Barriers to entry in Electricity Reserves Markets: Review of the status quo and options for improvements

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***Abstract*—As the share of intermittent renewable energy sources increases, it will be necessary to increase the volume of frequency regulation reserves (FRR). New sources of reserves can be found in distributed energy resources (controllable loads, Electrical Vehicles (EVs), distributed generation units). However, it is necessary to adapt the FRR market-design in order to allow forparticipation of these new resources through new market actors called "aggregators". The aim of this article is to provide a modular framework to analyze frequency regulation markets or mechanisms in orderi) to make a comparativeassessmentof four majorEuropean frequency regulation markets; ii) to identify barriers to entry for aggregators and iii) to identify some options to overcome them.**

***Index Terms*—Marketdesign – Frequency Regulation Services – Distributed Energy Resources**

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I. INTRODUCTION

In the current context where the share of intermittent and non-dispatchablerenewable energy sources (RES) is increasing in the electricity generation mix, additional flexibility will become an increasingly valuable resource to balance real-time generation and consumption. This balance in the electrical system is essential to ensure stability of power supply and to maintain the security of the grid. The primary parameter which reflects this real-time equilibriumis the system frequency.Anysystem imbalance will result in a deviation of the frequency aroundits nominal value set at 50 Hertz in Europe. In order to ensure security of the system and the correct delivery of electricity at all times, transmission system operators(TSOs) must procure generation reserves to cover system imbalances. TSOs rely on flexible actors who can adapt their generation either by producing above or below their set schedule in order to solve the imbalance of the system.To be able to provide negative reserves, a generation facilitymust produce above their minimum capacity to allow for flexibility downward, whereas the provision of positive reserves requires that production is below maximum capacity for the opposite reason.TSOs mustactively manage different types of reserves (generation profiles)with varying time responses (amount of time required to change production schedules) in real-time.

Since electricity production from intermittent RES such as wind and photovoltaics is volatileand production forecasts still contain error, an increasing share of renewables will,c. p.,lead to a higher risk of imbalance between generation and demand and to a decrease of stability of the electrical system, which will increase the reserve requirements(Hirth & Ziegenhagen, 2015)(Brouwer, et al., 2014). TSOs will have to explore alternative options to organize thisreserve provision both in terms of capacity dispatch (short-termaction, scheduling reserve providers to adjust their power production) or in terms of capacity provision (longer-termaction, encompassing the procurement of reserves).

At the same time, new sources of flexibility are starting to emerge, especially distributed energy resources (DERs). Electric vehicles (EV) have technical characteristics that enable them to provide very short time flexibility products, when the charging system allows for flows of electricity from the Vehicle to the Grid (V2G). Due to their low energy capacity,EVsare best employedas short time powerreserve, such as primary or secondary reserves.EVs are able to change the flow of power they withdraw or inject into the network very quickly and, if it is managed efficiently, they have flexible patterns of recharging before the next use(Kempton & Tomic, 2005).EVs however,are not suited for bulk energy markets, such as day-ahead markets or intraday markets, where exchanges are made in terms ofenergy ratherthan in capacity. The EV market is likely to take offdue to both strong incentives by governments and local authorities in order to reduce CO_2-emissions, and a decreasing total cost of ownership(International Energy Agency, 2013)(Wu, et al., 2015). Furthermore,decentralized and dispatchable RES such as bioenergy, power storage systems, and demand side management are emergingas new sources for flexibility provision (IEA, 2008).

Historically, only centralized generators were used provide grid reserves due to their reliability and the technical realities at the time when energy markets were first developed. Accordingly, technical and economic rules have been built in this paradigmand may not be suited for the provision by new decentralized sources of flexibility. Moreover, energymarketshave been built on a national basis, which has led to a diversity of regulation and market designs(Neuhoff, et al., 2015)(ENTSO-e, 2014a)(Rebours, et al., 2007a)(Rebours, et al., 2007b). Revenues for the provision of reserves by EVs are highly dependenton the set of rules in place(Codani, et al., 2015b). Thanks to the EU’s Third Energy Package with therevised Directive on common rules for the internal electricity market (2009/72/EC), there has now been indication from the ENTSO-E (European Network of Transmission System Operators) and ACER (Agency for the Cooperation of Energy Regulators) to harmonize energy marketrules through the use of generally agreed principles known as Network Codes(ENTSO-e, 2014b)(ENTSO-e, 2013).

Technical and economic feasibility of provision of FRR by different types of DERs has been studied in the literature: in (Singarao & Vittal, 2016) and (Dias-Gonzalez, et al., 2014), where authors analysed the provision of FRR by wind-farms, respectively in United-States and in United-Kingdom. Participation of domestic load was analysed in (Samarakoon, et al., 2012). In (Villalobos-Garcia, et al., 2014), authors presented a review of the current EV chargingalgorithms, including FRR participation. In our view however, there is still a lack of a general framework to analyse the participation of DERs in different markets.

From an economic point of view, the participation of (all) small providers is not necessarily desirable as transaction costs of including them may prohibit an increase in economic welfare. That notwithstanding, market entry by new decentralized flexibility providers can increase competition in reserve markets, and potentially improve the carbon balance of the electricity mix if fossil fuel-based reserve capacities can be replaced. Consequently, in some European countries there are ambitions to open the reserve power markets for small providers (see e.g.(Federal Ministry of Economic Affaire and Energy, 2015)). Against this backdrop, we are focussing in this paper on barriers to market entry for small providers of flexibility and possible means of overcoming them. The issue of what kind of flexibility actually should participate in the reserve market however, is out of the scope of this paper.

The purpose of this paper is to develop a framework to assess barriers to entry for DERs in different markets. This framework could be used ex-ante, to guide decisions of a TSO or a regulator when he wants to redesign markets; or ex-post, to assess the impact of a new market-design on provision of reserve by DERs.In order to give illustration on how this framework could be used, a comparative assessment of market designs and rules for the provision of reserves is presented in three leading European countries (France, Germany and UK) and in Denmark where new innovative solutions are implemented. We will focus on the provision of frequency-control reserve, called primary (R1) and secondary (R2) reserves.We exclude tertiary reservesbecause they correspond to a long-term product when compared to primary and secondary reserves (half an hour or longer service provision time), which requiresa comparatively large amount of available energy.We will identify possible technical and regulatory barriers to entry in these markets and options for overcoming them.In section II, we describe the modular framework, which will be used for our comparative assessment. In section III, we examine how RES integration is affecting reserve markets, and provide an outlook on potential costs and trade-offs associated with new methods of FRR procurement.Then, we provide adescription of the market-designs for reserve provision in the different countries included in our study in section IV. Based on this modular analysis, we identify different types of barriers to entry for DERsand options for their resolution in section V.

II. Description oftheModular Framework

A. *Why Using a Modular Framework*

To analyze the possibility of provision of frequency-regulation reserves by DERs, we want to identify parameters which help us to normalize the study of different market-designs and to understand the mechanisms which could hinder the participation of DERs.

In this paper we will use the modular analysis initiated by (Baldwin & Clark, 2000) to analyze the creation and improvement of complex systems. A substantial body of empirical literature suggests that modularity has largely influenced product development processes in different industries, such as computers (Baldwin & Clark, 2000), textbooks (Schilling, 2000), mortgage banking (Jacobides, 2005), aircraft (Argyres, 1999), and air-conditioning (Cabigiosu & Camuffo, 2012). This is also true for the auto industry and its original equipment manufacturers (MacDuffie, 2013). Modularity plays a significant role in the design ofcomplex systems such as electricity markets. In this organizational theory, electricity markets can be described by analyzing theirmarket design, defining theirpeculiar modules, interfaces and architecture. Market design architecturerefers tothe global combination of administrative rules and market mechanisms used to ensure electricity provision to final consumers. Market design describes thesequence of events of the overall electricity market from long-term (years in the future) to real-time (seconds or minutes), it specifies what tasks will be part of the system and what their functions will be. A module is defined as aprecise task that can be connected or combined to build a subsystem that is independent from the rest of the architecture. Modules can be internally organized withmarkets, administrative rules, or both. An interface describes in detail how the modules will interact, including how they will fit together, connect and communicate. A perfect modular form is illustrated by the example of a perfect "plug and play system" in which all possible plugs on acomputer work without any compatibility concerns (Baldwin & Clark, 2000).

In electricity markets, there is no perfect market design for the architecture nor the modules or the interfaces,and ex post governance solutions are needed to correct for unforeseen issues(Glachant & Perez, 2009). From our perspective, this diversity of electricity market designs can beconsidered as field experiments and are useful in order to provide new guidelines for future adaptations of the current schemes.In the electricity market design studies, amodular framework has been applied by (Wilson, 2002)to analyze electricity market efficiencies, by (Glachant & Perez, 2008) and (Glachant & Perez, 2009) to analyze the European process of liberalization, by (Rious, et al., 2008)to improve the design of TSO main activities, and by (Dubois & Saplacan, 2010) for analyzingDSO core activities.

Concerning the issue of DERs and FRR, (Codani, et al., 2015a)proposed to consider two main modules to describe the market designs for reserves.This work was as a first attempt to address the new FRR provisionand itwas restricted to the inclusion of one type of DERs(EVs) on a single market for reserves (R1). As our question here is broader we need to adopt a more complete perspective to better understand the existence of barriers to entry for DERs in FRR modules R1 and R2.

We think it is necessary to complete this framework in order to have a better description of the markets, in accordance with what had been done in (Rebours, 2009). In our new setting, we add a third Module (B) to the initial framework composed of Module A and C, and adapt its organization as summarized in Table 1

TABLE 1: NEW MODULAR FRAMEWORK FOR FRR

Module A	Rules toward the aggregation of DERs
Module B	Rules defining the products on the market
Module C	Rules defining the payment scheme of grid services

The rationale behind the organization of the modules is explained in Figure 1, through a decision tree. This decision tree shows us that there is a rankingofthe impact each module will have on DERparticipation: the organization of the first module will have more impact on participation than the second module, which will have more impact than the third.

Therefore, if the body responsiblefor setting the rules(e.g., TSOs, a regulatory agency or the government) wants to open the market to DERs, theyshould first redesign the first module, then the second and finally the third. In the first module, rules can forbid or limit participation of aggregators in the market. In this module, administrative barriers to entry can be present: if the module is organized to exclude DERs, revenues of aggregators will be null.The second module will define if the aggregators are able to offer all their available reserves to the TSO. Indeed, aggregators maynot be allowedto provide all their available reserves due to an inflexible definition of products. This will limit aggregatoraccessto the market, and their profitability(Ruester, et al., 2012).The third module defines the remuneration an aggregator can expect withregard to the reserves provided. Depending on the market-design, the same amount of reserve provided will be remunerated in different ways. A market-design should allow the aggregator to be remunerated at afair value regarding the service it provides to the network, and give incentives to actors to reveal their true costs in order to select providers at the lowest possible systemcost.

In the view of the authors, technical requirements concerning the provision of reserve (ramping requirements, availability requirements) does not constitute an economic barrier to entry, as long as they apply for every type of resource. Thus, this study will not question technical feasibility. It would be the role of the aggregator to demonstrate to TSO that it is able to deliver reserve following technical requirements.

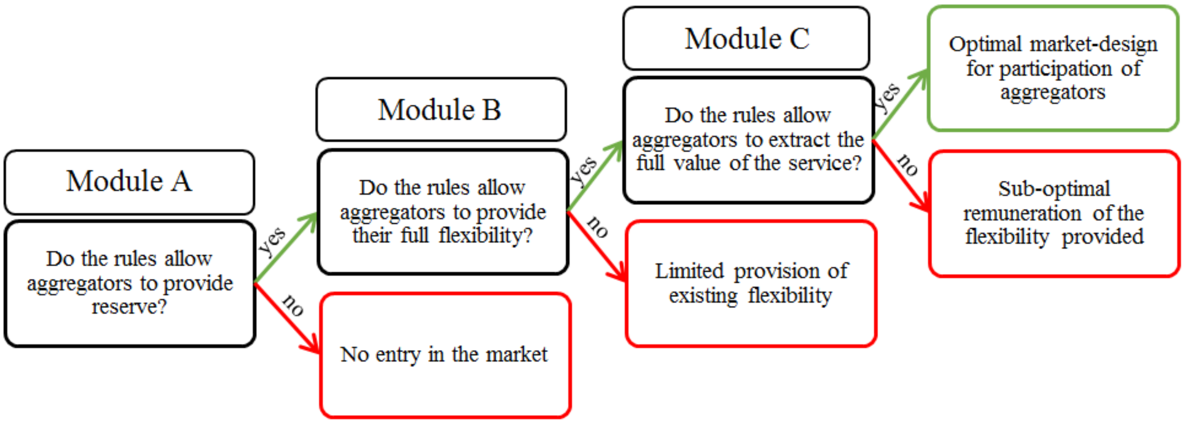

Figure 1: Decision tree for participation of DERs to FRR provision

We will now describe the parameters of each of the three modules used in our framework.

B. *Module A: Rules toward the Aggregation of Distributed Energy Resources*

1) *Technical discrimination against aggregated resources*

Some rules may be issued in order to discriminate against some actors with regard to participation in reserve markets. This discrimination is sometimes made based on the voltage level of the connection point of the actoror the type of actor (e.g., consumption unit). Technical discrimination is alsobased on the maximum level of reserve provided by a type of actor or by priority given to certain actors.Specific technical requirements for aggregated resources are also defined as technical discrimination.

2) *Interoperability among Distribution System Operators (DSO)*

There is a largediversity of DSOs in European countries, depending on the electricity system's history, construction, and market reforms in the last 20 years. For example, there is only one major Electricity Distribution Company (EDC) in France (ERDF – representing 97% of the market share) and few others (115) who deliver electricity to a limited number of clients (3%),whereas there are 65 EDCs in Denmark and 869 in Germany.To ensure that aggregation is possible, new entrantsmust be able to aggregate units among multiple DSOs (especially for EVs which can move from one DSO to another during the same day).

3) *Aggregation level*

Two methods of aggregation are identified in (Codani, et al., 2015a): telemetry and financial aggregation. Telemetry allows the aggregator to combine bids and power flows.Dispatching is handled by the aggregator, allowing themto use algorithms in order to optimize thedispatch of energy.

On the contrary, financial aggregation only allows for the aggregation ofbids while the dispatch of energy is controlled by the TSO. This solution does not allow the aggregators to use theirown dispatching algorithm to take into account consumer behavior.

C. *Module B: Rules defining the products in the market*

1) *Minimum bid size*

The minimum bid size that can be made will define the minimum level of aggregation necessary to deliver reserve and is a key parameter for the participation of DERs. If the minimum bid is set too high, it will be difficult for aggregators to participateasit would require managing an overly cumbersome number of small generation sources. However, market designers may want to set bid size at a high levelto minimize the number of market actors and the associated transaction costs.

2) *Time definition of products*

The time definition is the period of time during which providers must have their power available. This parameter is essential for new participants who aggregate consumption units or EVs since the availability of reserves is highly dependent on the habits of consumers.Thus the amount of reserve they are able to provide is highly variable and they will be precluded from a market where the time definition is too long.

3) *Distance to real-time of reservation*

This parameter defines how long in advance of delivery the procurement of reserve is made. This may have an impact on new participants such as aggregators due to the uncertainty it may induce in decision making. Indeed, if the procurement is made long before delivery, aggregatorsmust make assumptions that have an impact on the amount of reserve they can provide (behavior of consumers, number of aggregated units, etc.). For example, if procurement is made one year in advance, the aggregator will bid based on the number of units at the time of the bid, and it will not be able to take into account all the potential new aggregated units.

4) *Symmetry of products*

Two sorts of products can be sold in a reserve market: upward products – increase of generation or decreaseinconsumption (i.e. provision of positive reserve) – or downward products – decreaseof generation or increasein consumption (i.e. provision of negative reserve). Some markets allow for bids which differentiate between upward and downward provision while other markets only allowfor symmetrical bids, meaning the provider mustdeliver the same amount of downward and upward reserve simultaneously. If marketproducts are only symmetrical, the aggregator will not be able to provide the optimal amount of available reserve, since there may not be the same amount of upward reserve and downward reserve. For example, when consumption levels are low, an aggregator of demand response unitswill have more downward reserve than upward reserve. If symmetrical bids are required, an aggregatorwill be forcedto offer the minimum of the available upward reserve and downward reserve regardless of overall capacity.

D. *Module C: Rules defining the payment scheme forgrid services*

1) *Nature of payment*

Different schemes exist to remunerate reserve: regulated tariffs, pay-as-bid, and uniform pricing. These schemes are not equivalent regarding provision of reserve, in particular concerning entry of new actors. Indeed, thelevel of remuneration and bid strategies will be impacted by the remuneration scheme.The use of a regulated tariff is associated with mandatory provision by a few participants (often large producers) since there is no information to select providers based on their costs. Even if the rules allow for new entrants such as aggregators to propose reserves, the selection of the reserve will be made by an administrative rule which would not allow new participants to compete effectively with incumbentactors. Moreover, regulated tariffsdo not take into account the market value of electricity generation. In the European EPEXpower spot market, prices vary greatly in real-time. For example,in the intraday marketprices can fluctuate between the minimum and maximum values of-3000 to 3000€(Epex Spot, 2016). With a fixed and guaranteed yearly remuneration, a generator receivescross-subsidies.

The two market solutions – pay-as-bid and uniform pricing – allow for aggregators to compete with large producers and to enter into the market effectively.In a pure and perfect market setting (including perfect competition),the allocation of reserve should be optimal for both schemes(Kahn, et al., 2001). However, under real world conditions the bidding strategies will not be the same.With uniform pricing, market players have an incentive to bid at the marginal cost of service provision, whereas with pay-as-bid, actorswill bid at what they expect will be the highestaccepted bid to maximize their revenues (Kahn, et al., 2001). It is difficult for new entrants to perform well in guessing the maximum bid, as they enter a new market and have less information about the market.So they wouldnot capture the entire welfare as they mightunder a uniform pricing scheme.

2) *Extra-bonus for flexibility*

Technical requirements for frequency-regulation have beendefinedbased on capabilities of large generators since historically this was the only available or economic option. These producers have a high inertia present in their generation assets and cannot adapt their output instantaneously when the TSO requires it, thus an acceptable time delay for the delivery of reserves has been defined. New DERs that could participate in reserves provision are much more flexible and are able to adapt their production or consumption almost instantaneously. They are capable of delivering a service that is faster than large producers which benefits the system in the form of increased flexibility. Increased flexibility can allow for more renewable sources of energy to be integrated which can lower carbon emissions and air pollution; however remuneration is the same for both slow and fast acting sources if no additional scheme for extra-flexibility is implemented.

Table 2recalls the main parameters to be analyzed in the comparison of market designsfor reserve provision.

TABLE 2: PARAMETERS OF OUR FRAMEWORK

Aggregation of DERs	A1	Technical discrimination
	A2	Interoperability Among DSOs
	A3	Level of Aggregation
Definition market products	B1	Minimum size
	B2	Time definition
	B3	Distance fromreal-time
	B4	Symmetry
Definition of the payment scheme	C1	Nature of payment
	C2	Extra-bonus

In conclusion, policymakers open to the provision of reserves by DERs should have three objectives in mind:1.) Remove administrative barriers to aggregation. 2.) Create clearly differentiated services by redefining products (upward/downward, time horizon…) and 3.) Incentivize actors to reveal truecosts in order to have clear price signals.

III. REDESIGNING RULES IN EUROPE: CONTEXT AND COST-BENEFIT ANALYSIS

A. *The transformation of reserve marketsin Europe*

As the responsible entities for procuring reserves, European TSOs are at the convergence of two main policies within the European Union: (1) the harmonization of market-rules through the 3rd Energy Package (EU, 2009a) and the creation of ENTSO-E and ACER to build common Network Codes (NC) and (2) decarbonisation of the energy mix through the 2020 targets (EU, 2009b), which will greatly impact the penetration of renewables in electricity systems as can be seen in Table 3. It is essential for TSOs to transform the way they managereserve marketsin both the short and long-term to be able to cope with these two objectives. The different functions of TSOs, presented in Figure 2, will be affected by this transformation(Glachant, et al., 2015).

TABLE 3: RES CAPACITY AND RESERVE REQUIREMENTS

	France	*Germany*	*Denmark*	*UK*
Wind Farm Capacity (MW)(ENTSO-e, 2015)	9 120	36 561	4 897	12 900
Solar Capacity (MW)(ENTSO-e, 2015)	5 292	37 981	605	5 385
Share of Intermittent RES in the total capacity	11%	39%	37%	22%
Primary Reserve[1] (MW)	570	590	47	500-900
Secondary Reserve (MW)	700	2000	200	1100-1400
Central Scenario 2030 EWEA Wind Capacity(European Wind Energy Association, 2015)(MW)	32 250	80 000	8 130	40 000
Reserve requirements by 2030[2] (MW)	2400 (+89%)	4750 (+83%)	400 (+62%)	3300-4000 (+74%)

[1]Primary reserve need for France, Germany and Denmark is decided by ENTSO-E based on consumption of the country
[2]Assuming there is an increase of 5% of the new installed wind capacity by 2030 (mean value based on the literature (Hirth & Ziegenhagen, 2015))

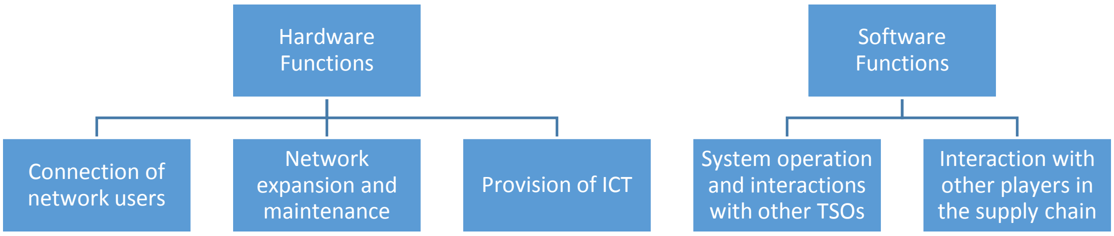

Figure 2: Classification of different Functions of a TSO(Glachant, et al., 2015)

Redesigning market rules for the provision of FRR by DERs will have an impact on software functions as TSOs will have to adapt how reserves are operated and how information is exchanged with the others players (other national TSOs, DSOs). The Network Codes could influence TSOs to converge on a market-design to address these issues while taking national specificities into account.

B. *Costsassociated with the opening of markets*

Opening the provision of frequency-regulation reserves to DERs is necessarily associated with costs for TSOs. The impacts of such costs should be assessed in order to be sure that opening this market is beneficial.

We have seen in the previous sections that opening and redesigning the market could be made in three steps:

- Removal of barriers to entry for DERs
- Redefinition of products in order to allow better flexibility in their provision
- Granting appropriate remuneration to DERs

First, TSOs will have to learn how to manage the provision of FRR by DERs. For example,TSOs will have to establish new prequalification tests. The prequalification testsforcentralized resources arewell known by TSOs and arerelatively easy to implement: TSOs test if producersare able to correctly respond to a predefined pattern of frequency deviation. However, prequalification ofdistributed resources, such as aggregation of consumers or EVs, will be more complicatedand possibly more expensive. TSOs will needto build new prequalification processesto adequately certify that new actors are able to function reliably. Then, TSOs will needto verify*ex-post* if providers have really delivered the reserve product they have been called on for. This supervision will also be more costly with new actors as the amount of units providing reserves will increase. Thus TSOs and DSOs must build new processesto share information effectivelyand to redefine roles and duties of each of the actors.

The redefinition of reserveproducts will be associated with increased transaction costs. Indeed, with reduced minimum bids and time-stepsin addition to asymmetrical products, the number of transactions in the market will increase as well as associated costs (management of data, communications with the providers, and transfers of money). Given a hypothetical example where provision of reserve is made through week-long products with a minimum bid of 10 MWsymmetrical productswhere the TSO requires 500 MW of reserve. The maximum number of transactions the TSO will have to manage is 2,600 in one year. If this TSO were to shift to half-day asymmetrical products with a minimum bid of 1 MW, it would be necessary to manage a maximum of 730,000 transactions.

It is clear that security and stability of supply should not be endangered by opening the markets. Opening the provision of reserves to DERs will increase volume risks for TSOs: the number of actors will increase,they will be less identifiable, and the number of time-slots will increase. Therefore, as TSOs are responsible for balancing generation and consumption, a risk management strategy should accompany the opening of markets. For example, TSOs could hedge some reserves through long-term contracts with large producers when markets are opened to reduce system risks through a strike price option contract (Rebours, 2009). This hedging would not be a permanent solution but it would allow for a transition period. The decision makercould also impose a minimum participation inthe market for large producers or let the aggregators hedge their positions inthe market by implementing secondary markets where different actors could buy and sell their reserves.

TSOs could also reduce their risks by mutualizing reserves across Europe. This however requires a harmonization of rules which is the aim of the Network Codes, which will also lead to increased learning costs and transaction costs. Another way is to mutualize imbalances in order to limit secondary reserves requirement. This strategy has been implemented among several European countries through International Grid Control Cooperation (IGCC).

It is out of the scope of this article to evaluate theserisks and costs. However, as decarbonization of the electricity mix is in progress and should intensify in the next 10 years (c.f. Table 3), it will becomeunavoidable at some point to shift from the previousmodel (provision of reserves by centralized generators) to a new one (provision of reserves open to new actors). Costs and risks could be better managed if this process is anticipated and well managed. We think it is necessary forTSOs to initiate this shift long before their backs are against the walldue to a serious lack of available flexibility. It would be beneficial to open serviceprovision gradually in order to accompany the deployment of new technologies (distributed generation, demand response, EVs…).

As we will see in the following sections, the four countries of our study have begunthis shiftbut are at different steps in the process and maytake different directions.

IV. SURVEY OFEUROPEAN RESERVE MARKETSFACING FLEXIBILITY ISSUES

We will now describe four market-designs for primary and secondary reserves in France, Germany, Denmark, and the UnitedKingdom. These countries were chosen due to their diversity in terms of generationmix and market design. Table 3 providessome key characteristics regarding penetration of intermittent RES, flexibility needs, and future objectives of wind penetration. According to the EWEA central scenario(European Wind Energy Association, 2015), the share of intermittent RES should increase significantly in every country of our study, which implies there will be an increasing need for reserves to be efficiently managed.

A. *France*

Rules are issued by RTE (Réseau de Transport d'Electricité) and are described in(Réseau de Transport d'Electricité, 2016). Historically the procurement scheme is based on mandatory provision by large producers and pro-rated to their production. Each dayRTE informs each producer the reserve theymust provide to the system for the next daywith a 30-minute time-step based on individual generation schedules. The minimum capacityan aggregation of production units must be able to deliver is 1 MW with symmetrical bids and the system is the same for primary and secondary reserves. The regulator sets allowableremuneration with a fixed and annually regulated tariff. There is remuneration for capacity (18.2€/MW/h.) and for energy (10.54€/MWh, payment to the provider if regulation is upward, payment to the TSO if regulation is downward).However, rules have evolved in the last two years to allow new participants (consumers connected to the distribution network and storage units) to deliver primary and secondary reserves.These units are not subject to mandatory provision and they can provide asymmetrical products, but the minimum amount of reserve they must provide is still 1 MW. They provide RTE a program each day of the reserves they will deliver for the next day with a 30-minutetime-step. They are remunerated at the same regulated tariff as producers entitled to mandatory provision. There is however a limitation of the total amount these units can provide to the system which has been set to 40 MW for 2016. The selection of this volume is made with a "*First Come, First Served*" rule. This rule is inefficient, since providers are not selected based on their operating costs, contrary to a market solution where providers have an incentive to reveal their costs.It should be notedthat most of these rules are transitoryand could/should evolve in the coming years, creating uncertainty about the possible evolution of the market design.

As a conclusion, Table 4 provides an assessment of these different rules regarding provision of FRR by DERs. The opening of the market is still limited by administrative rules and is in a testing phase. There is currently no information available about the level of reserves actually provided by RES. The results of this testing phase and the orientation that will follow will allow us to have a better assessment of this market opening. Remuneration is the main issue in France as a regulated tariff is still used. We cannot assess what is the impact of this tariff (if it is at a low or high level compared to the costs of provision by DERs?). There is high uncertainty about the viability of this tariff as the French regulator has regularly called for the implementation of a market-based procurement (Commission de Régulation de l'Energie, 2015)(Commission de Régulation de l'Energie, 2014).

TABLE 4:ASSESSMENT OF THE PARAMETERS OF THE SURVEY IN FRANCE

	R1	*R2*
A1	-/+	-/+
A2	+	+
A3	+	+
B1	+	+
B2	+	+
B3	+	+
B4	+	+
C1	-	-
C2	-	-

B. *Germany*

Auctions in Germany are held on a common platform (www.regelleistung.net) for the four TSOs(Consentec, 2014). Switzerland, Austria, Netherlands and Belgium joined this platform and are procuring part of their reserve jointly. Auction rules were revised in 2011by the Federal Network Agency, to allow for an increased participation of small electricity producers such as RES in addition to demand side management aggregators and storage systems(Federal Network Agency, 2011)(Koliou, et al., 2014). To facilitate market entry by DERs further, another revision of rules for secondary and tertiary reserve is currently underwayas of 2015/2016 (Federal Network Agency, 2015)(Federal Ministry of Economic Affaire and Energy, 2015).

Both for primary and secondary reserve, there is no technical discrimination.

For primary reserve, a call for tenders is organized on a weekly basis. The minimum bid is 1 MW and the products are symmetrical. However, it is possible to aggregate plants that can only contribute positive or negative reserve in a pooled bid(Federal Network Agency, 2011). The bidder must provide reserves for an entire week. In order to better allow small reserve providers to comply with the time requirement, it is possible to contract prequalified third parties to provide collateralization.

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

For secondary reserves, products are asymmetrical. A call for tenders is currently organized on a weekly basis. A change to daily auctions however, is being considered to facilitate bids by distributedflexibility resources including intermittent RES (Federal Network Agency, 2015). Also, a shortening of product duration is being discussed. Currently, bidders can propose reserve for peak periods (working days, 8:00 am to 8:00 pm) or off-peak periods (the rest of the time). Under the new regime, they would bid for six time slots of four hours each on the day following the auction. The minimum bid of 5 MW will remainbut the revised rules propose to allow bids of 1 MW, 2 MW, 3 MW, and 4 MW so long as bidders only make one bid per secondary reserve product within the balancing zone. This is to give small generators or aggregators of small-scale flexibility resources another participation option besides pooling (Federal Network Agency, 2015).

Secondary reserve remuneration is pay-as-bid. Bids are selected based on capacity prices, but remuneration is offered both for capacityand energy if a reserve is activated. A change to uniform pricing (with bids based on energy prices) is being discussed, but viewed critically by the Federal Network Agency. Under the current system, successful bids with low capacity prices and high energy prices are common. Since reserve scheduling follows a merit order based on reserves' energy prices, consequences for total reserve provision costs are limited. With a uniform pricing rule, all utilized reserves would be remunerated at the energy price of the last successful bid in the market, which could lead to significant cost increases (Federal Network Agency, 2015).Table 5 shows average remuneration for provision of secondary reserves.

TABLE 5: AVERAGE REMUNERATION FOR SECONDARY RESERVES IN GERMANY IN 2015(€/MW/H)

	Off-peak	*Peak*
Upward	5,67	6,12
Downward	2,97	2,21

[1]Data: www.regelleistung.net

The German market design does not have any administrative barriers to entry but still has major issues concerning technical optimization, especially with provision of primary reserves, as can be seen in Table 6.

TABLE 6:ASSESSMENT OF THE PARAMETERS OF THE SURVEY FOR GERMANY

	R1	*R2*
A1	+	+
A2	+	+
A3	+	+
B1	+	-/+
B2	-	+
B3	-/+	+
B4	-	+
C1	-/+	-/+
C2	-	-

C. *United-Kingdom*

The main procurement scheme used by National Grid for reserves is mandatory provision by large producers(National Grid, 2015d).However, a complementary scheme, Firm Frequency Regulation (FFR) has been implemented to allow other participants to enter the market(National Grid, 2015b). The participants can, each month, make a bid to provide different services (based on response lag and duration of utilization). The bid can be made for one or several months at a time and can schedulereserve provision for only part of the day (only one window is authorized), which can be different for weekdays, Saturdays, and Sundays. However, it is not possible tochangethe amount of reserve provided during the day or during the month.

All products are asymmetrical with a minimum bid of10 MW.The selection criterion of reserve on this complementary scheme isbased on the total cost of provision for National Grid.To be selected, the provision of reserve with FFR must be cheaper than mandatory provision. However, given the number of parameters included in a bid (number of months and period of the day during which the reserve is provided, price and volume for differentiated services), the selection criteria is not transparent. (Rebours, 2009)and(Chao & Wilson, 2002) have shown that even two-part multi-dimensional procurement is complicated and in the current bid scheme there are more than 20 parameters present.

In order to allow aggregators with lower volume than 10 MW to participate, NG has implemented the FFR bridging contract(National Grid, 2015c). This contract lasts one or two years, and remuneration is regulated and increases as more MWs are aggregated. The payment rates are not public.

Besides this complementary scheme, NG is now implementing a new scheme to procure ultra-fast reserve, which would be ideal for DERs such as EVs(National Grid, 2015a). The implementation however is still in progress and there is not enough information yet to assess the efficiency of this scheme.

The conclusions of this case are presented in Table 7. NG is implementing new schemes but the products that can be sold in these schemes do not correspond to what DERs could provide (e.g., full provision during one or two years for FFR Bridging Contract). This gives mixed signals about the willingness to open the market to DERs. We think NG should work on a unified market-design for all actors.However, the implementation of a scheme to remunerate very fast reserves is positive. The return on experience that NG will receivewith this implementationcould be useful for other countries.The UK synchronous area is rather small compared to the Continental Europe synchronous area and is therefore more exposed to flexibility issues.

TABLE 7: ASSESSMENT OF THE PARAMETERS OF THE SURVEY IN UNITED-KINGDOM

	R1	*R2*
A1	-/+	-/+
A2	+	+
A3	+	+
B1	-	-
B2	-	-
B3	-	-
B4	+	+
C1	-/+	-/+
C2	+	+

D. *Denmark – DK1*

In Denmark, rules are issued by the Danish TSO Energinet.dk(Energinet.dk, 2012). There are two control areas in Denmark (Western Denmark, DK1, and Eastern Denmark, DK2) and procurement of reserve is differentiated between these two zones. We will focus for our study on the DK1 zoneas the DK2 zone is connected to the Nordic Synchronous Area where the procurement scheme is different(Ekman & Jensen, 2010).

In DK1, Primary and secondary reserves can be provided by both production and consumption units.For primary reserve, the provision of reserve is made through a daily auction. Bids can be submitted for the next day for a period of 4 hours. The minimum bid is 300kW and the bids can be made for upward or downward regulation. Remuneration is based on uniform pricing: each accepted bidder is remunerated at the price of the highest bid (one price for upward and one price for downward reserves). Energinet.dk procures on average 25 MW where 10 MW isprovided by long-term contracts. Average payments for upward and downward reserves are presented in the Table 8.

Secondary reserve is procuredon a monthly basis. The products are symmetrical and remuneration is based on pay-as-bid scheme. However, Energinet.dk has a long-term contract until 2020 withthe Swedish interconnection for the provision of secondary reserve, so the procurement scheme will only be used if the interconnection is out of service or insufficient.

TABLE 8: AVERAGE REMUNERATION OF PRIMARY RESERVE IN DENMARK DK1 IN 2015 (€/MW/H)

	Upward Reserve	*Downward Reserve*
00:00 – 04:00	8,92	2,35
04:00 – 08:00	11,94	2,09
08:00 – 12:00	16,90	1,12
12:00 – 16:00	15,64	1,05
16:00 – 20:00	15,94	1,15
20:00 – 24:00	13,04	1,17

Data: http://energinet.dk/EN/El/Engrosmarked/Udtraek-af-markedsdata/Sider/default.aspx

Denmark is paving the way in Europe for the opening of FRR markets to aggregators, especially for primary reserve. The return on experience of this process for primary reserves could be useful for other countriesshould now be extended to secondary reserves as well.

TABLE 9: ASSESSMENT OF THE PARAMETERS OF THE SURVEY FOR DENMARK-DK1

	Denmark - DK1 R1	Denmark - DK1 R2
A1	+	-
A2	+	N/A
A3	+	N/A
B1	+	N/A
B2	+	N/A
B3	+	N/A
B4	+	N/A
C1	+	N/A
C2	-	N/A

The average annual cost for the four countries of our study is given in Table 10. It can be seen that different services (Primary/Secondary reserves, upward/downward reserves) can have very different economic values and that it makes sense to differentiate them in order to have a clear price signal for different services.

TABLE 10: ANNUAL REMUNERATION OF FRR IN 2015 (€/MW)

	Primary Upward Reserve	*Primary Downward Reserve*	*Secondary Upward Reserve*	*Secondary Downward Reserve*
France[1]	80 200	80 200	80 200	80 200
Germany[2]	97 200	97 200	51 100	23 600
DK1[3]	91 000	30 400	31 500	31 500
UK[4,5]	35 190	N/A	23 300	63 700

[1]Data: www.clients.rte-france.com
[2]Data: www.regelleistung.net
[3]Data: http://energinet.dk/
[4]Data: www.nationalgrid.com
[5]Data only available for mandatory provision

V. IDENTIFICATION OF BARRIERS TO ENTRY AND OPTIONS FOR THEIR RESOLUTION

Table 11and Table 12 provide a summary of the assessment of the different parameters of this study. In each of the assessed market designs, there are some barriers to market entry for DERs. To facilitate market entry, the case studies suggest that a combination of different rules would be beneficial, as presented in Table 14. However, it should be noted that countries are currently in a transition phase and that rules will evolve in the coming years in order to comply with the European Network Codes.Table 13provides a summary of existing barriers in the four countries and the possible options for their resolution.

TABLE 11: ASSESSMENT OF THE DIFFERENT PARAMETERS OF THE SURVEY FOR PRIMARY RESERVE

	France	*Germany*	*UK*	*Denmark - DK1*
A1	-/+	+	-/+	+
A2	+	+	+	+
A3	+	+	+	+
B1	+	+	-	+
B2	+	-	-	+
B3	+	-/+	-	+
B4	+	-	+	+
C1	-	-/+	-/+	+
C2	-	-	+	-

TABLE 12: ASSESSMENT OF THE DIFFERENT PARAMETERS OF THE SURVEY FOR SECONDARY RESERVE

	France	*Germany*	*UK*	*Denmark - DK1*
A1	-/+	+	-/+	-
A2	+	+	+	N/A
A3	+	+	+	N/A
B1	+	-/+	-	N/A
B2	+	+	-	N/A
B3	+	+	-	N/A
B4	+	+	+	N/A
C1	-	-/+	-/+	N/A
C2	-	-	+	N/A

TABLE 13:BARRIERS TO ENTRY AND OPTIONS FOR THEIR RESOLUTION

	Type of issues	
Module	Barriers to entry in the market	Options for resolution
Mod. A	**France**: limitation of volume provided by DERs, uncertainty about the evolution of the rules, mandatory provision for large producers **Denmark**: long term contract **UK**: mandatory provision for large producers. Too many different schemes with inappropriate rules	**Germany/Denmark(R1)**: no specification of any technical discrimination, all the providers are on the same playing field **All**: interoperability among DSOs and telemetry
	Barriers to technological optimization	Options for resolution
Mod. B	**Germany:** High minimum bid size for R2. Week-long product for R1, without variability of volume. Symmetrical product for R1. **UK:** minimum bid onFFR scheme of 10 MW. Minimum time of one month, without variability from one day to another	**France:** Implementation of asymmetrical products. Time definition of 30 min., program of provision given on day-head market. Minimum bid of 1 MW **Denmark (R1):** minimum bid of 0,3 MW, asymmetrical product, blocks of four hours of delivery, daily auction
	Barriers to fair remuneration	Options for resolution
Mod. C	**France:** regulated tariff,no bonus for extra-flexibility **Germany:** pay-as-bid, no bonus for extra-flexibility	**UK:** creation of a scheme to remunerate extra-flexibility **Denmark:**uniformpricingremuneration

This analysis shows that there is currently no major issue in module A(except long-term contracts for secondary reserve in Denmark), i.e. rules that would simply disqualify aggregators. DER can participate inthe provision of reserve in all four markets. There are minor issues, however, in France and in the UKdue to the fact that there is still a scheme to mandate provision by large producers. We think that the existenceof conflicting schemes in the

UK andin France gives a mixed signal for the participation of new actors: are these schemes permanent or transitory? How will the rules evolve in the future? This evolution seems to be positive (participation of DERs was forbidden in France until 2013).However, rules should not be subject to endless revision and complication.

In module B, rules should evolve to allow actors to provide more flexible products: reduction of the minimum bid, flexibility in the definition of the period of delivery, auctions held on a daily basis, possibility of delivering asymmetrical products. However, TSOs might be reluctant to adapt these rules because they may fear to have insufficient reserves which would affect the security of the system.

Paradoxically, the country of our assessmentwhere the definition of products for DERs is the most flexible is France which may be due to the fact that since provision of reserve is mandatory for large producers, RTE does not fear insufficient capacity and allows other providers to be very flexible. Another possible explanation could lie in the size of the nuclear fleet and its low capabilities of being technically flexible. However, the Danish case shows us that it is possible to have a very flexible scheme using a market solution.

In module C, major issues are:

- The regulated tariff in France, which does not allow DERs to compete withother types of more expensive providers (which is highly linked tothe mandatory provision oflarge producers)
- No scheme to remunerate the extra-flexibilityin most countries. The lessons from UK's new scheme will be very important regarding that issue.

Concerning pay-as-bid remuneration, further research is necessary to determine whetherit should be replaced by uniform price remuneration. Uniformpricinggives incentives for providers to bid their marginal cost while the complexity of making bids is reduced which may be an important factor to increase participation by small reserve providers. However, uniformpricing is more sensitive to strategic gaming such as capacity retention. Therefore, a closer examination is necessary which of the two pricing rules is likely to lead to a lower cost of reserve provision.

TABLE 14: COMBINATION OF MOST FAVORABLEOPTIONS FOR DERS OBSERVED IN THE CASE STUDIES

Parameter	*Best Option*
A1	No discrimination ofDERs
A2	Interoperability among DSOs
A3	Telemetry
B1	300 kW
B2	30 min
B3	Day-Ahead
B4	Asymmetrical
C1	Pay-as-cleared
C2	Implementation of a new scheme to remunerate extra-flexibility

VI. CONCLUSION

An increasing share of renewables impliesan increasing need of reserves. In order to procure reserves at the least possible cost, there is a need to implement a well-functioning market design. We have developed in this paper a modular framework that can be used to analyze different marketdesigns and different barriers for provision of reserves by DERs. This framework can also be used to analyze the evolution of marketdesigns, which could be useful in a context where rules are changing constantlydue to the will of the European Union to harmonize markets. There is currently no marketdesign that would be optimal for the participation of DERs in the countries of our study. Based on the case study analysis of four

European reserve markets, this work has identified a combination of rules which facilitates reserve provision by DERs.Should regulators wish to open reserve markets to DER, a convergence of market rules towards such a combination would be recommended.

Opening FRR provision to DERs is not without cost for the TSOs. Learning costs as TSOs will have to implement new procedures to exchange information with different actors, and transaction costs are present. These costs should be assessed, in order to balance them with the potential benefits. However, given the increasing share of intermittent renewables, TSOs,regulators,and governments should anticipate these flexibility issues and explore options for opening markets to new participants, in order to ensure an adequate testing phase and manage the transition smoothlybefore being forced against the wall.

We believe that opening the market to new actors such as aggregators should not mean introducinggreat complexity tothe market-designs, as is currently the case in France or in the UK. Exceptions to the rules or complementary schemes targeting DERs especially can be created in order to foster investments, but in the end a unified market-design should be implemented to procure reserves at the least possible cost.

As DERs can provide very flexible products to the market, which are above currentstandards, a scheme should be created to remunerate extra-flexibility if flexibility issues are identified.The UK is currently a forerunner in implementing this type of scheme.

Finally, we have not identified a country where there is already a large share of reserves provided by DERs. However, some projects are promisingsuch as Nikola project (Nikola Project, 2015) in Denmark, to test the provision of primary reserve by electric vehicles.

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