, there are barriers to independent aggregators. The flexibility providers should have the possibility to place their bids in a way that they can be activated at highest value. In the USEF study [41] described in chapter 3.2, the relationship was partially discussed, which sets standards for a fair and clear competition between suppliers, BRP, and aggregators [46]. For the implementation of a local DSO market, defined rules should be in place. Report [46] strongly suggest to establish those criteria a-priori. Moreover, for the bid selection, beyond (economical) merit order, also the technical aspects, to ensure grid stability, should be considered and be made transparent.

[12] Under heavy regulation when it comes to revenues and distribution grid tariffs

4.3 DSOs in Europe State of Play

The Directive 2009/72/EC, which defines the unbundling requirements and obliges Member States to separate the vertical integrated energy companies with the aim to create neutral and fair competition among all actor. The DSO, being a regulated monopoly, is allowed by the NRA to earn only a certain revenue (remuneration scheme is defined in a period of five years ahead) and remunerated by the final costumers. Charges that are either components of an integral tariff or part of the access tariff. For DSOs serving fewer than 100’000 special regulation apply. In Europe there are 2400 DSOs [70], and more than 90% are beneath to this limit. As in many other areas, Europe has a big diversity regarding the number of DSOs. Whereas some countries have few DSOs, other have a high number of DSO like Germany and Austria, countries like Ireland or Lithuania have only one as shown in **Figure 25**. In Austria 130 DSO exist (list of DSO per country can be found in the annex A4) and currently 13 DSO are serving more than 100’000 customers, four DSOs are serving more than 50 % of all customers for a total of 69’000 km of MV and 173’400 km of LV grid [71], [70].

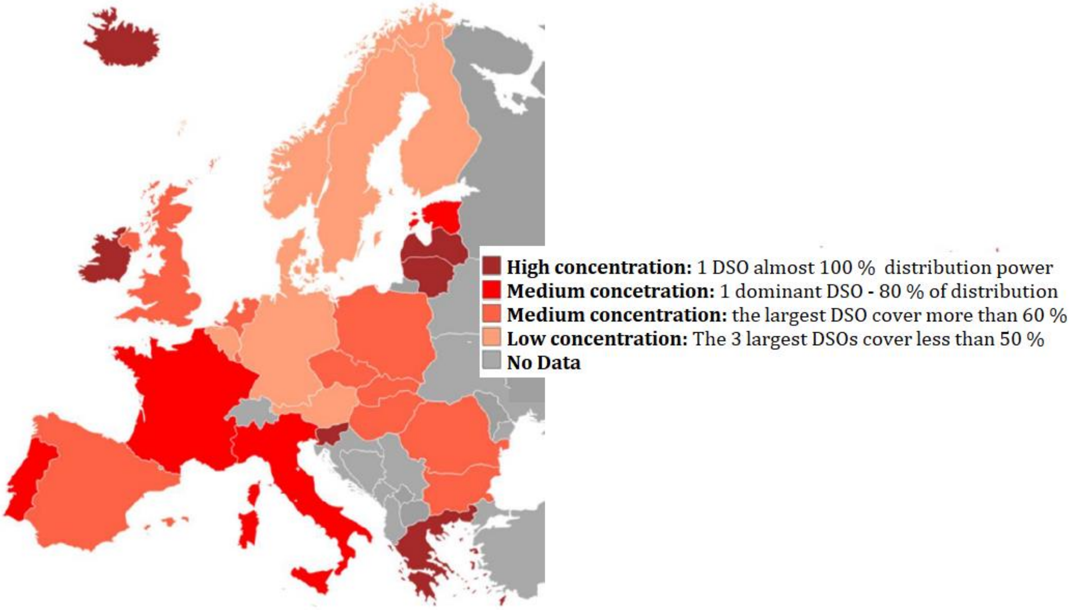


Figure 25: Concentration of DSOs per European Country, Austria has 13 main DSO and four are serving more than 50 % of all costumers [70]

Regarding the tariff in the European context, according to [70] average costs vary greatly from country to country in Europe. Austria, highlighted in **Figure 26**, roundabout[13] 28 % is accounted for the network costs. In the majority of the cases, charges are based either on energy consumption or on the measured power, even though the final costumer's tariffs include both elements. In the following chapter current remuneration schemes are briefly described. A very restricted number of DSOs already started to put in place DR in Europe [71].

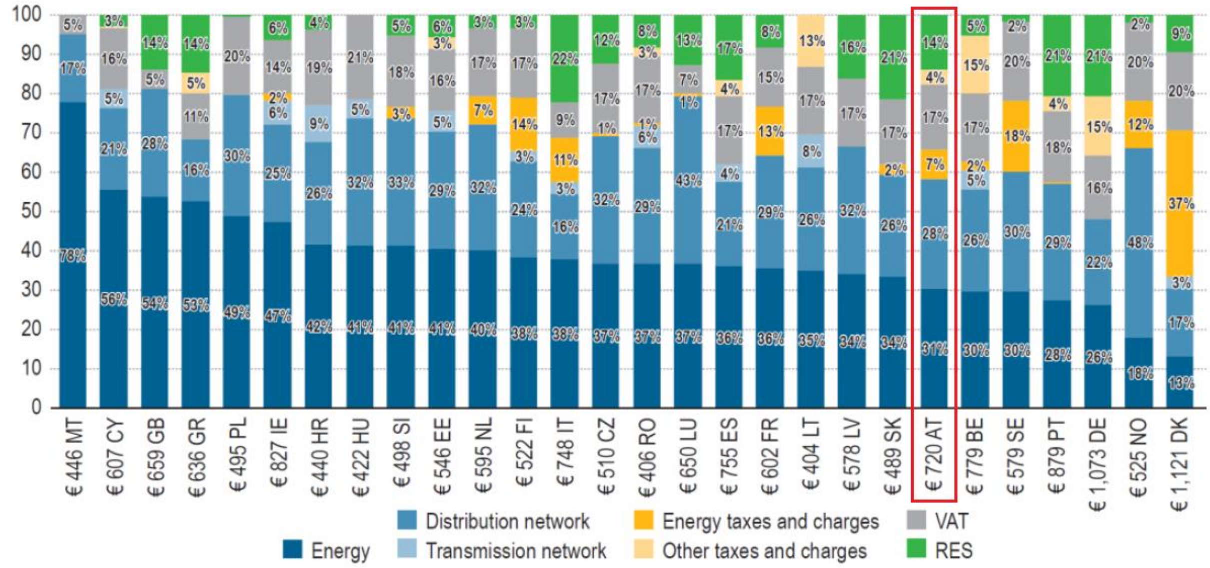


Figure 26: DSO tariffs for each European country, in Austria 28 % is charged for the DSO grid [70]

In the new rules for the internal electricity market, the Directive establishes new common rules for all actors with the aim to integrated flexible resources, promoting smart grids and to further reduce market distortion. As mentioned in chapter 3.5, EV and the Vehicle-to-grid technology is expected to play an important role. In the new Directive, SO are still not allowed to own and manage[14] EV charging points or storage facilities. In Directive [71] data protection is also emphasized. Privacy and security should be of system operator's duty in a compromise between sharing the necessary data and maintain the confidential data unrevealed.

[13] The precise value to 2019 is 27,9 % and includes TSO and DSO cost

[14] Only under specific requisites

4.3.1 Tariff Structure

Generally the tariff structure is driven by CAPEX and OPEX and is referred as the use-of system charge paid periodically. Different charges may be applied, volumetric which are proportional to the energy demand in Euros per €/kWh or capacity charges which reflect the contribution of loads for peak demand in Euro per kilowatt €/kW [72]. In **Figure 27** the composition of the Austrian Tariff is depicted, as previously mentioned, 28% goes for system charge.

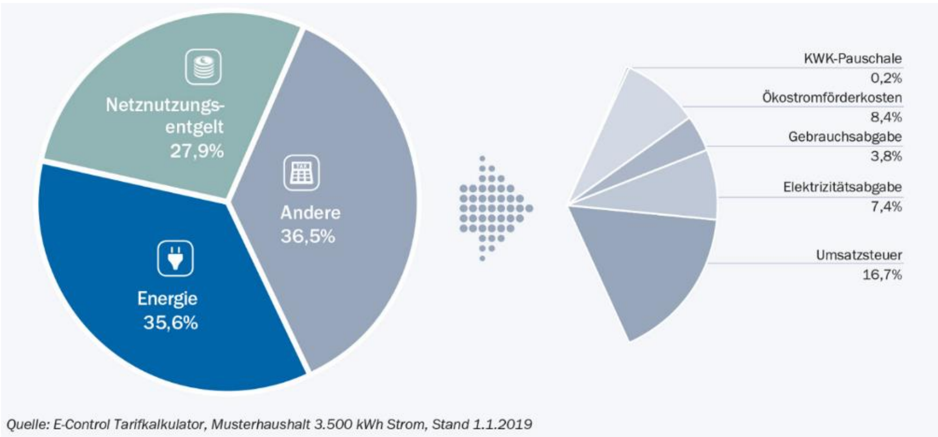


Figure 27: Tariff in Austria, system charge is 28 % of the total amount

As suggested in [39] the tariff structure should veer away from exclusive volumetric charges towards an incorporation of capacity charge to reflect the impacts of each costumer. Furthermore, it should encourage the peak-load mitigation. In **Table 3** the distribution tariff design options and the direct impact on load is summarized: peak shaving, load shifting, strategic conservation or valley filling. It is important to distinct between network tariffication and network regulation. The latter is limited to the remuneration of the total allowed network costs and incentives to network operators and pertain to daily operation expenses of power flow management [73].

Type of network tariff	Design	Direct load impact
Volumetric charge	Energy (€/kWh)	

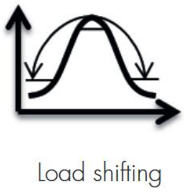
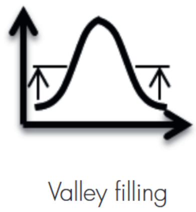
Capacity & volumetric	Power Energy with a flat rate charge	
Time-of-use volumetric	Peak (€/kWh) Low (€/kWh)	
Capacity-based	Power Or dynamic components with high prices at peak hours	

Table 3: Distribution tariff design options and direct impact on load [39]

4.4 Remuneration Schemes

For the distribution grid tariffs each NRA is responsible. The remuneration scheme varies among European countries. In the following two main remuneration schemes are presented to describe and to show the effect of DSOs decision to invest in the grid. As previously stated, those remuneration schemes should be revised in order to foster the investments in smart grids.

- **ROR method**

  In the Rate-of-Return method the regulator defines a rate for DSOs based on time t, required revenue RR_t, operating expenses OE_t, depreciation expense and tax expenses. RB is the rate base. With this remuneration scheme the DSO is encouraged to invest in grid reinforcement rather that in grid efficiency [70].

$$RR_t = OE_t + D_t + T_t + (RB - ROR_t)$$

- **Incentive-based regulation**

  In the incentive base approach, the revenues and prices are set ex-ante the period with the aim to minimize DSO cost and to encourage DSOs to be more efficient. The revenue cap is defined by a *CPI-X* formula. Revenues and prices are calculated in

$$P_t = P_{t-1}(1 + CPI - \boldsymbol{X}) \pm Z$$

$$R_t = [R_{t-1} + CGA \times \Delta Cust] \times [(1 + CPI - X) \pm Z]$$

Where P_t and P_{t-1} are price ceilings and *CPI* the Consumer Price Index. *X* is the productivity factor, it sets high incentives for DSO to achieve a higher productivity. *R* are the allowed revenues in the period *t* and *t-1* while *Cust* and *CGA* are just customer's adjustments factors. A full description may be found in [70] and [69]. Also this approach has drawback e.g. underinvestment in the short term and thus should be reviewed [9].

In Austria *E-Control* is the responsible authority, according to [71] the incentive-based regulation-price gaps scheme is used to remunerate DSO in a 5 years timeframe. With the increase of DERs at distribution the network cost as reinforcement is needed when power injection causes an increase in network costs and upgrade is required even if only for peak hours.

4.5 Summary

In summary the regulation and the correct tariff structure is important to plan further investment and long term investments based on CAPEX and OPEX. As shown in **Figure 28** only throughout the right signals the actors are encouraged to participate actively for a more efficient use of the system. The end costumers throughout the right tariffs capacity based and the system operators via the correct remuneration or rates of return in order to postpone grid investments.

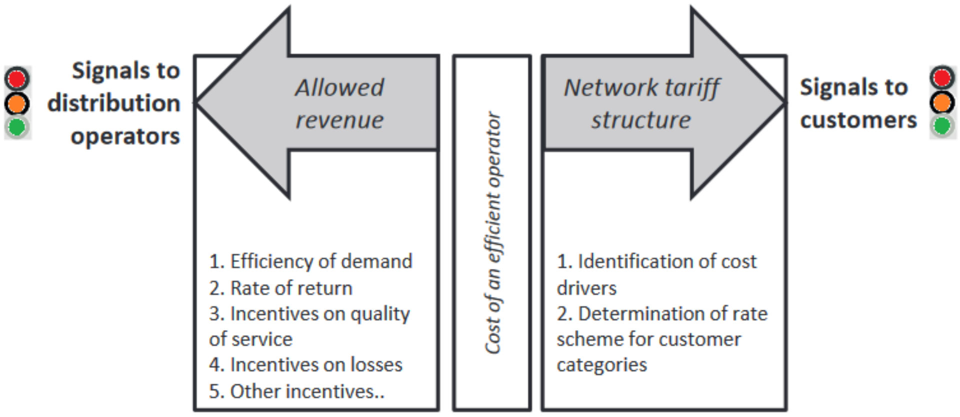


Figure 28: Summary of signal to incentivize an efficient use of the system [39]

5 TSO / DSO Interaction

5.1 Literature Review

Resources in distribution grids should be used without jeopardizing the local grid, thus the coordination between TSO and DSO to ensure security and reliability is essential. Moreover both SO are competing for the same resources, creating conflicts and market inefficiency. In this chapter a brief literature overview is provided to give an overview of the current status of TSO and DSO interaction. Furthermore previous projects and regulatory boundaries are compared, based on literature inferences and the most promising coordination schemes, those of the *SmartNET* project, are presented more in detail [74] [56].

Across Europe many demonstration projects proposed technical solution to improve TSO-DSO cooperation. E.g. the *EvolvDSO* project [75] developed new methodologies for an efficient operation at DSO level including power flow constraints and tools. In France for instance, flexible resources located at distribution grid are already successfully activated by the TSO and is a common practice.

In Germany, the traffic light concept [76] has been developed, which basically informs the SOs about the grid status with specific colors [15]as seen on the right in **Figure 29**. In the normal "green" status there is no network congestion and all the market products can be traded without restriction. In the alert state "orange" the DSO acquires demand flexibility from a dedicated market to relieve congestion. In the unsecure status "red", DSO directly intervenes to regain the full system security regardless the prior acquired resources. As also mentioned in [76], again the regulatory framework and technical risks should be duly considered [48].

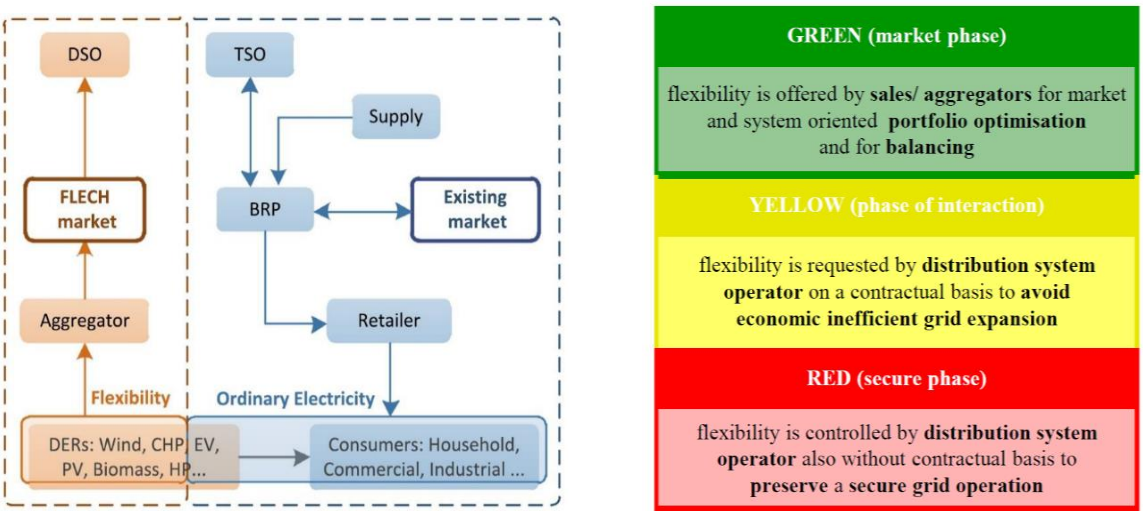


Figure 29: Right figure shows the FLECH project mechanism, in which a market runs in parallel rather than coordinated and the left figure shows the traffic light concept for a coordinated congestion management [76]

[15] As with a traffic light: red, orange and green

In Denmark a different approach named *FLECH-project* discussed in [77] and shown on the left in **Figure 29**, studied the integration of small scale DERs as flexible resources for the DSO. For this project a local flexible market runs in parallel to the actual electricity market (intra-day, day-ahead etc.). In this case the local market assists the DSO in mitigating grid congestion estimating the required amount a-priori. At the end, the aggregator is the only responsible party for the activation and the scheduling of DG resources.

The *SmartNET-project* [33], on which this thesis is based, provides possible architectures and coordination schemes for an optimal interaction between TSO and DSO. It was launched in 2017 and is currently under investigation. In the following chapters, the most promising coordination schemes are re-discussed, being of importance for the subject of this thesis.

Finally, another important project to maximize the value of flexible DR, the USEF [41] project discussed in chapter 3.2, is suggested by many authors and thus seems to be a promising framework to integrate smart energy products in the current grid structure.

From the literature review in emerges, that the DSO for sure will play an important role, but also problems like bidding process, operation for congestion management or balancing need to be tackled. When more than one actor acts on the same resources and also to provide the necessary framework to valorize those resources. Due to the heterogeneity in grid organization in the Europe, a harmonized solution has to be found [78]. In summary the main stakeholder involved for in process in the coming years are:

- EDSO for Smart Grids - System operators associations
- ENTSO-E
- CEER - Council of European Energy Regulators
- ACER - Agency for the Cooperation of Energy Regulators
- NRAs - National Regulatory Agencies
- ISGAN - International Smart Grid Action Network

5.2 TSO / DSO Coordination for Congestion Management by ENTSO-E

As mentioned above, the traffic light concept is a useful approach to involve and to engage the DSO in the congestion management. In **Figure 30** the flow chart explains the process when congestion appears and how the resources are acquired and activated. It is worth to mention three main phases, namely the preparatory phase and prequalification process, the forecasting and market phase and operational phase [76].

In the preparatory phase the product is prequalified and defined whether the unit is allowed to deliver the required service, which includes if no grid constraints are violated. In the forecasting and market phase, historical data, state estimation as well as real time forecast data is compared with the injection schedule of that resources to be able to ensure a secure operation. The system operates should always be aware and informed about the actual power injection. The market process starts only when congestion appears, namely in the alert state. For this process the merit order approach is adopted ensuring market efficiency.

Finally, in the operational phase, when the market is cleared, the accepted flexibility bids are activated and congestion in monitored. The SO can curtail generating units in the event of emergency ("red" phase). This concept is suggested and described in the recent report [46] by ENTSO-E and stakeholder with focus on the so-called *Active System Management for DSO.*

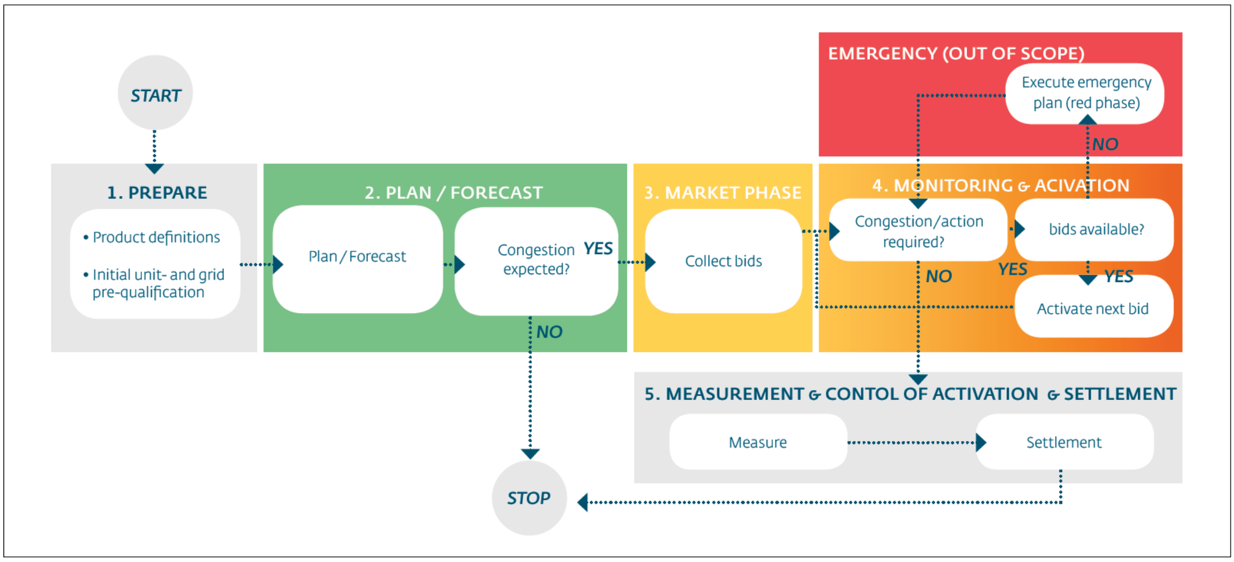


Figure 30: Congestion management by means of the traffic light concept [46]

5.3 Overview on possible Coordination Schemes for Balancing

The observability of transmission systems has always been very limited from the point of view of the DSO and indeed unnecessary. In report [44] of *ENTSO-E* recommendation are made, suggesting three different options to solve congestion and balancing. In annex A2 an overview of three option can be seen, those are:

1. **Option 1:** Separated TSO and DSO congestion management
2. **Option 2:** Combined TSO and DSO congestion with separated balancing
3. **Option 3:** Combined balancing and congestion for all SO together.

In the European project *SmartNET* those problems were tackled, and possible coordination schemes were developed where the idea of a local AS (real-time) market considering balancing and congestion management services has been investigated. An optimized coordination is only possible with appropriate information exchange. The main requirements for the implementation are briefly discussed in chapter 6. The project offers promising solution for possible coordination, but it does not focus on detailed implementation in accordance with the national regulations or grid configurations. The project gives a general overview for a possible interaction and thus an important contribution for future and detailed analysis on the optimizing decentralized market schemes [35]. In total five coordination schemes were developed in which the DSO may or may not be engaged to take over more responsibility in helping to balance the system or to solve congestion. In the schemes different actors are depicted each of which is interacting with different parties. The main actors are depicted in **Figure 31** most of them are already in place, while other like the Aggregator will be in place by 2030.

Figure 31: Overview on the main actors interacting for the coordination schemes discussed below, data from [35]

5.3.1 Centralized AS Market Model

In the centralized market model depicted in **Figure 32**, the TSO which, up to date is responsible for the grid stability of the transmission grid also contracts with DERs connected at the DSO level. The DSO is not actively involved in the procurement or the activation in real time or near real time of the AS. Instead, the TSO is responsible for the operation of the entire AS market without taking into account DSO constraints. A separated process needs to take place to guarantee that the activation of those resources does not cause a constraint violation on the DSO grid. Especially technical prequalification needs to be evaluated up-front by the DSO. The involvement of the DSO is limited and in this scheme the market is organized in a centralized market rather than a decentralized. Consequently, the TSO will need to have an extended observability of the entire grid (transmission and distribution grid) [79].

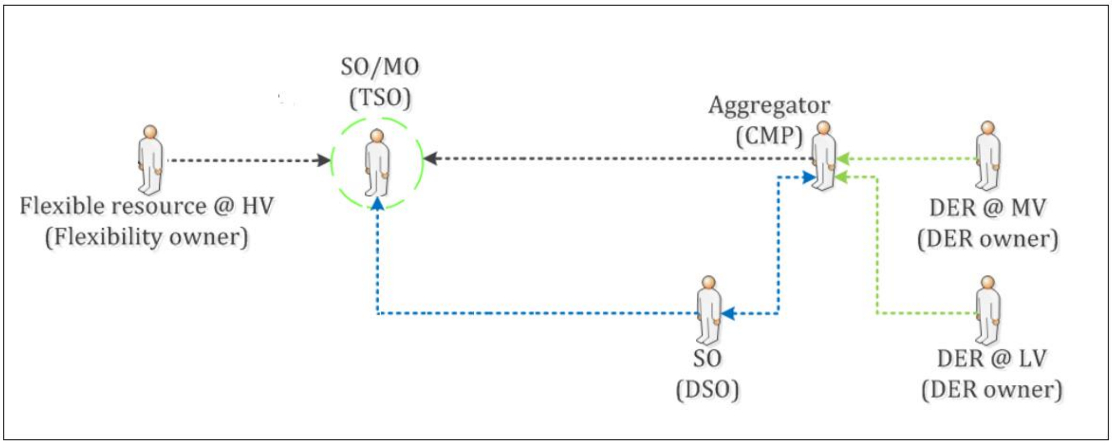


Figure 32: Centralized market scheme, the TSO is the only responsible partly for the procurement and activation of DG resources [80]

5.3.2 Local DSO Market Model

In this market model a separated local AS market is run by the DSO. As shown in **Figure 33** the local DSO market model distinguished by the centralized model by the implementation of a local flexibility market and therefore the responsibility for grid stability is shifted towards the DSO. In this scheme the DSO collects/receives the bids (already aggregated by a third party or not) and clears the local market for his own requirements (e.g. congestion management). The remaining bids can then be transferred aggregated to a centralized AS market run by the TSO, obviously local grid constraints are already considered. To put it differently, resources connected at the distribution grid can only be procured by the TSO via the DSO local market and only after the DSO has solved and selected all the resources needed to solve congestion and grid constraints at on his own grid [79]. In this scheme priority is given to the DSO.

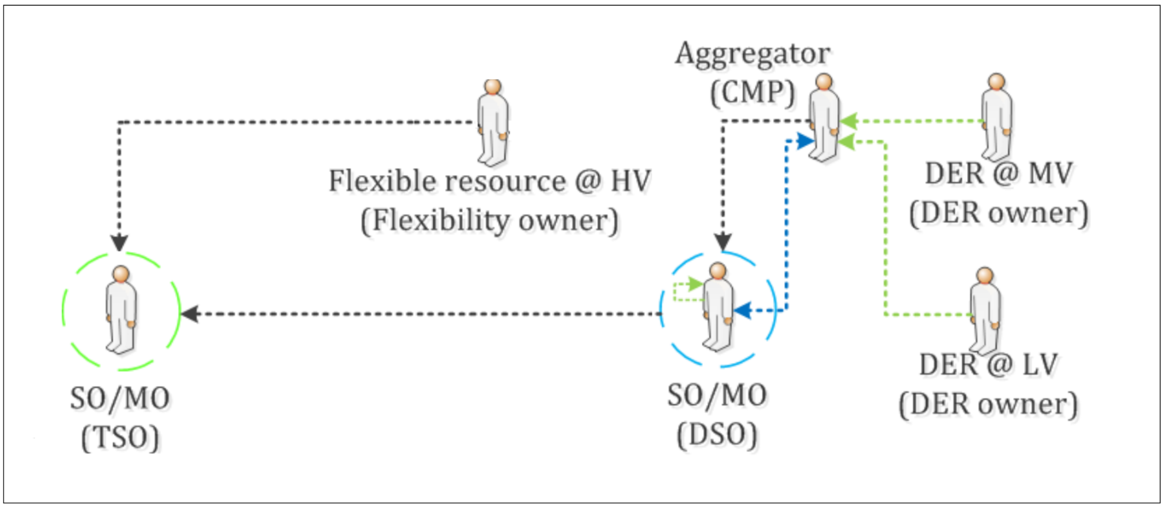


Figure 33: Local AS market, the DSO is involved in the balancing process and DG procurement [74]

5.3.3 Shared balancing and responsibility Market Model

In this market model, **Figure 34**, same as in the previous model the "balancing" responsibility goes to the DSO. The DSO will need to respect the predefined net injection or withdrawn schedule defined a-priori, for instance by using historical data at of the TSO-DSO interconnection point. The idea is to create for each DSO a so-called balancing area and a nomination of a BRP. The TSO is the party responsible to operate the entire AS market, but limited to the activate resources connected at transmission grid; has no access to the resources at distribution level. The DSO instead operates the local flexibility market (collects the resources connected to his own grid) and is also responsible to keep the grid balanced respecting the predefined schedule, in a similar way as BRPs currently operate [79].

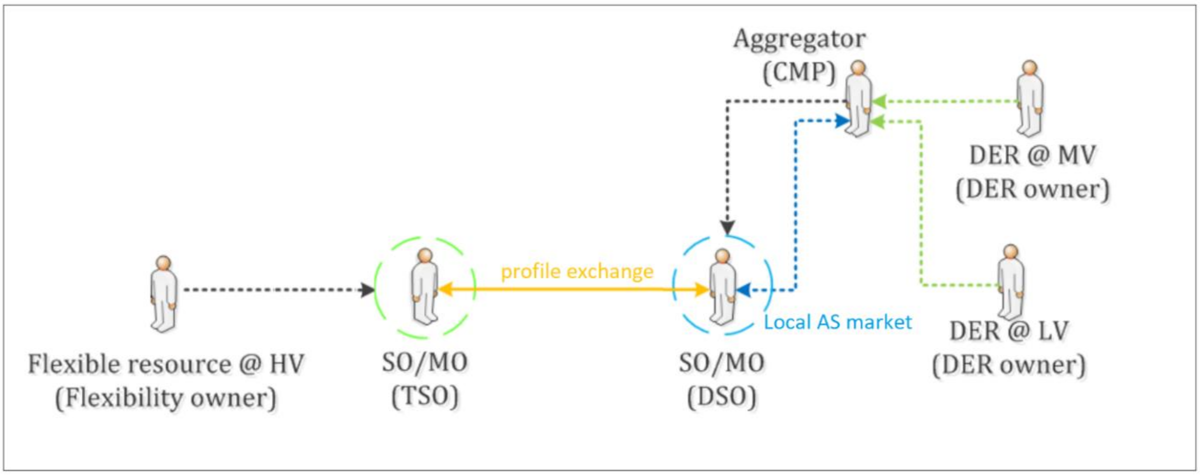


Figure 34: Shared balancing responsibly model; TSO and DSO are both jointly for balancing the system [80]

5.3.4 A common TSO-DSO Market Model

The "common" TSO-DSO ancillary service market model has a common flexibility market shared between the system operators. The DSO and the TSO are both responsible for the operation of the market. In the common market all resources (those connected at transmission and also distribution level) are used with the main goal to reduce and minimized the overall procurement costs. This idea was promoted by the position paper of CEER [36], which emphasized that is essential to create and incentivize the entire outcome, rather than focusing only the costs of each party in isolation. In any case, in the common market all the (grid) constraints need to be to be included. Two different approaches were defined in [80] to optimize this process.

In summary, we can say that the TSO and the DSO are jointly responsible for the market and this model can be seen as an extension of the centralized market model and the local AS market model with the sole difference that the all resources and grid constraints are included in the common market as depicted in violet in **Figure 35**.

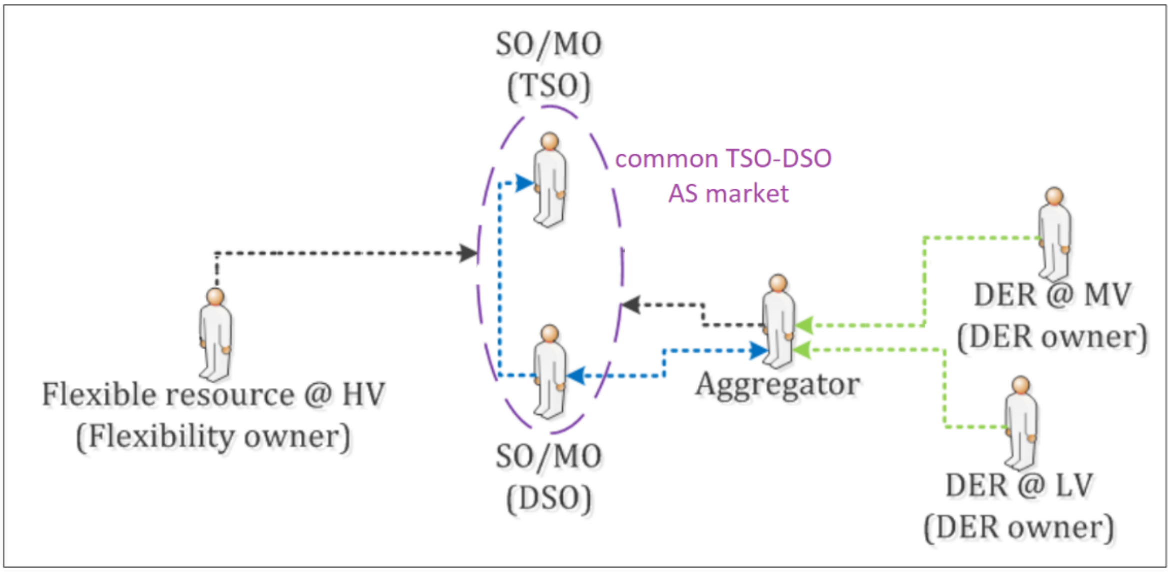


Figure 35: Common TSO – DSO market, there is only one market in which all resources are traded and both SO are responsible for systems security [80]

5.4 Summary on Coordination between TSO and DSO

In **Figure 36** a summary of all coordination schemes is provided. Depending on the coordination, the DSO may assume more responsibility in supporting the TSO in congestion or balancing purposes. In the centralized market, there is no engagement of the DSO and no local market is present. This market scheme is most likely to be present by 2030, due to close similarity to the present centralized market scheme and the regulatory framework does not require a lot of revision. In the Local AS market scheme and Common TSO - DSO AS scheme a local market is present and the DSOs engagement for balancing/congestion purposes is much higher. In fact, priority is given to the DSO.

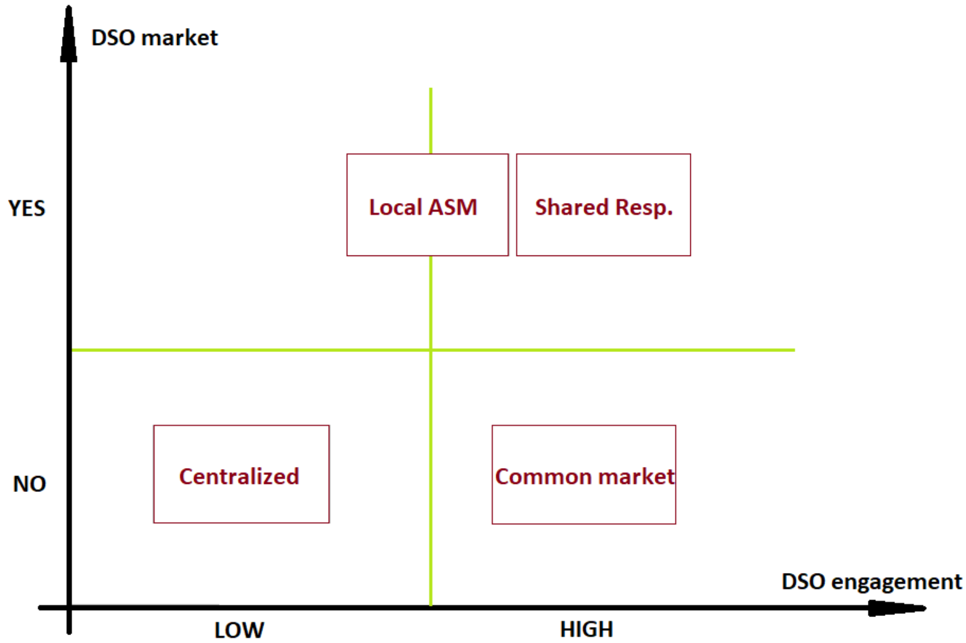


Figure 36: Summary of coordination schemes to show the engagement of the DSO and the presence of a local market for flexibility (Source: own representation)

So the TSO and DSO are jointly responsibly for the balancing of the entire system, either together or partial, still being independent stakeholders.

In the local ASM, the aggregation at DSO level and the procurement at DSO level is allowed while also the procurement at TSO level is allowed. Bids out of merit order in the local AS market can be bidded in the centralized market and they guarantee no violation of DSO grid constraints. The local ASM and bidding process is further analyzed being the scheme affecting the market, operation and regulatory framework the most.

5.5 Local Services Market: DSO - TSO procurement

For a local AS market, the primary objective should be to create a competitive and fair situation for all parties. In particular it should be prevented the creation of a single market power which would be lead to monopoly rather than competition. The competitive conditions should be established a priori and the market should be operated by an independent operator [56]. In this context the DSO emerges which could be seen a BRP, with a portfolio of assets, for his own grid as shown in **Figure 37**. Currently in Europe the zonal model is the most used approach, by switching to a local balancing approach higher balancing costs are induced[16]. The idea to switch to the nodal approach (LMP) emerges. However, because of the aforementioned reasons a local market might increase operational efficiency as well as economical due to a decentralized market clearing process. So, the key issue is to find a compromise between local congestion management, efficiency and fair competition[17].

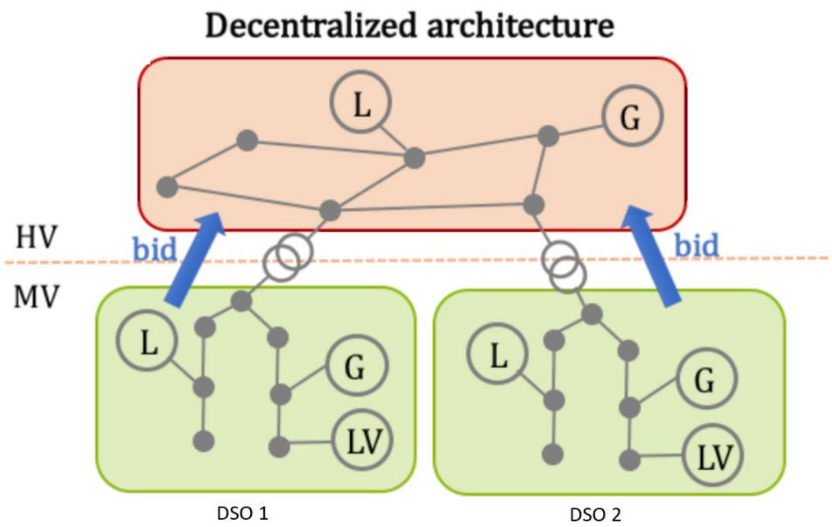


Figure 37: Each DSO is responsible to operate a local market, remaining bid may be sold to the centralized AS market [36]

In **Figure 38** the timeline of each market actor is shown. For this specific market scheme the central market runs in parallel with the local DSO market. The DSO clears the local ASM close to real-time considering all security and grid constraints. A close to real time operation is needed because due to the high amount of RES high volatility sudden congestion may appear. The remaining bid can still be offered to the centralized ASM market, allowing the TSO to access to resources placed at DSO level. Also, in **Figure 38** the importance of aggregators holding a portfolio of small-scale resources can be seen. Furthermore, the aggregator funding as interface between end-user and SO receives and sends activation signals [81].

[16] The overall social welfare is always maximized when no constrains are active

[17] To give fair access to all actors

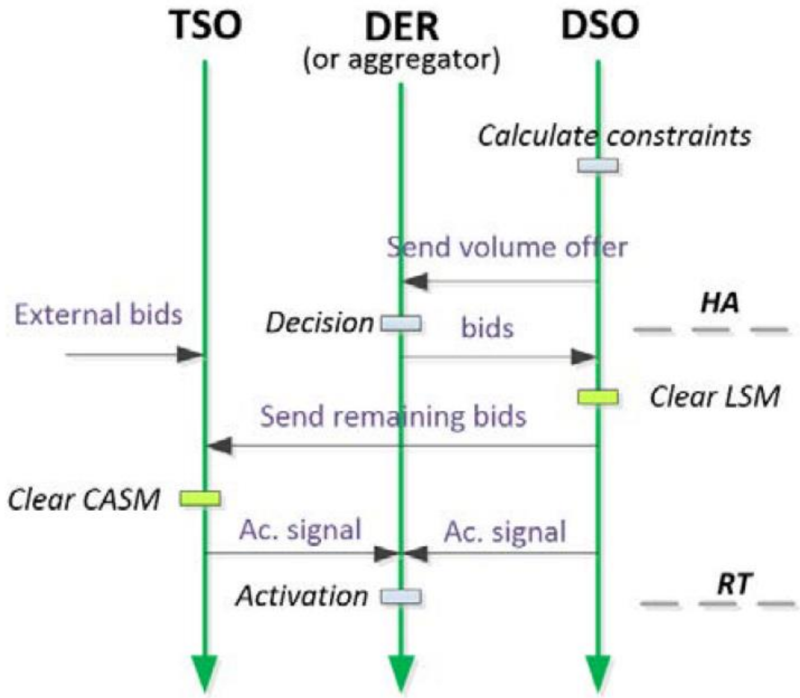


Figure 38: Timeline for biding and activation of resources for a local market model [81]

5.5.1 Optimization Problem Formulation

The optimization problem aims to minimize the overall DSO's cost of acquiring flexibility for congestion management. Two types of services are needed to solve congestion namely UP and DOWN flexibility. As previously mentioned the DSO acts as market operator and thus responsible for the clearing considering all constraints which generally is done by running an Optimal Power Flow (OPF). According to [9], the objective function can be formulated as:

$$min_{P_{n,t}^{UP/DOWN}} \sum_{t=1}^{24} \sum_{n=1}^{N} P_{n,t}^{UP/DOWN} \lambda_{n,t}^{UP/DOWN}$$

Subject to grid and line constraints. The DSO must avoid to activate flexibility bids that are technically infeasible considering power flow equations and the already mentioned rebound effect. In [9], two approaches are introduced, the deterministic and the probabilistic approach, the latter represents a much closer model to reality, since demand uncertainty and forecasting errors are common problems in electricity markets.

In any case in the case study in chapter 7, for the sake of simplicity not the social welfare maximization was use but rather the objective to minimize the activation cost as show in **Figure 39**.

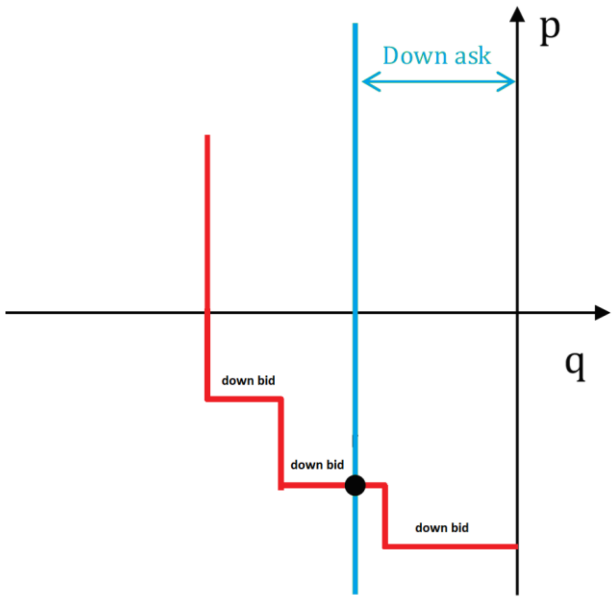


Figure 39: Market clearing by minimizing the cost of activation [own representation]

5.5.2 DSO's Cost for Flexibility Activations

The DSO's summed cost (C_{tot}) for flexibility is composed of the cost of flexible capacity activated during the day ahead period (DA) for the most likely congestions events (C_{DA}), the cost to reserve capacity for the with medium probabilities of congestion during the real time period (C_{RtU}) and finally the activation cost of flexibility for sudden and unforeseen congestion events (C_{RT}) [9].

$$C_{tot} = C_{DA} + C_{RtU} + C_{RT}$$

5.6 Regulatory Framework to foster TSO/DSO interaction

Regulatory arrangements need to be in place in order to create the framework and the right price signals and of fundamental importance to create a competitive market at DSO level. With the correct remuneration the development in those schemes will be promoted [82]. Moreover, the regulatory framework could hinder or foster cooperation and thus, given the rapidly changing context, a proactive regulation is suggested also in [83], avoiding strong regulatory measurements which could not fit for the future scenarios. As mentioned in chapter 4.1 system organizations varies among European countries, therefore it is up to each Member State to choose the most effective coordination scheme and related market models. In any case, it should be taken into account that the balancing system will be harmonized over Europe especially cross-border interaction is foreseen. Finally, the most efficient and best coordination scheme is not yet deployed and thus a profound CBA and pilot projects for each specific case is needed considering the mentioned uncertainties [46] [82]

The recent report of CEER on the flexibility use at Distribution level [82] the revision of NRA is suggested and stating:

"...the greater the responsibilities given to the DSOs, and the more DSOs are involved in non-core activities, the greater the need for regulatory control or effective unbundling"

With the network code for Electricity Balancing (EB) an integrated and competitive European balancing market is pushed forward. Especially common rules for balancing including reserves procurement and activation and the cross-border exchange of balancing services [84]. TSO-DSO cooperation is not explicitly addressed in those NCs.

In summary for the development of new market structures aspects such as country characteristics (national regulation, state of grid), ICT requirements (existing and expected evolution) or ongoing market and NCs developments, have to be considered.

6 Information and Communication Technologies

6.1 Introduction

The ever-increasing penetration of DER the management and operation is crucial. The big challenge is not only to coordinate the operation of thousands different devices or subsystems, but also to manage the increase amount of new services and data from the commercial parties from and to the aggregator as shown in **Figure 40**.

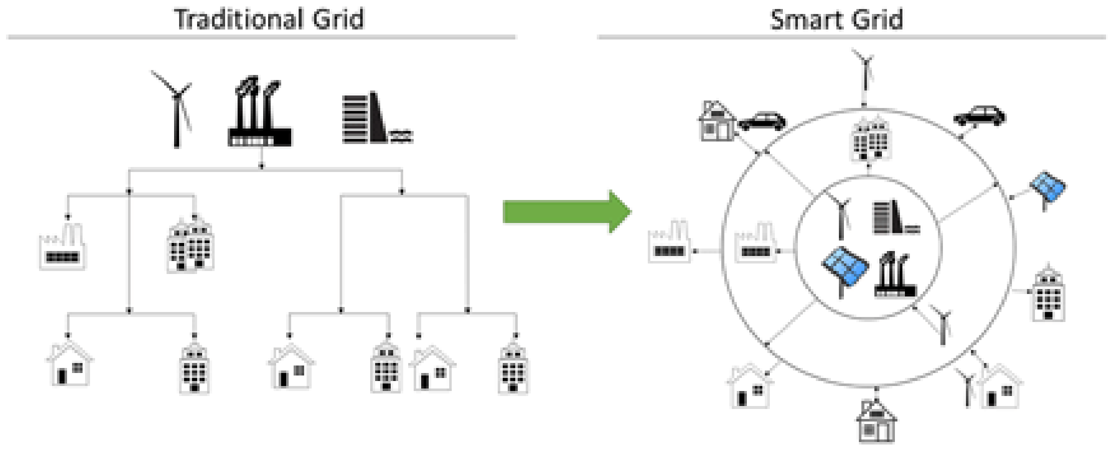


Figure 40: With an increased DG information and communication among actor in necessary

Information and Communication Technologies play an important role for the future grid structure. Indeed, the concept of Smart Grids relies significantly on the interaction between the energy sector, business actors and the ICT infrastructure.

In particular for TSO/DSO interaction and the activation of AS in real time ICTs are of fundamental importance. For instance, the information and data exchange between market actors and for the activation of resources in real time, to ensure power quality and full operability in the grid which can be monitored from a central point. In summary, the ICT architecture needs to be able [8]:

- to fulfil all monitoring criteria at DSO level
- to be able to guarantee observability (TSO and DSO observability)
- to control all DG including flexible demand response programs
- to permit a full nondiscriminatory participation of DERs

For the procurement of ancillary services on a market-based approach clear requirements must be defined such as time limits or data amount (information flow) is defined. Thus, latency has to be considered when designing an ICT infrastructure. It is suggested to have an always-on IP (for security and reliability) connection for an efficient, reliable and secure between distribution grid and the SO control center [85].

Furthermore, aspects such as capital (CAPEX) and operational expenditures (OPEX), coverage, interoperability or bandwidth should be considered as well. The former two are important aspects when considering new investments e.g. grid reinforcement versus demand response programs. In chapter 7 an estimation of required ICT costs can be seen.

The main categories and assets for automation in the distribution grid are described in the annex A1. An overview and an important scheme for interoperability in the grid structure, defined in the Smart Grid Architecture Model (SGAM) , is discussed more in detail in the following section.

6.2 The Smart Grid Architecture

The Smart Grid Architecture Model depicted in **Figure 41**, offers a support to implement smart grids and provides an standardized architectural approach with the main aim to enhance and leverage interoperability among all participating parties.

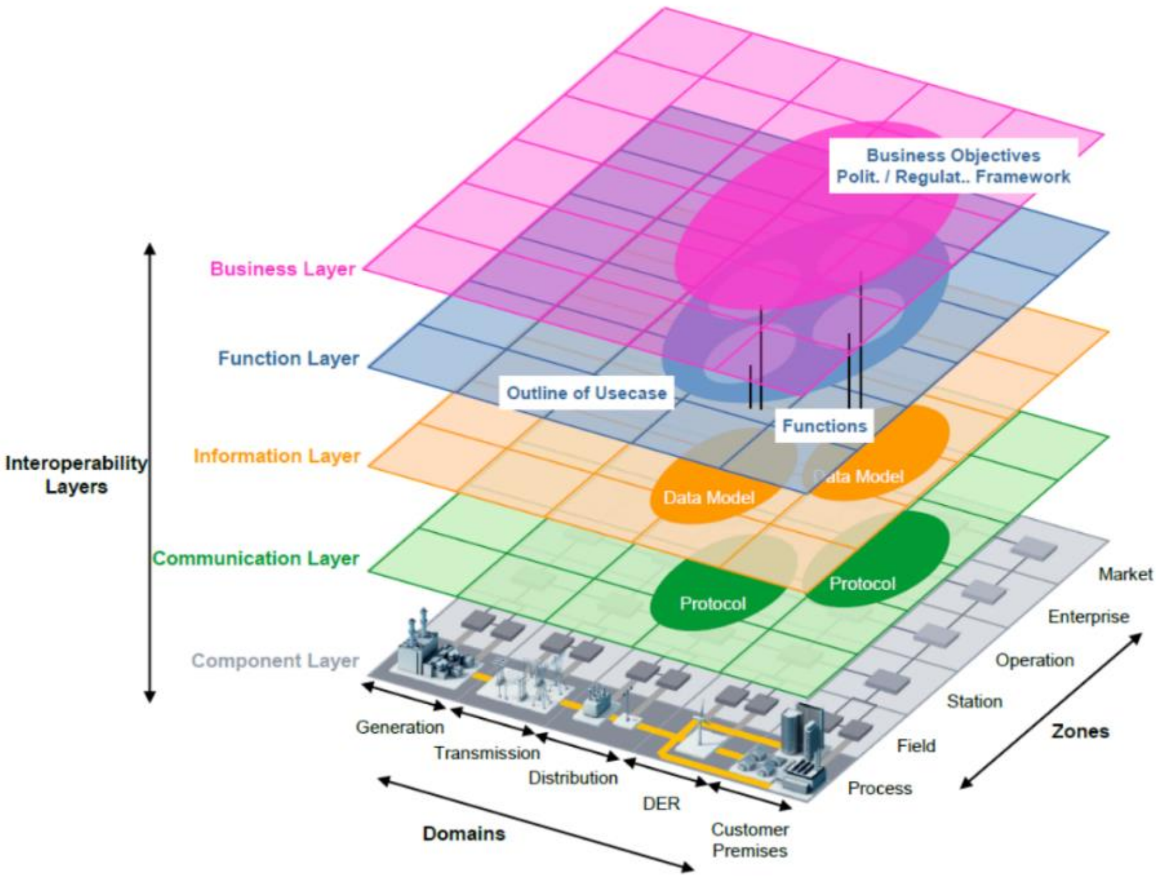


Figure 41: Smart Grid Architecture Model to standardize and foster interoperability between all stakeholders [86]

It is a three-dimensional framework divided in zones, domains on five layers namely [86]:

• Business Layer	In the business layer all exchanges on information are represented. It can be used to map regulatory and economic structures or policies.
• Function Layer	In the function layer all relationships for functions and services and their relationships are represented
• Information Layer	This layer is used to describe the information used and exchanged between functions, services or components
• Communication Layer	In the communication layer, communication protocols and mechanisms for the interoperable exchange is described.
• Component Layer	In the component layer the physical distribution of all actors and their relationship is represented which includes power system application and equipment.

As seen in **Figure 42** in the component domain the traditional grid structure is depicted: generation, transmission, distribution, distributed generation and final customers. It is a useful tool to visualize the design and interaction between stakeholders. In [87] in particular for the TSO/DSO data exchange, the following issues for an efficient data exchange should be considered:

- Purpose of data exchange
- Frequency of data exchange
- Type and timeframe of exchanged information

Moreover, from an ICT point of view it is practical to design the needs for security, latency and interoperability [86]. Especially interoperability and the use of one agreed methodology is an important issue for the efficient use of smart grids. Concerning interoperability ICT standards and regulation should prospect for the implementation at European level based on European standards to reach the economy of scale effect [88].

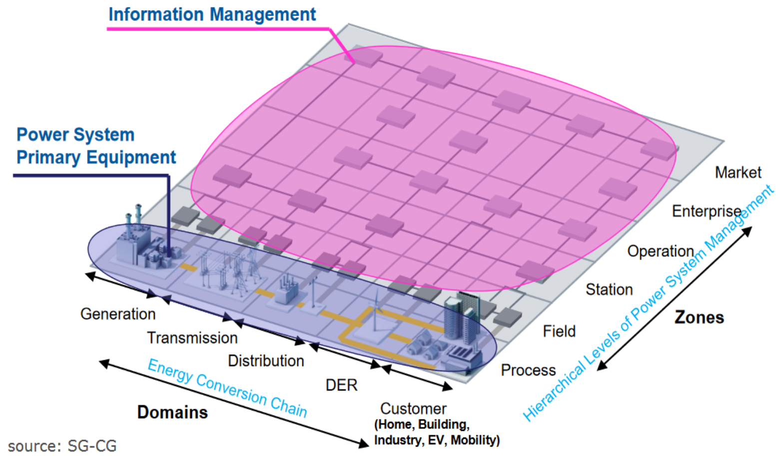


Figure 42: Component Layer, and the proper communication towards the markets and other stakeholders

Generally, and as previously discussed, referring to aggregation and market clearing different phases ICT requirements are subdivided in different phases, namely prequalification, procurement, activation/ operation and settlement. For the scope of this thesis only the operational phase is considered, due to special requirements for activation and monitoring in real time, it can be considered the most critical phase what concerns ICT infrastructure.

Communication Requirements

ENTSO-E library EDI [89] contains documents and standards-sheets for the implementation and harmonization of data interchange among European TSOs and different stakholders. For the market operation CIM (Common Information Model) standards can be used while for the operation of DERs the communication is based on the IEC-61850 stadard, which are both described further in the following chapters. Furthermore, in the "System Operation Guidelines" [90] of the European Commission the information exchange requirements between actors are addressed.

A key technology in future smart grids is the communication via Wide Area Network (WAN), the communication is mainly based on Internet Protocol (IP) which is the basis for the communication among actors. For the local application the current Power to Line Communication PLC, currently used for Smart Meters, may be used to collect data and information from end costumers [89].

6.3 General Overview on the main ICT Standards [88]

In this section a brief overview on them main ICT standards is given. For the different utilities and requirements other standards do apply. Partially those standards come from the telecommunications sector ITU (ENTSI) and are listed below [87]. Two important standards namely IEC 61850 and IEC 60870 -5 are described more in detail in the following sections.

- IEC 61850: Power Utility Automation (mainly used in substations)
- IEC/TR 62357: Service Oriented Architecture (SOA)
- IEC 62056: Data exchange for meter reading, tariff and load control (e.g. smart metering)
- IEC 62351: Security standard
- IEC 61970: Common Information Model (CIM) / Energy Management
- IEC 61968: Common Information Model (CIM) / Distribution Management

IEC 61850 standard

This norm is the international standard which defines communication protocols for power systems and in particular substations. It is not just the definition of communication protocols in substations, but rather, a 10-part set of standards addressing the main layers in the OSI model. All the communication and data exchange within the substation is normally done via IEC-61850 using GOOSE messages or MMS. The communication between TSO/DSO for smart SCADA system is performed via IEC 60870-5-104. All those protocols run over a TCP/IP networks using local LANs via high speed Ethernet [85]. The objective of all standards to control, observe and monitor energy resources in compliance with the requirements established by the NC [84].

IEC 60870-5-104 standard

A common and most used standard for the automation of systems, in particular to control power system devices remotely e.g. from the SO control room, is the IEC 60870-5-104 published in 1990 which defines the sending protocols for data transmission. This standard has six parts addressing protocols and equipment. As previously mentioned, many SCADA system use this protocol for a secure and reliable communication between SO to monitor the substation in the field. In this context in the future grid, it is expected that most of the SO will need to further invest especially at distribution level, for a higher degree of automation, observability and a communication between commercial parties such as aggregators.

6.4 ICTs for Decentralized Markets

For the upgrade from a central organized market to a decentralized market (local ASM scheme) with a high DSO engagement as described in chapter 5.3 a high information (data) exchange between all actors is required. In **Figure 43** the blue lines show the information exchange between stakeholders. In this scheme, unlike the centralized scheme the local ASM is in place. Which requires the operation of a local market and a constant communication with other actors such as TSO and aggregators.

The operation and communication between aggregator and DSO (local AS market) must be guaranteed. Even though the market might not run in real time, it still should be synchronized in with the TSO. For instance, the TSO market clearing could take place every 5 minutes, while local ASM takes place every hour to solve congestion. In any case, especially for the operational phase a high data exchange is required. Moreover, the TSO and DSO sent dispatch orders to the activated the reserves. In most European countries the digitalization at DSO level, as discussed in chapter 4.1, is not or seldom present, thus making it difficult and costly for most DSOs. Especially the operation of the local market requires high costs impossible to sustain for smaller DSOs.

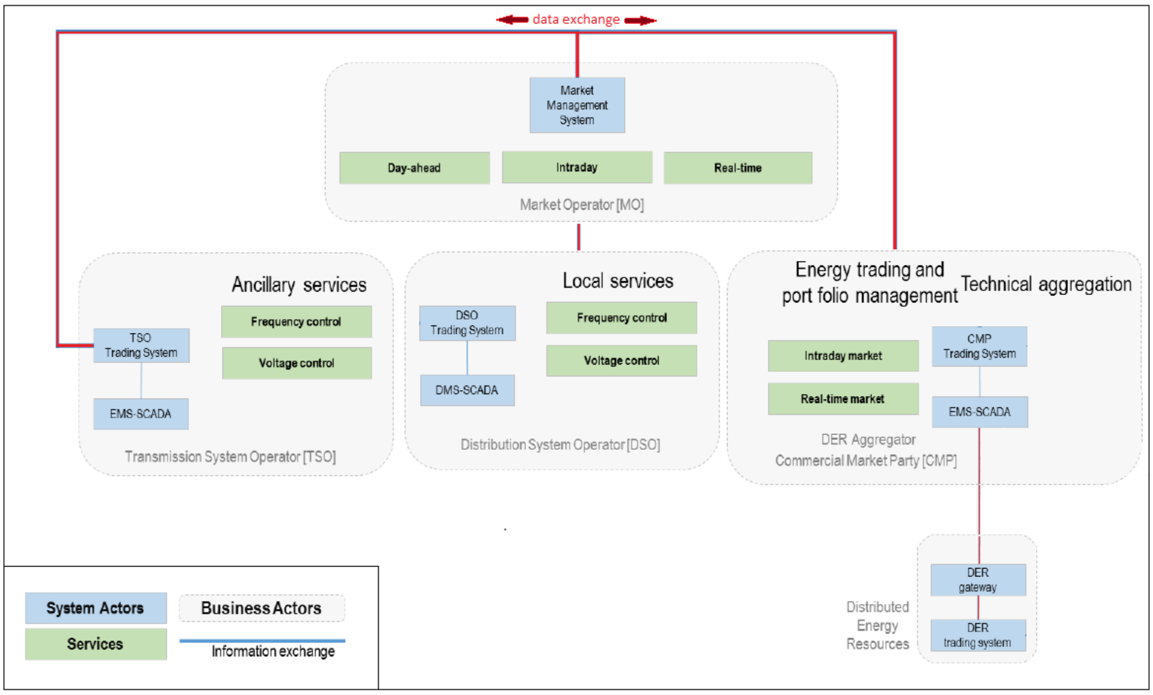


Figure 43: Information exchange between actors is represented with the blue connecting lines [91]

In the current energy market structure, which already rely a lot on ICTs for any kind of information exchange. In particular at TSO level a high degree of secure ICTs are already present (needed for state estimation). This is mandatory in order to avoid blackouts caused by lack of information or communication. It is also worth to mention, that the aggregator or any third party has to provide the necessary information for a secure operation while at the same time the SO should avoid to share commercially sensitive information which could lead to gaming and thus to an abuse of market power [46]. In other words, the aggregator should always provide the correct information to the SO which monitors the entire grid operation while protecting the sensitive data e.g. customers data [91] [92].This may be seen as one of the most challenging aspects when designing ICT infrastructure.

6.4.1 Operation and Activation of DERs

In the operational which involves the activation of resources in real time, is generally carried out by an Energy Manager System (EMS). The detail specifications for the operation of DERs is also defined in the standards of CIM and the standardized interface is addressed in IEC 61850.

In the operational phase, the SO sends dispatch orders to aggregators which in turn are responsible to activate their resources via EMS. It is worth to mention, that the final customer is not involved or notified by any of this action. It is the sole responsibility of the aggregators to contract and optimize energy resources activation. In **Figure 44** this process is depicted, again the TSO/DSO sends a co-called dispatch order to the aggregator, which activates and defines an injection profile, which is then activated by a local SCADA, generally placed in the substations. The local SCADA collects data and monitors the grid status in real time [85].

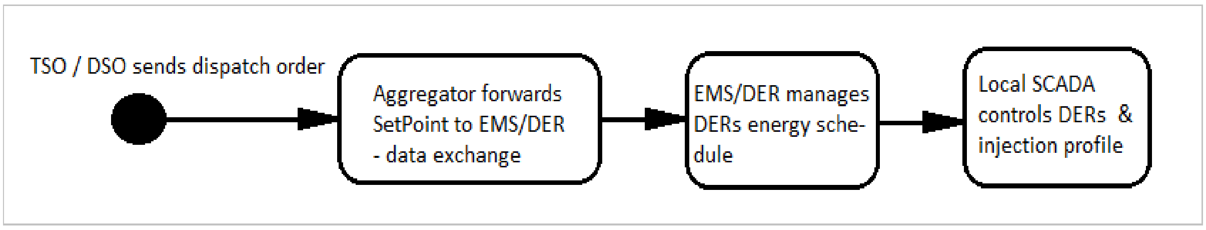


Figure 44: Activation of DER resources, SO sent dispatch orders on which DERs react [91]

To constantly monitor and operate the electrical grid the SCADA system is used. Most SCADA system of DSOs monitor and get only the most relevant information from devices and sensors in the field. Generally, primary substations have a local SCADA and the communication to the control center is performed via IEC 60870-5-104 protocol [91]. There is no direct communication to the TSO, only few data of the most important HV components is sent. It's important to mention that currently in the opposite direction, from the TSO to DSO, there is almost no communication at all. The communication to secondary substations is low due to economic reasons and if present, generally also performed using IEC 61850 protocols [85]. In the future grid the TSO should receive the most relevant information such as load forecast or forecast connected DG.

6.4.2 Smart Metering

With the roll out of smart meter many DSOs are able to improve many aspects such as billing, contracts etc. Even though most recent Smart Meters provide two-communication [91], they cannot activate resources nor provide support for distributed AS due to the missing capability of quick response (15 minutes). The collected data is an efficient tool to forecast loads and demand, state estimation and to improve grid efficiency. In this context there should be a data exchange between metering company, the DSOs[18] and aggregators. For aggregators this might be an efficient tool to further optimize products. It should be noted at this stage, that security aspects, cyber security or privacy issues, create complexity and thus regulation or partial regulation of metering companies or aggregators should be in place. In the following chapter the main security aspects are described. In **Figure 45** the development of the smart metering roll out in Austria is shows, the roll out will be completed by 2022 according to [93].

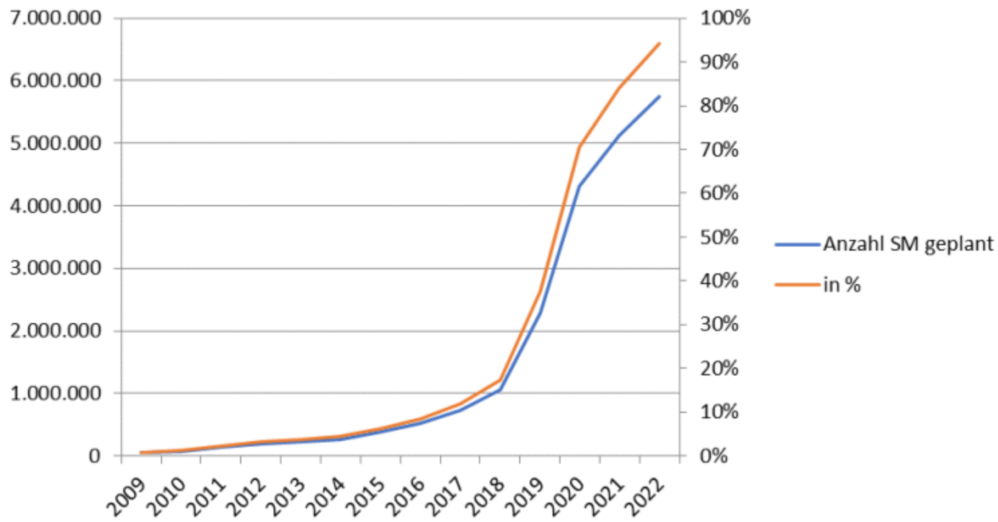


Figure 45: Smart Meter Entwicklung in Österreich bis 2022 [93]

7. Security Aspects

The communication between actors for security is based on IEC 62351, which provides technical security measures for IT-security and cyber security in digital power grids. More in detail it is addressing the protection from external attacks of telecontrol and data exchange in real time. As previously mentioned, security in an important aspect to consider for the implementation of smart grids, especially at the edge of the grid as pointed out in [91]. Normally, end-costumers, DER owner, or smaller DSOs don't not have the competence/expertise or the financial resources to install and operate secure ICTs, which may affect the entire grid security. Also, in this aspect the NRAs should create and incentivize the right regulatory framework [94]. It is currently not defined which actor should own the data, the

[18] In many countries the DSO is the metering company

aggregator could act as interface, owning data from customers and interacting with markets or with the SOs.

6.5 Digitalization in the Austrian Grid

Digitalization in the Austrian grid is far evolved in particular at high voltage level. At medium voltage not all areas are fully digitalized and at low voltage there almost none. With the roll out of smart meters by the end of 2022 many areas also at LV will be digitalized [92]. However as previously mentioned a complete automation especially at MV in areas (highlighted in red in **Figure 46**) such as state estimation, real time monitoring and operation need to be in place [92]. For the aggregation of resources and the market operation a complex IT infrastructure and communication is required, which is not considered in able. To fully integrate resources at DSO level regardless the coordination schemes the digitalization at MV and LV need to further evolve, especially to meet the requirements described in chapter 6, most ICTs currently in place are not designed for a decentralized energy system. The regulator should encourage and incentivize the involved parties and partially regulated it.

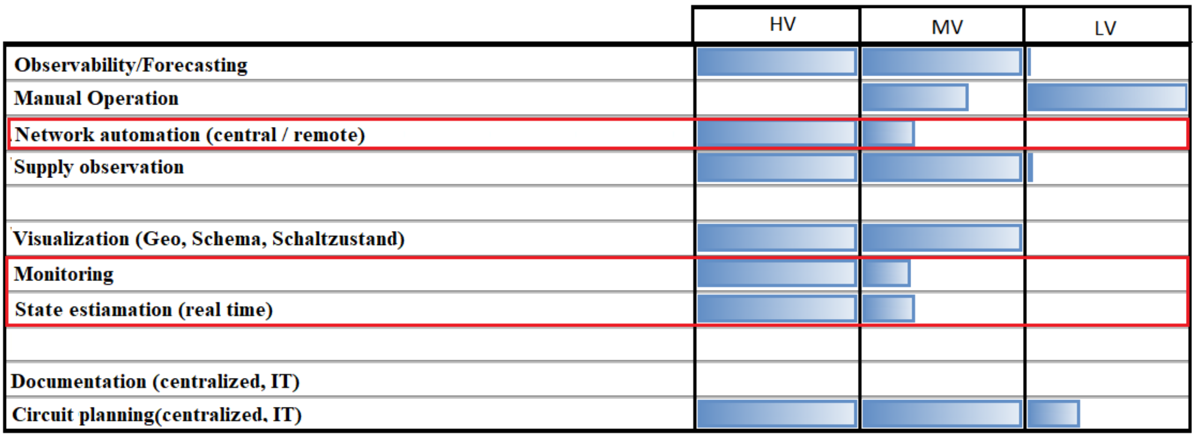


Figure 46: Digitalization in the Austrian grid for HV, MV and LV [92]

6.6 Existing Telecommunication Technology and 5G

The most recent evolution in the telecommunication sector is the LTE/4G technology, with the main goal to speed up broadband services. Even though there was a huge improvement in the 4G technology, the LTE/4G will not be enough to fulfill the future requirements and the commutation between devices.

The 5G technology was launched already in early 2019 and it is expected that it will enter in many sectors especially the industrial such as Automotive, Health or Energy, focusing on the communication between devices and a latency below *5ms* [95]. It has a huge increase of capacity and massive device connectivity as well as a far lower CAPEX and OPEX. For the energy sector this evolvement is very important as it may improve the performance for automation and a reduction in investment costs. The main targets and advantages are summarized in **Table 4**.

1000x mobile data	0,75 Tb/s
100x user data rate	1 Gb/s
1/10x in energy consumption	
1/5x in the end to end latency	< 5ms
User data rate	>50 Mb/s
Capable of IoT	>1 trillion

Table 4: Main advantages and capabilities of the 5G technology (data from [95])

7 Cost and Benefit analysis

7.1 ICTs Cost Estimates

Generally, ICTs are grafted to high installation and operational cost. To estimate costs for ICT it is really difficult due to uncertainties on prices for technology, moreover as mentioned there is not one single approach on how the electrical market structure will evolve by 2030, thus this estimate is based solely upon literature review in [96], [97], [98] for the implementation the of local market. For the implementation of a decentralized market with a high involvement of the DSO, which as previously stated requires platforms for the aggregation and the real time markets which increases the IT costs. Also, for the aggregator itself high cost apply for complex IT and communication systems, which are not included in this estimation. The cost estimates differ from DSOs and grid size. According to [97], the cost can be scaled up easily depending on grid and component size.

In [97] is expecting that the centralized model of chapter 5.3 with a higher engagement of the DSO will be in place in the coming years and thus a higher level of ICT will be in place in a natural way, which decreases the cost for this estimation. It is useful to differentiate between the main investment and operational cost, in other words between CAPEX and OPEX. In **Table 5** the main costs drivers (highlighted in red) are shown, many axillary equipment such as smart sensors are not included. Also, in this estimation cost for smart metering are not included, which as discussed in chapter 6.4 aren't necessarily needed for the implementation of local ASM, moreover according to [10] in Europe most countries will be equipped with smart meters. Based on [91] the operational cost can be assumed to be proportional to capital costs and roundabout 20 % of CAPEX.

	Investment in IT
	Investment in communication
CAPEX	*Investment at transmission level*
	Investment at distribution level
	• *Implementation of local market*
	IT maintenance costs
	Network management
OPEX	*Replacement costs*
	Operational costs at TSO level
	Operation costs at DSO level

Table 5: Main costs for ICTs divided in CAPEX and OPEX (data from [99] and [97])

In the literature review the Austria authority does not provide IT system costs benchmarks and thus the cost estimation of the Finnish NRA [99] is used, but still those estimates can be used as benchmark for other European countries. **Table 6** show the cost estimates in a timeframe of 10 years and can be found in [100].

Infrastructure	Supervisory control & data acquisition SCADA	
	System	€ 301 300
	per substation	€ 9 800
	per remotly controllable secondary SB	€ 2 200
	Distribution Management System DMS	
	System	€ 21 900
	per substation	€ 1 100
	per remotly controllable secondary SB	€ 550
	Telecommunication equipment	
	Communication network	€ 89 800
	per substation	€ 5 500
Information System	Network Information System	
	System	€ 112 500
	Costumer Information System	
	System	€ 75 500
	Energy metering for settlement & billing in DSO grid	
	Meter, remotly read, residential	€ 200
	Meter, remotly read, industrial	€ 570

Table 6: Cost for IT system by the Finnish Authority [99]

To upgrade the scheme from a centralized towards a decentralized with the operation of a Local AS Market run by the DSO the cost is estimated around 11,6 M€ according to [97].Also, estimation on cost of the three different schemes is provided. As shown in **Figure 47** for both schemes high ICT costs apply, especially for local AS market scheme which already suggests that a decentralization might not be profitable in all cases.

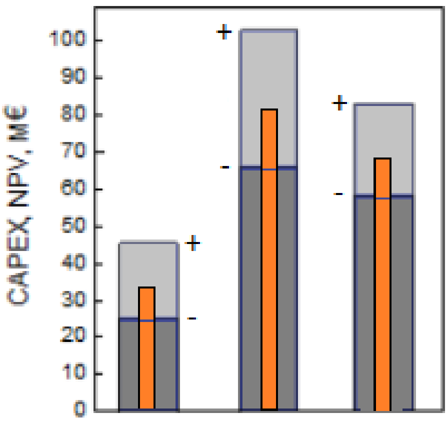


Figure 47: Cost estimation of three coordination schemes [91]

Considering calculations from and [96] for one substation and one feeder as depicted in the case study in **Figure 49** the cost can be estimated to be around 60’000. It includes the main costs for the parameters highlighted in red in **Table 5**. According to [98] the cost for the for one single household or industry is about 5 times higher than the cost for the actual smart meter roll out

7.2 Grid Investments

With the increasing electricity demand, in order to avoid curtailment, outages and to secure the entire operability, constant investments by system operators in the own grid are required. A common and easy solution is the reinforcement and refurbishment of lines and/or substation in the own grid which as earlier discussed is also incentivized by the NRAs although it may not be the most efficient solution. Changing needs and technological developments makes it hard for SOs to plan the investments years in advance (for example regulatory frameworks for RES, EV or new technologies such as ICTs). Especially investments in the energy sector are long time investments (up to 20 to 40 years). Thus, the investigation on benefits for a more efficient use of the system should be of DSOs interest. Previous studies such as [98] or [9] pointed already out the potential, benefits and cost savings for demand side management in distribution grids. Generally, decisions on project profitability are made based upon the Net Present Value method, in this thesis instead, the Net Present Cost method is used.

7.2.1 Net Present Cost (NPC) Method

The cost comparison based on the guidelines for conducting a cost benefit analysis for Smart Grid Project in [101] is a common method to estimate and make decision for economic benefits in smart grid. As a first step the boundary condition should be defined in order to set parameters for the cost-benefit analysis. The net present value (NPV) method represented in formula (3), is normally used to carry out a CBA.

$$NPV = \sum_{y=0}^{Y} \frac{cash_{in} - cash_{out}}{(1+d)^{y}} \tag{3}$$

In the NPV-method, the cost (cash-out) and benefits (cash-out) is subtracted in every years and discounted yearly. The sum of the total discounted values gives the NPV as shown in **Figure 48**.

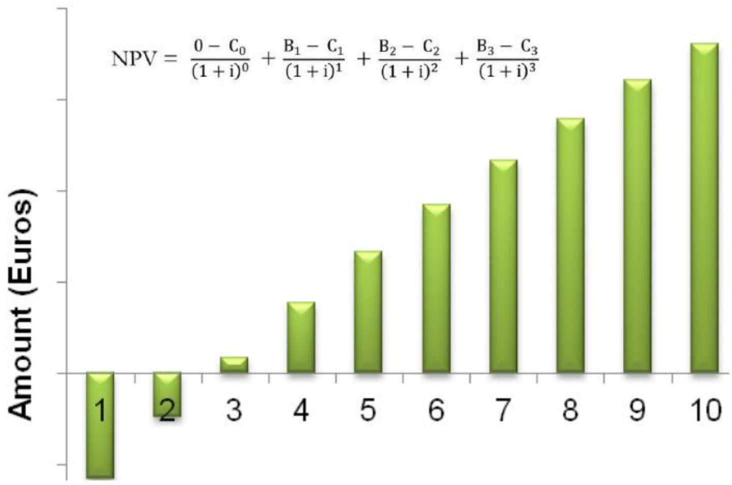


Figure 48: Representation of NPV of the years

Generally, projects with a positive NPV can be seen as profitable. In this case study, social (e,g. CO2 emmision) or other benefits are not considered and thus the NPC (benefits equal to zero) method is used. In this thesis only a cost estimation is provided, in order to analyze possible DSO costs or savings. In order to be able to prove a clear a detailed statement a comprehensive CBA should be carried out identifying all parameters. Here only two possible solution are considered, namely the benefits of a local market (LFM) where flexibility is acquired locally to solve congestion instead of the capital expensive grid reinforcement which is the current state of play for many DSOs.

The main cost drives summarized in **Table 7** are the investments to upgrade the current system with the required ICT infrastructure as discussed in chapter 6 and market operations for a decentralized clearing mechanism and aggregation as explained in chapter 5.

	Costs	**Advantages**
Grid Reinforcement	• Capital Cost for the upgrade • Operational and maintenance costs for new assets	• Reduction of congestion or congestion in peak times • No need for expensive ICT components and infrastructure • Customer are not restricted or penalized for the use of energy in peak times • Avoid dealing with uncertainty or the activation of flexibility products

LFM	• CAPEX for installing and upgrading ICT components • OPEX for maintenance and security • Cost for the activation of flexibility resources • Local market operation	• The investments for grid reinforcement can be postponed • Congestion is managed in an efficient and smart way • Reduction of carbon emission • Consumer become more active which may encourage new business models or aggregators • It encourages the consumers to invest in more renewable sources and has a direct impact on the reduction of carbon emission.

Table 7: Cost and advantages for a local market versus a grid reinforcement

In order to compare two projects of different period length, when using the NPC method the two lifespans has to be comparable. In other words, the considered period should be equal in order to reach an optimal decision. The standard lifetime for distribution grids which is also recognized by the NRA is generally roundabout 40 years [68]. Instead, for ICT technologies or smart components in general 10 to 15 years. To compare to projects with different lifespan another process should be used, namely the computation of the equivalent annual annuity (EAA) in formula (4).

$$EAA_{reinf/LFM} = \frac{d \times NPV}{1-(1+d)^{-n}} \tag{4}$$

The EAA calculates the annual cash flow, the NPV time the depreciation cost over its lifespan. In the same way as for the NPV the project with the highest EAA should be chosen.

7.3 Case Study

In order to give estimate the required amount of flexibility it is worth to simulate a case study. The MV feeder which could represent a realistic scenario was simulated in MATPOWER, a useful Matlab tool to study power flows. It can be found in the annex. In [9], [8] a similar simulation is proposed but the real cost for ICT were assumed and or neglected, furthermore the coordination with the TSO was not considered.

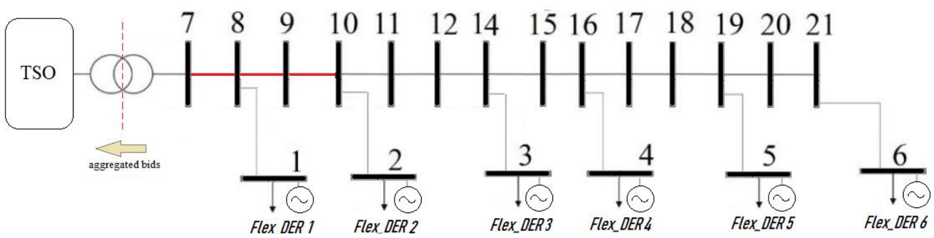


Figure 49: Case study for the simulation of flexibility in a DSO feeder [own representation]

For this case study a 20% of the total amount flexible resources is assumed which are already pooled by the aggregator (*Flex_DER1, Flex_DER2,…Flex_DER6*), the aggregation is not subject of this simulation. Moreover, it was assumed that there is a load increase of 3 % in scenario 1 and 1.5 % scenario 2 as depicted in **Figure 50** and that the lines are congested in peak hours for the reasons previously mentioned in chapter 2.4.4.

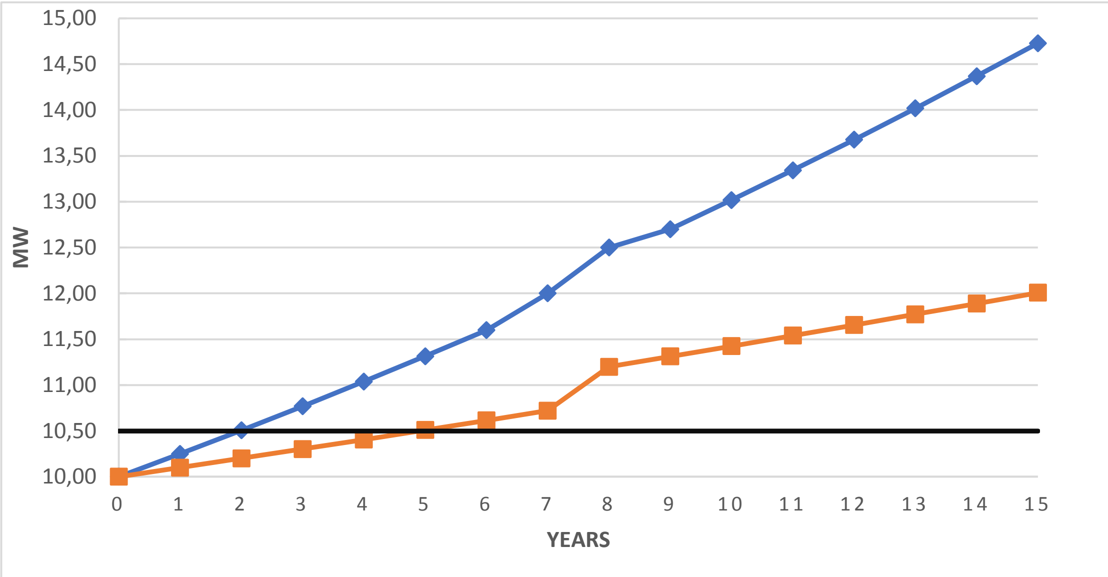


Figure 50: Scenario 1 and to 2 considering a demand growth of 3% and 1,5% respectively

The flexibility simulated as dispatchable load[19] was used to simulate the down reserve which could be provided for instance by load shifting: With an Optimal Power Flow which includes an market clearing process the number of activations per day.

[19] In Matpower this is done via negative generators

7.3.1 Grid Reinforcement

In table the costs according to the regulatory guidelines of ACER (see annex A6) are used to estimate a cost to reinforce and the scheme, which includes the reinforcement of a transformer with respective transformer housing. In scenario one the grid must be reinforced in the first year due to the increase of load demand.

Data: Scenario 1	CAPEX / €	OPEX (annual) / €	Size / km	total CAPEX / €	total OPEX / €
Transformer	9 903,00	460,00	1,50	14 854,50	690,00
Transformer housing	42 627,00	1 000,00	1,50	42 627,00	1 500,00
Overhead cables (km)	70 000,00	800,00	1,50	105 000,00	1 200,00
				162 481,50	3 390,00

Figure 51: CAPEX and OPEX for the scenario 1 considering grid reinforcement

In the second scenario due to a slower load increase the grid is reinforced in a later stage when the max power flow in reached. As can be seen in the total CAPEX does not vary considerably. It is worth to mention that the investment for the grid reinforcement can be postponed for many years.

Data: Scenario 2	CAPEX / €	OPEX (annual) / €	Size / km	total CAPEX / €	total OPEX / €
Transformer	9 903,00	460,00	1,00	9 903,00	460,00
Transformer housing	42 627,00	1 000,00	1,00	42 627,00	1 000,00
Overhead cables (km)	70 000,00	800,00	1,50	105 000,00	1 200,00
				157 530,00	2 660,00

Figure 52: CAPEX and OPEX for the scenario 1 considering grid reinforcement

In the next section the cost for a local flexible market is proposed in order to compare two feasible solutions.

7.3.2 Local flexible Market

The main cost for the DSO, also described in chapter 5.5 is the cost of activation to solve congestion. In Matpower a dynamic load flow was computed to simulate the peak hours and to estimate the activated amount per year. The market clearing, with the objective to minimize the cost of activation was between 70€/MW and 90€/MWh. It is difficult to estimate the clearing price for many years thus an average of 80€/MWh is used to compute the EAA. In diagram the cost increase over the years is shown.

7.4 Effect of Flexibility Penetration upon DSOs Cost

From **Figure 53** it can be seen, that a local market is beneficial only in the long-term scenarios, where lines are congested at peak hours. With an increase of demand as in scenario 1 the grid reinforcement remains the most profitable solution. It is worth to mention, that the cost of activation influences the cost of activation and thus the overall cost for the DSO without considering the depreciation cost. A critical aspect to remember is the market liquidity which affects the market price. At DSO level and especially for DSO with a small number of costumers willing to offers flexibility this can lead to an abuse of market power and thus an increase of costs for the DSO.

From this Cost analysis it can be deducted, that an implementation of a local market does rarely bring benefits to the DSO, especially if smaller one. For DERs owner and aggregators which gain profits if resources are activated more often the solution of a local market is always beneficial while for the grid reinforcement scenario a participation in the centralized market is not always guaranteed due to curtailment for security reasons.

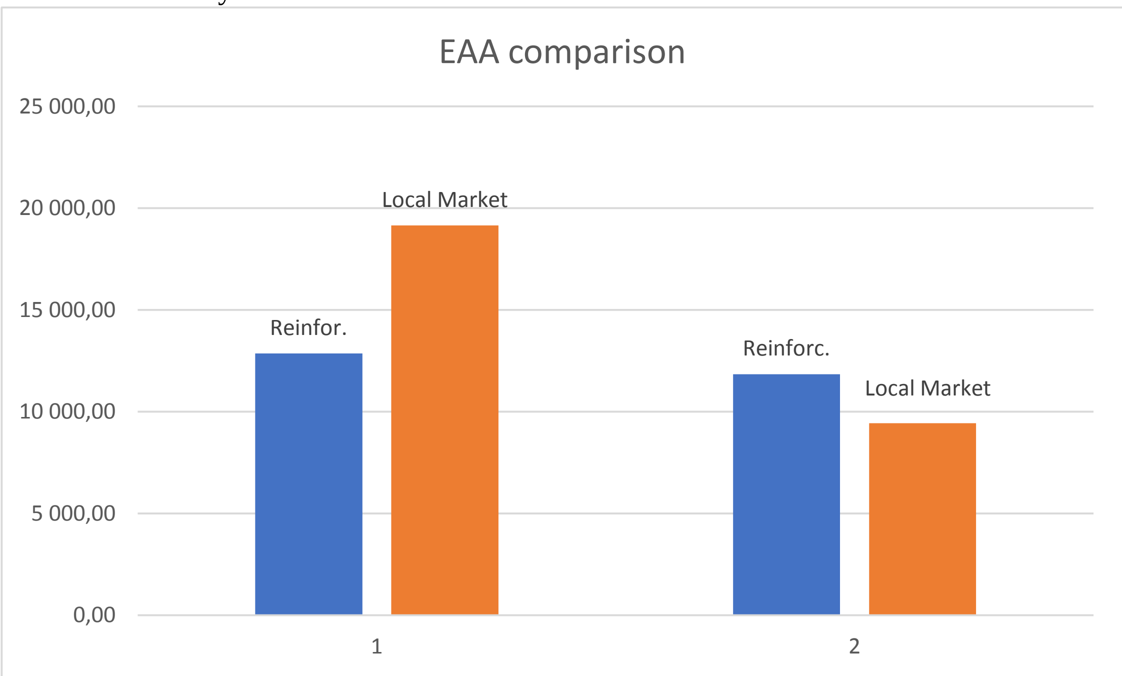


Figure 53: EAA comparison between two scenarios for the different approach LFM or grind reinforcement [Source: own representation]

The DSO should therefore be encouraged by the regulators to allow DERs to offer services to the centralized market even if not beneficial for themselves.

8 Summary and final Discussion

Is the use of DERs for ancillary services necessary?

Due to the ambitious plan for the climate targets in Europe and in particular in Austria with the #mission2030 strategy DERs will increase in volume by 2030 and thus the use of DERs for AS is necessary. It should also be considered that with the electrification of many sectors such as heating of transport the electricity demand will increase. At the same time with a higher share of RES and variable RES the high fluctuations arise which affects the real time balancing between demand and production. Especially the massive electrification of transport such as EVs may cause peak congestion at DSO level.

Traditional programmable generating units won't be available in the future grids and thus small-scale DERs will have to provide their services. As discussed in chapter 3 DERs indeed have a high capability especially battery storage systems. In the future grid structure different scenarios will evolve, in order to integrate the increase of renewables. At the same time the DSO may use those services to solve local congestion by operating an local market to capital intensive grid reinforcement. For an efficient use of those resources on which both operators make use of should not crated conflicts and thus efficient and clear coordination schemes must be in place which was discussed in this thesis.

Is decentralization always the best option?

The decentralization of the energy market will be important in the future grid. It is important to analyze if a decentralization is always the best option. As discussed earlier there are many different approaches. The centralized where the TSO is the only responsible party, a local market model in which the DSO engagement is high and the common scheme in which the responsibility is jointly shared. In any case the decentralization regardless the market model will require costly ICT which has been discussed in this thesis. In chapter 7 the cost estimation to upgrade the scheme to a local market model was shows.. Especially for smaller DSO as it is the case in Austria, those costs are not bearable, in addition 50 % of all customers are still divided in among four DSO. The decentralization of the and operation of local markets the DSO needs to have a considerable size. Moreover, only if the distribution grids are regularly congested a decentralization is worthwhile. In this thesis only the costs for ICT have been investigated, the market efficiency was not subject of this thesis. For small DSO with few flexibility resources the local market won't be able to solve congestion and a local AS market is not an option. On eoption could be for smaller DSO to pool-up in order to share the high ICT, market operational cost and increase the flexible resources. In countries where only few DSO are responsible for most of the costumer this scheme may be more suitable being able to efficiently implement local markets only where needed. If the distribution grid is owned by only one or few DSOs high costs for ICTs are can be sustained easier.

Not to forget that all ICT also have high operational cost of around 20 % of CAPEX. This is due the requirements needed in terms of reliability, security and cybersecurity. The latter will be a problem for the overall security of the grid and thus important that also smaller DSO are able to meet those requirements. Cost and Benefits have to be analyzed carefully as represented in **Figure 54**.

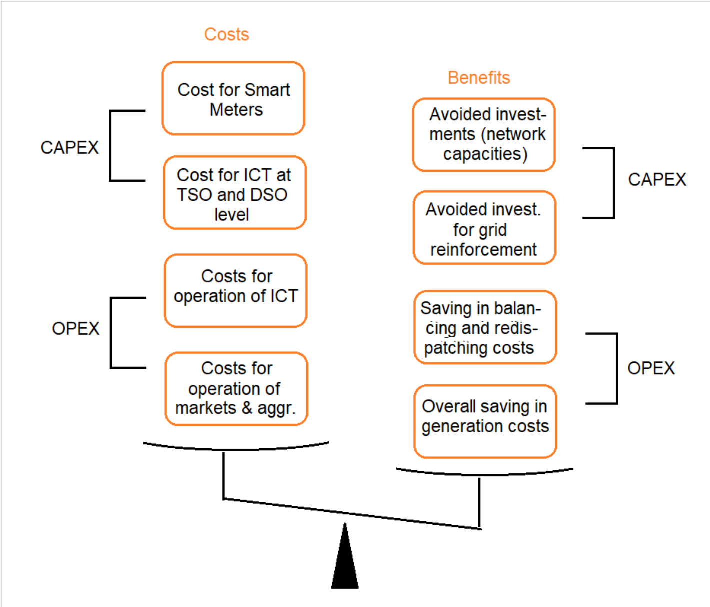


Figure 54: Cost and Benefits for when decentralize electricity markets

[Source: own representation]

The common market structure where the market clearing, and responsibility is shared may be more suitable. In this scheme the TSO and the DSO are jointly responsible for the procurement and activation of the resources. It may be noted that the that clearing and optimization process may be complex. In such a market scheme there is only one clearing and the bids must include many constraints, moreover the clearing process which should be fast may get congested by the number of small bids.

Aggregators Role

Regardless the market scheme the aggregator plays a key role. It was mentioned throughout this thesis that the aggregator not only play an important role to pool the all resources. It can also be seen as the key actor to foster the development of renewables incentivizing and encouraging the participation of end customers. Furthermore, he can be seen as interface between customers, SO and electricity markets. He may also be the interface regarding data and information exchange in terms of privacy and security. To the aggregator many crucial roles applies which could lead to market distortion. The NRAs should observe the development of aggregators and set the right regulatory framework. With a higher engagement the aggregators may no longer be allowed to act as commercial party, but rather as regulated actor, as currently do SO. An important issue in smart grids is the interoperability of all devices according to the standards and requirement listed in chapter 6, and thus a regulation and encouragement by the NRA is required.

ICTs importance for different Market Schemes

As stated in [91] the centralized market schemes is likely to be in place in the coming years due to evolvement of the ICT. Regarding the upgrade to the decentralized scheme of the common market scheme there are not significant differences in terms of investments cost.

Especially with the development of the 5G technology the new possibilities in the energy sector will evolve which is difficult to estimate in the considered period by 2030. Blockchain technology which had its peak times few years ago may help the DSO in the prequalification and/or settlement phase. In the 2030 horizon blockchain technology will not support or foster the integration of small scale DERs for balancing or congestion management.

Benefits for Providers and User of Flexibility

For the provision of flexible services, the main benefits for the providers are the financial compensation. The financial compensation depends from the electricity bill and or the agreed conditions with the aggregator e.g. the reservation of capacity may be rewarded too. Thus, the benefits for the costumers depend also from the services they provide such as load shifting or shedding. In order to increase those benefits the number of activations should be increased. With an efficient and coordinated scheme the flexibility services can be offered to the DSO to solve local congestion and once the DSO clears the market the remaining bids can be offered in a centralized market and therefore the amount of activations may increase. Furthermore, in a coordinated way small-scale DERs can offer also services for balancing purpose. In such a way the end-costumer are directly involved a marked based process, even if not directly, but only via aggregator. The aggregator play an important role, being the interface between electricity markets and SOs and is responsible to encourage costumer to offer their flexibility.

The use of flexible resources benefits also the SO, for instance to postpone grid reinforcement costs, to increase the hosting capacity or to avoid imbalances with the final aim to improve the quality of service and the increase of DER in the grid. The TSO will have access to valuable resources for balancing frequency regulation which will lack in the future due to the decrease of energy coming from programmable production units. From a social point of view, with increase of DERs there will be a reduction in carbon emission and due to the delay in grid reinforcement savings in resources or the building in new transmission lines.

As repeatedly said through this thesis, the regulator has a key role to incentivize the right market actors, to create market completion, to avoid the excursive of market power and finally to allow the interoperability of ICTs.

Regulatory Recommendations

Referring to SGAM in **Figure 55** in the functional layer three main functions need to be addressed in the coming years for the integration of small-scale DERs. The Market and Enterprise (Electricity Markets and Aggregator's incentives) which should foster the participation of smaller units. The Operation, to enhance the monitoring and observability mainly for System Operator (TSO and DSO interoperability).

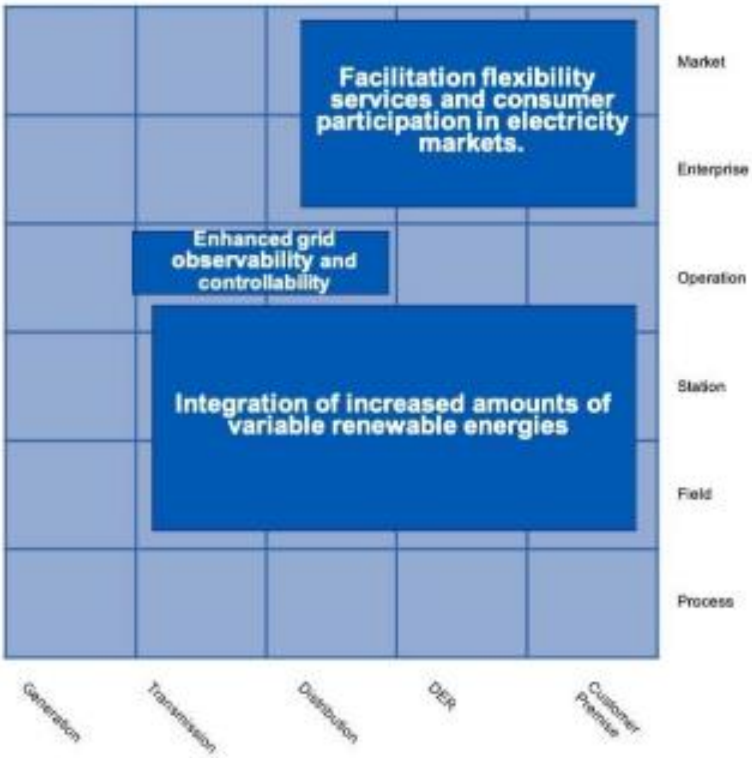


Figure 55: Regulatory framework and which areas should be incentivized most [81]

Integration of TSO – DSO coordination in the ATLANTIS simulation platform

The IEE in-house simulation model ATLANTIS can be used to model developments in the future grid models including economics benefits for novel market designs. Combining the energy imbalances with a detailed power flow computation it gives answers for future investments or energy policy needs.

ATLANTIS models the transmission grid (380, 220, 110kV) of the ENTSO-E network, including more than 19'400 units and electric power and supply utilities with respective balance sheets [102]. It can be used to model network reinforcements due to bottlenecks or systems security problems. Moreover, "Dry run" simulations can simulate scenarios of future market developments.

The ATALNTIS could be extended for distribution grids using the coordination schemes presented in this thesis to analyze the potential of DERs to provide services such as congestion management.

Furthermore, as can be seen from the CBA analysis the ICT cost should be considered when investments decisions are made. The ICT cost estimation could also be included in the ATLANTIS model, for a more accurate scenario simulation and being indispensable for the future grid development.

The model could investigate on the coordinated market efficiency, the benefits to solve congestion and thus reduce re-dispatch costs at transmission level and the implementation of the correct regulatory framework.

Another important aspect that could be investigated is the required local market liquidity and the real benefits for the transmission grid for congestion purposes. Finally, from the required flexibility amount and so the number of activations which can be deducted, could help other players e.g. Aggregators portfolio optimization.

Which Coordination Scheme fit best for the Austrian Scenario?

In Austria, as discussed in chapter 4 there are four main DSO rather than one single bigger DSO. This could lead to market illiquidity as discussed in this thesis and thus local markets might not be the most efficient. The idea to pool all smaller DSO in order to avoid a conflict of interest and thus being able to implement a liquid market at DSO level could be seen in the future grid, also condisering the harmonization at European Level.

9 Conclusion and future Work

The CEP and the last legislation were the motivation of this thesis. A general overview of possible roles that DSOs could take over in the coming years have been presented. Considering the interaction with TSOs and possible coordination schemes based on [74] have been presented. An efficient coordination between SOs is fundamental in order to integrate properly all the resources expected in the coming years and thus a profound cost benefits analysis should be carried out to find the right coordination scheme. In this thesis the idea of a local flexible market was analyzed more in detail, focusing on the cost and savings for the DSO considering the required ICT and aggregation cost. In the future grid investment decision, also the investment and operational costs for ICT should be considered. Operational cost for market clearing, aggregation or system security will be non-negligible aspects in the future grid developments.

A cost comparison using the net present cost method was used to assess whether local markets could be an alternative and profitable, simulating two different scenarios. The results has shown that the implementation of a local market is rarely profitable.

In a future work the CBA could be analyzed more in detail using real grid models with real flexibility providers. Moreover, it could be integrated in the transmission model to solve congestion. For instance, the ATLANTIS [102] model could be extended at DSO level where the DSO (pooled DSOs) could be seen as aggregators, offering flexibility[20] to the TSO market. It could be used to study the potential of demand side management coming from the distribution grid. Furthermore, the effect of unforeseen or forecasting errors should be considered and analyzed how this does affect the overall market efficiency and the operation cost of DSOs.

[20] The offered aggregated flexibility satisfies already the DSO requiremets

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Annex

A1 ICT and smart grid components

Asset	Description	Location
SCADA	Supervisory control and data acquisition system, information exchange between SO	Control Center
DMS	Distribution management system, calculates and analyzes the electricity network (frequency, voltage and power) in real time	Control Center
RTU	Remote Terminal Unit to monitor and control remotely DG and regulation systems. It receives setpoints from the DMS	Primary Substation
RGDM	Fault detector with the possibility detect outages and control DG disconnection	Primary Substation
IEC 61850 Modem	Router collecting and transmitting information between main nodes of the distribution network	Primary Substation
Broad Band Communication	IP based broad band connection	All
EMS	Energy Management System , collects data from commercial parties and sends dispatch set points regardless grid status	Primary Substation

A2 Active Management suggested by ENTSO-E

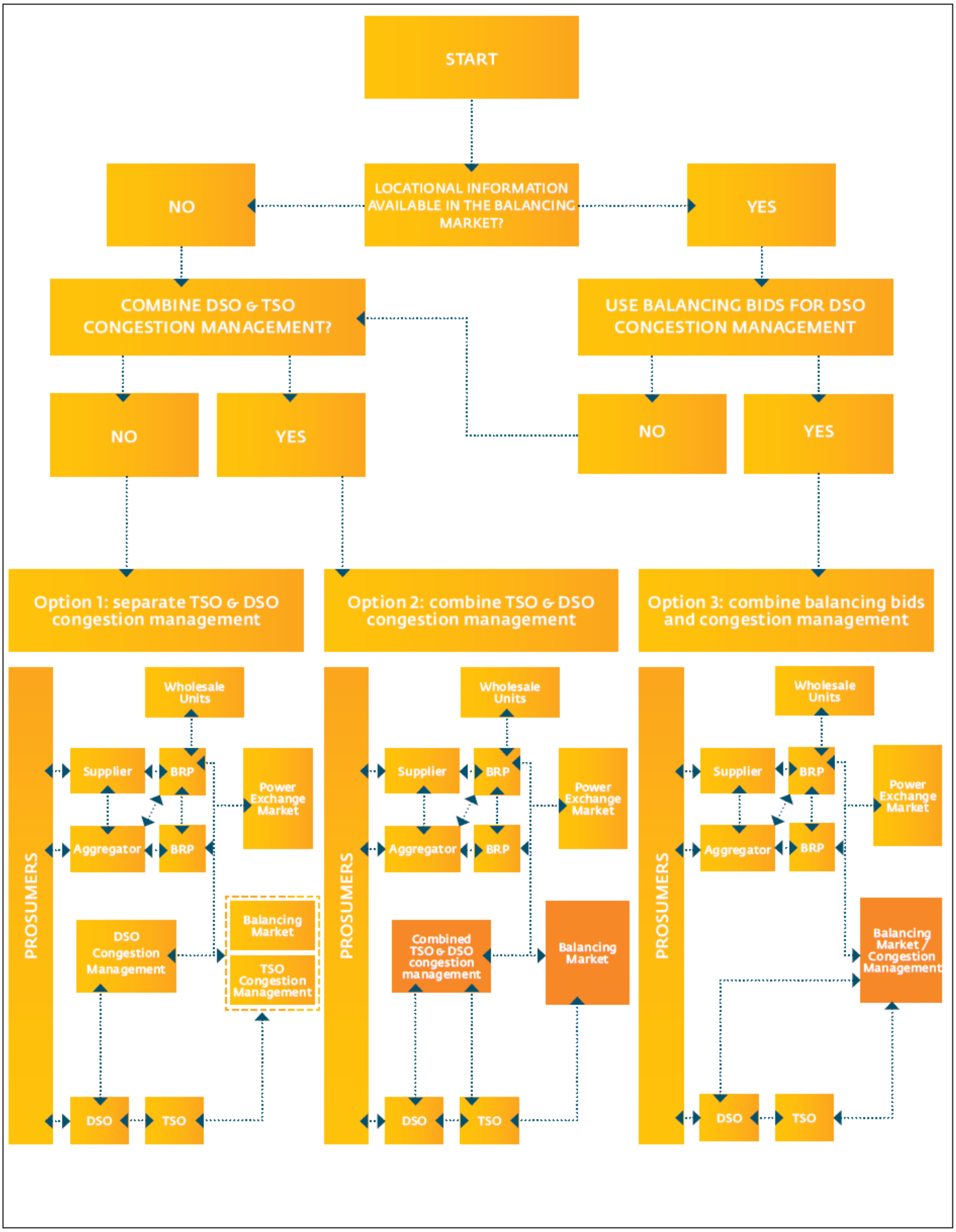

Figure 56: TSO / DSO coordination for congestion management by ENTSO-E [46]

A3 List of DSO per country in EUROPE

Country	Number of DSOs	Customers covered
Austria	4/13	27.9%
Belgium	2/15	77.0%
Bulgaria	1/3	34.3%
Croatia	1/1	100%
Cyprus	1/1	100%
Czech Republic	3/3	100%
Denmark	3/6	41.2%
Estonia	1/1	100%
Finland	7/7	100%
France	1/5	96.0%
Germany	31/75	49.7%
Greece	1/1	100%
Hungary	6/6	100%
Ireland	1/1	100%
Italy	3/3	100%
Latvia	1/1	100%
Lithuania	1/1	100%
Luxembourg	1/1	100%
Malta	0/1	0%
Netherlands	3/8	73.3%
Poland	5/5	100%
Portugal	1/3	99.0%
Romania	3/8	95.5%
Slovakia	2/3	73.3%
Slovenia	1/1	100%
Spain	5/5	100%
Sweden	5/6	78.5%
United Kingdom	5/7	70.7%
Total	99/191	82.73%

Figure 57: DSO per country in EUROPE [70]

A4 Amount of DSO per country

Country	Total number of DSOs (2013)	DSOs > 100,000 customers
Austria	138	13
Belgium	24	15
Bulgaria	4	3
Croatia	n/a	1*
Cyprus	1	1
Czech Republic	3	3
Denmark	72	6
Estonia	n/a	1
Finland	n/a	7
France	158	5
Germany	880	75
Greece	n/a	1
Hungary	6	6
Ireland	1	1
Italy	144	3
Latvia	11	1
Lithuania	1	1
Luxembourg	6	1
Malta	n/a	1*
Netherlands	11	8
Poland	184	8
Portugal	13	3
Romania	n/a	8
Slovakia	3	3
Slovenia	n/a	1
Spain	n/a	5
Sweden	173	6
United Kingdom	7	7

Figure 58: List of DSOs per country in Europe [70]

A4 Rasio Base Stations in Austria

	Mobilfunkstationen auf Dächern, Mobilfunkmasten und Fremdmasten	davon Mobilfunkstationen auf gemeinsam genutzer Infrastruktur	Mobilfunkstationen auf gemeinsamer Infrastruktur in Prozent
Burgenland	719	367	51%
Kärnten	1702	698	41%
Niederösterreich	3880	2306	59%
Oberösterreich	2810	1347	48%
Salzburg	1272	599	47%
Steiermark	2839	1172	41%
Tirol	1850	783	42%
Vorarlberg	756	337	45%
Wien	2195	722	33%
Österreich	**18 023**	**8 331**	**46%**

Figure 59: Radio Base Station per region in Austria [60]

A5 Development of EV in Austria

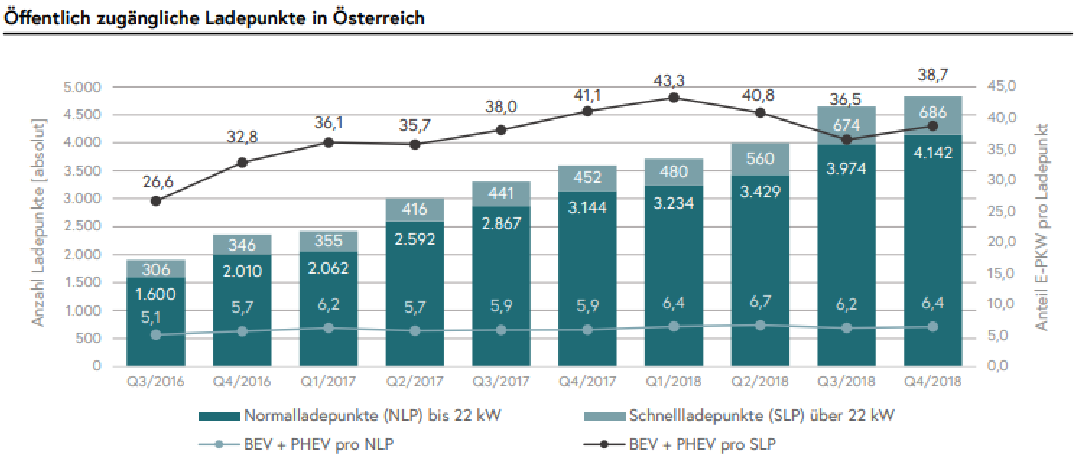

Figure 60: Expected growth of EV charging points in Austria [63]

A6 Cost estimation by the NRAs for grid components - ACER

Table 6: UIC indicators for AC substations by voltage

Total substation cost per voltage (kV)	Mean average UIC (€)	Min-max interquartile range (€)	Median (€)	No. of assets
All substations	42,627	24,994 – 55,508	36,755	114
All GIS substations	46,237	29,837 – 56,017	37,449	18
AIS with 9+ bays	44,008	28,838 – 56,157	41,080	17
AIS with 5-8 bays	35,593	19,936 – 37,251	29,021	24
AIS with 1-4 bays	33,192	20,276 – 48,319	26,628	30

Figure 61: Cost indicators for substations (Source: ACER: Electricity infrastructure cost indicators)

Transformer cost	Mean average (€)	Min-max interquartile range (€)	Median (€)	No. of assets
Per MVA rating	9,903	6,865 – 12,709	9,500	99
Total transformer costs in rating ranges				
500-800 MVA	6,108,414	5,432,864 – 7,144,674	6,412,420	18
300-450 MVA	3,819,670	3,251,819 – 4,274,942	3,669,497	26
150-280 MVA	1,803,607	1,640,847 – 1,934,558	1,833,541	39

Figure 62: Cost indicators for transformers (Source: ACER: Electricity infrastructure cost indicators)

Table 2: UIC indicators for overhead lines

	Mean (€)	Min-max interquartile range (€)	Median (€)	No. of assets
Total cost[1] per circuit route length (km)				
380-400 kV, 2 circuit	1,060,919	579,771 – 1,401,585	1,023,703	39
380-400 kV, 1 circuit	598,231	302,664 – 766,802	597,841	32
220-225 kV, 2 circuit	407,521	354,696 – 461,664	437,263	15
220-225 kV, 1 circuit	288,289	157,926 -298,247	218,738	5

Figure 1: Overhead lines by circuit route length (km) by box-plot

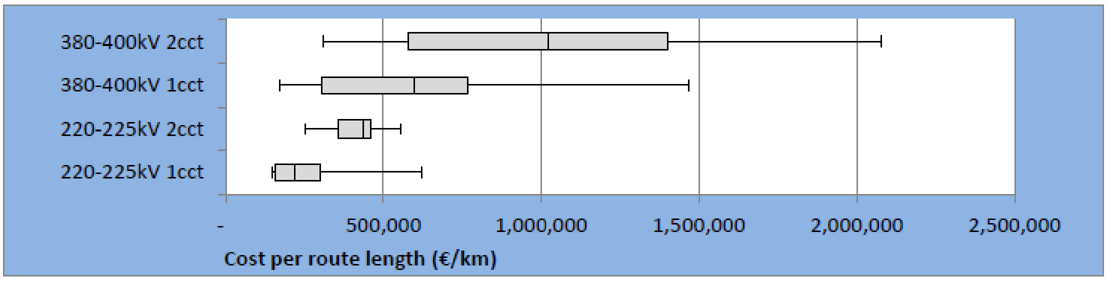

Figure 63: Cost indicators cables and overhead lines (Source: ACER: Electricity infrastructure cost indicators)

A7 Matpower Simulation, load curve and market results

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Bus Data
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Bus	Voltage		Generation		Load		Lambda	
#	Mag(pu)	Ang(Deg)	P(MW)	Q(MVAr)	P(MW)	Q(MVAr)	P	Q
-----------	------------	-------------	-----------	-------------	-----------	-----------	----------	----------
1	1.000	0.000*	10.50	0.00	-	-	10.00	-
2	1.000	-0.361	-	-	0.00	2.00	100.00	-
3	1.000	-1.504	-	-	-	-	100.00	-
4	1.000	-2.527	-	-	-	-	100.00	-
5	1.000	-2.767	-	-	1.60	0.00	100.00	-
6	1.000	-2.869	-	-	-	-	100.00	-
7	1.000	-3.383	-	-	1.00	0.00	100.00	-
8	1.000	-4.608	-	-	1.16*	15.00*	100.00	-
9	1.000	-5.341	-	-	-	-	100.00	-
10	1.000	-5.496	-	-	1.16*	12.00*	100.00	-
11	1.000	-5.623	-	-	-	-	100.00	-
12	1.000	-5.815	-	-	-	-	100.00	-
13	1.000	-6.007	-	-	-	-	100.00	-
14	1.000	-6.613	-	-	1.15*	15.00*	100.00	-
15	1.000	-7.045	-	-	-	-	100.00	-
16	1.000	-7.146	-	-	1.14*	12.00*	100.00	-
17	1.000	-7.259	-	-	-	-	100.00	-
18	1.000	-7.616	-	-	-	-	100.00	-
19	1.000	-7.974	-	-	1.14*	15.00*	100.00	-
20	1.000	-8.207	-	-	1.00	10.00*	100.00	-
21	1.000	-8.331	-	-	1.14*	12.00*	100.00	-

(Source: IEEE-30 radial structure, own market results)

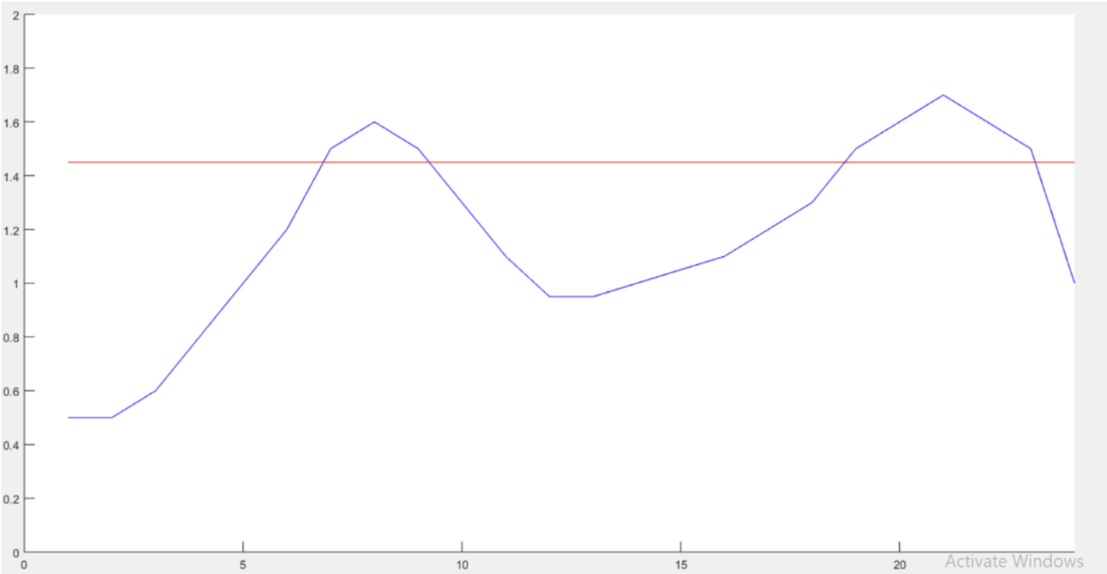

Figure 64: Simulation for load curve in MATPOWER (Source: own results)

Glossary

Aggregator — The aggregator's responsibility is to collect and bundle resources. He acts as interface between system operators and final costumers.

BRP — The BRP is responsible for maintaining a continuous power balance between production and consumption.

BSP — The BSP is the provider of Balancing services in a specific balancing area, in other words it is an eligible unit able to offer AS

Cons/Prosumer — The term consumer is used to describe the classical end-user that withdraws energy from the distribution grid. In our context it can be defined as a passive actor. The term prosumer can be used to describe an end user which is consuming and injecting energy into the grid e.g. storage system. In our context it can be defined as an active actor

TSO — The Transmission System Operator (TSO) is a regulated entity responsible for the high voltage grid in its own area. Thus the TSO is the only actor responsible for the acquisition and activation of the ancillary services. Furthermore the TSO is responsible for the information and interchange with other TSO and DSO.

DSO — The Distribution System Operator (DSO) is the entity responsible for the energy dispatch at medium and low voltage. The DSO is responsible for maintenance and power quality at distribution level.

NRA — National Regulatory Authority is a government agency in charge to monitor prices with the aim to regulate monopolists and finally to protect customers by regulating transmission and distribution and other tariffs. In Austria the NRA is E-control

CEER	Council of European Energy Regulators a nonprofit organization where most European Energy Regulators cooperate
ACER	Is the Agency for the Cooperation of Energy Regulators, it coordinates and the work of NRA and creates European network and market rules.