evolvDSO

Development of methodologies and tools for new and evolving DSO roles for efficient DRES integration in distribution networks

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D1.2 – Evaluation of current market architectures and regulatory frameworks and the role of DSOs

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Executive Summary

This deliverable aims to describe the current environment in which Distribution System Operators (DSO) act and their current role with respect to distributed renewable energy sources (DRES). The study is motivated by emerging challenges related to the increase of DRES. In addition, the availability of two way communications allows active grid management and cooperation with grid users. The setting is described in terms of DSO regulation, electricity market design, and the current practices of the DSO with respect to DRES. In order to achieve these objectives, a survey was used to gather information about the setting in each of the participating countries. The information was then compiled and compared in order to identify trends and draw conclusions about the current situation. At the same time, the study looks at the current practices that DSOs are implementing to deal with the changing environment. The research work presented in this report is related to the analysis performed in Task 1.1 (scenarios) and will serve as a basis for further research on the future roles of DSOs (Task 1.3), which will take into account a longer term perspective of even more DRES integration. Deliverable 1.4 will further elaborate longer term progressive evolutions and solutions for market architectures and regulatory frameworks in order to analyse their impact on the future role of DSOs.

The main aspects of the DSO regulatory framework identified as most relevant are unbundling, connection and access, remuneration schemes and quality of service (QoS). DSOs have been unbundled from generation companies in all the surveyed countries at least up to accounting and functional levels. In terms of access and connection charges the DSOs mostly cover all or part of the costs generated due to distributed generation and renewable energy sources connected to their network. This cost is transferred evenly through the tariffs according to the connection capacity and voltage levels of the end users. Incentive remuneration is used in one form or another for the DSOs of the surveyed countries to motivate them to operate in a cost efficient way. Nevertheless, cost and QoS present a clear trade-off. Three components of quality of service were identified as: customer service, voltage quality and continuity of supply. There is a trend to include an incentive in the regulatory remuneration formula of the DSOs for QoS indicators. All the surveyed countries at least monitor quality of service even if they do not remunerate it. Regulation needs to adapt with respect to DRES. DSOs need to have tools in order to deal with local grid issues. The current regulatory framework hardly supports non-traditional investments. There is little direct motivation to delay network investments, which are remunerated as part of the asset base, through smart grid management.

In terms of market design, Europe tends towards the synchronisation and expansion of areas of control of the markets. The northern European markets have been recently price coupled to the Central West Europe (CWE) and UK markets, resulting in the NWE (North Western European) price coupling. This harmonization of markets, however, presents challenges to maintain the adequate functioning of the grid in each area. Local conditions that can affect the grid are hard to take into account in ever larger markets. The preferred market pricing for the day ahead is a uniform marginal price, meaning that the most expensive unit during each time period sets the price for all the participants. In the intraday and the reserves markets, there are varied methods of preferred pricing, from pay-as-bid contracted through tenders to marginal price markets. Demand response is also being included in several forms, mostly in the reserve markets. However, the minimum participation criteria make it difficult for small users, or aggregators to take part in the day ahead or intraday markets. The introduction of smart grid technologies, and new market rules will enable a broader deployment of flexibility on the demand side. At a certain time before real time operation, called gate closure, market results are transferred to the transmission system operator (TSO). Traditionally DSOs were not aware of these results since they had very little or no generation connected to their networks. In the current changing environment, a growing number of units connected at the DSO grid bid and participate in the market. In most cases, the DSO is not aware of the market results, and the resulting unit commitment schedules. The current approach is to deal with problems that arise using a contingency resolution approach rather than a preventive one. The DSO takes action upon the request of the TSO, who has the bigger picture, or when there is a detected failure in its grid. Similarly, units connected to the DSO network bid in the reserve markets and provide ancillary services to the TSO. So far, DSOs generally do not contract reserves directly.

Local issues in the networks are already present and the surveyed DSOs are already dealing with them. The current practices implemented to deal with the changing environment are analysed on three activity areas; planning and network development, forecasting and optimization, and real time operation. DSOs are finding innovative solutions within their allowed regulatory spheres, pushing change forward through active problem solving.

The planning and networking development practices refer to long term distribution grid expansion planning. The distribution network needs to grow in order to provide indiscriminate access to all users who request it. A rapid increase in DRES requires DSOs to accommodate variable generation that might overload the network or cause stability issues. The practices of planning with respect to DRES are grouped into practices involving locational signals for DRES investments, and smart meter roll out.

Locational signals can be in the form of price signals regarding connection costs. It was identified in the study that most DSOs share the costs of connection with the requesting party. DSOs can enable information about zones where connection is more or less costly according to the state of the network in that area. Another type of locational signal identified is the designation of specific areas for wind or solar power production. The areas are chosen for their resource availability and DSOs are motivated by the regulator to make the necessary network reinforcements to accommodate DRES in those areas. Investment locational signals enable the possibility to delay investments in grid reinforcements. The disadvantage is that it might require a regulatory update as it might be seen as a discrimination of sorts, and alignment with RES support schemes is required. Currently, only two of the surveyed DSOs provide some form of locational signal for DRES investment. All of the surveyed DSOs are already investing in smart meter roll outs to different degrees of penetration. Most of them agree that the Information and Communication Technology (ICT) network of the smart grids should be built and managed by the DSO as long as their remuneration will cover the investment. Only one of the surveyed countries indicated that it would be better if telecommunication companies invested in the ICT network. The advantages of smart metering are enhanced visibility and operability of network resources, and the possibility to directly manage network users. The disadvantages are that a smart meter roll out requires a large investment, and poses data property issues.

Forecasting, network optimization, and contracting flexibility might be useful tools to relieve network constraints. It was found in the study that most of the surveyed countries do not yet forecast DRES generation for operational purposes. Forecasting functions include consumption and production forecasting. It can be applied for short term operational planning in order to undertake preventive system configurations, plan maintenance schedules, and take advantage of the available flexibility resources. Procuring flexibility to solve congestion relates to contracts with either generators or consumers allowing the availability of reserves in the former case and demand shifts in the latter. The disadvantage is that these services require investment in forecasting and measuring tools. A regulatory update is necessary to allow the DSO to contract different terms with certain users.

On the real time grid management the issues of controllability, net metering and temporal signals are important. The aim of real time management is to reduce congestion, reduce losses and detect problems that might cause component issues later on. Controllability refers to the ability of directly controlling/managing the DRES or consumption unit under predefined and agreed conditions by a third party different from the owner of the units. Controllability could be performed directly by the DSO or by an aggregator in communication with the DSO. Currently, where controllability capabilities exist, DSOs are only allowed to perform actions on third parties in case of emergency and not for optimal network planning. A regulatory update would be necessary to allow the DSO more controllability faculties through flexibility contracting. Net metering, the ability to subtract own produced energy from the total consumption in the electricity bill, is allowed in most of the surveyed countries. It promotes the implementation of DRES since participants can reap a profit from investing in it. It can be a disadvantage for the DSO where network tariffs are based on kWh and not on kW allowed capacity. Finally, on the real-time operation stage temporal signals can be used to reflect the state of the network and motivate consumers to act in benefit of the grid. This would enhance operational management and provide a way to value local flexibility resources. Currently, none of the surveyed countries apply time varying use of system charges (also known as time-of-use tariffs). Regulatory updates might be necessary for their implementation.

As a conclusion to the study it can be seen that DSOs are already dealing with unforeseen grid situations caused by technology change drivers. The rapid growth of DRES and the possibility of demand response mechanisms is causing changes in the way in which DSOs manage their grid. Issues such as reverse grid flows, congestion management, rapid component aging, and overall voltage stability are currently common fare. Regulation is not always up to date in order to allow the DSOs to optimally deal with such issues, and DSOs have had to make a patchwork of solutions to keep up with the changing system. Legislation is being led by needs of already existing problems, and is being tackled at different speeds and through different methods in all the surveyed countries. There are three main topics identified that need to be addressed in the coming years. The first, is the need for more coordination between the wholesale market, the TSO and the DSO. The second, is the need for DSOs to perform active grid management, preventive and operational, instead of ex-post corrective activities. DSOs will need tools and new business and technical procedures that allow them to change to a more proactive approach. The third, is the need for flexibility contracting/procuring. DSOs need access to consumer and producer flexibility in order to optimise real time operation. DSOs are recognizing these needs and looking for innovative solutions. These solutions will require capital investments for ICT solutions and therefore the regulation needs to allow them to recover these investments and see the benefit out of carrying them out. In a similar manner, market structures that allow market participants to make a profit out of maintaining an optimal grid operation will help spread the investment burden.

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1 Introduction

1.1 The evolvDSO project: target and objectives

Due to the increasing share of distributed renewable energy sources (DRES) and the increasingly pro-active demand for electricity, power systems and their mode of operation need to evolve. As a consequence, roles and responsibilities of stakeholders in the power system and the energy market are expected to change as well.

The evolvDSO project, represented in Figure 1, will define future roles of distribution system operators (DSOs) based on future scenarios, and will address the associated main research and technology gaps to be solved for DSOs to efficiently fulfil their emerging and future roles in the European electricity systems. New tools and methods will be developed, encompassing a wide array of DSO activities related to planning, operations scheduling, real-time operations and maintenance. Selected methods and tools will be tested and validated to maximise their deployability, scalability and replicability.

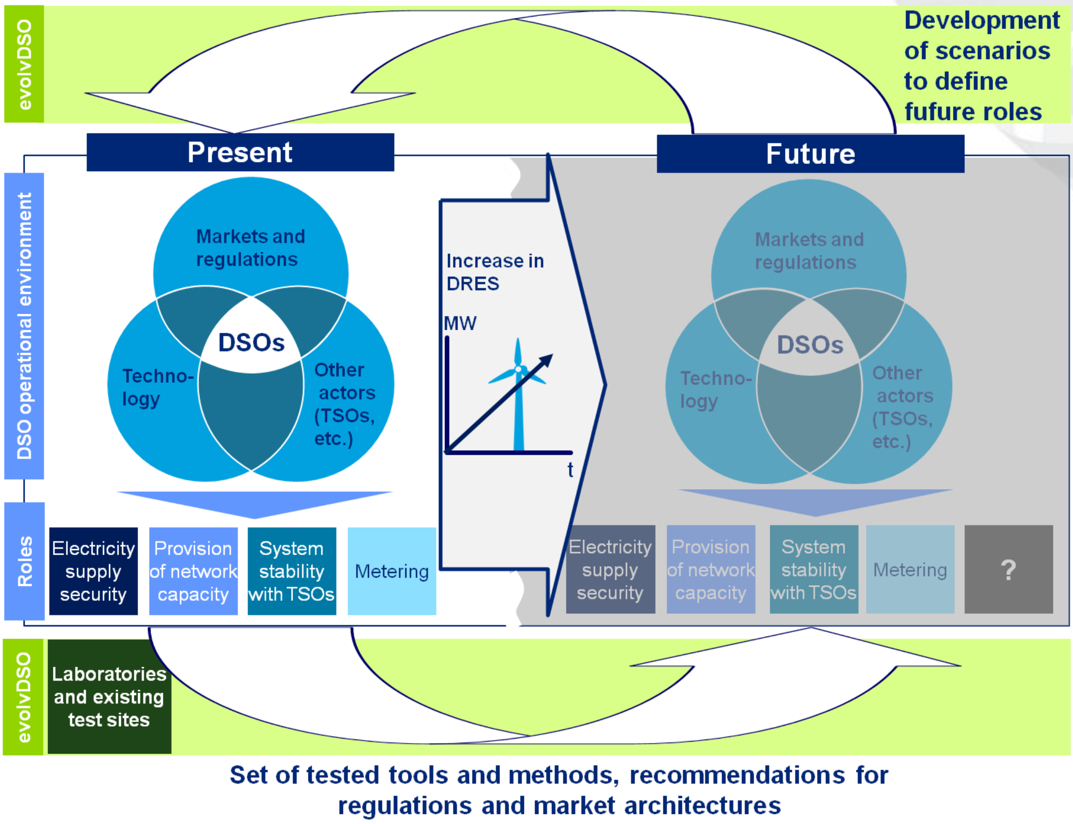

Figure 1: The evolvDSO approach

The envisioned activities and associated work packages within the evolvDSO project are summarised in Figure 2.

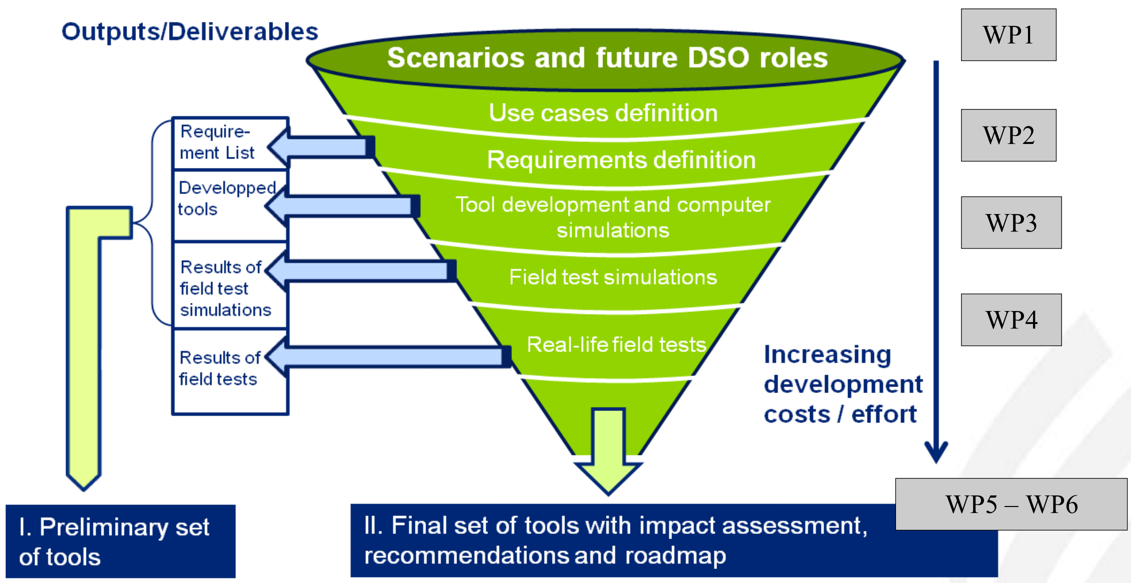

Figure 2: Activities within the evolvDSO project

1.2 Introduction WP1 on scenarios, regulation and markets

This report was compiled in the framework of the first work package of the evolvDSO project. Within the evolvDSO project, the objectives of WP1 can be summarised as follows:

- Elaboration of a limited but representative **set of scenarios** describing the evolution of the power system (Task 1.1; Deliverable D1.1);
- Description of the **current role of DSOs in the context of the current market and regulatory framework** in Europe and current status of DRES integration (Task 1.2; Deliverable D1.2, i.e. this report);
- Description of **evolving future roles of DSOs** in light of **future scenarios with high penetration of DRES** in the context of future market and regulatory frameworks (Task 1.3; Deliverable D1.3 and D1.4);

1.3 Scope and objectives of this document (D1.2)

DSOs operate their business in a changing environment. One of the major drivers for this change is the increasing share of DRES connected to the distribution grid. DSOs are expected to adapt to the changing environment (changing role) in order to guarantee the stability and reliability of the grid, as well as a certain quality of service. In addition, the framework (both market designs and regulation) is expected to undergo some needed changes to allow DSOs to optimally act within this changing environment.

This document, entitled “Evaluation of current market architectures and regulatory frameworks and the role of DSOs”, seeks in the first place to describe the current environment DSOs are operating in, being the current market settings and regulatory frameworks in different European contexts (i.e. differences and similarities between countries, specific characteristics of national and/or cross jurisdictional power systems, etc.). Particular attention has been paid to DRES integration in the system from a DSO perspective. Secondly, this report aims to describe the current role and practices of DSOs in these contexts, and more specifically how DSOs currently handle DRES and the associated challenges. A discussion on the suitability of the current framework to deal with DRES is included as well.

1.4 Report structure

The document comprises the following chapters:

- Chapter 2 describes the general context in which DSOs are operating their business from a specific holistic European point of view. It also explains the approach to information gathering as a basis for the analysis presented in this report.
- Chapter 3 presents the approach and outcome of the analysis used to describe the current market design and regulatory framework "as it is".
- Chapter 4 outlines the current role of DSOs and their practices to deal with DRES connected to the distribution grid. In addition, it includes a discussion on the suitability of the current context for handling ever-increasing DRES from a DSO perspective.
- Chapter 5 provides the main conclusions on analysis performed on the role of DSOs in the current market and regulatory setting.

1.5 Notations, abbreviations and acronyms

AGC	Automatic Generation Control
AON	All Or None
BRP	Balance Responsible Party
BSP	Balance Service Provider
CAPEX	Capital Expenditure
CWE	Central West Europe
D-1	Day Ahead
DAM	Day Ahead Market
DEA	Data Enveloping Analysis
DR	Demand Response
DRES	Distributed Renewable Energy Sources
DSO	Distribution System Operator
DUoS	Distribution use of system
EHV	Extra High Voltage
FAK	Fill And Kill
FCR	Frequency Containment Reserve
FOK	Fill Or Kill
FRRa	Frequency Restoration Reserve activated automatically
FRRm	Frequency Restoration Reserve activated manually
HV	High Voltage
ICT	Information and Communication Technology
IDM	Intraday Market
LV	Low Voltage

MCP	Market Clearing Price
MO	Market Operator
MV	Medium Voltage
NEBEF	Notification d'Échange de Blocs d'Effacement
OPEX	Operational Expenditure
OTC	Over The Counter
QoS	Quality of service
RAB	Regulated Asset Base
RES	Renewable Energy Sources
RR	Replacement Reserve
TOTEX	Total Expenditure
ToU	Time of Use
TSO	Transmission System Operator
UoS	Use of System

Table 1: Acronyms list

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2 DSOs in a European context

The following sections sketch the general context in which DSOs are operating (section 2.1), stress the diversity of DSOs in terms of numbers per country, concentration, size, and responsibilities (section 2.2), and explain the approach taken for gathering country-specific information (section 2.3).

2.1 Background

European energy policy strives for a sustainable energy system and security of supply. In practice, this implies an evolution towards increasing shares of renewable energy sources (RES) in general and DRES in particular. Some examples can be found in Figure 3. In the near and far future, this trend is expected to intensify, leading to massive integration of DRES on the distribution grid.

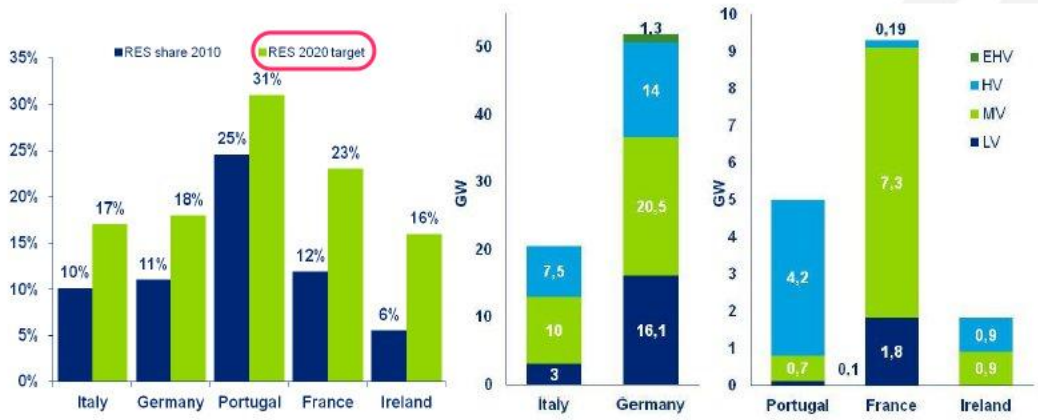

Figure 1: Share of DRES (solar and wind) in gross inland consumption in 2010 and target share 2020
Figure 2: Wind and solar connected to LV, MV and HV grids per country
Sources: Eurostat; Directive 2009/28/EC of 23 April 2009; Rapporto Statistico 2011 – Solare fotovoltaico, GSE

Figure 3: Current & expected RES penetration in selected countries

This evolution challenges the way the power system is operated because DRES are characterised by volatility of power generation, less predictability and less controllability. This leads to more uncertainty on the generation side and requires much more flexibility in the power system (both on the generation and consumption side) on different levels (transmission – distribution). A paradigm shift is observed from “generation follows loads” to “loads follow generation”. This is illustrated by the emerging business of activating the demand side (demand response) in many countries.

This evolution of increasing the penetration of DRES and emerging demand response (DR) activities concerns not only technical aspects. New commercial players like aggregators are entering energy markets. Those aggregators can be defined as actors who “primarily group and manage the flexibility of a cluster of flexible devices with the purpose to offer DR-based services to the different power system participants through various markets” (Harbo and Biegel, 2013). The changes related to increasing levels of DRES and emerging DR activities are complicating the existing relationships between different stakeholders in the power system and consequently impacting the traditional value chain.

Transmission and distribution of electricity is a regulated business. As a consequence, the regulatory framework is supposed to provide the right mechanisms and incentives for TSOs and DSOs to operate their business. Given the aforementioned evolution of the system, TSOs and DSOs are increasingly facing additional complexity in dealing with higher amounts of DRES and DR. This requires an adaptation of their processes and procedures, in order to enhance observability of the grid. In addition, innovative solutions (smart grid technologies, methods, tools, etc.) should allow them to respond optimally to the emerging challenges in the power system. Furthermore, those innovative solutions and adapted processes should allow an intensified interaction and cooperation with other market players, both regulated (e.g. TSOs) and deregulated (Balance Responsible Party (BRPs), aggregators, etc… (Eurelectric, 2010; Peeters et al., 2009). Those adaptations should be established in line with the regulatory framework and taking into account the economic environment they operate in.

However, the current market and regulatory framework where system operators are operating in, was initially set up based upon the traditional approach of the power system ("generation follows loads"), not taking into account high shares of DRES and a more active demand side ("loads follow generation"). Nowadays, this situation is changing in many countries, as described previously. This evolution is expected to even intensify in the upcoming years and is resulting in a call for adaptations in the economic and regulatory framework according to the changing power system challenges and needs.

In this perspective, the THINK project, led by the Florence School of Regulation (FSR), (Perez-Arriaga et al., 2013) reports that *current regulation of DSOs needs updates to allow for welfare-enhancing DER technologies to be adapted efficiently and in a timely fashion…* [These] *updates are needed to provide the right regulatory tools to DSOs such that they can also benefit from the services DER can offer for system operation and planning.* Furthermore, the document states four regulatory areas that require an update, namely DSO revenue, distribution grid tarification, DSO boundaries concerning markets and DSO boundaries concerning system management. The THINK report further states: *a sound regulation at distribution that incentivises active system management accounts for: 1) changing Operational Expenditure (OPEX) and Capital Expenditure (CAPEX) structures, 2) optimal choice among both and 3) incentives to deploy innovative solutions.* These statements take into consideration increased DRES penetration levels (supported by country targets and EU targets) and the expectation that DSOs are aiming for smart distribution systems (Perez-Arriaga et al., 2013).

2.2 Diversity of DSOs in the European landscape

The electricity distribution sector in Europe is characterised by a diversity of DSOs (see Figure 4, and Figure 5, (Perez-Arriaga et al., 2013)). They are diverse both in concentration and in the magnitude of control areas. While some countries - like Portugal, Italy and France - have one dominating DSO, other countries - like *Germany*, and *Austria* - have a large number of DSOs.

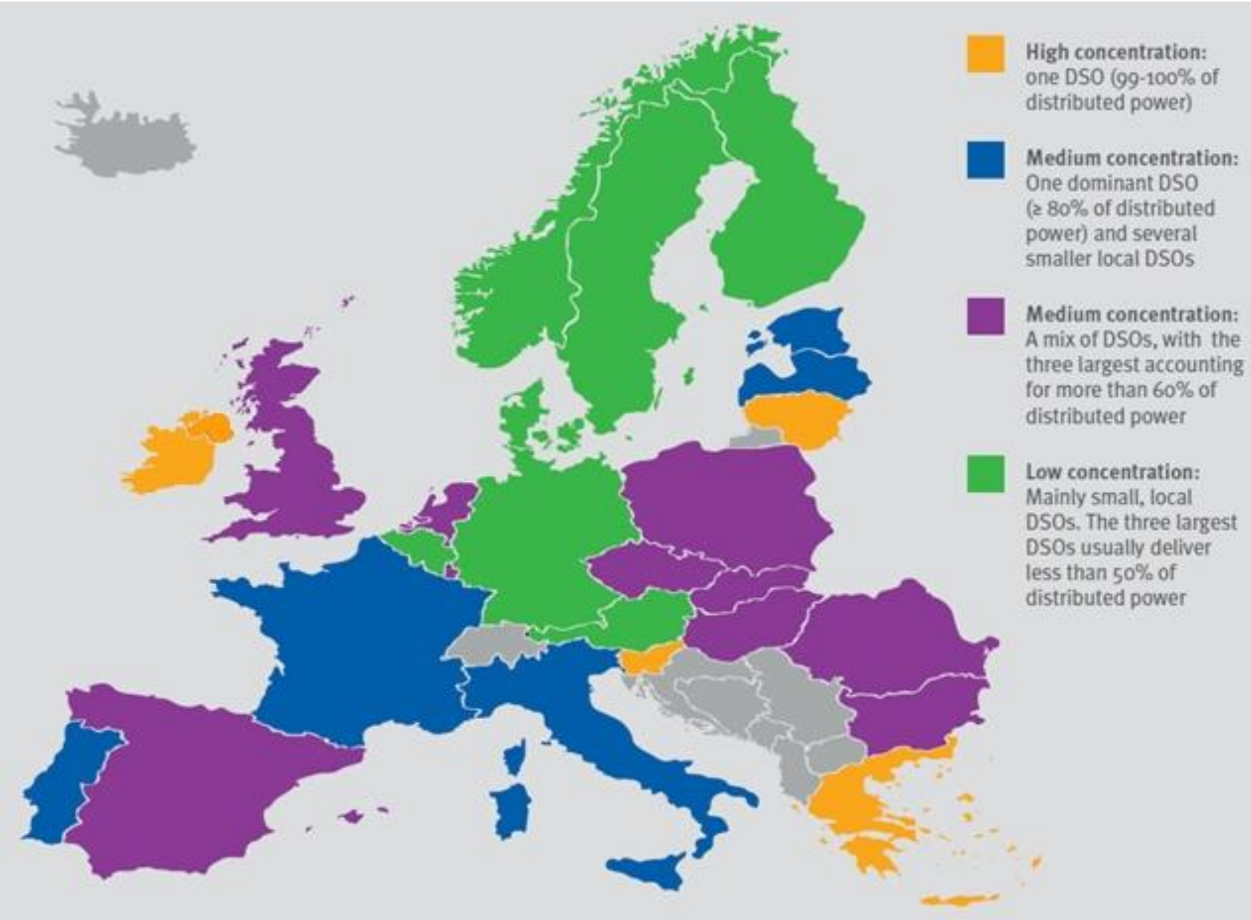

Figure 4: Concentrations of DSOs per area (Source: Eurelectric, Power Distribution in Europe: Facts & Figures (2013))

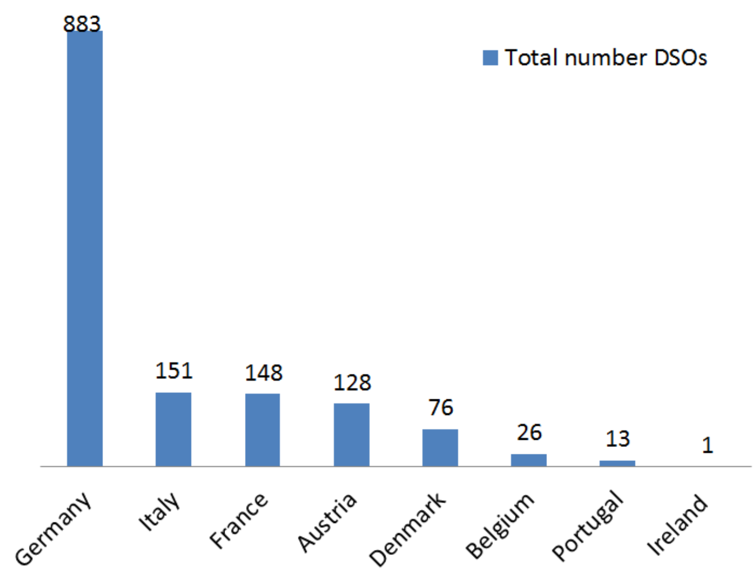

Figure 5: DSOs across Europe (adapted from Perez-Arriaga, I.J. et al., From Distribution Networks to Smart Distribution Systems (2013))

Moreover, the maximum grid voltage levels for which DSOs are responsible, varies from country to country, as illustrated in Figure 6 (Perez-Arriaga et al., 2013). In addition, every country has different objectives in relation to the 20/20/20 EU directive and different starting points concerning the amount of DRES in the power system.

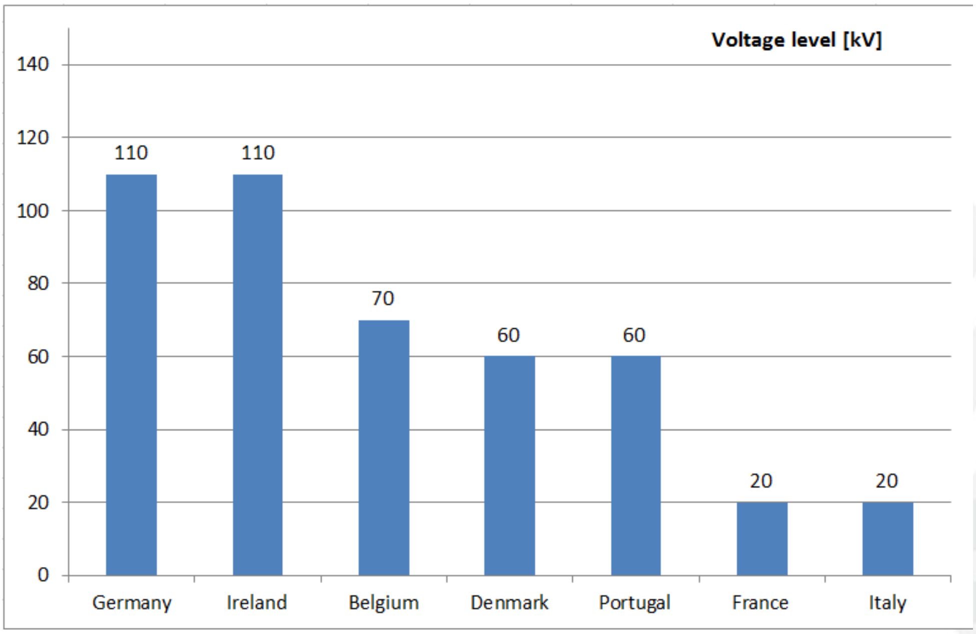

Figure 6: Heterogeneity of voltage levels (adapted from Perez-Arriaga, I.J. et al., From Distribution Networks to Smart Distribution Systems (2013))

The observed diversity and number of DSOs in Europe makes coordination and regulation complicated, especially with regard to coordination with the TSO and the existing electricity markets.

2.3 Information gathering: surveys

Country-specific information was assembled by means of surveys. Those surveys aimed at obtaining general information on the current power system, market and regulatory framework for the particular countries, insights in the status and impact of DRES integration, and a better view on the role of DSOs.

The inquiry was carried out in two forms. An extended survey (word document) rolled-out to consortium members only and a "light" (web-based) survey meant for countries outside the consortium.

The countries for which an extended survey was completed are summarised in Figure 7. The countries for which limited and fragmented information could be obtained are the following: Spain, Greece, Czech Republic, Poland, Latvia, Netherlands, UK, Hungary, Slovenia, and Cyprus.

The extended and light survey consisted respectively of 126 and 75 questions. The rationale behind launching a light survey in addition to the extended one, was to gather as much information as possible from other DSOs/countries outside the evolvDSO consortium to check potential deviating tendencies.

Both surveys inquire upon factual information (relying on the knowledge and experience of the responders) on the power system, markets and regulation on country-level on the one hand, and about expectations, opinions and estimations on DRES integration and the role of DSOs on the other hand.

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Austria
Belgium
Denmark
France
Germany
Ireland and Northern Ireland
Italy
Portugal

Figure 7: Countries covered by extended survey

Both surveys contained the following thematic blocks:

- Characterization of the power system
- Market architecture
- Regulatory framework
- DRES in the power system, the market and regulation
- Demand-side participation.

On the characterization of the power system, responders were asked about the current activities of stakeholders (including the financial, data, and contractual links amongst them), both in regulated and liberalised domains.

The market design/architecture section contained questions on the characteristics of wholesale markets (e.g. market bidding and matching, congestion management, ancillary services), and the interaction between regulated and deregulated players.

The regulatory framework section inquires on the characteristics of DSOs regulation (e.g. key performance indicators, incentives and their rationale, connection and access, curtailment, further obligations/issues framed by grid codes), and support schemes.

Concerning DRES, specific questions were raised on every section related to special considerations for DRES (e.g. recognition of impacts) and issues relevant to the integration of DRES across the value chain of electricity (e.g. DRES controllability).

A specific section was dedicated to demand-side participation and more specifically on the characteristics of the schemes in place for the activation of demand side flexibility. The section aimed at obtaining relevant information on the interactions between this flexibility on the one hand, and existing market architectures and regulatory frameworks on the other hand.

In addition, anticipating the analysis of the future roles of DSOs within the evolvDSO project (task 1.3), both surveys launched questions on potential (future) roles of DSOs and associated services. The input serves as basis for the development of a short to long term vision on the necessary (future) roles of DSOs and associated services.

3 Current market design and regulation

In this chapter, the regulatory framework of the DSOs and the market design for electricity trading will be analysed. Section 3.1 describes the major aspects that regulate distribution system operation. Comparative results for the surveyed countries are presented with respect to the level of unbundling, characteristics for connection and access, remuneration schemes and quality of service (QoS) regulation. Finally, the way in which regulation approaches and is affected by DRES is analysed in section 3.1.5. Next, electricity market design aspects are compared among the surveyed countries in section 3.2. The analysis is carried out regarding different market aspects such as participation conditions, market characteristics, bidding methods, price formation, and regional market coupling. In addition, demand response programs are presented in section 3.2.2. The market for reserves is analysed from the point of view of procurement and payment methods in section 3.2.3. A conclusion of the impacts and considerations for RES with respect to market design is presented in section 3.2.4

3.1 The Distribution System Operator: Regulatory Framework

Competition is allowed in the electricity business of generation, but not in the delivery of it (carried out by the transmission and distribution system operators). The distribution business is regulated as a natural monopoly in all of the surveyed countries and in Europe in general. This is because it is considered a public good to which all people need to have access to and to take advantage of economies of scale. The regulator in each country defines the way in which the DSO will act. The main DSO related topics treated ahead are unbundling, connection and access, remuneration schemes and quality of service.

3.1.1 Unbundling

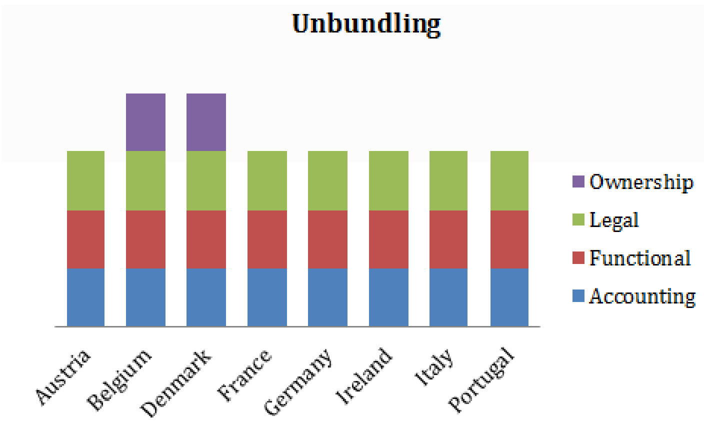

Figure 8: Level of DSO Unbundling

Unbundling refers to the separation of electricity distribution activities from electricity production activities. Four levels of unbundling can be distinguished: Ownership, legal, functional and accounting. If the DSO is vertically integrated, ownership unbundling "constitutes the separation of an undertaking's generation assets from its network assets", legal unbundling "requires the creation of a separate network company (legal form)", functional unbundling means "management independence and separation of effective decision making rights", and accounting unbundling "entails the separation of the accounting of the activities just as if the activities were carried-out by separate undertakings" (Ropenus et al., 2009).

Figure 8 presents the level of unbundling for DSOs in the surveyed countries. They have all achieved at least a functional level of unbundling. The countries that have achieved full ownership unbundling for most DSOs are *Belgium* and *Denmark.* It is worth remarking that Belgian DSO's have are required by law to be 100% local government owned by 2018 (so called "pure inter-communalities"). In this line, 12 Belgian DSOs present ownershipi.e.). "Pure inter-communalities" can be seen as the effort from the Belgian regulator to separate the network business from the deregulated one.

3.1.2 Connection & Access

Connection charges: Charges paid by the owner of the generation (or consumption) unit in order to be connected to the desired network. The charges are collected by the relevant grid operator. Within this survey three types of connection charges are identified for DRES: Shallow, Shallowish, and Deep.

- **Deep**: connection costs include the connection assets (transformer) as well as all or parts of the costs of necessary network reinforcements; that is network reinforcements at transmission and distribution level (Ackermann, 2005).
- **Shallow**: shallow connection costs include the direct connection costs, that is, the cost for new service lines to an existing network point- and partially also the costs for the transformer that is needed to raise the voltage from the generator to the voltage in the distribution or transmission network (Ackermann, 2005).
- **Shallowish:** combination of deep charges and shallow charges, as the connection charges include a contribution to reinforcement costs based upon the production of increased capacity required by the connectee (Ackermann, 2005).

Figure 9 represents the results of the survey. Most countries vary between a shallow and a shallowish connection charge model, meaning that connection charges are mainly shared between the DSO and the user. In *Denmark* connection charges are deep for large consumers and shallow for DRES, especially wind turbines In *Ireland* DG pay for a portion of the deep connection costs proportional to their dedicated capacity of the reinforced asset.

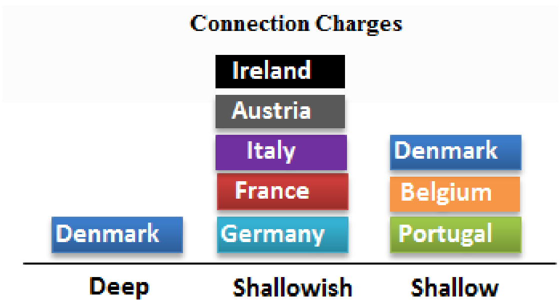

Figure 9: Connection charges

Use of System charges:
Charges aiming to reflect the share of system usage (grid utilization) that generating units make to the grid they are connected to. They can be calculated either per use (kWh), or per connected capacity (kW). Access to the distribution system needs to be indiscriminate to all parties within their allowed capacities, however DRES usually have preferential access in case of congestion.

Figure 10 presents the results of the survey for describing the payment of use of system charges (UoS). For some countries, there is a partial collection of UoS charges.

In *France*, generation units connected at a voltage level ≤ 130 kV do not pay the "injection component", which is one of the 9 components of the French tariff (TURPE). They only pay two components of the tariff: the management component and metering component. The network tariff follows four concepts:

1. It must be the same across the national territory.
2. It must be calculated independently to the distance between the injection and the withdrawal points.
3. It depends on the voltage and the energy subscribed by the use.
4. It differs according to the season, the day of the week and the hour of the day.

In *Italy* only pure generators (defined as those generators who inject the whole energy produced except the necessary part for auxiliary services) do not pay Use of System charges.[1]

In *Belgium* units below 10 kW do not pay UoS charges. Distribution network tariffs depend on the kWh amount used by each consumer. The cost of the use of the network is defined per area or DSO and is the same for all periods of time and for all users.

In *Denmark* UoS charges are not paid by DRES.

In *Austria* UoS charges ("system utilization fee") have to be paid by some connected units[2]: pump storage power plants, units supplying balancing energy. Generators (independent of technology) have to pay a "system losses fee". All generators (and park of generators) with a capacity of >5 MW have to pay a "system service fee" depending on the injected energy. This is an advantage for small DRES and DG <5 MW.

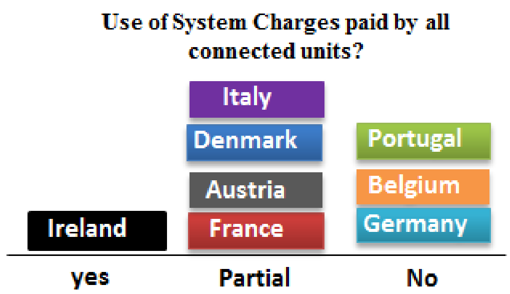

Figure 10: Use-of-System charges

In countries where the UoS charge is not required for generating units, the full cost of the network is transferred to the end consumer through the tariffs.

[1] In *Italy* customers and prosumers both pay UoS charges.

[2] In *Austria* consumers also have to pay UoS as well as a 'system losses fee'.

3.1.3 Remuneration schemes

Given that the distribution business is regulated as a monopoly, the remuneration scheme is traditionally decided using three methods: cost of service, price quality benchmarking, and yardstick or benchmarking remuneration. In either remuneration scheme, the dominating idea is that an evaluation of the costs of the DSO will be made, examined and measured against quality indicators in the case of incentive regulation. The costs incurred by the regulator in order to remunerate the DSO are then transferred to the final consumer as a fixed cost in the tariffs.

Cost-of-service regulation is based on audits of the company's accounts and more specifically its expenditure and investment records. Such regulation is very difficult to implement in this type of business, which involves a large number of small facilities and investments. It can cause a tendency by the regulator to micro manage the regulated firm in order to obtain efficiencies, keep an adequate quality level and control costs.

Price quality benchmarking, or incentive based regulation, uses incentives to induce the regulated firm to operate in a certain way by making the firm partially claimant of the residual gains resulting from better performance (Ajodhia, 2005).

Yardstick remuneration is a variant of incentive based regulation, where the company's performance indexes and costs are compared to an industry standard and the remuneration is allocated according to efficiency with respect to other companies.

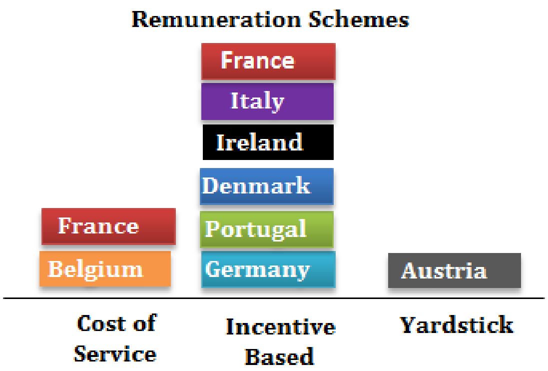

Figure 11: Remuneration Schemes

Most of the surveyed countries apply some sort of incentive based regulation, be it price caps, or yardstick remuneration as can be seen in Figure 11 .

Belgium: Cost-Plus (cost price), a multi-annual tariff mechanism (with a 4 year regulatory period, currently until the end of2012) is based on the cost recovery of all reasonable costs (incl. financing costs) and contains a fair profit margin as remuneration on invested capital. Current regulatory tariffs were prolonged for two years (2013-2014) by decision of the CREG (federal energy regulator). The responsibility for DSO remuneration will be, in the coming months, transferred to the departmental level regulators.

Portugal: The revenue cap strategy is used in conjunction with a price cap, and it is a type of incentive regulation. According to this approach, the Regulatory Agency approves the maximum value that the regulated revenue can reach as a function of some variables emulating the cost structure of the activity under analysis. Once this remuneration is approved, it is then converted into the tariffs for the Use of Distribution Networks. These tariffs are split in tariffs for the High Voltage (HV) network, for the

Medium Voltage (MV) network and for the Low Voltage (LV) network and all of them are set in terms of prices on the contracted power and on the peak power. Cost drivers can be seen as price capped, in order to limit the DSO's revenues.

Germany: DSO (and TSO) networks in Germany are regulated by an elaborate incentive regulation approach that covers Total Expenditure (TOTEX) (i.e. OPEX and CAPEX) and includes an efficiency benchmark. The regulatory period lasts 5 years and uses a revenue cap approach. The cap is calculated by a cost review and benchmark. In the benchmark Data Envelopment Analysis and Stochastic Frontier Analysis are applied to two different cost bases and a best of four approaches is used to come to the final result.

France: The current regulatory framework applied to the French DSO ERDF is based on a hybrid regulation: the model of cost-of-service and the incentive-based regulation are applied. The allowed revenue of the DSO covers the costs determined via the cost-of-service methodology on one hand and includes performance mechanisms on the other hand. The regulatory formula includes the covering of capital and operating costs. The formula takes into account the financial incentives resulted from the incentive-based regulation (for service quality, continuity of supply). Finally, it also includes a "claw back mechanism", called CRCP, which takes into account possible variances between the estimated and real figures of some costs that are difficult to predict. The result of this extra-account can increase or reduce the allowed revenue of ERDF.

Italy: The regulatory scheme is incentive based regulation. In the scheme, OPEX are subject to a price-cap mechanism. CAPEX are not subject to an ex-ante approval by the Regulator regarding both the single investment and the total amount, and are included in the Regulated Asset Base (RAB).

Denmark: Incentive-based scheme: Price cap (which can also allow for a revenue cap). Quality of Service (QoS) is considered in the regulatory formula. Note that Denmark has the highest level of QoS in Europe. This means that it is substantially more costly to improve QoS in Denmark than in other systems. Due to this measures for increasing this level are not expected.

Ireland: The revenue regulation scheme applied is an incentive based scheme. To set such charges, the regulator (CER) first determines the revenue that the DSO, is allowed to earn in order to cover the cost of providing the network. This is done every five years on an in-depth basis and only equitable levels of costs are permitted to be recovered from customers. For the tariff regulation the revenue the DSO is allowed to collect from customers is reviewed and refined each year and the 'allowed revenue' is used to calculate the distribution use of system (DUoS) tariffs, which are approved by the CER. DUoS tariffs are charged to suppliers on the basis of the amount of energy used by their customers, and include standing charges. There are different DUoS tariffs for different types of customers.

Austria: The regulatory approach is mainly based on incentives.. The regulator defines efficiency goals and benchmarks are used to compare different utilities, where the most efficient one gets the highest reward, while less effective DSO get reduced rewards.

Costs Calculation:

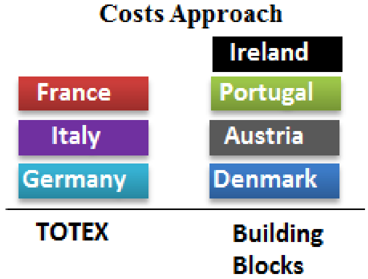

Figure 12: Costs Approach

The costs approach defines the way in which DSO costs are calculated in order to be included within the regulatory formula given the chosen remuneration approach. There are different ways to approach the cost calculation for remuneration of the DSO: TOTEX and Building blocks as can be seen in Figure 12:

- The *Building blocks* approach evaluates total distribution costs with separate assessments for OPEX and CAPEX (Cossent, 2013).
- Under the *TOTEX* approach the regulator does not differentiate between OPEX and CAPEX, but sets the incentive factor on the basis of the sum of the two concepts. This means that the regulator does not need to consider investment projections by the firm but instead performs a benchmarking analysis of actually incurred levels of TOTEX (Ajodhia, 2005).

In *Austria*, the approved benefit of the DSO is based on the interest rate related to CAPEX. OPEX, which are approved by the regulator, are also used in the calculation of the grid tariff but overheads on OPEX are not allowed. TOTEX is compared to benchmarks. If TOTEX is too high compared to other national DSOs and the regulator's objective, the approved benefit will be reduced.

In *Italy* OPEX are subject to a price-cap incentive mechanism and CAPEX are not subject to an ex-ante approval by the regulator regarding both the single investment and the total amount. Similarly OPEX are included in the RAB.

In *Belgium* the approach so far has been Data Enveloping Analysis (DEA), which is a type of benchmark cost calculation. It takes TOTEX into account. However, it is uncertain whether this or another regime will continue in the future as the regulation is being transferred from the federal to the departmental level.

In *France* there are two types of remuneration models since 2009, the economic model and the accounting model. In the economic model (TURPE 3) the allowed revenue of the DSOs usually includes the covering of capital (remuneration + depreciation) and OPEX, increased or reduced by the result of the performance-based regulation. In the accounting model the capital costs are calculated according to the financial statements of the DSO. Therefore, the capital costs are equal to the sum of the operating income, the financial income and the "exceptional" result. The remuneration is calculated by multiplying the equity of the DSO by the cost of equity.

In *Portugal*, there are two different regulatory approaches in terms of allowed revenues: one for CAPEX and the other for OPEX. OPEX is limited, through price caps on cost drivers, while CAPEX is given a rate of return, estimated as the weighted average cost of capital. The regulator allows the DSO to receive a rate of return applied to the RAB, which is not subject to efficiency targets. On the other hand, the OPEX's cost drivers are subject to efficiency factors, and reduced yearly (in real terms), during the regulatory period.

In *Germany*: DSO (and TSO) networks in Germany are regulated by an elaborate incentive regulation approach that covers TOTEX (i.e. OPEX and CAPEX) and includes an efficiency benchmark. The regulatory period lasts 5 years and uses a revenue cap approach. The cap is calculated by a cost review and benchmark. In the benchmark Data Envelopment Analysis and Stochastic Frontier Analysis are applied to two different cost bases and a "best of four" approach is used to come to the final result.

Regulatory Period Length
The regulatory period is the amount of time between revisions of the payment scheme for the DSOs. The regulatory period length for the surveyed countries can be seen in Figure 13. The longest period reported is years, which is usually not enough time to recover costs for capital investments. Longer regulatory periods allow the DSO to reap benefits from large investments, especially in incentive based remuneration schemes.

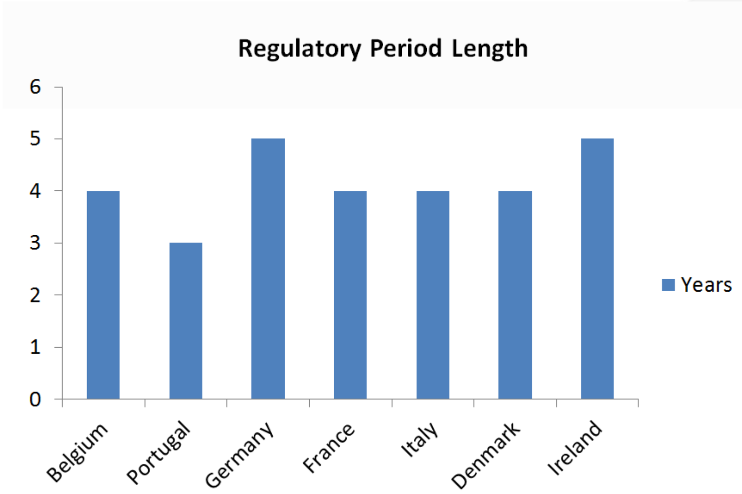

Figure 13: Regulatory period length

3.1.4 Quality of Service

QoS is characterised by three main aspects: continuity of supply, power quality, and customer support. Continuity of supply or reliability, measures the ability of the network to continuously meet the demand from consumers. Power quality refers to the physical quality of the voltage waveform and covers phenomena like variations in frequency, fluctuations in voltage magnitude, transients and other distortions. Commercial quality refers to individual agreements between the distribution firm and their consumers, including connection of new consumers, installation of measuring equipment, reading and billing, and response to problems and complaints (Ajodhia, 2005). There is a trade-off between QoS and costs which must be maintained. Incentive regulation means to motivate the DSO to upkeep certain quality standards by rewarding good performance.

Common indicators are related to reliability from the consumer perspective (Ajodhia, 2005):
SAIFI: measures the probability that a customer will experience an outage. It is calculated by dividing the number of customer interruptions by the total number of customers served. The number of customer interruptions is the total number of interrupted customers for each interruption.

SAIDI: provides a measure for the average time that customers are interrupted. It is calculated by dividing the total customer interruption duration by the total number of customers. The customer interruption duration is defined as the aggregated time that all customers were interrupted.

CAIDI: is defined as SAIDI divided by SAIFI, it is a measure for the average time required restoring service to the average customer per interruption. It is calculated by dividing the total interruption duration by the total number of interruptions.

Energy not supplied: considers the amount of energy not supplied because of interruptions, normalised by the number of connected consumers.

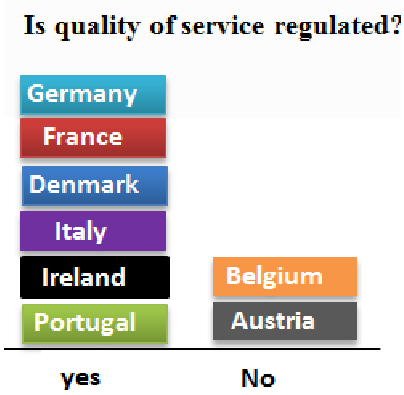

Figure 14: Quality of Service Regulation

As shown in Figure 14 in *Belgium* and *Austria*, QoS is monitored but with no financial implications on the remuneration of the DSO. In Belgium the regulator monitors specifically the number of interrupted minutes, there is no remuneration linked to it but there can be a penalty in case of default. In all other countries the remuneration received by the DSO is linked to quality indicators.

In *France,* there is a regulatory framework regarding quality of service: "Décret qualité". The monitored criteria are overall voltage stability, continuity of supply and differentiation of quality requirements among zones. Regarding voltage stability, the voltage level must not deviate more than 10% in relation to the reference value. Continuity of supply is measured by the number of long interruptions, the number of short interruptions and the accumulated value of interruptions during a year. These values must not exceed certain limits. Last, there is also the possibility to differentiate the levels of required continuity of supply according to geographical areas.

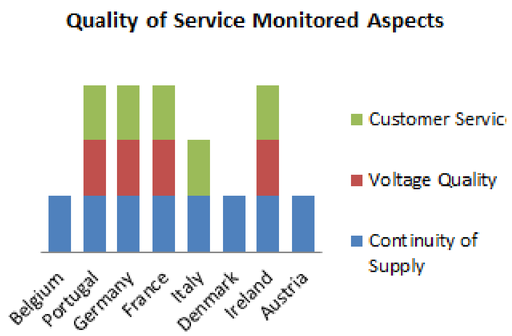

Figure 15: Regulated or Monitored QoS Aspects

Figure 15 depicts which QoS aspects are being monitored by the DSO within the regulatory formula of the surveyed countries.

3.1.5 DSO Regulatory Framework and DRES

Change drivers in the electricity industry are calling for changes in the way that power systems are managed. DRES in particular has impacts on distribution grid management. DSOs now have to accommodate generation in their networks, provide connection and access, manage this generation, and still upkeep a good quality of service. Demand response and expanded communication technologies, are another change driver for the electricity industry. Smart management of the network is enabled, and investments in reinforcements can be postponed. However, the regulatory framework needs to motivate and allow the DSOs to invest in smart management systems. Regulatory aspects such as unbundling, connection and access, remuneration schemes and quality of service are analysed in terms of the introduction of DRES and the results of the survey presented above.

The **unbundling** of electricity production and delivery activities means that the DSO cannot own generation assets. If the DSO owned generation assets this would lead to an unfair advantage in case of network constraints, economies of scale and investment risk. It would also pose an entry barrier for other market players. Therefore, unbundling encourages free market activities and private investment of generation within the network. As reported above, most surveyed countries have legally and functionally unbundled but are not yet a fully ownership unbundled. Unbundling rules, however, dictate the establishment of Chinese walls of information between the regulated monopoly and the competitive businesses and penalise market power abuse in the electricity market.

The DSOs need to provide **connection & access** to both generation and consumers who request it. Current renewable energy support schemes motivate investment in DRES, mainly in the form of wind parks and solar panels in households. The DSO needs to foresee future DRES connection possibilities and requests in the network planning. It is important to evaluate whether a new connection will cause network congestion or instability issues. Similarly, a high amount of DRES can cause reverse flows from the substations of the DSO to the TSO, a situation for which the network was not initially designed. If this is the case, the DSO needs to build the needed grid reinforcements or apply congestion management mechanisms. All users are entitled by law to get connection and access to the grid under the valid payment scheme in the country. Regarding connection costs, as was seen in section 3.1.2, the dominating trend is to divide costs between the DSO and the party requesting connection. However, this mostly applies to the connection of the user to the network and not the effect that his use might have on the rest of the network. Reinforcements and actions for possible congestion management still fall under the responsibility of the DSO.

Some form of incentive based DSO **remuneration scheme** is preferred in the surveyed countries. The aim of the regulation is to motivate the DSO towards cost efficiency while maintaining standards of quality of service. Traditionally this is a sound type of regulation, however, it is not conducive to high investments in innovative solutions. DSOs get remunerated for grid reinforcements; therefore there is no immediate need to find solutions in order to postpone the reinforcements through active congestion management. In contrast, reductions in operating expenses are rewarded in incentive regulation. However, the regulatory period is too short for the DSO to see operating expenses reductions if they invest in smart grid technologies. Whether or not the DSOs will finance the smart grids depends on whether they can reap the rewards of doing so within the remuneration scheme they are allowed.

Quality of Service *(QoS)* is a concern when regulating for efficiency. There exists a clear trade-off between operating expenses and quality of service. In all of the surveyed countries the regulator monitors quality of service indicators such as interruption duration indexes, frequency of interruptions, and total non-delivered energy. The traditional solution to repeated quality of service issues has been to invest in grid reinforcements. Given the variability of DRES there are other solutions which could help to alleviate problems that occur only in a limited number of hours. Smart grid storage or demand response can alleviate problems in the grid without resorting to investments in reinforcements. Quality of service indicators could be potentially linked to smart grid management.

In conclusion, the main aspects of the DSO regulatory framework are the level of unbundling, the way of charging network connection and access, the remuneration scheme of the DSO and the quality of service regulation. The introduction of DRES changes the playing field and regulation needs to be adapted accordingly. Remuneration linked to performance is a key element in progressive DSO regulation. It is the definition of what exactly 'performance' means that will change in the future as it is correlated to smart grid management and DRES.

3.2 Electricity Market Design

Electricity markets are characterised by different trading times in relation to the actual system operation. Market participants interact in the following submarkets: long term market, the day-ahead market, the real time or intraday market.

Electricity markets in Europe are generally single price markets, meaning that the market is cleared at the marginal cost of providing electricity to the demand, and all units are paid the same for each time period. There is a tendency towards coupling different markets (i.e. setting up a common clearing based on available cross-border capacities), first at a regional scale and, when possible, at the continental level.

Ancillary services, or grid support, consist of the market for reserves and other ancillary services needed to maintain system operation. The market for reserves is more diverse, as each market has defined their own rules. Generally speaking there are three main reserve services: Frequency containment reserve (FCR), frequency restoration reserve (FRR) and replacement reserve (RR) - all applicable to the transmission level network operation. All three serve to correct frequency deviations during grid operation, with a time frame of 0-15 minutes. Other grid support services include black start capabilities and reactive power management.

Grid support is also contracted in advance, usually through tendering procedures, or supplied via a day-ahead and/or a real-time market for grid support. In both cases, tender and market, two types of payment are possible, one for reservation of the capacity and one for energy dispatched.

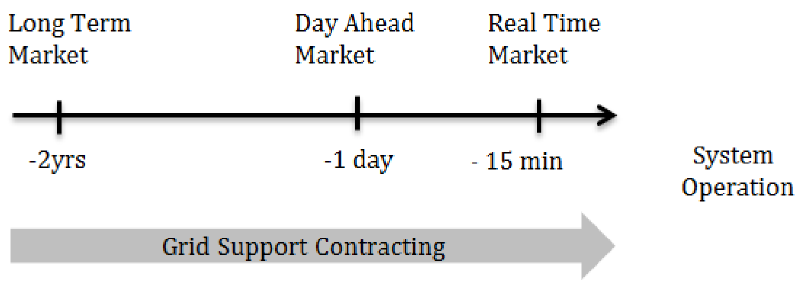

Figure 16: Time horizon on electricity markets

3.2.1 Energy Only Market description

3.2.1.1 Participation Conditions

Parties willing to participate in electricity markets must register as market actors, either on their own or through a representative. They are usually required to work with a bank and to provide bank guarantees covering all or part of the transactions presented to the market. Parties without generation assets are allowed to take part in the market. Such entities perform only purely financial transactions and make their living out of their arbitrage capabilities.

In order to run smoothly, organised markets need a standardised definition of the traded products (e.g. ceiling price, minimum quantity). Unfortunately, the minimum bid amount requirement may be prohibitive for smaller parties, such as distributed renewable resources, or demand response aggregators. The average for the interviewed countries stands at a minimum energy offering of 0.1 MWh. All countries require a minimum offer or 100 kWh as can be seen in Figure 17.

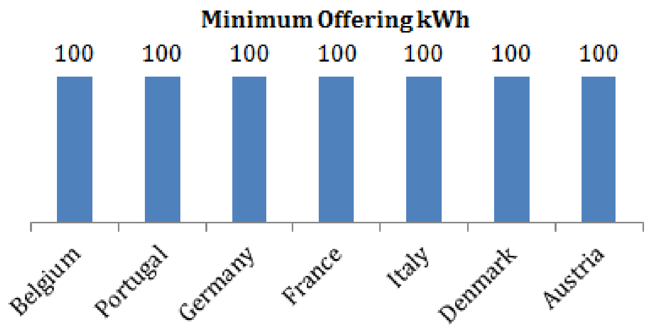

Figure 17: Minimum Offering kWh

3.2.1.2 Market Characteristics

Electricity markets are characterised by the way they are organised in terms of trading periods, number of sittings, and bid modes. Trading periods refer to whether the market is cleared at pre-defined periods of time, discretely, or if bids are continuously accepted and matched. The number of sittings refers to the number of times a day that a discrete market will match bids together. Bid modes refer to the types of bids accepted. The bids can be simple price quantity pairs, or complex bids containing technical information about the generating units.

Trading periods:

Discrete or Continuous Clearing:
Under discrete clearing schemes, market bids and offers are matched on discrete period of times, one, two or up to six times during the market session. In a continuous clearing scheme there is only one market session where offers and bids are matched as they are submitted. Figure 18 and Figure 19 present the trading periods allowed for the day-ahead and intraday markets respectively.

In Figure 18 it can be appreciated that all day ahead markets prefer to have discrete trading periods where the markets is cleared on a marginal price basis and all bids accepted will pay or receive the same price.

Figure 18: Trading Day Ahead Market

Figure 19 shows that the intraday market is more evenly spread between discrete or continuous trading. In cases where there is continuous trading available bids and offers are accepted up to a period of time before real time varying between 75 minutes (*Austria*), 1 hour (*Denmark*), 45 minutes (*France* and *Germany*), and 5 minutes (*Belgium*).

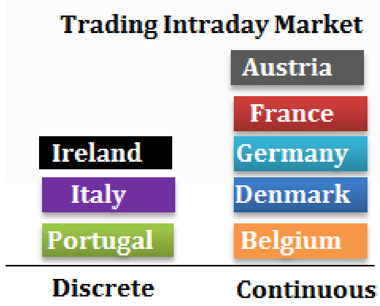

Figure 19: Trading Intraday Market

Sittings (sessions):
The amount of times that participant's bids are evaluated and matched during a session constitutes the amount of sittings of that market. For continuous markets, there is only one sitting, since submitted bids are matched on a rolling basis.

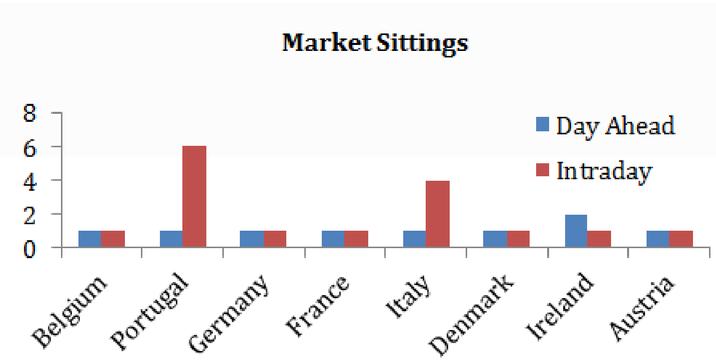

Figure 20: Market sittings

3.2.1.3 Bidding methods

Bidding methods explain the way in which bids and offers are accepted into the market. The differences in bidding methods lie in whether generating units must bid separately or they can bid within a portfolio, and whether the bid accepts technical characteristics of the units (complex) or not.

Bid mode:
Portfolio bidding: means that the organised market output does not induce automatically any piece of a generators' program (unit commitment) to be taken into account by the TSO. The bids are not linked to specific generating units. The organised market physical output is then a clearing balance that the portfolio is committed to include in its final imbalance settlement. In other words, all the unit commitment is done by portfolio managers separately from (and after) the organised market clearing.

Unit bidding: means that each bid must be linked to a specific unit (generation or load) and the organised market physical output translates directly into the programs for generators and loads.

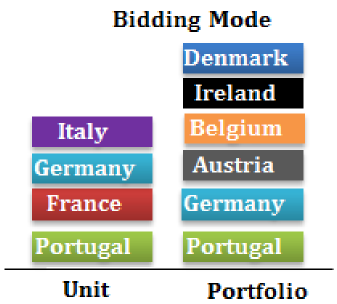

Figure 21: Bidding mode

There is a tendency towards portfolio bidding. This allows companies with many generation assets to propose a single price quantity pair and then manage their output in the best way possible with their available assets. This decreases the risk of imbalances, since a default of one unit can be covered by another unit in the portfolio.
In the case of *Portugal,* unit bidding is usually specified, except for RES which can bid within a portfolio, therefore, the two methods apply, unit and portfolio.
In *Denmark,* markets operate with portfolio bidding, for ancillary services (section 3.2.3); they are pre-qualified unit-wise, but still bid into the market in portfolios.

Bid Type:
Simple bid: a simple order consists in a unique proposed quantity at a unique proposed price for a unique time, cf. bid granularity. The allocated quantity of each step may be any value between zero and the proposed quantity.
Complex bid: These bids reflect the cost characteristics of the unit (including the marginal, start-up and no-load costs) as well as some technical parameters (minimum and maximum output, flexibility) (Kirschen and Strbac, 2004).

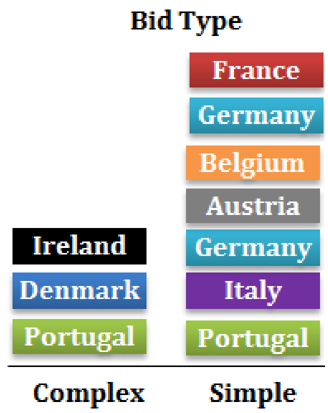

Figure 22: Bid Type

Block/Single Orders:

A block order consists of a quantity that is offered or requested in multiple hours at an average price limit. Besides this inter-temporal rigidity, blocks also have a fill-or-kill constraint, meaning that the order has to be accepted completely or not at all (Meeus, 2006). In contrast, a **single order** applies only for a certain time period of time and is not dependent on the acceptance of the orders in adjacent periods of time. In addition, a block order can contain execution conditions such as: Fill-And-Kill (FAK) – the unexecuted part of the limit order is immediately and automatically cancelled. Fill-Or-Kill (FOK) – if not executed in full the order is immediately and automatically cancelled. All-Or-None (AON) – if not executed in full the order remains in the order book till it can be executed in full. Figure 25 presents whether block or single period orders are accepted in each of the surveyed countries.

Stepwise divisible order: a stepwise divisible order is proposed at a unique price; see Figure 23 for a graphical representation. A stepwise order may be partially accepted if and only if the Market Clearing Price is equal to the price limit of that order.

Linear divisible order: a linear divisible order is proposed between a lower limit price and an upper limit price see Figure 24 for a graphical representation. A linear order may be partially accepted if and only if the Market Clearing Price (MCP) is between the two price limits of that order (linear curve). In general, the order must thus be accepted in proportion of the distance from the MCP to the price limits.

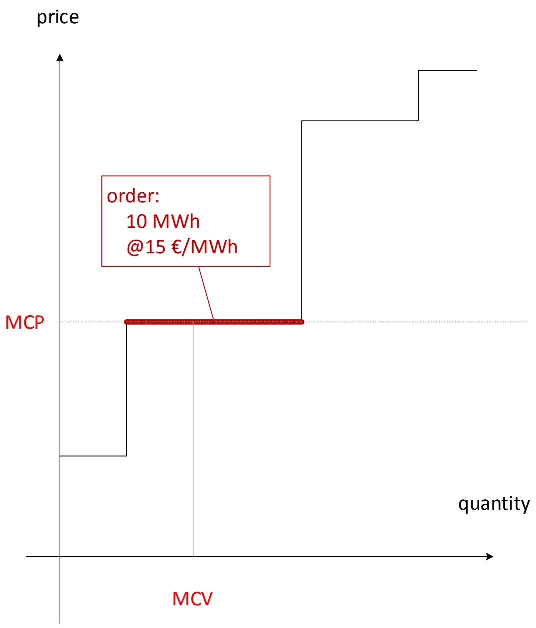

Figure 23: price determination/stepwise order

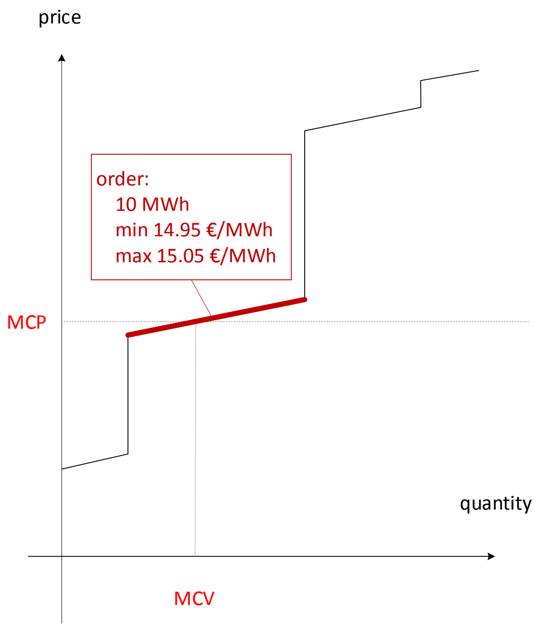

Figure 24: price determination / linear order

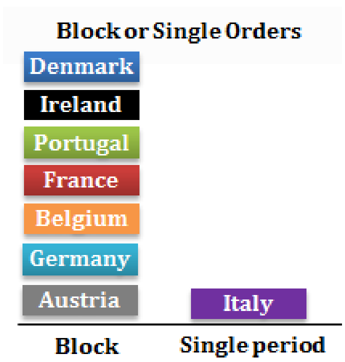

Figure 25: Block or single orders

In *Belgium* the day-ahead market accepts block orders subject to same day delivery. The volume may vary for all bids within a block order. Conditions such as fill and kill orders, fill or kill orders and all or none orders are applicable. During the intraday market block orders are accepted, the volume and price for all the periods of energy within the block must be equal, and execution conditions are not applicable.

In *France* and *Germany* all orders can only be either accepted fully, or rejected fully due to the fill or kill constraint.

Germany accepts block orders with varying volumes. Such an order is executed for the whole quantity in every hour or not by comparing its price with the volume-weighted average of the hourly market clearing prices related to the hours contained in the block. Thereby, a specified minimum period of a generation output is considered.

Portugal and *Ireland* introduce intertemporal links though the allowance of technical generator constraints such as minimum on and minimum off times.

3.2.1.4 Pricing

Pricing refers to the area for which a market is cleared and the price formation mechanism used.

Clearing area:

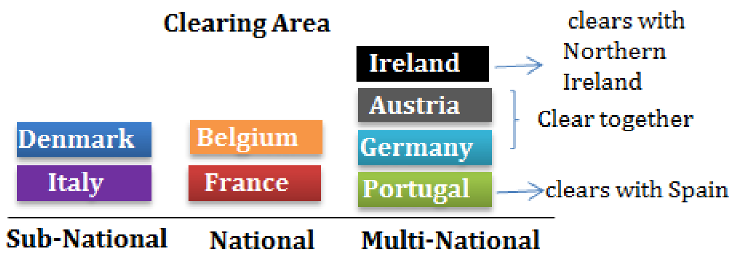

Figure 26: Clearing Area

Figure 26 indicates whether the surveyed countries clear the market in a sub-national, national or multi-national approach.

Sub-national or zonal clearing: There can be different prices within one country in the presence of congestion.

Wholesale market clearing: the whole market area is cleared in a single market and one price is defined for the whole market.

Multi-national clearing: a region consisting of two or more countries is cleared in a single market, and in the absence of congestion a single price exists for the entire region. This is the case for Germany and Austria, and for Portugal and Spain. In case of congestion in the interconnection the market is split and two different prices exist. The procedure is referred to as market splitting, it is different than market coupling, where individual markets accept bids from neighbouring countries and then clear their own area. Market coupling will be discussed in detail in section 3.2.1.5 on Market Coupling.

Price Formation Mechanism

A merit order of generation units is created, starting with the cheapest available unit up to more expensive units until the entire amount of load is covered (Meeus, 2006). The price at which electricity is traded can be determined in different ways, there can be a single price for a market or several prices depending on the type of mechanism selected:

Pay-as-cleared or Marginal price (single price market): all units are remunerated at the marginal price of the system given by the intersection of the supply and demand bids (Barroso et al., 2005). The price is given by the most expensive generator that would have to be dispatched in order to clear the market. In a single clearing area the entire system is cleared at once based on economic principles without taking into account the physical network. Congestion and losses are then accounted for by the system operator and the costs for these are levied equally to all system users (Delgadillo et al., 2011). Figure 27 shows that all surveyed countries have a pay as cleared approach to day ahead market trading.

Figure 27: Price Formation Day Ahead Market

Pay-as-bid: units submit a price-quantity bid and are paid at their nominated price for the quantity cleared in the market (Ventosa et al., 2005). This means that each generating unit will receive a different payment and there is not a single price for electricity. Figure 28 shows that for the intraday markets that trade continuously the price formation mechanism is pay-as-bid, where matching orders are paired on a first come first serve basis and the trade is closed at the price of the first bid/offer made.

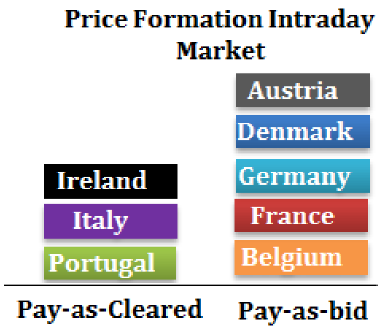

Figure 28: Price Formation Intraday Market

Negative Pricing

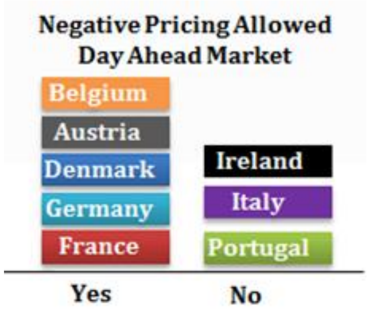

Figure 29: Negative Pricing

Figure 29 shows which countries allow negative prices as a result of the wholesale market clearing operation. Where allowed prices indeed are sometimes negative due to the effect of connected RES that are available during low peak hours. In countries where negative prices are not allowed, like Portugal, prices are known to reach the 0€ minimum market price.

Price Step

Figure 30 shows the minimum price step allowed for bidding in the day ahead wholesale markets of the surveyed countries. The price step is small in all countries surveyed, allowing specific price quantity bids to all participants.

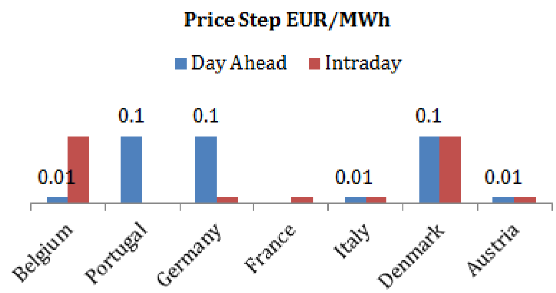

Figure 30: Minimum Price Step in the Day ahead and Intraday Markets

3.2.1.5 Market Coupling

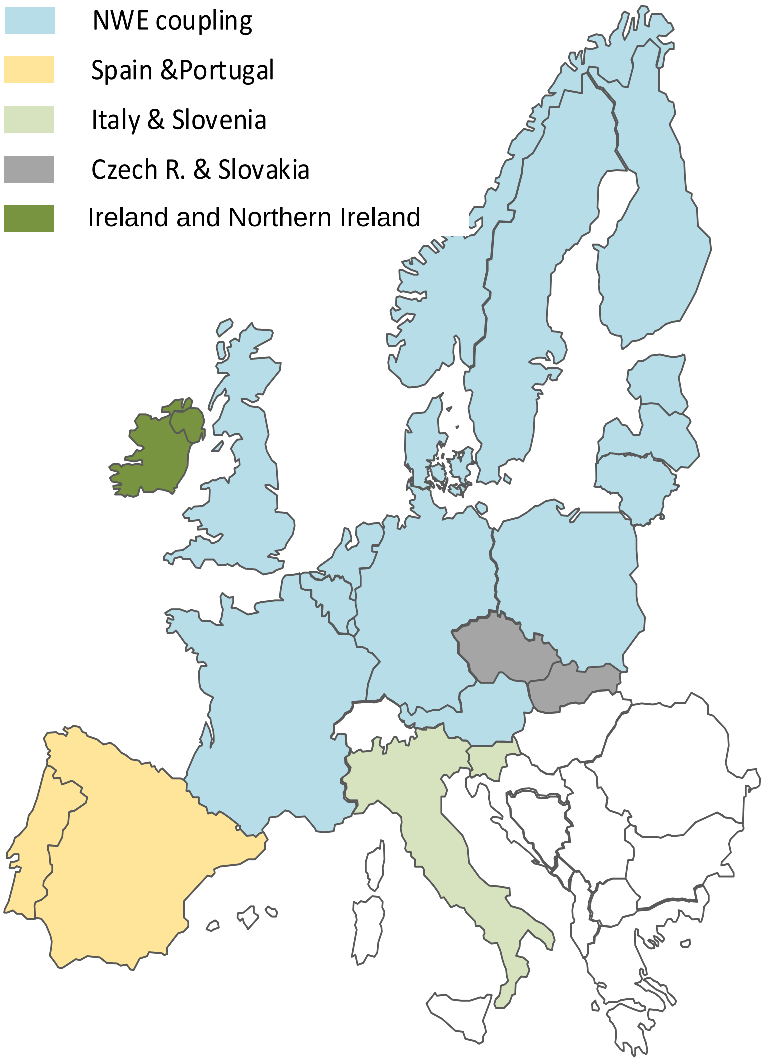

Figure 31: Multinational Market Coupling

Multinational market coupling procedures are enabling larger areas where players can trade. In a market coupling mechanism national markets still exist and are cleared separately. However, they accept bids from other coupled countries as far as the interconnections allow. Since February 4th 2014 the North Western European markets have been integrated into a price coupling mechanism as can be seen in Figure 28. The new cross-border trading platform integrates 15 European countries (Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Great Britain, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland (via the SwePol Link) and Sweden), accounting for 75% of the European electricity market.

Market coupling: Market coupling is best described as market clearing in an international context with network constraints. Note that the term market coupling wrongly suggests that it is about coupling markets that were previously not coupled. In Europe, it is about replacing the explicit allocation of transfer capacities in separate interconnector capacity markets by a system where exchanges can use the capacities to optimise the clearing of orders introduced to their auctions (Meeus, 2006).

Market splitting: the market operator determines a single price for all zones in the absence of congestion; otherwise the market is split into predefined price zones (Meeus, 2006).

3.2.2 Demand Response

An increasing need for flexibility due to intermittent RES drives the introduction of demand response programs to the electricity markets. There are several ways in which demand can participate in the market, either through price signals or through dispatchable programs. Figure 32 shows which countries have implemented some type of demand response program. Time of use tariffs are implemented in all the surveyed countries but they are not taken as a demand response program since it is not possible to control those resources (directly through communication signals, through requests, or market bids).

Demand response: refers to the actual response/reaction of demand on certain signals or incentives to change their behaviour, i.e. changes in electric usage by end-use consumers from their normal consumption patterns in response to changes in the electricity price or to a request from a supplier or aggregator.

Demand side participation: refers to active participation of small and large electricity consumers, potentially acting through a third party coordinator, and prosumers in the power system markets and in the provision of services to the different power system participants.

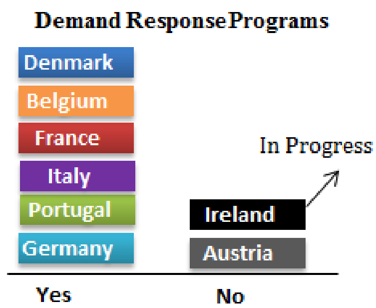

Figure 32: Demand Response Programs

In *Belgium* several commercial Demand Response products are already in place and applied: FCR (Frequency containment reserves), for loads, FRR ICH (Frequency replacement reserves, Interruptible Contract Holders), FRR APP (Aggregated Power Plants) and FRR R3 Dynamic Profile, all open for aggregation. The latter two can be activated on distribution grid as well.

In *Germany,* big industry companies can take part in the reserve market in the form of interruptible loads.

In *France* there are a number of programs available for consumers connected to the transmission grid, ranging in different time frames. The *Appel d'offres effacement* mechanism allows the TSO to contract demand capacities to be available for delivery within two hours. The *Safety Reserves*, both the fast reserve and the complementary reserve are open to demand capacities. Similarly there is also an interruptibility program for large consumers (above 60MW) to reduce demand within 5 seconds. Time of use tariffs and supplier curtailment schemes can be contracted by end users to reduce their electricity bills. In addition, the NEBEF (Notification d'Échange de Blocs d'Effacement) mechanism was designed to allow end-users or third parties acting on their behalf to sell the energy from a demand reduction on the French day-ahead market. The mechanism started in 2014. The French TSO is currently opening frequency response reserves (FCR and FRRa) to demand side capacities. Participation of demand side resources to these reserves is due to start mid-2014. Finally demand will also be able to participate either implicitly or explicitly in the capacity market from 2015 onwards. Demand response will be able to get a tradable availability certificate, just like generation, which must be traded by suppliers in order to cover peak demand. Although the landscape is large for demand side resources to participate in balancing and ancillary services in France, there is currently no business as usual program allowing demand to provide flexibility to the DSO.

In *Portugal* all consumers connected in Extra High Voltage (EHV), HV and MV that procure their energy in the daily market or through bilateral contracts or via contracts with the regulated retailers can provide demand reduction to deal with emergency situations and to increase the flexibility of operation of the system. The remuneration of this service is obtained as the addition of a monthly amount that considers the investment and fix operation costs of gas combined cycle turbines plus a term depending on the usage of the service. This variable term depends on the electricity market prices during the hours the service is used and on the number of hours the service is used in each month.

In *Italy* the authority has set time of use tariffs for residential consumers, two time bands are applied to 25 million consumers. In addition, there are trial projects, such as the Isernia Project in the substation of Carpinone, where consumers receive a monitoring kit in order to manage their consumption more actively.

In *Denmark* demand can participate in all markets on equal terms with generation. However, there is a technical challenge to comply with the requirements for fast reserves (online monitoring and communication). Large demand like electric boilers for district heating does participate.

Ireland has legacy demand response programmes which are being updated. The DSO also has an ongoing mechanism for demand side units participating in the market.

3.2.3 Ancillary Services

Reserves markets exist in order to procure services that aid in grid support, such as maintaining overall balance between generation and load, voltage quality, black start capabilities and reactive power control.

Frequency containment reserves (FCR): operating reserves necessary for constant containment of frequency deviations (fluctuations) from nominal value in order to constantly maintain the power balance in the whole synchronously interconnected system. Activation of these reserves results in a restored power balance at a frequency deviating from nominal value. This category typically includes operating reserves with the activation time up to 30 seconds. Operating reserves of this category are usually activated automatically and locally (ACER, 2012).

Frequency restoration reserves (FRRa and FFRm): operating reserves used to restore frequency to the nominal value and power balance to the scheduled value after sudden system imbalance occurrence. This category includes operating reserves with an activation time typically up to 15 minutes (depending on the specific requirements of the synchronous area). Operating reserves of this category are typically activated centrally and can be activated automatically (FRRa) or manually (FRRm) (ACER, 2012).

Replacement reserves (RR) are activated after 15 minutes in order keep the FRR available to respond (ENTSO-E, 2013). Other grid support services are reactive power regulation, and black start capabilities. Replacement reserves have not been fully implemented as an ancillary service in all countries, and are therefore not taken into account in the following sections.

3.2.3.1 Procurement

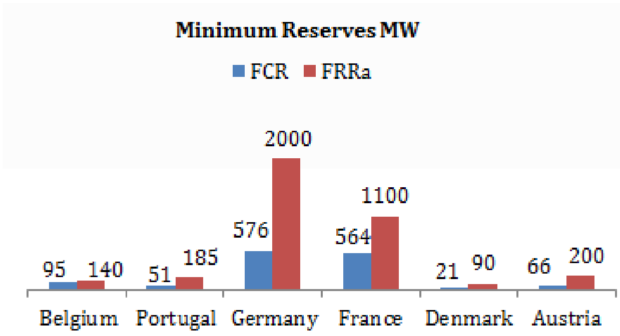

Figure 33: Minimum Amount of Reserves Procured

Reserves are dimensioned in relation to the size of the system in question, which means that larger systems need a higher minimum amount of reserves than smaller systems. However, a scale effect shall be taken into account, reducing the relative reserve need (ie. percentage of the mix) with a larger system.

Reserves are procured differently across the surveyed countries. The most common form of procurement is through a tender in which interested parties submit proposals and are selected according to price and system needs. The tender is carried out on a mid to long term basis, e.g. Yearly, trimonthly, monthly, etc… Figure 34, Figure 36, and Figure 37 present the procurement methods used for FCR, FRRa, and FRRm respectively.

In *Belgium* ancillary services are purchased using a European call for tenders. Required volumes for the wanted ancillary services are published at the beginning of each year (inviting interested suppliers to apply). Bids submitted by providers (use of capacity – balancing energy) are selected by financial merit order (lowest to highest until the predefined volume is reached). Units providing primary reserve should have an automatic speed, rotation and frequency control system. Consumption facilities that provide tertiary [offtake] reserve should have signed an interruptibility contract.

In the case of *France*, the fast acting FCR reserves are procured in the day ahead and intraday markets on a continuous basis. Shares of FCR and FRR are allocated proportionally to their own generation programs. Balancing service providers (BSPs) are free to choose which groups will provide reserves; they send their programs [P, FCR, FRR]. FRRm is activated manually and should be offered within 13 minutes when asked. Only generators connected to the transmission grid are able to offer ancillary services (technically speaking) and are obliged to do so (FCR and FFRa are compulsory); production units connected to the MV and LV network have no legal obligation to participate to frequency reserves. The amount is determined as a share of their generation program and remunerated at €18 per MW per hour of supply of primary or secondary reserve. Yet they are able to transfer their compulsory reserve to other generators through over the counter (OTC) contracts, and state it to RTE.

In *Portugal* all generating units directly connected to the national grid must provide primary regulation. Every generating unit should allow this primary regulation (or FCR) in the band of at least

5% of the nominal power around each stable operating point, adjustable between limit values (4 and 6%). Secondary Regulation (or FRRa) is an optional ancillary service that is contracted and managed by the TSO under a pool based market mechanism. The secondary regulation dynamic ranges between 30 seconds and lasts for 15 minutes: orders are sent to different regulation zones that comprise a set of automatic generation control (AGC) units, although might include non AGC units as well) every 4 seconds. Secondary reserve is allocated through an auction the day before delivery at 13h00. The generating units mainly used for providing secondary reserves are the hydro units; however some thermal units are also capable of providing it. Tertiary reserve (FRRm) requirements are calculated by the TSO every hour 15 minutes before the beginning of the delivery period and even during the delivery period if needed. Mobilization lead-time for tertiary regulation is always 15 minutes and the maximum duration could be up to 2 hours (but it is usually no longer than 1 hour). Again for the tertiary reserve, hydro units are the main providers, followed by the thermal units.

In *Germany* primary reserve (FCR) is contracted through a weekly tender procedure. The FCR is geographically evenly distributed within the interconnected power system, because it is frequency dependent. The secondary reserve (FRRa) is provided within the TSO control area and contracted through a weekly tender procedure. The minute reserve (FRRm) is also automatic in this case and it is a scheduled product contracted on a daily tender.

In *Italy* ancillary services, like primary reserve, voltage support or black start-up must be provided by producers on a compulsory and regulated basis. The system operator procures resources in the Ancillary Service Market (MSD), which takes place daily after the Energy market. Once positions resulting from the Day Ahead Market (DAM) and Intra Day Market (IDM) have been finalised, the TSO Terna procures any ancillary services that it requires in order to ensure system security, then the system operator acts on the MSD as single purchaser/seller of the submitted offers/bids. Those units on the continent and those in Sicily, which participate in the regulation of the primary frequency, must ensure active power reserve of no less than 1.5% of the maximum capacity communicated to the TSO. In the island of Sardinia, and in Sicily when the interconnection with the mainland is open, each unit has to provide a primary reserve of at least 10% of its maximum power. The TSO determines, for each scheduling interval, the secondary control reserve needed for the next day. The available unit must provide the maximum value between 10MW and 6% of its maximum capacity for thermoelectric power plants and 15% of its maximum capacity for hydroelectric power plants.

In *Austria* primary control (FCR) is contracted through a tender. The tendering period (the period in which the primary control power should be provided) always extends from Monday 00:00 to Sunday 24:00 (a product over 7 days). The total volume of primary control power must be available in this period without interruption. The product contains equal amounts of negative and positive primary control reserve. Separate offers for positive or negative primary control power are therefore not possible. Secondary control (FRRa) is also contracted through a one week tendering period. Tertiary control is tendered daily on 6 different time slots. In addition, there is a short-term tender in which no power price is paid for the reserved tertiary power control ("day-ahead tender"). In this tender, different energy prices can be bid for the 6 product time slots on each individual day (i.e. 6 products per day).

In *Ireland* in principle,, any service provider may offer to provide ancillary services, provided they can fully meet the technical specifications of a give service, regardless of the underlying technology used to provide the service. There are a number of eligibility conditions which must be satisfied before a contract can be put in place. For each month, the System Operator calculates the payments due to, and the charges due from, each Service Provider. In Northern Ireland, payments are calculated for each Trading Day.

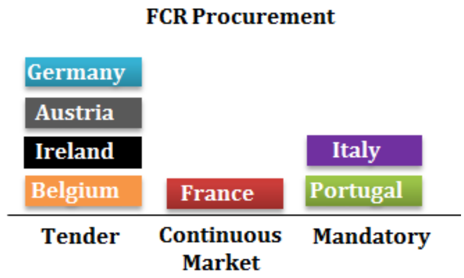

Figure 34: FCR Procurement Methods

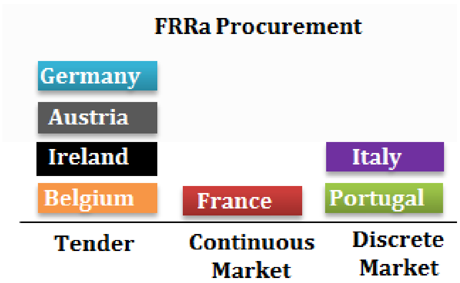

Figure 35: FRRa Procurement

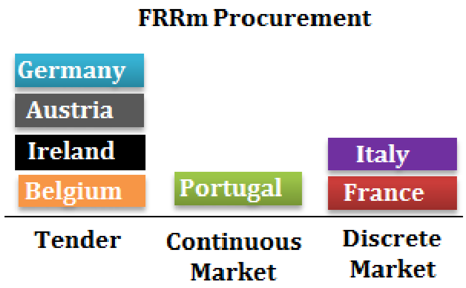

Figure 36: FRRm Procurement

3.2.3.2 Payment

Reserves are usually remunerated on a pay as bid basis; with the exception of FCR procurement, which is mandatory and not remunerated in *Italy* and *Portugal*. There are generally two types of payments for reserves, a reservation for availability payment and an energy payment for dispatched energy. Figure 37, Figure 38, and Figure 39 below outline the payment methods for each type of reserve for the surveyed countries.

In *Belgium FCR* is paid for both energy and reservation. Units submit prices for net upward pays/downward activation. Prices are checked against real costs (fuel) and a market reference price (Belpex). FRRa is also paid for both energy and reservation. The size of the activation payment is set on the basis of bids submitted by the grid user on D-1. Bids are selected by financial merit order: Elia first chooses the least expensive bids and the selection process is stopped when the reserve volume is reached. The bids have to meet a number of requirements: they must be submitted per block of at least 5 MW, per production unit and per tariff period. Each bid must include two prices: a price for net upward activation and one for net downward activation. The prices must always be positive for upward activation (Elia pays the grid user) and negative for downward activation (the grid user pays Elia). The volumes included in the bids must at least cover the reserve that the grid user has undertaken to supply to Elia throughout the contract. FRRa is similarly paid for energy and for reservation, If Elia requests activation of the tertiary power reserve, the producer will be paid for activation. The amount paid is calculated using a formula stipulated in the contract, taking account of the price of the fuel used and the specific characteristics of the unit.

In *France* new pricing is being implemented. For FCR & FRRa there is a regulated price for capacity (~18€/MWh), and energy (~10€/MWh). FRRm & RR: upward capacity reservation only. Services are pay-as-bid for both capacity and energy.

In *Germany* FCR or primary reserve is paid as bid only for reservation, there is no payment for energy activation. Secondary and minute reserves or (FRRa, and FRRm) are paid as bid for both reservation and activation. Pricing and awarding schemes functionalities are similar. TSOs demand a certain reserve in an auction and award the bidders with the cheapest reservation price until the demand is covered. When an actual utilisation in necessary such supply is activated in ascending order of the utilisation price. Bidders get paid by their bids in reservation and utilisation (Pay-as-Bid).

In *Italy* the primary or FCR reserve is compulsory and not remunerated. Both the FRRa and the FRRm are contracted through a market process and paid for both reservation and availability.

In *Portugal* primary regulation is mandatory although its remuneration is not explicit. Secondary reserve covers voluntary service remunerated under two concepts (the same for both upward and downward directions): available capacity (power band in MW and price in €/MW) and energy (energy price in €/MWh and mobilised reserve in MWh). Under the criteria of minimum cost (economic merit order) band bids are selected and remunerated with the band marginal price in each hour. The remuneration of the energy used to provide this service is valued at the marginal price of tertiary energy regulation that would have been necessary to be used instead (in other words, tertiary energy that would have been necessary to schedule in each hour in each direction – upward/downward).

Concerning the penalty for non-fulfilment, a fine of one and a half times the marginal price of secondary reserve is applied to production units that have not respected the terms of the contract. The cost of the band is paid by demand proportionally to metered energy, except pumping consumption and export. Generation and demand units that have deviated from their programmes pay the cost of the energy. This is done through an uplift of the energy price. The tertiary reserve is contracted through reserve bids, separated by upward and downward directions, comprising quantity (MW) and hourly price (€/MWh). These bids are selected by economic merit order, without causing technical constraints. Tertiary regulation (energy) is remunerated at the marginal price set by the last offer assigned at each direction (increase/decrease) on each hour. The costs of the provision of tertiary regulation (energy) are covered by generation and demand units that have deviated from their programmes (excluding pumping consumption and exports) through deviations penalties.

In *Ireland,* all FCR, FRRa and FRRm prices are determined by the regulator and calculated on a monthly basis based on utilization.

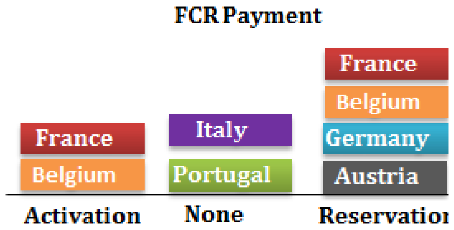

Figure 37: FCR Payment Methods

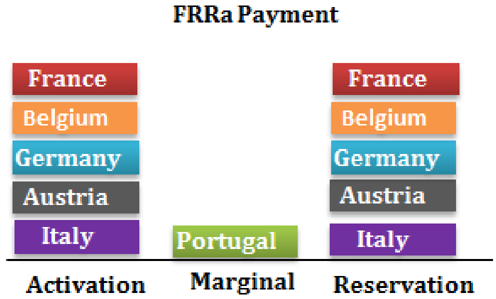

Figure 38: FRRa Payment Methods

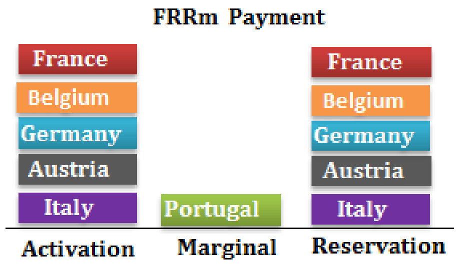

Figure 39: FRRm Payment Methods

3.2.4 Market Design and DRES

The wholesale market is currently designed to allow large generation units to offer their electricity production to wholesale retailers. There is a direct link between the market results and the TSO. Market participants are obliged to nominate, based on the market results, the specific units that will be running during a period of time. The TSO then performs safety checks to ensure that the resulting schedule is physically feasible. The DSO is not included as a part of this process, and is not informed of market results or the resulting dispatch schedules, even for units connected to its network. In the past this was not a problem since there was a limited amount of units connected to distribution. As DRES grows, managing generation in distribution becomes more important. The communication link between the market results, the TSO and the DSO is key for preventive management. Market design has an effect on the way that DRES is dispatched. This relationship will be examined starting from participation conditions to bidding methods, market clearing, regional markets, demand response and finally reserve markets.

In the wholesale market there are minimum **participation conditions** which might be prohibitive for new parties offering flexibility such as aggregators, for small DRES, and for services necessary at a specific location. In terms of trading periods, there is a trend among the surveyed countries to have shorter trading periods closer to real time. This facilitates RES participation in the market as the risk of having forecast errors is minimised.

In terms of **bidding methods**, the main types identified were portfolio and unit bidding. Most of the surveyed countries tend towards portfolio bidding. Market participants are allowed to bid a price quantity pair without specifying the units that will be used to provide that electricity. This allows risk diversification especially in the case of RES where forecast errors might cause imbalances. Under portfolio bidding schemes the bidder has the faculty of choosing, in his best interest, which units will be dispatched, and so can use fast ramping fuel units to cover unexpected variances in RES generation. This is an advantage for large portfolios, but it might pose a barrier to entry for RES-only portfolios, small portfolios or new market participants.

The current **market clearing** mechanism used in all the surveyed countries is a pay as cleared single price scheme for the day-ahead market. Where continuous markets are allowed during the intraday period, the clearing is paid-as-bid according to the matched orders. This means that the marginal, most expensive, unit dispatched sets the market price which will be paid to all dispatched units for the corresponding trading period. The price is cleared for the entire market area without considering network effects of the dispatch schedule. In case of congestion the system operator will select units for re-dispatch, and both the selected unit in the economic merit order and the re-dispatched unit will receive payment. Given that RES has zero variable costs, a large quantity of RES in the system drives prices down. RES also has priority of dispatch, meaning that, whenever available it will be dispatched before other units with the same variable costs. In markets where negative prices are allowed, RES bid below zero down to the amount of the support scheme they receive, since they get paid for being dispatched. This is a disadvantage and possible problem for peaking units with low ramping rates, since they will have to pay the market to keep operating during negative price hours. It is also a disadvantage for units with high marginal costs that are consistently being left out of the merit order. They need to run a determined amount of hours per year in order to recover their investment costs and make a profit. If the market is unprofitable for these plants they will be decommissioned. Nevertheless, due to the variability of RES fast acting fuel or gas based generators are still necessary in the system, even if for a limited amount of hours. This conundrum leads to the discussion of side payments to the energy only market, the growth of the reserve markets and the possibility of capacity markets.

The **regional markets** in Europe are moving towards harmonization. The recent coupling of the CWE area with the Nordic markets is a clear example of this trend. Larger clearing areas allow a more liquid and competitive market where resources are optimally allocated as long as the interconnection capacities allow it. However, RES causes local congestion issues in the network that are not taken into account in the wholesale market. So far, it has been up to the system operators, mainly the TSOs, to deal with congestion issues either arbitrarily or through the reserve markets. In the future, with the growth of distributed generation resources, there might be a need for a market system that addresses local grid management issues. This might allow actors to make a profit from solving grid issues, and so they would be motivated to invest towards this goal.

Demand response and demand side management strategies are a change driver in the way that power systems are currently managed. Through the introduction of dynamic pricing, smart meters and other pricing signals or contracts demand can now decide whether it is worth it or not to reduce electricity consumption during a given trading period. The market thus becomes a two sided exchange as demand goes from being a passive price taker to an active participant. Aggregated demand response can provide extra flexibility to the market which could replace peaking units that would only be needed a few hours a year. In a similar way, demand response can help solve local congestion issues in such a way that the need for grid reinforcements is postponed. Where it has been introduced as part of the market it is only participating at the wholesale market without taking into account locational signals. Currently, demand response programs are targeted mostly towards large industrial consumers. In the future, with the introduction of smart meters, small consumers are expected to be aggregated in order to participate in the flexibility markets. In some instances it has been the TSO who proposes demand response options to large consumers in an effort to decrease the cost of reserves and better manage the grid. So far, the DSOs have taken limited actions in terms of contracting demand response.

The **market for reserves** is gaining importance with the introduction of variable RES into the electricity systems. A larger amount of fast acting reserves are needed to cover unforeseen variations in RES generation. There are different procurement methods used in the surveyed countries, from bilateral tender procedures led by the TSO to market oriented mechanisms. Similarly, the ways in which reserves are remunerated vary. In some cases it is remunerated both for reservation and for activation, in other cases only for activations, and in some cases it is not remunerated at all. There are no official reserve mechanisms or contracting for reserves done by the DSOs. What's more generators connected at a distribution level can offer reserve services directly to the TSO. Communication between the DSO and TSO is then key for solving constraints at a distribution level.

Overall the energy market design defines the way in which actors can trade. Trading can be continuous or discrete and it can include the complex technical characteristics or not. All wholesale markets present rather high minimum participation amounts criteria, usually 0.1 MW. The surveyed day-ahead markets are cleared at the marginal price and all units are paid as cleared. Where congestion is not present, regional markets are moving towards price coupling, therefore, single price areas are expanding. The introduction of DRES drives prices down, which leaves peaking units out of the merit order economic dispatch. Reserves markets are growing in importance, use and design in order to accommodate RES variability and make sure that necessary peaking units remain in the market. DSOs are currently not linked to the wholesale market in the surveyed countries. At most they participate, directly or indirectly, in order to buy grid losses. They are, however, not informed of market results and so they resort to a passive management of the grid upon instruction from the TSO or in response to grid issues during real time operation.

4 Current role of DSOs concerning DRES

In light of the current challenges (see chapter 2) DSOs are searching for ways to enhance their levels of network observability and controllability. Similarly, they are evaluating possible cooperation mechanisms amongst the different actors (e.g. TSOs).

In response to these needs, the analysis presented below dives into the current practices for handling DRES at distribution system level. Practices are studied because they are the transposition of the current regulation (rules and incentives)[3]. Since the activity to distribute electricity is regulated, it is safe to say that current practices are a reflection of the allowances of current regulation.

Only selected practices are deeply analysed in this document. The approach for the selection of practices was as follows. First, the challenges that DSOs are currently facing were identified from the survey (see section 2.3). Then, practices that tackle these challenges were extracted. The selected practices can be classified in three broad areas:

- Planning and Network Development
- Forecasting, Operational Scheduling and Grid Optimization
- Real-Time Operation

The evolvDSO project will take into account these areas in order to create tools to assist DSOs on their (future) operational responsibilities.

In the following section, the current DSOs' practices to handle DRES are presented for the surveyed countries. Afterwards, the potential benefits and barriers of those practices are discussed. This discussion makes use of D1.1 outputs (Schuster et al., 2014) for the contextualization of systems in terms of the current DRES capacity and the expected change (Figure 40).

[3] The Regulatory framework could enable (discourage) the application of a certain practice. In other words, regulation allows (constrains) the creation of mechanisms for the accomplishment of objectives.

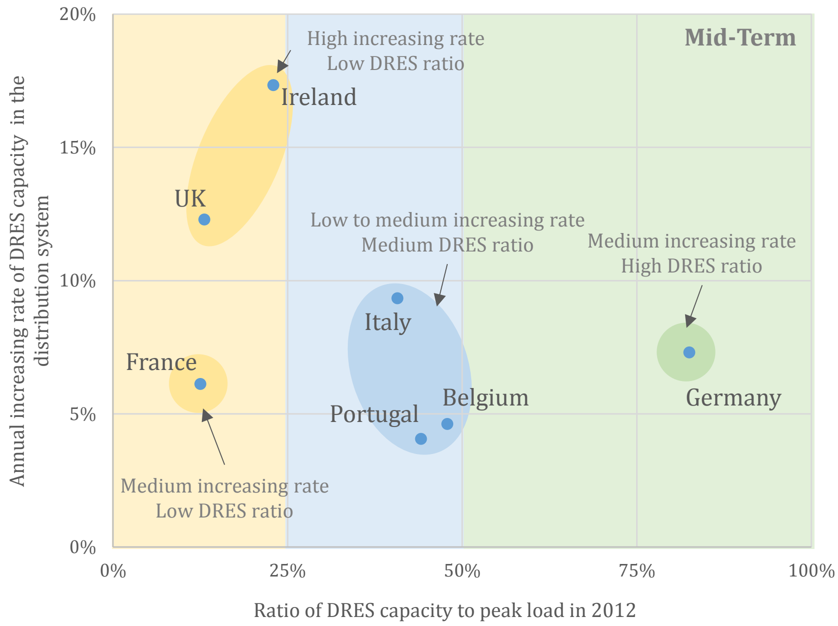

Figure 40: Increasing rate of DRES in the distribution system over RES capacity ratio. Scenario: mid-term, most-likely

Figure 40 shows a clustering of different systems based on the RES capacity ratio (to peak load) and expected annual increasing rate of RES capacity in the distribution system. Current RES capacity is referred to peak load to even out the effect of the size of the systems in the comparison. In this regard, the figure shows that Germany has a significant RES penetration. The ratio of RES capacity to peak load in Germany is above 80%. This is the highest RES penetration amongst the surveyed systems. In the mid-term RES penetration is expected to increase at distribution system level. In most systems a medium annual increase rate (between 5 to 10%) is expected (Figure 40). Taking a closer look, it is observed that *Belgium* and *Portugal* display a medium RES capacity ratio and foresee a low to medium increase of RES capacity. In *France*, the distribution system is limited to MV and LV and the great majority of hydro generation is connected to the transmission system.

4.1 Planning and network development

The aim of planning and network development activities is to provide a future optimal network configuration mainly through investments assessed in terms of capacity, location and timing. The challenge of these investments consists of updating and harmonizing the planning procedures while taking into account new system management practices. These capital intensive and long term (e.g. 30 years) investments are meant to provide an adequate network configuration to support the grid operator on the distribution of electricity. Where the DSO is responsible for grid losses these must also be considered in the planning phase. In *France* for example, the DSO must buy electricity in the market to cover losses, so they enter into long term contracts to hedge price risks. More on responsibility for grid losses will be mentioned in section 4.2.2.

One of the ways to optimise the network expansion is via locational signals. In this case, the DSO provides the investor with a clear indication of preferred location of the DRES plant.

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In the following sections, practices relating to locational signals and investments are explained and discussed.

4.1.1 Locational signals

Any party interested in making use of the distribution network, either to withdraw or to inject energy, must first request a connection point to the DSO and pay the corresponding connection charge (see 3.1.2). Via these connection charges, the DSOs may provide long term investment signals (locational signals) to locate generation in a place where network management is optimized[4]. Locating DRES where its output is most beneficial (e.g. close to consumers or in areas with "strong" grids) improves network operation management (e.g. avoiding congestions). It could also help to reduce the need for reinforcements. These signals are static only providing an incentive at the time of connection (i.e. long term one-time investment incentive).

There are three main types of connection charges: deep, shallow and shallowish as explained in section 3.1.2. Shallow connection charges do not reflect real connection costs and thus, DSOs find it difficult to correctly allocate the cost of network development to the interested party (e.g. generator). The implementation of shallow connection charges incentivises DRES developers to invest, but hinders DSOs to provide locational signals to the investment. Shallowish or deep connection charges may allow DSOs to provide these locational signals. These types of charges permit to incorporate (in part or in full) the real costs of the connection.

Currently, most of the surveyed systems implement shallow connection charges (Figure 9). Among the countries that implement shallowish connection charges, only in France locational signals are provided (Figure 41). These individual costs partially reflect the connection on the network. In the French system, these signals are provided to RES generators above 36 kVA. The connection charges imposed to these generators consider both, regional and individual costs. The region scale components take into account the costs at HV network and HV/MV substation (e.g. reinforcement costs). The costs of these region scale components are socialised. The individual components refer to the costs at LV and MV networks. i.e.

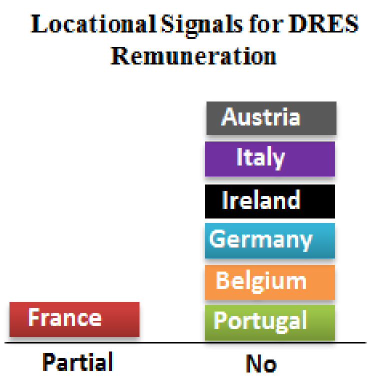

Figure 41: Are locational signals provided to DRES?

It should be mentioned that although in *Denmark* no locational signals are provided through connection charges, there are special sites defined for the connection of DRES. In other systems such

[4] For signals that may be given by DSOs to modify the output of generation technologies close to real time the reader is referred to 4.3.3

as *Austria*, it was noted that DSOs have the obligation to provide a suitable connection point for every planned power plant. If network capacity is sufficient, DSOs connect DRES generation on grid nodes that optimise its generation output as long as its connection costs are not increased by the measure. In the case of insufficient network capacity, the investor carries the costs of grid expansion. These costs and location are stipulated by the DSO. As such, the connection point can be far away from the planned location. DSOs use this in order to either reduce the capacity of the project or to allocate capacity (and reinforcements) where most needed (although this might not be in the best interest of the investor).

4.1.2 Investments on smart metering infrastructure

From the survey, it can be concluded that DSOs are moving forward with the implementation of smart metering infrastructure. Figure 42 shows that, within all surveyed systems investments in this technology are taking place, although at different paces. The different implementation stages observed may be due to the different levels of regulatory support. For instance, in *Austria* only two (out of eleven) DSOs are implementing an ambitious roll out of smart metering technology. The current regulation in *Austria* does not provide a clear framework that supports the implementation of smart metering technology. That is why almost all Austrian DSOs are shifting this roll-out until certainty for this investment is provided by the legal frameworks. In *Belgium,* the cost benefit analysis of installing smart meters has been shown to be negative for household consumers. However, DSOs are progressively rolling out smart metering infrastructure.

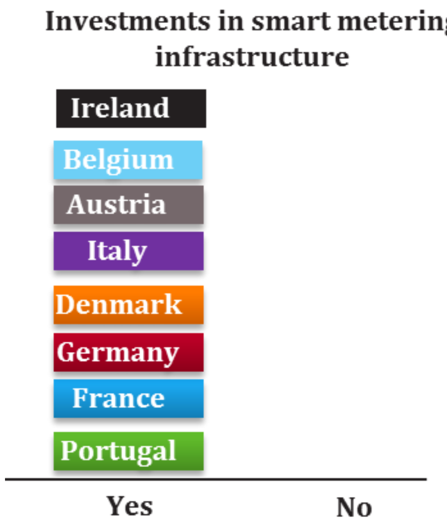

Figure 42: Investments in smart metering infrastructure

Figure 43 shows that most DSOs aim at investing in their own solutions for ICT networks. Only *Danish* DSOs have the intention of supporting its smart grid infrastructure with an ICT network that is not their own. The decision to do this is mainly economic. Additionally, their centralised data hub approach guaranties non-discriminatory exchange of information since all information collected from the smart metering infrastructure will be fed by DSOs into this national data hub.

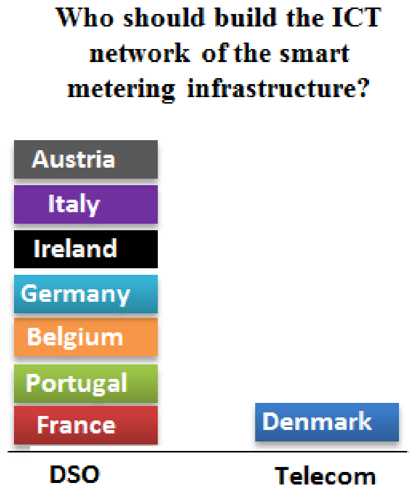

Figure 43: Who should build the ICT network of the smart metering infrastructure?

4.1.3 Discussion

The use of locational signals may provide an optimal selection for DRES sites while, in parallel, assist on operational measures that take place after the planning phase (e.g. congestion management). As discussed above, these locational signals could be given by appropriate connection charges. These charges that include network situation or local grid capacity constraints might prove beneficial for the planning of the distribution network. Countries that implement these types of charges might be better suited to deal with DRES generation right from the planning phase.

Moreover, the connection charges should be defined so that they provide the correct incentive in line with the network development plan. This alignment might reduce sub-optimal investments or prevent unfair charges e.g. a party that choses to pay for the grid reinforcement might be subsidizing the parties that connect after the reinforcements takes place. The latter might benefit from lower connection charges than the first.

The effectiveness of these locational signals might be reduced or blocked by the RES support scheme in place. Feed-in-tariff schemes, for instance, promote RES generation but at the same time shield the producer from most external signals. Additionally, connection charges are only part of the total costs for the implementation of the project. Therefore, a case might still appear where a poorly situated project (from network perspective) is preferred to one that offers a better situation.

Figure 40 shows the expected increase in RES capacity for the surveyed countries. Systems with expected increase of RES capacity from medium to high (such as Ireland, Italy and Germany), might find it beneficial to include locational signals or cost reflective connection charges as a practice at planning and network development. In this line, the definition and implementation of locational signals would require the DSOs and regulator to work together.

Investments related to the implementation of innovative solutions such as smart metering infrastructure and its ICT network are key to handle DRES generation. Smart metering provides the DSOs with relevant and accurate information that can be used to enhance network observability and controllability.

In all systems smart metering is being implemented, even if not yet fully rolled-out. In *Germany*, the expectation was to reach 80% smart metering coverage by 2020. In *Italy*, 95% of consumers already have smart meters (32 million smart meters as of 2011). The data collected from this infrastructure is used by Italian DSOs for planning purposes (in existing planning tools) and to check on reverse power flows.

Results from the survey suggest that there is no forced relationship between RES and smart metering implementation. Smart meters are only one option within the smart grid concept. In this line, a cost-benefit analysis on smart metering deployment performed in *Germany* concludes that a complete smart meter roll-out may not be cost-efficient. Nevertheless, the implementation of smart metering (partial or complete) broadens the options for DSOs to handle current and future DRES capacity at distribution level.

In a nutshell, locational signals may stimulate (discourage) DRES investments at the most appropriate (least attractive) locations in the grid, leading to a more cost-reflective integration of DRES in the power system. Investments on smart metering infrastructure might improve DSOs' capabilities in respect to network observability and controllability. In addition, smart metering data may be used to enhance planning tools and, ultimately, calculating connection charges.

Long term investment signals, such as locational signals, and investments on innovative solutions, such as smart metering infrastructure, could add value to the current quest for handling DRES at distribution level. The value that these practices may add is highly dependent of how well aligned the objectives for RES promotion and DSOs are under the current regulatory framework. RES Support schemes could be designed in a way that allows DSOs to provide cost-reflective connection charges and avoid as much as possible sub-optimal investments.

4.2 Forecasting, operational scheduling and grid optimization

The aim of forecasting, operational scheduling, and grid optimization is to provide the network operator with possible scenarios that might arise during real-time operation. Accordingly, possible network management actions are defined and evaluated. In order to evaluate those options, network operators must possess relevant information concerning (predicted) network flows and network state. This information can be collected from internal (e.g. smart metering) or external (e.g. generation forecast from third parties) sources.

In the following subsections, several practices in this area, namely forecasting, responsibility of grid losses, DSO-TSO cooperation and congestion management, are presented and discussed.

4.2.1 Forecasting

Forecasting DRES generation for operational purposes increases DSOs' observability of the network by providing an estimation of the DRES in-feed in the area of interest. By having access to good DRES forecasts DSOs could also anticipate possible issues like voltage problems, grid congestion, etc. and implement preventive measures in due time. On the other hand, forecasting requires expertise and the appropriate tools and data. Furthermore, forecasts are preferably updated with newly available information up to real time (if possible). On the latter issue, the smart metering infrastructure could play a key role (see section 4.1.2).

Figure 44 displays Germany as the only country in which some DSOs are currently forecasting DRES generation for operational purposes. Although, TSOs are responsible for DRES generation prognosis, German DSOs use their own tools to forecast DRES generation for their own distribution areas. This management practice allows them to monitor DRES above 30 kW. Note that this technology is new in Germany and not all German DSOs have implemented such kind of tools.

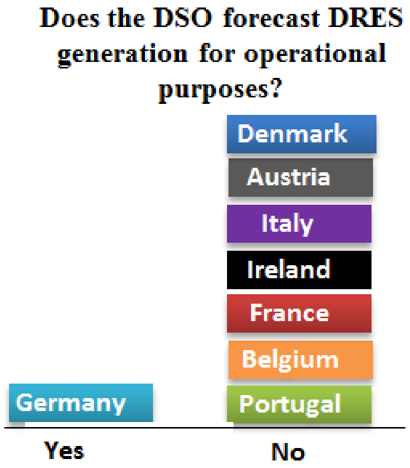

Figure 44: Does the DSO forecast DRES generation for operational purposes?

In some countries where DSOs do not forecast DRES, other measures are implemented. For instance, although French DSOs do not currently forecast DRES generation (except for demonstration sites), they receive forecasting information from the TSO. The procedure is as follows: DSOs collect real-time data from the smart metering infrastructure and feed this information to the TSO, which uses this information to create the forecasts. Once forecasts are ready (updated) the TSO sends them back to the DSOs.

Furthermore, some French DSOs are moving forward to develop generation and demand forecasting tools. In *Italy*, some DSOs have developed forecasting tools for operational purposes. These tools are ready to be used but, up to the authors' knowledge, they have not been used yet. Another example is *Austria*, where the lack of DSO forecasts is complemented by information on generation forecasts of DRES above 50 MW. This information is provided by a third party.

Finally, in some countries, the DSOs have no information at all on DRES generation forecasts. For instance, in *Portugal* DRES production is sold (entirely) to the "Last Resource Retailer" (i.e. EDP Serviço Universal) and only the TSO produces or buys forecasts for wind farms connected to EHV and HV networks.

4.2.2 Responsibility for grid losses

In transport and distribution networks, the majority of the power injected is consumed by the grid user. Grid losses are the fraction of the energy that does not reach the end user due to the inherent characteristics of electrical networks (i.e. technical losses), capacity constraints, etc[5]. Network operators are responsible for the energy that is lost in their grids when serving the energy to the end consumer.

[5] The so called "non-technical losses", i.e. energy stolen from the power system, are also part of this fraction.

Within this report, the responsibility for grid losses refers to the obligation of DSOs to compensate for incurred losses. The survey showed that this responsibility is assigned to all surveyed systems under the current regulation, although the price at which distribution grid losses are valued varies from system to system. In general, two pricing groups were observed: regulated through an efficiency indicator and regulated through market purchases. In the former, DSOs are required to comply with an efficiency indicator imposed by the regulator, e.g. threshold for grid losses. The latter imposes an obligation that goes a step further than a regulatory indicator since DSOs have the obligation of compensating grid losses by buying the lost energy at the wholesale market. Both regulatory practices aim at stimulating distribution system efficiency[6]. These practices give incentives to the DSOs to innovatively manage their grid and to invest in grid infrastructure in a timely manner. Moreover, they motivate DSOs to reduce grid losses by optimizing the location of new installations and/or grid reinforcements (4.1.1), so it is also related to long term planning, and not just short term forecasting. Note that the responsibility for grid losses also has to be taken into account when selecting tools to deal with DRES.

Figure 45 shows that in most of the surveyed countries DSOs buy energy at the wholesale market in order to compensate for grid losses. This suggests that the practice of compensating distribution grid losses by market purchases is widely extended among the surveyed systems.

In Denmark, France, Belgium, Austria and Germany, DSOs buy energy at the wholesale market to cover for realized grid losses. This is done in addition to their regulatory efficiency indicators[7]. In order to pay for grid losses, DSOs may use different schemes. For instance, French and German DSOs have the opportunity to become a BRP and balance their own electricity losses.

In Ireland, Italy and Portugal, DSOs do not buy energy at the wholesale market to compensate for grid losses. In these systems DSOs have to comply with the efficiency indicator, i.e. threshold for grid losses, set by the regulator. This incentive mechanism recognizes a fixed percentage of energy distributed related to grid losses. If the threshold is surpassed the DSO must assume the associated economic loss. In Italy, if real grid losses on the distribution network are above the set fixed percentage, the DSO must pay for the additional kWh that are outside the losses recognized by the regulator (not through the wholesale market).

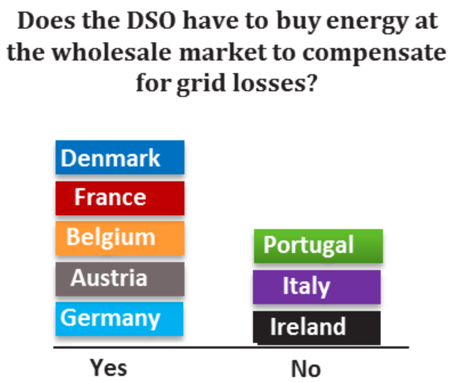

Figure 45: Does the DSO have to buy energy at the wholesale market to compensate for grid losses?

[6] Concerning the efficiency indicator, this is true when linked with a financial incentive.
[7] In Denmark, there is no specific indicator for grid losses. The regulator defines a maximum for operational grid costs. This includes all network costs including grid losses.

4.2.3 DSO-TSO cooperation

The cooperation between system operators at distribution and transmission level is crucial for the sustainability of a system with high penetration of DRES. The challenges imposed by DRES generation require that both operators exchange accurate information in an effective and timely manner.

Figure 46 shows the countries that receive (and do not receive) scheduling information of generation units. From the figure, it can be observed that most of the countries are not informed about the unit commitment of generation resources.

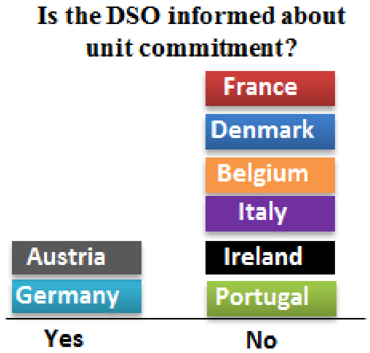

Figure 46: Is the DSO informed about unit commitment?

For the countries that do receive scheduling information, different approaches are implemented. For instance, German DSOs receive scheduling information of the power plants connected to HV. This information is used for optimal distribution grid management.

Austrian DSOs receive unit commitment from generation units above 50 MW (for all relevant voltage levels[8]) and HV connectors (15h00 D-1). This information is used to predict/detect potential congestions. In the case of emergency situations, generators can be forced to reduce feed-in or to switch-off.

In *France*, although they do not receive scheduling information, DSOs receive operational information from MV connected plans. This is mandatory for capacities above 5 MW and optional for capacities between 250 kW and 5 MW. This information is shared with the TSO and used to reduce generation output in case of HV constraints. Additionally, French DSOs are informed about next day demand side programs and activation (constantly checking the compatibility with real time system conditions). The information received (facility, type and amount of service) allows the DSO to check that no adverse effects on the system will arise concerning individual safety, quality of service, and costs.

In countries where DSOs are not informed about unit commitment some other measures are either being discussed or put in place. For instance, in the case of *Belgium*, the possible pre-qualification of flexibility sources (at certain access points) within the aggregator's portfolio for commercial or ancillary services is currently under discussion. Recently, the TSO has launched a DR product called R3 Dynamic Profile. In *Ireland*, DR operation requires knowledge and consent from the DSOs for security reasons.

TSOs might activate reserves from the generation located at distribution system level. Figure 47 shows that in most systems, DSOs are not informed about DRES activated as reserves. In *Ireland, The DSO*

[8] Unit commitment information of generation units below 50 MW can be requested if high impact on grid is demonstrated.

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may or may not have visibility of the output change from generation, depending on the monitoring available for a given site.
e.g.e.g.

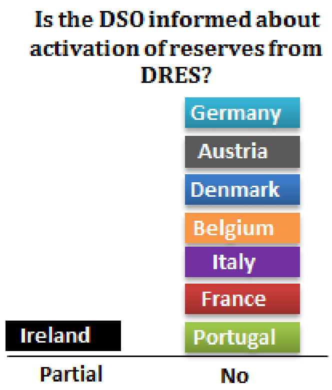

Figure 47: Is the DSO informed about activation of reserves from DRES? [9]

In general, it has been observed that information exchange amongst the network operators is insufficient in the majority of the systems. Additionally, a clear repartition of responsibilities amongst TSOs and DSOs is missing. Nevertheless, some systems are moving towards filling these gaps. For instance, French DSOs and TSO coordinate their efforts in order to maintain the system up and running. These efforts are especially taken at network code level and at operational level (in real-time in case of contingencies). In addition, services provided by the flexibility providers are certified by the TSO prior approval from the DSO. Note that in some countries (e.g.e.g. *France, Belgium*) the repartition of responsibilities for service certification amongst network operators is currently being discussed.

In *Germany* a cascading structure concerning system stability is in place. Under this structure, the TSO remains the main responsible for system stability while the DSOs are responsible for their own network. This makes them responsible for DRES curtailment for security reasons. In addition, TSO advise DSOs for DRES curtailment in case of (predicted) congestions within the transmission grid.

In *Portugal*, the focus of the cooperation between DSOs and TSO is shifting from long term activities (e.g. planning) to more short term operational activities (e.g. real time information exchange). Currently, the TSO and the main DSO are planning to join both dispatch activities via ICCP (Inter Control Centre Protocol) to increase the real-time information exchange of grid topology, production and power flows. This cooperation is also observed in services provided from the DSO to the TSO (e.g. compensation of reactive power) and in the establishment of joint agreements for the management of static compensation devices (switching-off transmission lines that are generating reactive power and not required for system security, starting up conventional synchronous compensators and installation of shunt reactors in order to absorb reactive).

4.2.4 Congestion management

As stated by Eurelectric (Eurelectric, 2010), cooperation between TSOs and DSOs is particularly relevant for dealing with congestions and RES connections at distribution system level. DRES penetration is expected to increase. A higher penetration of DRES may increase the frequency of situations in which bottlenecks (congestions) appear. Nowadays, DSOs usually do not curtail DRES to alleviate congestions (except for security reasons). However, as more congestion may appear, DSOs

[9] For Austria and Portugal DRES is not allowed to provide reserves.

will have to become familiar with those practices since TSOs is not allowed to act on the distribution grid.

From the above, it can be concluded that DSOs will be more and more in need of new solutions for handling DRES. Currently, most DSOs do not contract services to mitigate congestions (Figure 48). This may be due to the low to medium DRES penetration observed in most surveyed systems (Figure 40). In these systems, congestions at distribution level may seldom appear and if congestions do appear, they are dealt with mainly by reinforcing the grid.

In *Portugal,* the DSOs do not contract services to handle network constraints, but in case of foreseen emergency operation, they have some contracts with big clients that can be curtailed if necessary, the so-called interruptible contracts.

In *Germany*, congestions at distribution system level are dealt with in several steps. First, the DSOs act on the grid (e.g. changes on the switching stage). Then, if the congestion remains, the DSOs make use of market based measures (contracts) i.e. modification of feed-in of conventional power plants or controllable loads. If still the congestions persist, the DSOs make use of contracted curtailment agreements with DG resources. Non-planned (non-contracted) DG curtailment is only implemented under security reasons (e.g. persistent local congestions that jeopardize the distribution system). Thus, German DSOs may contract services to handle congestions coming from generation or load and may be acquired by different means (e.g. bilateral contracts, market).

Additionally, all the DSOs do not currently apply intentionally islanding for congestion management. This service is considered to be highly complex. In a future with high DRES penetration, intentional islanding could become a potential additional option for DSOs to solve congestion problems, provided that it increases QoS.

Figure 48: Does the DSO contract services to deal with network constraints?

4.2.5 Discussion

Imposing the DSOs to take responsibility for the grid losses triggers the need for an efficient grid management. For example, this is the case for German DSOs, with a high penetration of RES capacity (Figure 40) and a medium expectation for its increase. The practice of making German DSOs accountable for losses encouraged some (large) German DSOs to create their own DRES forecasting and contracting services to deal with network constrains. The German DSOs that implement these practices in combination with smart metering infrastructure (see section 4.1.2) may be in a good position to handle increased DRES penetration. From the survey, no other DSOs were observed to implement all of these practices.

Concerning DSO-TSO cooperation, it was observed that there are opportunities for improving information exchange amongst network operators. An intensified and standardised TSO-DSO interaction with reliable exchange of data and information would lead to an optimal tuning of actions at both levels. In addition, it could enhance the operation management for the entire system. This cooperation is highly relevant for defining services that serve to handle current and future DRES capacities and demand flexibility. Therefore, a continuous exchange of information in order to enhance system network management is perceived as a good practice and should be pursued by network operators.

A way to strengthen this collaboration might be to inform the DSOs about the activation of reserves provided by generation connected at distribution system level. The DSOs that are aware of the provision of reserves from DG might foresee possible contingencies and implement corresponding correction measures. Furthermore, there is a need for defining clear boundaries of responsibilities between the TSO and the DSOs concerning DRES and options to deal with them (like DR).

4.3 Real Time Operation

The activities presented within this section aim at the efficient distribution of energy at real time operation. DSOs take actions in order to secure a reliable and adequate energy distribution service. Such actions are mainly implemented on the physical assets at the distribution grid or at producer/consumer premises (e.g. activation of contracted resources, reconfiguration of distribution network, curtailment of active energy).

In the following subsections, practices that are relevant for real time operation focusing on DRES controllability, net metering and the provision of temporal signals are presented.

4.3.1 DRES controllability and compensation for curtailment

Within this report the controllability of DRES refers to an active/direct action on the output of a generation resource. In other words, it refers to the ability of directly controlling/managing the DRES unit under predefined and agreed conditions by a third party different from the owner of the unit. The control (decision on power output) is then in hands of that third party who contracted the unit for direct control or who is given direct control authority by law/regulation. Note that in this report (D1.2) the discussion is mainly on controllability of DRES by a DSO as the controlling third party.

Controlling a generation resource may provide the DSO with the possibility to alleviate (persistent) congestions and also to defer network reinforcements. A controllable generation resource may also increase network usage.

Figure 49 shows that controllability of DRES, where available, is limited. Countries in which controllability is possible are characterised by different implementation schemes. For instance, in *Austria* units above 50 MW may be controllable. At this capacity the network operator does not make any distinction between RES and conventional generation technologies. For capacities below 50 MW, Austrian DSOs do not pay to DRES generators on the basis of controllability. Any payment in terms of controlling DRES generation reduces the DSO's benefit since these are not included in the tariff calculation (the regulator does not acknowledge payments under this concept). The DSO can curtail DRES under emergency situations.

In *France*, a device allowing operational information interchange between generators and the DSO has been developed for MV-size connected plants. It is mandatory for units above 5MW and optional for smaller units[10]. This device can be used to disconnect or reduce generation output in case of constraints or when network maintenance is required. Currently, the contractual aspects of this control take into account two situations: constraints management or emergency situation. Constraints management includes a benefit for the customer, usually a cheaper or faster access to the grid. Emergency situations are supposed to be exceptional with no compensation.

In *Italy*, generators that have a capacity above 100 kW are controllable by the DSOs, but DSOs cannot implement any action upon these resources without the request of the TSO. This also applies to emergency situations.

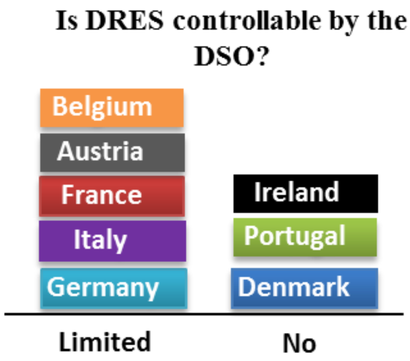

Figure 49: DRES controllability by DSO

In *Belgium*, customers with a "flexible connection/access contract" can be controlled. This type of contract allows DSOs to provide a conditional connection to installations that might jeopardize the capacity of the grid. In exchange of the connection, the customer agrees that in case of grid constraint, the access to the network can be limited by telecontrol. The threshold for installing telecontrol equipment is 1 MVA.

In *Germany*, some DSOs may control DRES units above 100 kW. In order to avoid grid capacity shortage (i.e. congestions) in a given area some German DSOs may use feed-in management to control DRES units equipped with a remote control device. Another option to control DRES units is through a voluntary contractual agreement between the DSO and the generator. This contract limits the output of the DRES unit. These types of contracts may be implemented in order to better integrate the generation unit into the distribution grid. The third option for DRES control concerns grid safety (emergency): in the situation that the system is on the brink of collapse, the DSOs may curtail DRES generation output.

In general, the DSOs may curtail DRES generation if the system stability is in jeopardy. DRES curtailment under emergency situations is used as a temporal measure since the DSOs are expected to reinforce the network to dissolve bottlenecks that caused the curtailment (see section 4.2.4).

The increase of DRES penetration may create more situations in which DSOs will have to curtail DRES output under security reasons. Currently, RES generation benefits from priority dispatch in all systems (Figure 50). This assigns a preferential status to the energy generated from those sources and makes DRES curtailment as a last resort only. If DRES output is curtailed, the owner of the DRES unit might

[10] Units with a capacity above 250 kW but below 5MW.

receive a compensation for the lost energy. From the survey, it was observed that in some systems there are cases in which no compensation is foreseen for the plant operator. In systems where no compensation is foreseen, the revenue of the investor/producer would be impacted depending on how often this measure is implemented. The system also experience a loss since green/clean energy cannot be efficiently allocated.

Figure 50: Priority of access for DRES

4.3.2 Net metering

Net metering is a practice that allows a consumer to offset electricity consumption with on-site generated electricity (and delivered to the distribution grid) for an applicable billing period. The meter deducts the electricity injected to the distribution network from the electricity that has been withdrawn by the grid user. The implementation of this practice aims to promote investments on DG/RES technologies (e.g. PV).
From the DSO perspective, this practice reduces the incentive a consumer might receive to react to external signals (e.g. time of use (ToU) tariffs). Furthermore, the practice might negatively impact distribution costs. For example, consider a consumer that has injected as much energy as he has consumed. At the end of the billing period the consumer will have a zero electricity balance. This consumer has used the distribution network to inject/withdraw energy and since he has a zero energy balance no UoS charges are to be paid to the DSO. Figure 51 shows that in most systems net metering is implemented.

In *Denmark* net metering is allowed, but has been restricted recently. Previously, the net metering period was one year, allowing for seasonal compensation of e.g. PV with your winter consumption. Now it is 1 hour, so to take advantage of net metering it is necessary to align the consumption with the production within the hour. Almost all installed PV is contracted under the previous arrangement.

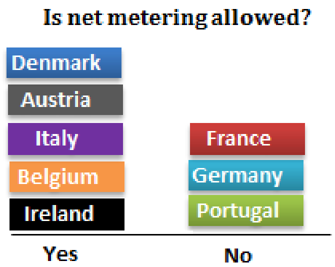

Figure 51: Net metering

4.3.3 Temporal signals

In section 4.1.1, the possibility to provide locational signals (long term) via connection charges to generation resources for their adequate placement at distribution level was discussed. Short term signals (close to real time) might also be provided to the generator/consumer to indicate the current status of the grid. The later differs from the previously mentioned long term signals in that the short term signals may vary in time and thus, can be used to provide a frequent update of the status of the distribution grid.

In this context, a temporal short term signal provides an indication of the stress of the network to generators/consumers located in the area of interest, and as such the recipient is prompt (receives an incentive) to act accordingly e.g. supporting the system by injecting power when load is high and reducing feed-in at times of low consumption. These types of signals provide a way to indirectly control resources (generators/consumers) connected at distribution system level. By applying indirect control the decision stays in hands of the recipient of the signal.

The use of pricing schemes that vary in time (e.g. ToU, critical peak pricing, dynamic pricing) provide incentives to consumers to respond to (mainly) energy price signals. In general, these tariffs do not (directly) reflect network stress. These pricing schemes are meant to flatten the load curve by shifting loads from peak load hours to valley hours. From the survey it was observed that different types of pricing schemes are implemented, or being discussed, for some systems. For instance, in *Portugal*, the revision of the Tariff Code by the Energy Regulator establishes that network operators (both TSO and DSO) shall present a study on the viability of introducing dynamic tariffs for the use of the network.

The use of Time-variable UoS charges could "improve cost reflectivity of distribution network services rendered to distributed generators" (Jansen et al., 2007). These charges may be used as a mean for DSOs to fairly allocate the burden to the units that cause that network stress. The use of Time-variable UoS charges are by no means an imposition on generation/consumption resources since the plant operator/factory owner retains the decision to respond to the signal. Figure 10 shows that in most systems, some generation resources do not pay UoS charges[11]. Not implementing UoS charges hinders the possibility to pass temporal signals to DRES. On the other hand, providing time-variable UoS charges can yield the required stimulus for DRES to react on network stress. The survey shows that none of the systems implement time-variable UoS charges, even if the generators pay UoS charges.

4.3.4 Discussion

DRES generation is expected to increase in all the surveyed systems (Figure 40). It was observed that it is currently possible to directly control DRES output in some systems, although with some limitations. This controllability refers to both, active and reactive power of the unit. The direct control of reactive power is a powerful tool[12] since DRES impacts are mainly found at their connection point (voltage problems are dealt at local level). The use of this practice supports DSOs on the integration of DRES capacity.

[11] Usually, small units do not pay UoS charges.
[12] Specially at MV level

From the DSO's perspective, the implementation of net metering may create some barriers for the integration of DRES. Net metering may create a situation in which the charges imposed to a consumer are not representative of the DSOs' incurred costs when providing the service. This situation would make consumers that do not yet have net metering face higher tariffs to compensate for the costs that have not been recovered.

Currently, in none of the surveyed systems are time-variable UoS charges implemented. As previously argued, the implementation of this practice could add value to further integrate DRES. Note that the potential benefits this practice brings may be reduced by the existence of net metering.

Further integration of DRES capacity could result in more frequent congestions at distribution system level. This, of course, depends on the speed of the DRES penetration and the hosting capacity of the current distribution grid. In this regard, DSOs might face more situations in which DRES would have to be curtailed. Overall, DRES is curtailed as a last resort due to priority dispatch. Therefore, practices that provide a direct and/or indirect control of DRES capacity would help DSOs to reduce the curtailment of DRES to a minimum. In that case, the overall benefits that this technology provides would offset its integration costs.

5 Conclusion

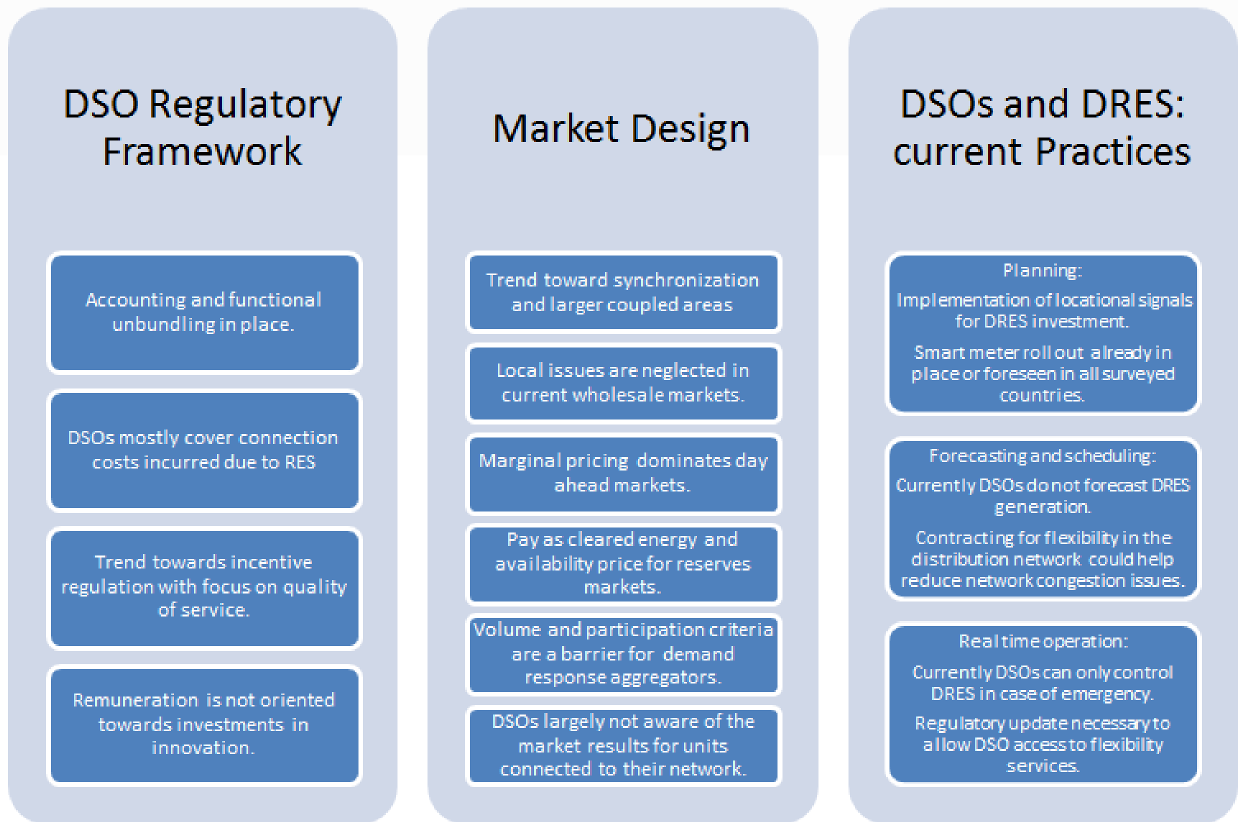

Figure 52: Main Conclusions

DSOs in Europe have to deal with fast growing DRES in a new technological context. The introduction of DRES can cause congestion issues, backflows, component life shortening, and affect system stability. In light of these changes, the report analysed the current regulatory framework and the market design of power systems across Europe. The study presented shows that the regulatory framework and the wholesale market design are lagging behind the needs created by current change drivers. Nevertheless, DSOs have started to take actions towards smart grid management. They are moving towards a more active role in grid management, in cooperation with the TSO. The study also highlights the current practices that DSOs are implementing 'on the go' in order to solve grid stability issues. Legislation is being pushed by the concerned actors in order to adapt to a changing environment. The regulatory framework should provide adequate remuneration signals for investment in innovative solutions. The wholesale market design and the DSO grid operation should be more coordinated - so far only the TSO is aware of the market results. A summary of the main conclusions of this report can be seen in Figure 52.

In terms of regulatory frameworks, DSO remuneration is currently linked to efficiency and quality performance indicators. There is little or no motivation for investments in innovative solutions that would not yield operational savings in the short term. This is especially true for systems where DSO remuneration is linked to investment in network reinforcements. DSOs have limited incentives to apply solutions that defer network reinforcements. Revisions to the regulatory framework are necessary in order to enable the effective deployment of smart grids. Market based mechanisms, where possible, would allow participants to recover costs of investing in communication infrastructures. Allowing markets for flexibility would enable the DSO to perform better grid

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optimization management. This would in turn defer copper investments and lower operational costs in the long term.

Wholesale markets tend toward harmonization and expansion of single price areas. This approach promotes an efficient use of resources as far as the grid situation allows it. As generation resources connected to the distribution grid bid into the wholesale markets local effects are not necessarily taken into account. DSOs, nevertheless, have to deal with the consequences in their networks. Currently markets do not take grid constraints into account, the market is cleared and the resulting schedules are transferred to the TSO. So far, the DSOs have not taken an active part in validating the resulting schedules.

As DRES grows, preventive actions to avoid congestion and grid failures will be more important. There is an inherent opportunity to reduce costs and optimise network management in preventive and operational grid management. Several DSOs have started to take such actions on the planning, forecasting and real time operation time frames. In terms of planning some DSOs have implemented locational signals to favour DRES connections in certain areas where either natural resources are highly available or the connection would help the grid. On the forecasting arena, some DSOs have already started to foresee the expected output of generation connected to their grids. They use this information to perform grid reconfigurations to decrease congestion and losses. A certain degree of active management is additionally available during real time operation. It is achieved through controllability or interruptibility contracts with DRES and consumers. So far, however, the implementation of this type of active management is limited due to regulation and to the lack of communication infrastructure. New roles are envisioned for DSOs in the future as they get involved in market and contracting activities, information technologies infrastructures, and active grid management.

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